Bidding Zone Review

Bidding Zone Review Region (BZRR)

Nordics

Background

This document provides additional information to what is provided in the overview Annex 2 Excel file which satisfies the requirements of Article 16.1 of the ACER Decision of 24 November 2020 on the Methodology and assumptions (hereafter the “BZR Methodology”) that are to be used in the bidding zone review process in accordance with Article 14(5) of the Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity. As per Article 16.2, the list of the minimum set of data to be published is outlined in Annex Ia of the BZR Methodology. The structure and contents follow from Part A of Annex Ia (e.g. Chapter 1 – Scenario, Chapter 2 – Generation etc.). For some items the input values are provided by the Excel files per bidding zone published at ENTSO-E's website for the BZ Study. For these sections, the link to find referenced data is given.

Following the original publication of this document on the 21st of December 2022, revisions have been done during the course of the BZ Study to reflect the latest information as well as updates and improvements done. The most important updates to the document are listed here:

- Update on sensitivities (chapter 1.2)
- Update on which FRM value used (chapter 5.3)
- Updated text on corrections done in the BZ Study with reference to the LMP-study (various chapters)
- Additional details regarding the modelling chain and simulations (chapter 6.1)
- Table added listing the changes done in the BZ Study with reference to the LMP-study (chapter 6.2)

2024-12-06

Contents

1 Scenario

1)Scenario

1.1 List of all climate years used as a basis for the study.

For the BZ Study the same climate years as for the LMP-study was used; 1989, 1995 and 2009. These years do not represent the full spread of variability for the Nordic system, but the advantage of using the same climate years for all BZR regions was considered more important and is also a requirement of the BZR Methodology. For more information regarding the selection of climate years, please see chapter 1.2, chapter 3.11 and Annex 1 of the LMP-study: ENTSO-E report on the Locational Marginal Pricing study of the Bidding Zone Review Process.

1.2 Description of the sensitivities used to complement the scenario of the 'main study'.

For the Nordics, originally the sensitivity study was planned for the same target year as the main study (2025), analysing the consequences of increasing the fuel and CO2 prices and excluding the fixed flows from Russia that are included in the main study. Furthermore, a sensitivity using a dry year e.g., a climate year with low hydrological inflows, was planned as the hydro power production has large impact on the Nordic power system.

Although, as the sensitivities are only required for any assessed configuration that results in higher economic efficiency in the main study compared to the status quo with regards to criterion 4 in the BZR Methodology, no such analysis was eventually conducted.

1.3 Network model for the scenario and sensitivities

The network model used for this study is the common Nordic planning model in PSSE which were also used for the LMP-study. PSSE is a power system model for power flow calculations and dynamic simulations used by all Nordic TSOs. The model includes the transmission grid for all the Nordic countries from 420 kV to 50 kV, as well as interconnectors to countries outside the region. The Nordic planning model represents the current power system in the region. For prospective studies, relevant changes were made to the grid, generation and consumption to reflect the future power system. The model was updated to reflect the Nordic power system in mid-2025. The study was performed for an intact grid adding N-1 restrictions. The network model was converted to the market model BID3 which was used for simulations in this study as well as for the LMP-study. The BID3 model uses three different levels of details for the grid model which are further described in chapter 6.1 alongside more detail information about the modelling chain.

The same network model was planned to be used for the sensitivities as for the main scenario.

The datasets regarding Nordic grid data (CGMs and CNECs) are confidential with very high protection value and cannot be published nor shared in public. As in the Nordics there is a common grid model, it only makes sense to publish the grid data of all Nordic countries. If one country's legislation does not allow the publication of grid data, there is limited value in publishing only the grid data of some countries.

1.4 List of additional infrastructure projects for the target year compared to the year when the BZ Study started.

Nordic TSOs have identified projects that are expected to be commissioned between 2020-11-01 and 2025-06-30 and therefore are included in the grid model used for simulations. The assumptions are kept the same as in the LMP-study. The table only include investments in Sweden, Finland and Denmark. System reinforcements/new connections are included in Table 1 and changes in production plants in Table 2.

System reinforcements/new connections	Area
220kV from Oulujoki area removed (Utanen, Nuojuankangas). In Nuojuankangas 220kV line bypass the substation. (Only Pyhänselkä-Seitenoikea remains as before)	FI
Current 400kV line Toivila-Vihtavuori bypassing Petäjävesi substation is connected to the substation forming two circuits: one is Petäjävesi-Toivila and the other one is Petäjävesi-Vihtavuori.	FI
New 400kV substations and lines to Forest line (new substations: Pyhänselkä-Pihlajaranta-Haapavesi-Pysäysperä-Hoikansalmi-Petäjävesi)	FI
Substation extension, Jylkkä 400/110 kV	FI
New substation, Kärppiö 400/110 kV	FI
New 400kV Substations and lines between them (Pyhänselkä - Isomaa - Simojoki - Viitajärvi)	FI
New AC line, Långbjörn-Storfinnforsen, 400 kV	SE2
New substation, Norrtjärn, 400/130 kV	SE2
New substation, Olingan, 400 kV	SE2
New substation, Torpberget, 400 kV	SE2
New substation, Tovåsen, 400 KV	SE2
Reinvestments, Storfinnforsen-Midskog, 400 kV	SE2
New substation, Gäddtjärn 400 kV	SE2
High temperature lines, Valbo-Untra	SE3
New AC line Lindbacka-Östansjö, 400 kV (partly replacing 220 kV lines)	SE3
Decomissioning of 220 kV grid Hallsberg area	SE3
New AC line, Anneberg - Skanstull, 400 kV	SE3
New AC line, Ekhyddan-Nybro, 400 kV	SE3
New AC line, Snösätra-Ekudden, 400 kV	SE3
New AC line, Örby-Snösätra, 400 kV	SE3
New substation in Skanstull	SE3
New substation in Snösätra	SE3
Upgrade substation, Hall	SE3
Connection of 400 kV grid to Tuna substation	SE3
North-south reinforcement (Himmeta-Karlslund upgraded to 400 kV)	SE3
New HVDC line, Barkeryd-Hurva (Sydvästlänken)	SE3-SE4
Reivestment, Huva-Sege, 400 kV	SE4
New substation, Hageskruv	SE4

Table 1: Additional infrastructure projects included in the model that are expected to be commissioned between 2020-11-01 and 2025-06-30 included in the study.

Procution plant	Area	Capacity (MW)
Decomissioning of Ringhals 1	SE3	881
Olkiluloto	FI	1600
New wind power	SE1	1000
New wind power	SE2	2200
New wind power	SE3	500
New wind power	SE4	300
New wind power	FI	5195
New CHP plant (Kemi new bio industrial site)	FI	250
Expected decommissioning of coal units due fossil phase out (aggregated)	FI	390

Table 2: Additional production capacity that are expected to be commissioned between 2020-11-01 and 2025-06-30 included in the study.

In the Finnish grid some small improvements are expected due to changes of cross-over line configurations, which should provide more capacity for 2025. These are not captured in the network model used in the BZ Study. As no major structural congestion was identified in Finland in the LMP-simulations it was assumed that that these changes would not have a significant effect on the BZ Study and thus the network model was not changed.

1.5 Assumptions on how different voltage levels were considered or not, per bidding zone.

There are operational security limits and contingencies at voltage levels below 380 kV that are important for secure operation of the power system. Therefore, the Nordic TSOs have chosen to include also 220 kV network elements in the analysis. However, in the LMP-study 220 kV grid was not monitored (i.e., set to very high Fmax) except for CNECs, meaning overloads in the Swedish 220 kV grid were generally not considered. In reality the 220 kV grid is seldom overloaded, so this was a fair assumption. In BZ Study all 220 kV lines are monitored, according to number 3 in Table 5. For information how voltage levels are considered in general in the model, please see also Chapter 1.3.

2) Generation

2.1 Generation time series for weather dependent generation units

Input for hydro, solar and wind power can be found from the input files published for the BZ Study. Please see Input data per BZ from BZR site: *Nordic_input_data*. For solar and wind power the granularity of data is per MTU, per technology and per climate year. Hydro power values are given as weekly inflows.

With regards to the LMP-study onshore wind power production have been updated in SE1, NO1, NO2, NO3 and NO4 for the BZ Study. See number 6 and 14 in Table 5. In addition, hydro power capacity in Sweden have been updated in the BZ Study according to number 4 and 5 in Table 5.

2.2 Minimum and maximum generating capacities

Maximum generating capacities are given in the input files published for the BZ Study. The minimum generating capacities are provided as minimum stable power for thermal plants. Please see Input data per BZ from BZR site: *Nordic_input_data*. Granularity of data is per technology.

2.3 Must run constraints

Must run constraints are provided for thermal plants in the input files published for the BZ Study. Please see Input data per BZ from BZR site: *Nordic_input_data*. Granularity of data is per technology.

Unlike the set-up in the LMP-study, Nordic nuclear power plants are modelled as must run in the BZ Study, see number 9 in Table 5.

2.4 Ramping capabilities

For thermal plants (except for nuclear power plants), the ramping is assumed to be 100% percent i.e., a thermal plant can technically ramp from being off to running at full power in one hour.

In the BZ Study nuclear power plants are modelled as must run i.e., not allowed to change production between hours (if not taken out on maintenance). In the LMP-study however, nuclear power was allowed to ramp unrestricted (see number 9 in Table 5).

2.5 Minimum run time

Min time on and min time off are provided for thermal plants in the input files published for the BZ Study. Please see Input data per BZ from BZR site: *Nordic_input_data*. Granularity of data is per technology.

2.6 Start-up and shut-down times

For the start-up and shut-down times we are following the simplification provided by article 9.8.b, the total off time of the plant between shutting down and starting up is provided as the min off time in the excels. Please see Input data per BZ from BZR site: *Nordic_input_data*..

2.7 Start-up costs

Warm start costs are provided in the input files published for the BZ Study. Please see Input data per BZ from BZR site: [Nordic_input_data](). Granularity of data is per technology.

2.8 Breakdown of short-run marginal costs used for market dispatch

In

Table 3 main fuel costs and CO2 costs are presented. Used variable operation and maintenance costs are presented in Table 4.

Fuel/Commodity	**Main scenario (€/MWh)**	**Main scenario (€/GJ)**	**Sensitivity analysis (€/MWh)**	**Sensitivity analysis (€/MWh)**
Nuclear	1,69	0,47	1,69	0,47
Lignite	3,2	0,89	6,48	1,8
Hard Coal	9,59	2,66	10,87	3,02
Gas	25,61	7,12	44,99	12,5
Light Oil	47,63	13,23	69,28	19,25
Heavy Oil	31,15	8,66	56,83	15,79
Oil Shale	8,28	2,3	6,26	1,74
CO2 price				
CO2	27,04			103,5

Table 3: Fuel and CO2 prices assumed in the LMP-study as well as in the BZ Study.

Fuel	Type	Variable O&M cost €/MWh
Nuclear	-	9
Hard coal	old 1	3,3
Hard coal	old 2	3,3
Hard coal	new	3,3
Hard coal	CCS	6,6
Lignite	old 1	3,3
Lignite	old 2	3,3
Lignite	new	3,3
Lignite	CCS	6,6
Gas	conventional old 1	1,1
Gas	conventional old 2	1,1
Gas	CCGT old 1	1,6
Gas	CCGT old 2	1,6
Gas	CCGT present 1	1,6
Gas	CCGT present 2	1,6
Gas	CCGT new	1,6
Gas	CCGT CCS	3,2
Gas	OCGT old	1,6
Gas	OCGT new	1,6
Light oil	-	1,1
Heavy oil	old 1	3,3
Heavy oil	old 2	3,3
Oil shale	old	3,3
Oil shale	new	3,3

Table 4: Variable O&M cost assumed in the LMP-study as well as in the BZ Study.

The reported fuel and CO2 prices in the LMP-study (taken from the Mid-term Adequacy forecast data collection for 2020) and the ones actually used in the LMP-simulations (presented in this document) were not the same. Although the difference is small. The modelled fuel and CO2 prices in the LMP-study are also used in the BZ Study. This means that the fuel prices used in the BZ Study for Central Europe are different from the ones used in the Nordics.

2.9 Additional costs used for the redispatching mechanism including specific opportunity costs, readiness costs and any other cost related to the participation to redispatching

Nordic are using the same costs as Central Europe BZR region, for the values, please see the document published by Central Europe TSOs.

In the Nordic context the redispatch is currently done rarely and in general the main source for redispatch is through the balancing market such, that in case of simultaneous balancing and redispatch needs, the more expensive bids activated are allocated to redispatch.

Nordics do not have data, which would enable calculating the mark-up cost according to Art 9.4 and 9.5, as the bids TSOs receive from BRPs are assumed to include also profit, and the price of bids used for the redispatch are also affected by the instant balancing situation. Please see more information: https://www.fingrid.fi/globalassets/dokumentit/fi/sahkomarkkinat/kehityshankkeet/balancing-philosophy-updated-211110.pdf (Page 14, Use of mFRR bids for special regulation).

Due lack of the reliable data, Nordics have decided to use the same mark-up values as the BZR region Central Europe use for different technologies. This is assumed to provide good assumption. However, it should be noted, that all technologies (for example Nuclear) listed are not assumed to take part to redispatch i the Nordic BZ Study.

3) Load

3.1 Load time series

The demand time series used as input can be found from the input files published for the BZ Study. Please see Input data per BZ from BZR site: *Nordic_input_data*.

3.2 Day-ahead demand elasticity

The demand elasticity in day-ahead timeframe is modelled with decreasing percentage with each price threshold step, steps are modelled separately for general and industrial demand. The used threshold and percentage values are provided in the input files published for the BZ Study. Please see Input data per BZ from BZR site: *Nordic_input_data*.

3.3 DSR: Maximum power [MW] which may respond

As in the modelling the respond is given as percentage relative to hourly demand, the maximum power is dependent on the peak demand. No limitation was set.

3.4 DSR: Minimum price [€/MWh] at which the response is triggered

Price thresholds are provided in the input files published for the BZ Study. Please see Input data per BZ from BZR site: *Nordic_input_data*.

3.5 DSR: Maximum activation duration [h]

No maximum activation duration is set.

3.6 DSR: Maximum activated energy per day [MWh]

No limit for activated energy per day is set.

3.7 DSR: Average amount of DSR [MW] available for the market dispatch

The amount is dependent by the maximum peak by the percentage given in the table in the input files published for the BZ Study. Please see input data from site: Please see Input data per BZ from BZR site: *Nordic_input_data*.

3.8 DSR: Average amount of explicit DSR [MW] not available for redispatching after considering market dispatch and technical constraints

All DSR is assumed to be allocated to the market dispatch. For Nordics DSR can also take part to redispatch and provide bids to mFRR market after day-ahead timeframe. However, the model is not taking into account in chain what is left for DSR after the market dispatch, so for simplification we have assumed all DSR to be available only for market dispatch.

3.9 Average amount of DSR [MW] available for neither of them

All DSR available is assumed to be allocated to the market dispatch.

4) Reserves

For the Nordics, the reserve modelling is taken into account the Frequency Containment reserve (FCR) and Frequency Restoration Reserve (FRR) products. Replacement Reserve (RR) is not currently in use. The reserves are taken into account in the model by holding constant the generation capacity that is assumed to be contributing to reserves and is thus not available for the day-ahead market dispatch.

In the modelling, the reserve holding is not allocated to specific plants. Instead, the model is given the reserve needed to co-optimise the holding for plants that is available alongside the main dispatch.

Currently, the reserve requirement is fulfilled in some Nordic countries with capacity that is not normally available for the day-ahead market dispatch. The corresponding reserve capacity is not included in the reserve holding requirement in the model; the plants not available for the day-ahead market are also not included in the model. In addition, part of the capacity fulfilling the reserve requirements is assumed to be procured from consumption. This demand contribution is not explicitly modelled, as it is assumed to have only little effect on the day-ahead dispatch. Also, the downward reserve requirements are not currently taken into account in the modelling, as its effect on the day-ahead dispatch is not assumed to be significant.

The used FCR and FRR values in the modelling are provided in the published input files for the BZ Study, the straight link is provided in Nordic overview Excel. It should be noted that the division of values between the bidding zones are based on the assumption done in Pan European Market Model Database. The division will be further assumed for the new bidding zone configurations.

4.1 FCR requirement [MW]

Information of values is provided in the published input files for BZ Study. Please see Input data per BZ from BZR site: *Nordic_input_data*.

4.2 FRR requirement [MW]

Information of values is provided in the published input files for BZ Study. Please see Input data per BZ from BZR site: *Nordic_input_data*.

4.3 RR requirement [MW]

No RR was considered for the Nordics in the study.

5)Capacity Calculation

5.1 Capacity calculation method per border

FB modelling was carried out within the Nordic CCR and cross-border capacities between other BZs were approximated by the NTC approach. HVDC links in the Nordic system were handled with the advanced hybrid coupling approach in FB modelling.

5.2 List of action plans and derogations for the target year considered pursuant to IEM regulation

There are no action plans assumed to take place in 2025 in the Nordics and thus none is applied in modelling.

5.3 Average FRM over all CNECs, per BZ

A fixed FRM of 10% of the Fmax is assumed for all CNECs.

5.4 PTDF threshold used by each TSO and, if different from default value, why the adopted threshold better reflects an economic efficiency analysis.

In the modelling a PTDF (Power Transfer Distribution Factor) threshold of 10% is assumed for all TSOs/zones, as per methodology Art. 6.8.

5.5 Allocation constraint per border/BZ.

Implicit losses are applied in the modelling for those HVDC where allocation constraint of implicit losses is in use.

In the LMP-study, the HVDC interconnector ramping was assumed to be 100%. For the BZ Study, this has been changed to being the same ramping constraints as the ones used in the Nordics during the start of this study. For the interconnectors to continental Europe and Great Britain, the HVDC ramping is set to 600 MW/h. No restriction was set for the internal HVDC links within the Nordics CCR (number 12 in Table 5).

For Finland combined dynamic constraints for Central-Finland cross-section and Oulujoki cross-section are used.

6) Miscellaneous

6.1 List and brief description of the main characteristics of the modelling tools used for the analysis

The capacity calculation, day-ahead dispatch, operational security analysis (OSA) and remedial action optimisation (RAO) were modelled using AFRY's BID3 power market model. BID3 is a unit commitment model which simulates hourly dispatch by minimising system cost (equivalent to maximising social welfare) using a rolling optimisation window and water values calculation. Simulations take a 'modular' structure, with individual 'modules' being run in sequence. The BZ Study required use of the Water Values module followed by the Dispatch module (capacity calculation and day-ahead dispatch) and the Redispatch module (remedial action optimisation). A simulation can be run for a number of future years, each in combination with a number of historical climate years which take into account variations in demand, renewable generation, hydro inflows and plant availability factors on an hourly basis. A rolling optimisation window ensures that inter-temporal constraints (e.g. thermal ramping or reservoir fill levels) are satisfied; additional discarded days are modelled at the end of each window to minimise the impact of edge effects. Grid modelling can be performed in the model on three different levels (DC OPF, FBMC or NTC) and detailed modelling of thermal, renewable, hydro and storage plants is performed on a purely deterministic basis. On the demand side, flexible demand (electric vehicles) and price threshold demand (DSR) can be modelled. Commodity prices are fixed exogenous inputs to the model.

Developments to the software were necessitated in order to satisfy the specific requirements of the BZ Study, in particular for (a) obtaining the flow-based parameters within the capacity calculation and (b) adaptation of the Redispatch module for grid-induced remedial actions.

Three levels of geographical granularity have been used in the simulation process.

- Node – the most granular level; within BID3 the nodal location of each asset is specified, and the configuration of nodes and transmission lines and transformers establishes the grid topology. The capacity calculation is carried out using the fundamental nodal inputs and the operational security analysis outputs are also provided on a nodal level.
- Hub – aggregations of nodes, designed to capture existing knowledge of the main transmission constraints. That is, all nodes were assigned to the electrically closest transmission hub (≥ 220 kV), and all the constraints within a transmission hub were relaxed. The full grid is still modelled, but internal constraints within each hub are disregarded. Lines crossing between hubs, regardless of voltage level, are considered and can be included in multi-line constraints. Within the modelling chain, hubs are used in the remedial action optimisation as they are expected to capture the main transmission bottlenecks while reducing optimisation time.
- Zone – the least granular level, on which the day-ahead market simulations are performed.

In the following chapters, more insight is provided regarding the modelling chain and assumptions made in the Nordic BZ Study.

6.1.1 Capacity Calculation

The capacity calculation determines cross zonal capacities for day-ahead exchanges on all bidding zone borders. In this study the Nordic CCR has been modelled in the day-ahead market dispatch with FB market coupling (FBMC). The principle behind FBMC is to maximise the efficiency of transmission utilisation by incorporating an approximation of the physical transmission grid constraints into the market optimisation.

Flow-based constraints

As they arise from the underlying physical power flows, FBMC constraints take the same structural form as the DC OPF constraints (see section Load flow calculations). In other words, the following relation holds for each constraint c:

$$[\text{market flow}]_c = \sum_z ([PTDF_Z]_{cz} \,.\, [zone\ balance]_z) \leq [RAM]_c$$

where $PTDF_Z$ is a matrix providing the linear relation between injections and flows, RAM is the limiting power flow on each grid element and the sum is over all zones z within the FB region.

The fact that the FB constraints are inherited from the fundamental nodal constraints implies that:

- $PTDF_Z$ is related to $PTDF_N$, the nodal PTDF which governs flows between all nodes in a full grid model.
- The set of FB constraints is a subset of the set of all AC grid elements (lines, transformers and simple contingencies).
- The RAM is related to the thermal limit of each transmission line.

All of these three items are calculated separately for each modelled hour.

While there is no first principles optimal mapping from the nodal to the zonal representation, the Nordic BZ Study has followed closely the BZR Methodology for the calculation of FB parameters. The methodology used is outlined in the following paragraphs.

An iterative approach was taken to defining the FB parameters, whereby for each week of the dispatch algorithm, two dispatch optimisations were run in succession. The following paragraphs describe the approach taken to calculating the FB parameters, followed by a description of the iterative process itself. A consequence of the approach is that the same simulation provided results for both the capacity calculation and the day-ahead market simulations.

Generation Shift Key

The linear relation between zonal power injections and flows, $PTDF_Z$, is obtained from the equivalent linear relation in the DC OPF for the nodal case, $PTDF_N$, through multiplication by a Generation Shift Key (GSK):

$$[PTDF_Z]_{lz} = \sum_n [PDTF_N]_{ln} \,.\, [GSK]_{nz}$$

The GSK is a weighting of the nodes within each bidding zone; the algorithm for determining the GSK is known as the GSK strategy. The choice of GSK strategy is important: the aim is typically to capture the (generation or demand) nodes within a zone which have the marginal change in injection. For the Nordic BZ Study the following GSK strategies were used:

1. Generation
2. Generation excluding wind and nuclear
3. Generation excluding wind and nuclear, plus demand
4. Demand

In Figure 1 an overview is presented of the GSK strategies used in the different bidding zones of the Nordic CCR. The same GSK strategies were chosen as in the external parallel run[1].

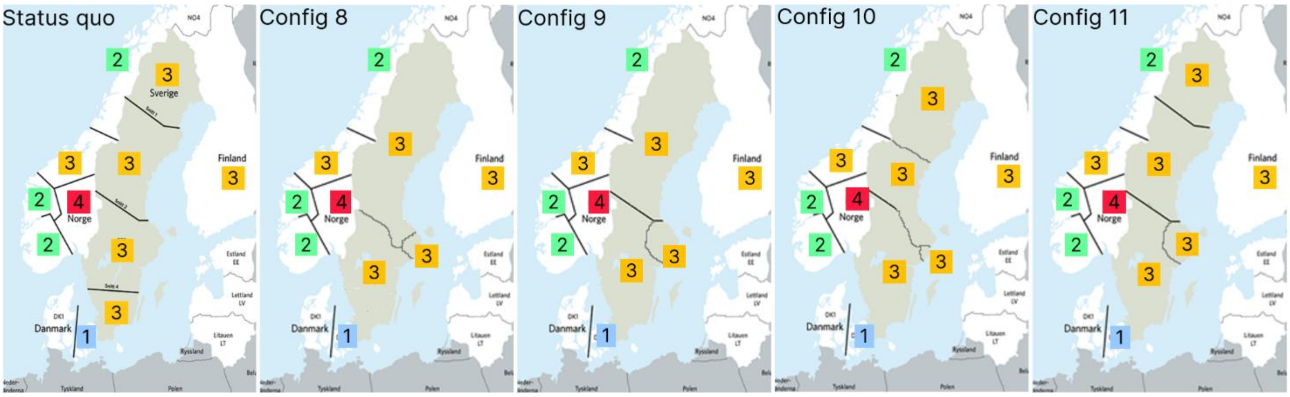

Figure 1: GSKs applied in the BZ Study for the Nordic BZs.

The use of actual generation and demand (as opposed to, say, available capacity) requires the use of an iterative approach. The choice of GSK strategy is taken as a model input, and has not been changed dynamically to, for example, maximise cross-zonal flows. A good choice of GSK strategy will capture the majority of the grid constraints relevant to cross-zonal exchanges and limit the subsequent requirement for remedial actions.

Identifying the constraints to apply to the day-ahead market simulations

The zonal PTDF is defined for all transmission lines. Nevertheless, only a subset of them is applied as constraints in day-ahead market simulation. Grid elements which satisfy either of the following two conditions were used to define individual FB constraints:

- Grid elements which connect two different zones.
- Grid elements which are important for cross-zonal transmission, but which do not directly cross a zone boundary. This is done by identifying those whose maximum absolute zone-to-zone PTDF is above a threshold of 10%. Only grid elements connecting two different hubs were assessed under this criterion. It is worth noting that the model therefore accounts for flows on some grid elements entirely within a bidding zone and that these may be binding despite the bidding zones being considered as copper plate for the purposes of price formation.

For a given grid element *l* and hour, the PTDF threshold comparison is done as follows:

1. Calculate $PTDF_Z$ using the latest available GSK.
2. For the row in $PTDF_Z$ corresponding to grid element l, compute the maximum difference between any two elements.
3. Compare the absolute value of this difference against the threshold. If the difference is above the threshold the grid element will have an associated constraint for that hour; otherwise, it will be ignored for the day-ahead market simulations.

An analogous algorithm is used to determine the contingencies represented by a FB constraint: the zonal PTDF for a contingency is assumed as a linear combination of the PTDF elements for lines and transformers, using the same coefficients that appeared in the multi-line constraint (see Section ‘Contingencies’).

Remaining Available Margin

Transmission flows in the day-ahead market are limited by the RAM. This quantity is calculated alongside the GSK as part of the iterative approach described in the following

[1] Simulation Results - Nordic Regional Coordination Centre (nordic-rcc.net)

paragraphs. The RAM of a given grid element is calculated from adjustments to its thermal limit F. The adjustments to F should achieve the following:

- Ensure a sufficient Flow Reliability Margin (FRM). For this study, FRM has been assumed to be 10% of F.
- Leave headroom for F_0, the flows not induced by cross zonal trade (see Section 'Analysis of flows not induced by cross-zonal trade'), as these are not seen by the market optimisation.
- As a requirement in the BZR Methodology, a minimum 70% of F should always be available.

The RAM is calculated iteratively due to the impact of the load flow in the calculation of F_0.

An analogous approach was taken to computing the RAM for contingencies, as described in Section 'Contingencies'.

Iterative base case

Use of outturn generation and demand for the GSK strategies requires an iterative process, where the GSK, through its impact on the PTDF and the flows, affects the dispatch pattern and hence the GSK calculation.

Likewise, the calculation of the RAM requires knowledge of F_0, which is a consequence of the dispatch pattern and of the GSK.

The following iterative process has been used:

1. Solve a given week w of the day-ahead market dispatch using all relevant inputs to week w (e.g., hydro inflows, renewable availability, demand) and the FB parameters of the previous week (h-168).
2. Recalculate the GSK and RAM according to the dispatch outcome.
3. Re-optimise the week using the new GSK and RAM (for the RAM, we use the new GSK). This is the final dispatch result for week w.
4. Recalculate the GSK and RAM according to the dispatch outcome. This provides the base case for week w+1.

The first simulated week lacks a predecessor, so for this week an NTC base case is assumed, where the NTC is approximated by the sum of thermal limits of all transmission lines between each pair of neighbouring bidding zones.

It was decided not to allow the iterative base case approach to converge fully for each simulated week, in order to retain a level of forecasting uncertainty. However, the GSK and RAM typically did not see large changes between steps 2 and 4 above, suggesting the limited number of iterations is close to convergence.

6.1.2 Day-ahead market dispatch

The day-ahead market dispatch simulations were performed using the BID3 power market model. As a unit commitment model BID3 was used to model least cost dispatch (equivalent to maximising socio-economic welfare) on an hourly resolution, optimising the behaviour of thermal, hydroelectric, renewable and storage units alongside transmission, demand side response and co-optimisation of generation with reserve procurement.

In order to provide a correct assessment of the flows on HVDC interconnectors between the Nordics and the neighbouring Core region, Baltic region and Britain, the geographical scope of the simulations covered the entirety of Europe. Nevertheless, FB modelling was only carried out within the Nordic CCR; transmission between other bidding zones being approximated by the NTC approach.

The day-ahead market dispatch is modelled in BID3 using a rolling optimisation horizon. Each solve optimises 10 days. Of these, the first 2 are kept fixed to the final 2 days of the previous solve, 7 are optimised and the results stored, and 1 is optimised and discarded. This overlapping approach ensures that relevant inter-temporal data such as thermal start-up costs are captured correctly.

Hydro modelling

In the context of hydro dominance in the Nordic system a particular focus has been placed on realistic hydro modelling. This was performed within BID3 using an SDP approach to obtaining water values for the Nordic region. Water values were defined for each of three 'reservoir regions': Northern Nordics (including Finland), Southern Norway, and Southern Sweden.

The SDP algorithm computes the water value (opportunity cost of storage) by a two-step process. In the first step a simplified initial dispatch captures the market dynamics and computes reservoir hydro production for a set of sample water values. The second step uses these results to determine the optimal storage levels which are implied at each sample water value for each time period and inverts this to provide the water value.

Calculated water values are used in the day-ahead market dispatch. At the beginning of each weekly loop of the dispatch simulation the tabulated weekly water value for each reservoir is read from the start filling reservoir level and the average filling level of the reservoirs in the other reservoir regions. Reservoirs are free to dispatch within their technical parameters subject to a cost in the objective function given by the product of the water value and hydro production during the week.

Hydro optimisation outside of the Nordics was simulated using a simplified perfect foresight approach. A low-resolution optimisation of the full year is used to determine an optimal hydro scheduling, which is passed to the main dispatch optimisation by means of reservoir start and end levels for each week of the optimisation.

Thermal modelling

The fundamental thermal plant characteristics used are full-load efficiency, start-up costs and minimum on and off times for each plant type. Plant operation is linearised, such that, for example, start-up costs apply to any proportion of a plant which transitions from 'off' to 'on'.

In this context thermal plants includes both gas and steam turbines and renewable and non-renewable fuels (biomass, coal, natural gas, nuclear etc).

EU ETS are incorporated into the effective fuel cost of thermal units, in proportion to the emissions intensity.

CHP

CHP plants are an important source of thermal generation in the Nordics. Both backpressure and extraction CHPs are modelled, with backup boilers where relevant. The relative proportions of heat and power are controlled by a plant's Cv and Cb parameters and heat production is set as an hourly user input value for each plant.

Wind and solar

Individual intermittent renewable generators were modelled. Each is assigned an hourly resource profile, indicating the maximum possible generation in each hour. In general, the profile is common to all plants of the same type in the same bidding zone. Plants enter the wholesale market at a cost of 0 EUR/MWh and are able to curtail output in periods of excess generation in the region.

Storage plants

Battery storage and hydro plants with pumping were not used in the Nordics modelling. For the pan-European market coupling simulations, storage plants were aggregated into three plants per bidding zone. Key parameters are the MW generation capacity, with separate hours to fill and hours to empty parameters as well as a roundtrip efficiency (assumed 90% for battery storage and 75% for pumped hydro). Storage plants are allowed to freely perform arbitrage when price differentials are above the variable cost of operation.

Demand elasticity

The model incorporated price responsive demand via aggregated demand response prices and volumes. Only downward activation has been considered.

Reserves

FCR and FRR were modelled for the Nordic region. Each bidding zone has been assigned a fixed requirement for each reserve type which must be met by thermal or hydro plants within that region. The reserve and power market are co-optimised, such that electricity needs are met at least cost while ensuring sufficient reserve is held back.

Socio-economic welfare

The model output socio-economic welfare is calculated from output pricing and dispatch data by summing the profit obtained by each market participant. The separate terms in the welfare are:

- consumer surplus – The benefit of consuming electricity (relative to value of lost load, VOLL, set to 5000 EUR/MWh in the model), including the cost of retaining a secure system via the cost of reserve provision.
- producer surplus – The profit from wholesale and reserve revenues, as well as the reservoir delta.
- congestion rent – The profit made by transmission owners on price differentials between zones.

The welfare split does not consider other unmodelled wealth transfers, such as capacity or CfD payments in markets where these exist, supplier profit, or grid fees.

A full comparison between different bidding zone configurations means the cost of remedial actions is added to the welfare after the remedial action optimisation (see Section 'Remedial action simulations').

Reservoir delta

The idea of the reservoir delta value is to make two simulations more comparable in terms of socioeconomic welfare. Differences in reservoir utilisation between simulations can create an artificially high change in producer surplus, using water that would have had value in storage. The reservoir delta is estimated by multiplying the change in the annual hydro production by the weighted average water value as a numerical integral of the water value curve between the start and end reservoir level.

The concept of the reservoir delta is only suitable as an adjustment to the full year socio-economic welfare, as compared to the sum of the socio-economic welfare for each modelled hour.

Congestion rent

For each transmission line, congestion rent has been calculated as the flow on the line multiplied by the difference in wholesale price between the bidding zones it connects. The FB optimisation can lead to counterintuitive flows against price gradients, and therefore transmission with negative congestion rent.

To account for this effect, congestion rent has been socialised over the Nordic region by assigning the absolute value of the congestion rent and rescaling to ensure the total congestion rent is unchanged. The socialised congestion rent is attributed in an equal split to the two regions connected by each transmission line.

Virtual bidding zones are not assigned congestion rent in the results. The congestion rent which would be associated with a virtual bidding zone, either through congestion on the HVDC line or on the AC grid leading to the virtual bidding zone, is assigned in an equal split to the 'non-virtual' bidding zone(s) at either end.

6.1.3 Grid calculations

Load flow calculations

DC optimal power flow

Physical flows on a transmission grid are governed by Kirchhoff's laws. In their most general form this is a set of non-linear relations between active and reactive power injections at each node or busbar on the system, and the voltage drop and the current through each transmission line. The full set of equations, known as the AC Optimal Power Flow (AC OPF), is nonlinear and challenging to solve for long horizons. An often-used approximation is the DC OPF equations, which linearises the full AC OPF under the assumptions of:

- resistance small compared to reactance on all lines
- small variations in voltage magnitude between nodes
- small variations in voltage angles between nodes

With these assumptions, the DC OPF approximation provides a linear relation between the active power injection/extraction at each node n and the power flow on each transmission line l:

$$[power\ flow]_l \ = \sum\nolimits_n (\ [PTDF_N]_{ln} \,.\, [node\ balance]_n) \ \leq \ [thermal\ limit]_l$$

where $PTDF_N$ is a matrix determined from the admittance matrix and grid topology and the sum is over all nodes in each synchronous region. An implication of these constraints is that power flows on an AC grid cannot be readily directed and are instead a consequence of the generation and demand patterns.

Reactive power and transmission losses are ignored to a first approximation. The grid has been modelled under the DC OPF throughout this study.

$PTDF_N$ has been calculated internally within BID3 from of the grid topology and line reactances, using the matrix relation[2]

$$PTDF_N \ = \ B\ A\ (A^T\ B\ A)^{-1}$$

where for a system of l lines and n nodes, A is the (l x n) incidence matrix, a sparse matrix containing +1/-1 at the start/end nodes of each line, and B is the (l x l) imaginary part of the admittance matrix (diagonal matrix whose elements are the susceptance = 1/reactance of each line). Invertibility of the matrix A^T B A requires removal of the row and column associated with an arbitrary choice of slack node. The PTDF calculated in this way is a 'node-to-slack PTDF', which specifies how power flows from a specific node through the grid to the specified slack node. The slack node can be moved to another node by subtracting from each column in the PTDF the entries of the column corresponding to the new slack

[2] https://www.mech.kuleuven.be/en/tme/research/energy_environment/Pdf/wpen2014-12.pdf

node. However, in the DC OPF the choice of slack node does not affect the power flow equations.

HVDC modelling

HVDC lines have different properties relative to AC transmission:

- lower losses
- controllable flows
- can connect regions which are not synchronous

These properties lend HVDC lines to be used for power transmission over large distances, including subsea transmission. In the Nordic context, HVDC lines connect the Nordic synchronous region to the neighbouring Baltics, Britain, and Continental Europe. There are also four HVDC lines within the Nordic region: Fenno-Skan between Finland and Sweden and the South–West Link (SWL) north-south lines within Sweden.

Flows on HVDC lines have been modelled as entirely optimised. This results in flows being triggered when price differentials are sufficient to compensate for any losses in transmission.

The landing points of HVDC lines have been considered as separate zones: virtual bidding zones (VBZs). VBZs are considered as ordinary bidding zones for the optimisation steps, although they affect the optimisation results by their presence causing more grid elements to be assessed in the capacity calculation.

Contingencies

In order to streamline the modelling of N-1 contingencies, outages were modelled by means of constraints on linear combinations of the flows on multiple transmission lines. These constraints, referred to as ‘multi-line constraints’, indicate how flows are redirected in the event of a contingency.

Contingencies were assigned PTDF constraints by analogy to the methodology used for transmission lines, with the coefficients of the constraints used to calculate both the zone-to-zone PTDF threshold and F_0 for use in determining the RAM.

Operational security analysis

A nodal DC load flow analysis is carried out after completion of the day-ahead market simulations. The net injection or extraction at each node is computed from the simulated generation and consumption. Flows are determined from the power flow.

In this part of the modelling chain, the flows on HVDC lines are kept fixed to the optimised values from the day-ahead market simulations.

The resulting flows on the AC network are compared against thermal limits to determine the number and frequency of overloads induced on the system.

Remedial action simulations

The goal of the remedial action simulations is to identify the actions necessary to ensure the day-ahead market simulations satisfy all grid constraints. This was done by a separate ‘redispatch’ simulation in BID3 following the combined capacity calculation and day-ahead market simulation.

The importance of reservoir hydro in the Nordics requires that plants are able to regulate their output in the remedial action stage. This has guided the methodology user in the remedial action calculations, to ensure that reservoir levels are handled consistently with the day-ahead market simulations. The main consequence is that the redispatch simulation was carried out for the full target year 2025, using the same 10-day optimisation window that was used for the day-ahead market simulations, with soft constraints applied to encourage reservoir levels to remain close to the results of these simulations.

The redispatch process can be summarised as a re-solve of the day-ahead market solution with an additional layer of constraints (the transmission constraints) together with a cost applied to the generation decision variables to enable the additional constraints to be satisfied at a minimal cost deviation from the day-ahead market solution.

The aim has been to identify redispatch costs due entirely to grid constraints; other sources of imbalance have been ignored.

Geographical scope

The redispatch simulations were carried out only for the Nordic CCR, fixing interconnector flows to third countries to the results of the day-ahead market simulations.

Grid constraints in the redispatch

The redispatch contains two levels of transmission constraints. The physical grid is represented on a hub level (see Section 6.1) using the DC OPF approximation (see 'DC optimal power flow'). The choice of modelling on a hub level rather than on a nodal level was taken due to reduce solution time and data intensity for the full year simulation. The grid within a hub was assumed to be copper plate and the hub-to-slack PTDF was calculated from the nodal PTDF via a generation-capacity weighted GSK.

In addition to the hub level transmission constraints, the FB constraints from the day-ahead market simulations have been retained. This ensures that remedial actions resolve solely the physical grid constraints. A consequence is that the overall cost of the final dispatch will be above that of the day-ahead market simulations. Removing the FB constraints from the redispatch simulations can allow for an overall lower system cost if the FB constraints are more binding than the physical grid constraints (for example due to an inaccurate GSK strategy).

Redispatch cost

The redispatch simulation re-solves for the generation variables, where the incremental cost is modified by the use of bids (to increase generation) and offers (to reduce generation). In the same way as for the market simulations, the objective of the optimisation is to minimise the total cost of dispatch.

The costs for bid and offers used in this study were, on top of each plant's short-run marginal cost, also an addition cost i.e., 'markups' (see chapter 2.9).

In addition, cost of 0.1 EUR/MWh was added to the redispatch of hydro power production. This increased cost for hydro power was proven to decrease the overall redispatch volumes used in the simulation and assumed decreasing the risk for the module to find a more optimal solution than that of the day-ahead market dispatch. However, the added cost was not included in the cost for remedial action in economic efficiency calculation (criterion 4 in the BZR Methodology).

The dominance of hydro in the Nordics requires reservoirs to be given sufficient flexibility in the redispatch process. During constrained periods it can become necessary to reduce hydro output in one region and increase output in another. In order to capture this flexibility, excess water from the day-ahead market simulation can be banked for use in future, or conversely water can be borrowed if it is the cheapest (or sometimes the only) way of covering demand. While the BZR Methodology stipulates that banking and borrowing may only occur within the same day, this constraint has been softened in the Nordic BZ Study to allow for banking and borrowing between different days, although at a cost. The total banking over an optimisation window is however represented as a cost saving (as less water is used) of 0.8 times the water value, whereas the overall borrowing cost is 1.25 times the water value. These values have been found to give sufficient flexibility to the hydro to be able to resolve constraints effectively, while encouraging a final dispatch close to the solution of the day-ahead market simulation. The penalty costs of hydro banking and borrowing are not directly included in the redispatch costs or welfare outputs.

As a further simplification, price threshold demand was fixed at its day-ahead activation levels.

Above description boils down to the following formulas used to calculate the cost for remedial action for all plants p and all hours h, that are assessed in criterion 4 together with the socio-economic welfare from the day-ahead market dispatch. SMRC is the short-marginal run cost. As short-marginal run cost for hydro power, the water value from the day-ahead market simulation was used.

$$\mathrm{RAO}_{cost\ up} = \sum_{h=1}^{8760} \sum_{p=1}^{n} \left(\left(prod_{RAO_{p,h}} - prod_{DA\ dispatch_{p,h}} \right) * \left(SMRC_p - markup_{up_p} \right) \right)$$

$$\mathrm{RAO}_{cost\ down} = \sum_{h=1}^{8760} \sum_{p=1}^{n} \left(\left(prod_{RAO_{p,h}} - prod_{DA\ dispatch_{p,h}} \right) * \left(SMRC_p - markup_{down_p} \right) \right)$$

$$\mathrm{RAO}_{cost\ tot} = \mathrm{RAO}_{cost\ up} + \mathrm{RAO}_{cost\ down}$$

Analysis of flows not induced by cross-zonal trade

The total flow on transmission lines can be decomposed into three components:

$$total\ flow\ =\ market\ flow\ +\ loop\ flow\ +\ internal\ flow$$

In the following paragraphs we show how to calculate the separate components.

Flows without commercial exchanges

The flow without commercial exchanges is defined as

$$F_0\ =\ total\ flow - market\ flow$$

In other words, this is the net flow on each line between the total flow determined by the nodal PTDF and nodal injections, and the market flow determined by the zonal PTDF and zonal injections. For a given line l the flow without commercial exchanges is computed as

$$F_0\ =\sum\nolimits_n (PTDF_N)_{ln}.[node\ balance]_n - \sum\nolimits_z (PTDF_Z)_{lz}.[zone\ balance]_z$$

or equivalently as

$$F_0\ =\sum\nolimits_n (PTDF_N)_{ln}\,.\,(\,[node\ balance]_n - [implied\ node\ balance]_n)$$

where

$$[implied\ node\ balance]_n = GSK_{nz}\,.\,[zone\ balance]_z$$

Here, zone balance is the injection or extraction of active power at each zone resulting from the optimisation algorithm; node balance is the actual split of injection or extraction to each node, using knowledge of the location of generation and demand assets; and implied node balance is the projection of the zone balance using the GSK. The node balance therefore gives flows from and to the actual nodes where power was generated/consumed, while the implied node balance has sources and sinks at the nodes indicated by the GSK. The magnitude of F_0 is therefore a measure of the accuracy of the GSK in predicting flows. Its value is taken into account in constructing the RAM in order to ensure sufficient headroom is retained on transmission lines for the loop flows which are likely to result, which are not captured directly in the market optimisation

6.2 All other assumptions and parameters set at pan-European or BZRR level with an impact on the results of the BZ Study

The main assumptions also used in the BZ Study are reported in published LMP study report. However further changes and updates have been done for BZ Study compared to LMP study:

- The list of Critical Network Elements with Contingencies (CNECs) was updated.
- The generation shift keys have been adjusted to represent the GSK strategies used today in flow-based parallel run. In Sweden the GSK strategy is same for whole country, thus the same GSK strategy is applied for current and alternative bidding zones.

Apart from the two improvements described in the previous section, improvements done during the Nordic BZ Study with respect to the data and assumptions in the LMP-study, are presented in Table 5.

No	Short description	Details
1	BID3 model interpreted reactance per grid element while the reactance was inputted per km	The inaccuracy has had an impact on simulations results, but most notably resulted in overloads in the Swedish 220 kV grid located in SE2, discovered during earlier BZ Study-simulations. The overload in the Swedish 220 kV grid was due to power not transferring correctly to the 400 kV grid, as transformers got unrealistic high reactance compared to the lines. Correcting this inaccuracy in BZ Study have considerably reduced overloads and have also led to large changes in social-economic welfare result. It is difficult to tell the exact consequences of the inaccuracy in the LMP-study, but correct reactance would have led to other results which could have resulted in different proposals for bidding zone configurations. As this inaccuracy has been fixed in the BZ Study the assessments of the studied configurations are still valid. Two out of four configuration (9 and 11) are also modifications of the LMP-result based ones (8 and 10), modifications in which current operational practices and flow patterns have been accounted for in the proposal of these bidding zones.
2	Wrong capacity of CNEC in Stockholm	In the Stockholm metropolitan region, the LMP-results showed one 220 kV CNEC causing very high shadow prices for a limited number of hours. In the BZ Study the capacity of this CNEC have been increased

		(setting Fmax very high) as it is more aligned to operational practices. This resulted in reduced overloads and no longer occurrences of loss of load that were formally present in the BZ Study-simulations. In the LMP-study the limiting CNEC in Stockholm gave rise to high prices in nearby nodes which could have had an impact on the suggestions of bidding zones for Config 8 and 10.
3	220 kV grid not monitored	In LMP-study 220 kV grid was not monitored (i.e., set to very high Fmax) except for CNECs, meaning overloads in the Swedish 220 kV grid where generally not considered. In reality 220 kV grid is seldom overloaded so this was a fair assumption. In BZ Study all 220 kV lines are monitored which led to number 1 in this table was able to be identified as high overloads could be seen here.
4	Reserve capacity not substracted from production capacity in Sweden	Reserve capacity (FRR UP and FCR UP) was not subtracted from production capacity in Sweden (as it should have been). As reserve capacity was already subtracted in the input data for the Swedish hydro capacity (see number 5 in this table) this would have had a minor impact on simulation results from the LMP-study.
5	Input hydro capacity already substracted by reserve capacity in Sweden	The capacity for Swedish hydro power had already been subtracted by reserve capacity before inputted to the model. This has now been fixed, and total installed hydro capacity is inputted to the model. As reserves, according to number 4 in this table, was not properly reducing the hydro capacity, this inaccuracy would have had minor impact on the LMP-result. Hydro power capacity between the Swedish bidding zones were also rescaled to reflect more correct data.
6	Wrong allocation of wind power in Norway and Sweden	Wind power plants in Norway were connected to only three nodes. This led to a large share of the overloads in Norway. Wind power capacity for some nodes in Sweden have also been corrected, reducing overloads in mainly SE1. Again, it is hard to determine the exact consequences of this inaccuracy in the LMP-study, but it would have most notably impacted nodal prices internally in Norway.
7	Wrong capacity of certain CNEC	a) Increased capacity on some Norwegian CNECs resulting in reduced overloads in BZ Study. These changes mainly impact internal cuts within Norway. The effect on the LMP-study, and consequently on the bidding zone proposals for Sweden, are therefore deemed minor. b) In BZ Study we have implemented 'Cut 3' in SE3 (bottleneck for east-west flow patterns) which were not taken into account for in the LMP-study. Simulations show only minor impact on the overall result.
8	SE1 area in Sweden not assigned to the Northern reservoir	For the water values calculation in BID3, the reservoir regions are split into two: North and South. In the LMP-study, the northernmost Norwegian area, the Finnish area as well as the two northernmost Swedish areas were supposed to be assigned to the Northern reservoir region. Although in LMP-study SE1 was not assigned to the Northern reservoir. This has been corrected in the BZ Study database. This will have had minor impact on the resulting grid constraints that were identified in the LMP-study. At most, this will have had a slight impact of some percentages on the water values used.
9	Nuclear power was allowed to ramp unrestricted	In the BZ Study nuclear power plants are modelled as must run, i.e. not allowed to change production between hours (if not taken out on maintenance). In the LMP-study however, nuclear power, was allowed to ramp unrestricted. The impact on the LMP-results is difficult to estimate, but it has likely had an impact on what lines are constrained. By letting the nuclear power plants ramp up and down they could help alleviate constraining CNECs which should have been further constrained if must-run constraints had been applied to them.
10	Wrong fuel prices being used	The reported fuel and CO2 prices in the LMP-report (taken from the Mid-term Adequacy forecast data collection for 2020) and the ones

		actually used in the LMP-simulations were not the same. Although the difference was small. The modelled fuel and CO_2 prices in the LMP-study are also used in the BZ Study. This means that the fuel prices used in the BZ Study for the Central Europe and in the Nordics are different.
11	Approximately 400 MW hydro production capacity not being used	Because of a model issue approximately 400 MW of hydro power plant capacity mainly in Norway (50 MW in SE1 rest in Norway) were not able to output anything in the model. This has had an impact, especially on network elements close to these plants and has also impacted Norway total net position.
12	HVDC ramping	In the LMP-study, the HVDC interconnector ramping was assumed to be 100%. For the BZ Study, this has been changed to being the same ramping constraints as the ones used in the Nordics today. For the interconnectors to continental Europe and Great Britain, the HVDC ramping is 600 MW/h. For the internal HVDC links within the Nordics CCR, no ramping restrictions are applied.
13	Finland – NO4	In the BZ Study the line between Finland and northern Norway is modelled in BID3 as closed. This connection can be either open or closed based on the operational situation, and for the LMP-study modelling the connection was kept accidently open. However, as the connection continues on the Norwegian side on a lower voltage level than 220 kV, this change does not imply changes to network model provided with voltage level 220 kV and over, but as also the lower voltage levels are modelled in BID3, we expect to have some exchange between FI and NO4 in the final results. However, as the connection capacity is small, this change is not expected to have any significant impact compared to LMP-study.
14	Wrong wind series being used in Norway	For some nodes wind series were wrong i.e. the wind series for northern Norway were used for wind power nodes in southern Norway and vice versa.
15	Availability Norwegian HVDC	An availability profile was incorrectly assigned to the Norwegian interconnectors, causing their availability to be somewhat lower than intended. A new profile has been assigned to better reflect their availability.

Table 5: Inaccuracies found in the LMP-study that have been corrected in the Nordic BZ Study.