Bidding Zone Review

Bidding Zone Review Region (BZRR)

Nordics

Background

This document provides additional information, to what is provided in the overview Excel file "*Publication BZR Input Data and Assumptions Overview Nordic.xlsx*" which satisfies the requirements of Article 16.1 of the ACER Decision of 24 November 2020 on the Methodology and assumptions that are to be used in the bidding zone review process (hereafter the "Bidding Zone Review methodology") 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 Bidding Zone Review 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 published at Entso-E's website in the Locational Marginal Pricing (LMP) study phase. For these sections, the link to find referenced data is given.

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1 Scenario

1) Scenario

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

For the BZR analysis same climate years as for LMP study; 1989, 1995 and 2009 will be used. 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 is considered more important and is also a requirement of the ACER methodology. For more information, please see Chapter 1.2 and Chapter 3.11 of 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 Nordics, the sensitivity study is done for the same target year 2025 as main study, the change compared to the main scenario is changed fuel prices and excluding the fixed flow from Russia, which is included in main study.

1.3 Network model for the scenario and sensitivities

The network model is the same as used in the LMP study. The network model used as a basis for the Nordic BZR study is the common Nordic planning model in PSSE which is converted to main tool to conduct the study (BID3). 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 are 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 will be performed for an intact grid adding N-1 restrictions. The model will be run on a so-called transmission hub level for the BZR calculations. That is, all nodes are 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.

Nordic TSOs have done the following improvements in the way modelling is done in BZR in comparison with the LMP- study. However, these do not pose changes to the topology of the network model used in LMP:

- In the BZR the line between Finland and northern Norway will be modelled in BID3 as closed. In the LMP study this line was missing. This connection can be either open or closed based on the operational situation, and for the LMP modelling the connection was kept accidently open. However, as the connection continues in Norwegian side with 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, we do not expect this change to have any significant change compared to LMP study.
- The operational rules for the South West Link in Sweden have been implemented, because some errors were found in the flows.

We use the same network model in BZR for the main scenario and sensitivity.

1.4 List of additional infrastructure projects for the target year compared to the year when the BZR starts.

Nordic TSOs have included a list of 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 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.

Tabel 1 additional infrastructure projects included in the model

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

Tabel 2 Change in production

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

Lately in Finnish grid there is expected some small improvements due the changes with cross-over line configurations, which should provide more capacity for year 2025. These are not captured in the network model used, as congestions inside Finland were not causing significant congestions in LMP, it is assumed that that these changes would not have significant effect on the BZR study and thus the network model is 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 contingencies also on 220 kV network elements in the analysis. 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 can be found from the input files published for the LMP study. Please see Input data from site: *https://www.entsoe.eu/news/2022/09/06/entso-e-publishes-locational-marginal-pricing-data-items-as-part-of-bidding-zone-review-study/.* For solar and wind the granularity of data is per MTU, per technolgy and per climate year. Hydro values are given as weekly inflows.

2.2 Minimum and maximum generating capacities

Maximum generating capacities are given in the input files published for the LMP study. The minimum generating capacities are provided as minimum stable power for thermal plants. Please see Input data from site: *https://www.entsoe.eu/news/2022/09/06/entso-e-publishes-locational-marginal-pricing-data-items-as-part-of-bidding-zone-review-study/*. 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 LMP study. Please see input data from site: https://www.entsoe.eu/news/2022/09/06/entso-e-publishes-locational-marginal-pricing-data-items-as-part-of-bidding-zone-review-study/. Granularity of data is per technology.

2.4 Ramping capabilities

For thermal plants ramping is modelled slightly differently in BZR than was done in LMP. For LMP, the ramping was considered to be 100 % meaning that the plant was able to ramp up/down it's total capacity within 1 hour. For the BZR we included also an assumption of one hour of start-up and shut-down times, which mean that each plant will reach its minimum stable generation in 1 hour, and ramping to full capacity will take another hour. Similar principle will also apply for ramping down.

2.5 Minimum run time

Min time on and min time off are provided for thermal plants in the input files published for the LMP study. Please see input data from site: https://www.entsoe.eu/news/2022/09/06/entso-e-publishes-locational-marginal-pricing-data-items-as-part-of-bidding-zone-review-study/. Granularity of data is per technology.

2.6 Start-up and shut-down times

In the BZR we will use an assumption of one hour start-up/shut-down time for all thermal plants (excluding nuclear, for which there is no outages included in the market dispatch and with the maintenance, the start-up/shut-down time can be assumed to be included in the maintenance time). This means, that the time from start to minimum stable generation, and from minimum stable generation to zero will both take 1 hour. This will also change our ramping time such that the minimum stable generation is reached in 1 hour. After having reached minimum stable generation, the thermal plants can then ramp up to full power in the second hour. This is also true for ramping down, i.e. that power plants need to ramp down to minimum stable generation before going to zero.

2.7 Start-up costs

Warm start costs are provided in the input files published for the LMP study. Please see the input data from site: https://www.entsoe.eu/news/2022/09/06/entso-e-publishes-locational-marginal-pricing-data-items-as-part-of-bidding-zone-review-study/. 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.

Table 3 Fuel/Commodity prices

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 4 Variable O&M cost

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

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 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 used in Central Europe for different technologies, as redispatch is there used and thus assumed to provide good assumption on mark-up cost for different technologies. However, it should be noted, that all technologies (for example Nuclear) listed are not assumed to take part to redispatch.

3) Load

3.1 Load time series

The demand time series used as input can be found from the input files published for LMP study. Please see input data from site: *https://www.entsoe.eu/news/2022/09/06/entso-e-publishes-locational-marginal-pricing-data-items-as-part-of-bidding-zone-review-study/*

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 LMP study. Please see input data from site:*https://www.entsoe.eu/news/2022/09/06/entso-e-publishes-locational-marginal-pricing-data-items-as-part-of-bidding-zone-review-study/*

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 LMP study. Please see input data from site: https://www.entsoe.eu/news/2022/09/06/entso-e-publishes-locational-marginal-pricing-data-items-as-part-of-bidding-zone-review-study/

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 LMP study. Please see input data from site: *https://www.entsoe.eu/news/2022/09/06/entso-e-publishes-locational-marginal-pricing-data-items-as-part-of-bidding-zone-review-study/*

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, currently 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 for 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-optimize 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 LMP study, the straight link is provided in Nordic overview Excel. It should be noted, that currently the dimensioning of reserves is done for TSOs control area, not per bidding zone, so the division of values between the bidding zones 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 LMP study. Please see input data from site: *https://www.entsoe.eu/news/2022/09/06/entso-e-publishes-locational-marginal-pricing-data-items-as-part-of-bidding-zone-review-study/*

4.2 FRR requirement [MW]

Information of values is provided in the published input files for LMP study. Please see input data from site: *https://www.entsoe.eu/news/2022/09/06/entso-e-publishes-locational-marginal-pricing-data-items-as-part-of-bidding-zone-review-study/*

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

Flow based method is used for all borders and MTUs.

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 5% of the Fmax is assumed for all CNECs which is the value currently used in Nordic flow-based parallel run.

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. However, it should be noted that currently the value for PTDF threshold in approved Nordic CCM is 5 %.

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.

HVDC ramping restrictions are not applied in modelling.

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 and remedial action optimisation 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 BZR 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 BZR, 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.

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

The main assumptions are reported in published LMP study report. However further changes and updates have been done for BZR 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.
- Some technical improvements have been done for hydro modelling.