Methodological developments for European Resource Adequacy Assessments

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1 Introduction

In recent years, Resource Adequacy Assessments have been subject to significant methodological improvements transitioning from deterministic calculations to probabilistic simulations [1]. Main drivers for these developments are the legal requirements outlined by the Clean Energy for all Europeans Package (CEP), specifically Regulation (EU) 2019/943 [2] and the current transformation of the European energy system triggered primarily by climate neutrality ambitions.

This paper focuses on key methodological developments within the European Resource Adequacy Assessment (ERAA) [3], published in its first edition in 2021. As a successor to the Mid-term Adequacy Forecast (MAF), the ERAA will ultimately be a pan-European resource adequacy assessment covering the horizon from one to ten years ahead. The first edition included a single-year Economic Viability Assessment (EVA) and a Proof-of-Concept (PoC) study for Flow-based Market Coupling (FBMC). Their respective methodologies are summarized and expected improvements in the upcoming editions are investigated, with a special emphasis on the modelling of implicit Demand Side Response (iDSR). Such developments and their planned implementation will follow the structure presented in the ENTSO-E's indicative ERAA roadmap [3, p. 23].

2 Flow-Based Market Coupling (FBMC)

In its mature implementation, the ERAA is required to be built upon a Flow-Based (FB) model for regions where this capacity calculation methodology (CCM) for cross-zonal trade is in use. In the European Electricity Grid, FBMC is currently applied in the Central-Western Europe (CWE) Region, including Austria, Belgium, France, Germany, Luxembourg and the Netherlands. An extension to the CORE region, thus including Croatia, Czech Republic, Hungary, Poland, Romania, Slovakia and Slovenia, is planned for 2022. The ERAA 2021 included a PoC study for the pivotal year 2025; hence, the geographical scope of the CORE region was used.

Compared to the Net Transfer Capacity (NTC) market coupling – where the amount of energy traded across bidding zone borders is limited by deterministic values – FBMC more realistically represents the physical limitations of the grid through the calculation of a FB domain. The FB domain represents the feasible space for net positions (exports minus imports) of bidding zones within a capacity calculation region (CCR). It is defined by a set of linear constraints that correspond to Critical Network Elements and Contingencies (CNECs), i.e. those specifically affected by cross-border flows and to operational contingencies, which are provided by the Transmission System Operators (TSOs). Those CNECs are then used to calculate two groups of parameters that define the flow based domain, the Power Transfer Distribution Factors (PTDFs) and the Remaining Available Margin (RAM). For each CNEC, PTDFs represent the sensitivity of the power flow with respect to a change in the net position of a specific bidding zone, and the RAM describes the available capacity for day-ahead (DA) trading.

Operationally, FB domains are derived in a complex forecast process starting two days ahead (D-2). The FB PoC in the first ERAA edition consisted of a five-step approach to calculate FB domains which is briefly described below, following the approach presented in [3].

2.1 Flow Based approach in ERAA 21

The following five-step approach describes the computation of FB domains as it was applied in the ERAA21 process. It was developed as well as performed by the participating TSOs of the CORE region:

1. In a first step, in analogy to the operational work stream, a list of CNECs was defined in a consultation phase with all concerned TSOs. This CNEC selection followed the rules and guidelines laid out for the DA capacity calculation as good as possible.
2. Following the definition of elements and contingencies that could potentially be limiting cross-zonal trade, an initial market simulation was performed to estimate the dispatch within the CCR. The market model used for this step was the market model of the MAF 2020, pivotal year 2025, as it was considered reasonably close in terms of input parameters to the ERAA21 market model, which was not yet available at that point in the process.
3. Considering the results of the initial market simulation, the third step aimed at determining the reference loading of the grid elements. This was performed through a load flow calculation. The underlying grid model was the National Trends 2025 grid model of the TYNDP 2020 [4].
4. In step four, a nodal PTDF matrix was taken from the previous step and used to determine a zonal PTDF matrix. To allow for a zonal representation, a set of Generation Shift Keys (GSKs) was defined including the information of how the nodal power injection changes with regards to a change of the net position of a bidding zone. Multiplying the (nodal) PTDF and the GSK matrices, the zonal PTDF matrix was obtained, which yields the left-hand side of the linear FB constraints. The respective right-hand side was derived by considering the maximum flow on each CNEC and subsequently accounting for the reference flow, a Flow Reliability Margin (FRM) as well as a mandatory minimum margin for trade of 70%, required from 2025 onwards as in the CEP [2].
5. Finally, to reduce complexity (e.g., to ease the data handling within the market model), the 8760 hourly domains were clustered into 6 representative groups with a k-medoids algorithm. To assign each hour of the year to its "nearest" cluster, a probability matrix was calculated, mapping one domain to each Monte-Carlo (MC) year. For this final step, characteristics such as climate dependant input or load have been used as criteria.

Following the domain calculation process, the resulting constraints were included in the market model of the ERAA21 and used to retrieve adequacy results. Additionally, an ex-post analysis was performed to mitigate results in the economic dispatch that are not in line with current regulation, especially regarding flow factor competition and violation of local matching (section 6.8 of the Euphemia algorithm description [5]). However, a detailed description of how exactly this was applied is beyond the scope of this paper.

3 Economic Viability Assessment (EVA)

In compliance with the Regulation (EU) 2019/943 [2] and specifically Article 23 (5) (b, c, f), the ERAA methodology [6] sets the requirements for an Economic Viability Assessment (EVA) of the generation (or flexibility) capacity in the electricity market. The main scope of the EVA is to assess the likelihood of retirement, mothballing and new investments of generation (or flexibility) assets. An asset may be deemed as "viable" if its expected future revenues (over its economic lifetime), including consideration of uncertainty and risk aversion of market players, are sufficient to generate profit over its variable and fixed costs (and CAPEX in case of new investments). The main revenue stream comes from the Energy Only Market (EOM), whereas any other relevant additional revenues shall be considered, if robust estimates exist on these. Additional revenues may include revenues from the heat market, ancillary services, energy future markets, etc. One key purpose of such an exercise is to assess the impact of existing and approved future Capacity Mechanisms (CM) in respective Member States.

The first ERAA edition (2021) included EVA as a simplified single-year assessment performed for the Target Year 2025 based on National Trends data. Two scenarios, "with" and "without" existing and future Capacity Mechanisms, were considered. Several assumptions and simplifications applied to this first EVA implementation, whereas continuous developments are expected in line with ENTSO-E's roadmap towards a mature ERAA implementation [3, p. 23]. Given the single-year nature of the market model adopted, the costs faced by an asset were included in the form of annualized fixed and variable costs (and annuity of CAPEX for new investments). Considerations of the uncertainty of future revenues and risk aversion of investors were integrated by means of technology-specific hurdle premiums on expected revenues, following the approach described in [7]. Other key assumptions were:

- Gas and DSR units as the only candidates for capacity expansion (new investments);
- Thermal units excluding Nuclear as the only candidates for disinvestment (retirement);
- Revenues from the EOM only (most of CHP units excluded from the assessment);
- Consideration of forced outages as fixed derating of units;
- Consideration of seven historical climate conditions for wind, solar, hydro and demand (1983, 1984, 1990, 1995, 1996, 2006, 2009);
- Market cap set to 15 k€/MWh; CO_2 price set to 40 €/ton (other sensitivities performed).

In the scenario without CM a long-term planning model was used to minimize the overall system costs, namely the sum of new investment costs, the costs of existing operational units, as well as the cost (welfare loss) of unserved energy. The key decision variables were the economic decommissioning of existing units and the investment in new units. The scenario with CM was defined through an iterative approach bringing back retired units or investing in new units in Member States where a CM is in place (or approved for 2025) until the corresponding Reliability Standard (RS) was achieved.

4 Demand Side Response (DSR)

In the first edition of the ERAA, the modelling of DSR was limited to explicit interruptible load, as opposed to the rest of the demand being assumed inelastic to endogenous prices. Future editions of the ERAA will build upon this first approach and enhance the existing modelling of DSR, including price-reactive implicit DSR. In particular, an implementation of iDSR leveraging the explicit modelling of (among others) Heat Pumps (HPs) and Electric Vehicles (EVs) as demand flexibility resources reacting to endogenous marginal prices is projected.

A possible approach to implement iDSR in the modelling tools used for adequacy assessments was benchmarked in a test environment within Austrian Power Grid AG (APG). The ERAA 21 NTC model for the post-EVA without CM scenario served as a test bench. The geographical perimeter was reduced to amplify the impact on the Austrian bidding zone. This reduction resulted in two models, a tri-lateral model including the Austrian, Swiss and Northern Italian bidding zones (in analogy to the system covered in [8]), and a second model covering the CORE CCR, respectively. In the following sections, the modelling methodology of iDSR will be introduced together with a summary of the input data. Finally, the impact of this approach on adequacy simulations will be analysed.

4.1 Methodology

To quantify the partition of the total electricity demand to be attributed to iDSR, the demand time series were obtained from three sources: a regression model (the tool TRAPUNTA [9]) delivered the demand time series for the bidding zone by analysing historic demand and climate data. On top, the peculiar demand profiles for HPs and EVs were gathered through joint studies commissioned to the Austrian Institute of Technology ([10] and [11]).

For the representation of iDSR (EVs and HPs) in the modelling tools, a methodology was defined leveraging existing features and “objects” available for the modelling of flexible resources (e.g. batteries or closed loop pumping hydro power plants) and combining them with additional ad hoc constraints to achieve the desired dispatch flexibility. In the following section, the underlying mathematical formulation is described as it was developed within the ERAA modelling team [12].

The demand time series are provided in hourly granularity and also the economic dispatch problem will be solved in discrete time steps, therefore we define the time index k denoting the time step δ, with $k \in \mathcal{K} \coloneqq \{1, \dots, 8760\}$. For each δ, two decision variables are introduced, $p_i^{\mathrm{DSR}}(k)$ and $e_i^{\mathrm{DSR}}(k)$, which can be interpreted as follows:

- $p_i^{\mathrm{DSR}}(k)$: curtailed or increased demand due to price-sensitive time-shifting of the demand at time step k
- $e_i^{\mathrm{DSR}}(k)$: amount of energy demand that still has to be served or has already been served at time step k

The consumptive limitations of the flexibility resources, quantified by the respective time series, require the definition of the following constraint:

$$\underline{p_i}^{\mathrm{DSR}}(k) \leq p_i^{\mathrm{DSR}}(k) \leq \overline{p_i}^{\mathrm{DSR}}(k),$$

with $\overline{p_i}^{\mathrm{DSR}}(k)$ and $\underline{p_i}^{\mathrm{DSR}}(k)$ denoting the maximum demand that can be curtailed at time step k, and the maximum curtailed demand that can be shifted to time step k, respectively. For the amount of energy shifted to a later point in time, we define the following two constraints:

$$\underline{e_i}^{\mathrm{DSR}}(k+1) \leq e_i^{\mathrm{DSR}}(k+1) \leq \overline{e_i}^{\mathrm{DSR}}(k+1), \text{ and}$$

$$e_i^{\mathrm{DSR}}(k+1) = e_i^{\mathrm{DSR}}(k) + \delta \cdot p_i^{\mathrm{DSR}}(k).$$

Here, $\overline{e_i}^{\mathrm{DSR}}(k+1)$ and $\underline{e_i}^{\mathrm{DSR}}(k+1)$ represent the maximum amount of energy demand that can be curtailed or shifted up to time step $k+1$, respectively. Finally, as an arbitrary boundary condition, we can define

$$e_i^{\mathrm{DSR}}(1) = e^0,$$

where the superscript 0 refers to the initial condition.

In order to define discrete timeframes within which the demand can be shifted (either forward or backword), the profiles $\overline{e_i}^{\mathrm{DSR}}(k+1)$ and $\underline{e_i}^{\mathrm{DSR}}(k+1)$ should be such that there exist time steps in which the two bounds coincide, i.e. there exist $h \in \mathcal{K}$ such that:

$$\overline{e_i}^{\mathrm{DSR}}(h+1) = \underline{e_i}^{\mathrm{DSR}}(h+1) = e^{\mathrm{H}}.$$

Consequently, we define the subset $\mathcal{H}$ of all these points in time as

$$\mathcal{H} \coloneqq \left\{k \in \mathcal{K} \text{ s.t. } \overline{e_i}^{\mathrm{DSR}}(k+1) = \underline{e_i}^{\mathrm{DSR}}(k+1) = e^H \right\}.$$

Practically speaking, the elements of $\mathcal{H}$ define the boundaries of time windows within which the load can be shifted. To ensure that all the flexible demand is eventually supplied within each time window, bound by the time steps in $\mathcal{H}$, the boundary conditions are set equal to the initial condition, thus:

$$e^{\mathrm{H}} = e^0.$$

After introducing the constraints above, an appropriate set of parameters needs to be chosen. Assuming that $\overline{p_i}^{\mathrm{DSR}}(k)$ follows the hourly demand time series of the corresponding iDSR element (e.g. HPs or EVs), we have to define the remaining parameters $\underline{p_i}^{\mathrm{DSR}}(k)$, $\overline{e_i}^{\mathrm{DSR}}(k+1)$, $\underline{e_i}^{\mathrm{DSR}}(k+1)$, e^{H}, e^0 and $\mathcal{H}$.

To begin with, the set $\mathcal{H}$ is defined with arbitrary time windows of 6 hours; it follows that $\mathcal{H} \coloneqq \{6, 12, 18, 24, \dots, 8760\}$. For the sake of simplicity let $e^0 = 0$, then

$$\overline{e_i}^{\mathrm{DSR}}(k+1) \coloneqq \begin{cases} +\infty \text{ if } k \in \mathcal{K} \setminus \mathcal{H} \\ 0 \text{ if } k \in \mathcal{H} \end{cases}, \text{ and}$$

$$\underline{e_i}^{\mathrm{DSR}}(k+1) \coloneqq \begin{cases} -\infty \text{ if } k \in \mathcal{K} \setminus \mathcal{H} \\ 0 \text{ if } k \in \mathcal{H} \end{cases}.$$

To avoid negative values for $e_i^{\mathrm{DSR}}(k)$ the boundary condition $e^0 = e^{\mathrm{H}}$ can be shifted to an arbitrarily large positive number yielding the same effect. Finally, we can dimension $\underline{p_i}^{\mathrm{DSR}}(k)$ in order to allow for a maximum power absorption that matches the maximum demand curtailment in the same time window. Denoting two consecutive indices in $\mathcal{H}$ (e.g., 6 and 12) with h_i and h_{i+1}, then

$$\underline{p_i}^{\mathrm{DSR}}(k) \coloneqq \max\left\{\overline{p_i}^{\mathrm{DSR}}(x) \text{ s.t. } h_i \ \leq x \leq h_{i+1}\right\}, \forall k \in [h_i, h_{i+1}] \subset \mathcal{K}\ .$$

For the purpose of the simulations performed in this paper, the methodology introduced above was followed as close as possible when the iDSR resources were included in the market modelling tool Plexos[1]. The existing battery class object was used and constrained as explained above by the hourly time series of the respective iDSR technology: for the battery discharge capacity, the hourly values of the flexible demand time series were directly used as upper bounds; whereas for the battery charge capacity the maximum value of each particular flexibility timeframe (e.g. 6 hours) served as upper bound over that very time window. The boundary condition $e^0 = e^{\mathrm{H}}$ was chosen such that it corresponds to 50% State of Charge (SoC), while the energy storage capacity was dimensioned arbitrarily large, such that a SoC of 0% or 100% can never be reached, as this would unintentionally limit the availability of iDSR. The only notable difference to the approach presented was the efficiency, which had to be set to 99% (instead of a theoretical 100%) in order to avoid unnatural behaviour (simultaneous charging and discharging) of the battery.

4.2 Input Data

The model used for the simulations presented in this paper was the ERAA 21 NTC model for the post-EVA without CM scenario for the pivotal year 2025. Two geographical reductions were applied, resulting in a CORE model and a “tri-lateral” model constituted by the AT00, CH00 and ITN1 bidding zones of the day-ahead market. The ERAA 21 input data (e.g. load, renewable generation and hydro inflows) is based on 35 (1982 to 2016) historic climate years. In this paper, we are presenting results for two particularly interesting years in terms of generation adequacy: 1985 and 2006. For these years, the general configuration of the market model, as well as the input data have not been changed, except for the load time series of the Austrian bidding zone (AT00). In fact, to assure consistency with the load time series for EVs and HPs, the whole electricity demand time series of the Austrian bidding zone was updated, as this data was not available at the time when the ERAA 21 model was built. These new demand time series aggregate output from the load forecasting tool TRAPUNTA, as well as load figures retrieved from joint studies commissioned to the Austrian Institute of Technology for EVs and HPs. Figure 1 depicts the hourly load for the whole year, normalized to the maximum value of the dataset. Following the Austrian climate conditions, a typical seasonal distribution is clearly visible, with higher base load as well as peaks during the winter season. Furthermore, the exceptionally high peak during the first hours of the climate year 1985 motivates the choice of such climate conditions as a “stressed scenario” for adequacy assessments.

[1] https://www.energyexemplar.com/plexos

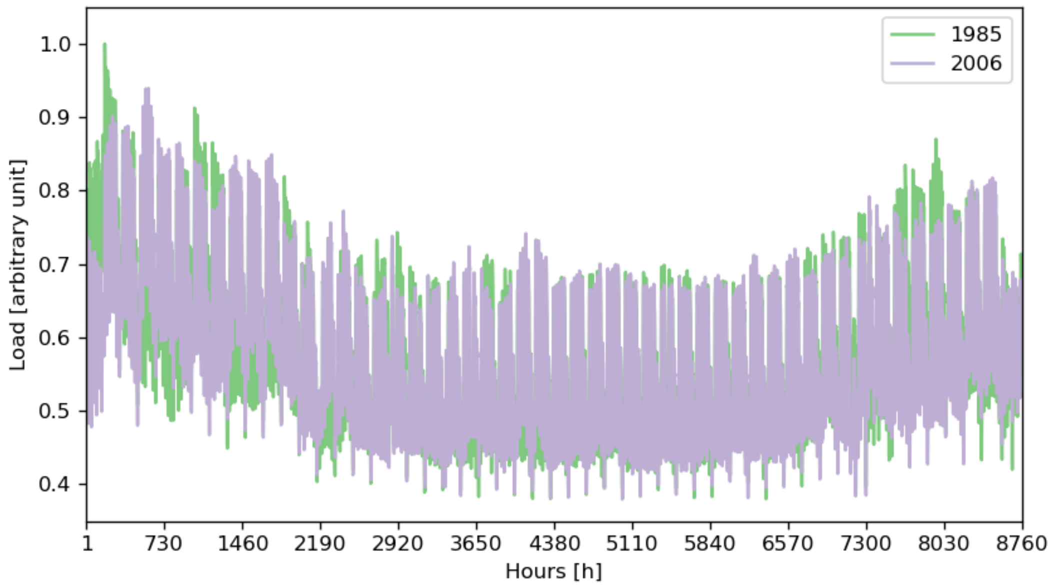

Figure 1: Hourly load time series for the Austrian bidding zone used in the simulations, normalized to the maximum value of the dataset.

The load attributed to EVs and HPs is included in the total demand figures above, however it is worth reviewing those time series individually in order to gain a better understanding of their temporal variability. Figure 2 displays the time series for the two types of load for a selected period of time. The timeframe covers hours 336 through 504 of the year, which correspond to the forecasts for a full standard week (Monday to Sunday). Both technology-specific load profiles show daily patterns that seem to be more (HPs) or less (EVs) dependant on the prevailing climatic conditions.

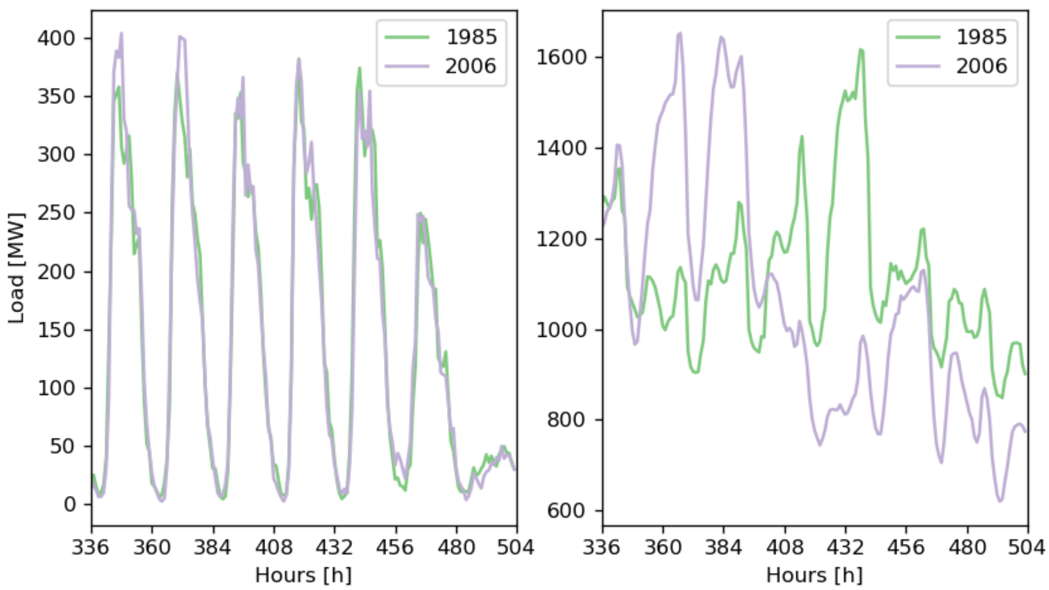

Figure 2: Hourly load time series of electric vehicles (left) and heat pumps (right) for a selected period of 7 days of the respective climate years.

In general, as the Austrian climate allows for less intensive HP usage during summer compared to winter, the respective time series show a clear seasonal pattern with lower values in summer, even stronger than the trend associated to the total demand. EVs, instead, show a lower dependency on seasonal climate.

4.3 Results

All simulations were performed for a modelling horizon of one year, discretized in hourly steps. For each climate year, a random set of 20 availability time series of thermal power plants was created to account for forced outages. The results presented below are averaged over the respective set of 20 outage patterns. The benchmark scenario (hereafter referred to as "base case") included the same total hourly demand; however, it did not allow for any demand shifting potential for HPs and EVs. The respective results for the Austrian bidding zone are summarized in Table 1. For a qualitative comparison, two indicators are listed: the unserved energy and the unserved energy hours. It is worth mentioning that the market model minimizes the total dispatch costs (with unserved energy accounted with the highest cost in terms of welfare loss) and thus a decrease in unserved energy from one scenario to another does not necessarily lead to a decrease in the number of unserved energy hours. The same market cap and Value of Lost Load (VoLL), i.e. the "cost" associated to unserved energy in terms of welfare loss, apply to all bidding zones in the market model. On the one hand, this assumption allows for a level playing field of market areas competing for the same scarce resource, i.e. electricity supply. On the other hand, this may lead to "equivalent" optimal solutions during certain hours in which unserved energy can be arbitrarily allocated to different areas in simultaneous scarcity, as it results in the same cost from a global system perspective.

Geo. perimeter	CY	Unserved energy (GWh)	Unserved Energy Hours (h)
Tri-Lateral	1985	0.0014	0.05
Tri-Lateral	2006	685.49	385.10
Core region	1985	1.30	3.80
Core region	2006	0.01	0.20

Table 1: Summary of the adequacy indicators for the Austrian bidding zone in the base case simulation.

A common observation, shared amongst all scenarios, is that the load in Austria cannot be covered self-sustainingly (i.e. exclusively by local generation within the bidding zone) during all hours. The country is thus strictly dependent on imports to ensure its electricity supply. This comes with no surprise, as the reduced geographical perimeters were taken on purpose to evaluate the system under artificial stressed conditions. Intuitively, it can be deduced that in the model covering the CORE region the availability of imports is higher than in the tri-lateral configuration. After running the base case simulation, the demand shifting potential for iDSR was set to a fixed percentage, such that a given fraction of the total EV or HP load is elastic to endogenous prices. Two scenarios were studied, one with 10% flexibility potential and the other with 100% flexibility potential.

4.3.1 10 % flexibility potential

In this first step, it was assumed that 10% of the load time series of EVs or HPs can independently react to endogenous prices following the methodology described in section 4.1. In Table 2 and Table 3 the same adequacy indicators as for the base case are summarized. For each technology two time windows (hence sets $\mathcal{H}$) were analysed: 3 hours and 6 hours for EVs; 6 hours and 12 hours for HPs.

Compared to the base case, the availability of flexible demand leads to a decrease in unserved energy as well as unserved energy hours for each configuration. In the tri-lateral configuration, when iDSR is provided only through electric vehicles, the 6 hours flexibility timeframe results in a worse adequacy situation compared to the 3 hours option. This may seem counterintuitive, but it holds only when the adequacy indicators are analysed for the Austrian bidding zone alone. The total value of unserved energy in the system is in fact lower in the 6 hours scenario and is consistent with the global system optimization approach adopted. In general, it is worth stressing again that these islanded geographical configurations are in their very nature strongly dissimilar to normal dispatch conditions and the resulting adequacy indicators should therefore be considered as pure academic exercises.

Flex.	Geo. perimeter	CY	Unserved energy (GWh)	Unserved Energy Hours (h)
3h	Tri-Lateral	1985	0.00026	0.05
	Tri-Lateral	2006	676.81	371.85
	CORE region	1985	1.04	3.40
	CORE region	2006	0.01	0.20
6h	Tri-Lateral	1985	0.00026	0.05
	Tri-Lateral	2006	681.47	369.4
	CORE region	1985	1.03	3.20
	CORE region	2006	0.01	0.20

Table 2: Summary of the adequacy indicators for the Austrian bidding zone considering 10% of the EV load as elastic to prices.

Flex.	Geo. perimeter	CY	Unserved energy (GWh)	Unserved Energy Hours (h)
6h	Tri-Lateral	1985	0.00	0.00
	Tri-Lateral	2006	680.93	377.80
	CORE region	1985	0.97	2.60
	CORE region	2006	0.00	0.00
12h	Tri-Lateral	1985	0.00	0.00
	Tri-Lateral	2006	676.27	368.25
	CORE region	1985	0.95	3.00
	CORE region	2006	0.00	0.00

Table 3: Summary of the adequacy indicators for the Austrian bidding zone considering 10% of the HP load as elastic to prices.

4.3.2 100% flexibility potential

In a second step, it was assumed that 100% of the load time series of EVs or HPs can independently react to endogenous prices. In Table 4 and Table 5 the same adequacy indicators as for the base case are reported. The same time windows for demand flexibility as in section 4.3.1 were studied.

Flex.	Geo. perimeter	CY	Unserved energy (GWh)	Unserved Energy Hours (h)
3h	Tri-Lateral	1985	0.00	0.00
	Tri-Lateral	2006	683.57	361.25
	CORE region	1985	1.13	3.60
	CORE region	2006	0.00	0.00
6h	Tri-Lateral	1985	0.00	0.00
	Tri-Lateral	2006	678.60	350.90
	CORE region	1985	0.80	2.20
	CORE region	2006	0.00	0.00

Table 4: Summary of the adequacy indicators for the Austrian bidding zone considering 100% of the EV load as elastic to prices.

Flex.	Geo. perimeter	CY	Unserved energy (GWh)	Unserved Energy Hours (h)
6h	Tri-Lateral	1985	0.00	0.00
	Tri-Lateral	2006	669.12	355.90
	CORE region	1985	0.82	2.20
	CORE region	2006	0.00	0.00
12h	Tri-Lateral	1985	0.00	0.00
	Tri-Lateral	2006	685.33	364.00
	CORE region	1985	0.57	1.80
	CORE region	2006	0.00	0.00

Table 5: Summary of the adequacy indicators for the Austrian bidding zone considering 100% of the HP load as elastic to prices.

Similarly to the previous observations, the availability of flexible demand resources leads to a decrease in unserved energy as well as unserved energy hours for each configuration. In the tri-lateral configuration, when iDSR is provided only by heat pumps, the 12 hours flexibility time window results in a worse adequacy situation with respect to the 6 hours approach. As mentioned in the previous section, this is due to the single bidding-zone focus, as opposed to the global system perspective, for which the overall adequacy indices improve moving from 6 to 12 hours of flexibility timeframe.

4.3.3 Combined iDSR resources

In a final step, 10% of EVs and HPs were assumed to be price-reactive and available in the same scenario, to evaluate their interaction and simultaneous impact. A 6 hours window for both technologies was assumed. The results are displayed in Table 6.

Geo. perimeter	CY	Unserved energy (GWh)	Unserved Energy Hours (h)
Tri-Lateral	1985	0.00	0.00
Tri-Lateral	2006	684.20	371.65
CORE region	1985	0.82	2.20
CORE region	2006	0.00	0.00

Table 6: Summary of the adequacy indicators for the Austrian bidding zone considering 10% of the EV and HP load as elastic to prices.

As expected, a comparison between this setup and the base case shows a general improvement in terms of the adequacy situation, with higher benefits in the CORE configuration. This can be (partially) explained by the fact that more frequent and longer sets of consecutive scarcity hours occur in the tri-lateral system, sometimes exceeding the flexibility timeframe of iDSR (i.e. 6 hours). It follows that such prolonged situations of structural lack of generation resources cannot be mitigated through demand flexibility, which does not introduce additional generation capacity into the system. Considering the values presented in section 4.3.1, when focusing on the CORE region, the simultaneous availability of both EVs and HPs does achieve a lower unserved energy than the contribution that each technology can yield individually. However, the impact of adding a second resource is for some cases relatively low, implicating a coincidence of low availabilities for both technologies (cf. Figure 2) during scarcity hours. When considering the Austrian bidding zone alone, the tri-lateral configuration for the climate year 2006 shows worsened adequacy indicators. As already explained, this counterintuitive observation can be explained by the global system perspective adopted by the solver. In fact, the total value of unserved energy in the whole system (the sum of the three bidding zones) is lower in the combined EVs and HPs scenario. In general, it is worth stressing again that these islanded geographical configurations are in their very nature strongly dissimilar to normal dispatch conditions and the resulting adequacy indicators should therefore be considered as pure academic exercises.

5 Conclusion

Resource Adequacy Assessments have been – and in the future will be – subject to significant methodological improvements. Three selected improvements were presented in this paper. FBMC in its current implementation consists of a five step approach that starts with the collection of critical network elements and contingencies and results in a set of six distinct domains that are then included in the market model. The Economic Viability Assessment was included for the first time in the ERAA 2021. The main scope is to assess the likelihood of retirement, mothballing and new investments of generation through a global cost minimization subject to a set of necessary assumptions and simplifications. Several key improvements are planned according to the roadmap towards a mature ERAA implementation by end of 2023.

For the inclusion of iDSR, a methodology to enable electric vehicles and heat pumps to provide demand flexibility was defined and described. Leveraging the Plexos modelling tool, this methodology was implemented in a market model and its impact on a diverse set of configurations was successfully tested. Such configurations included different combinations of two geographical perimeters (CORE and tri-lateral), low (10%) and high (100%) share of flexible demand, as well as different assumptions for the definition of consecutive discrete timeframes for the demand flexibility (3, 6 and 12 hours). The adequacy indicators of unserved energy [GWh] and unserved energy hours [h] were analysed for the Austrian bidding zone. Although from a global system perspective the total system costs (thus total unserved energy) of each scenario could be reduced through increased availability of demand flexibility resources (both magnitude and timeframe), the same did not always hold for the local Austrian adequacy indicators. Moreover, the tri-lateral model, due to its structural deficiency of generation capacity, lead to several hours of consecutive scarcity and proved to be a less adequate framework to evaluate flexibility options over short multi-hourly consecutive cycles, as in the case of iDSR. Counterintuitive results could therefore not be excluded. The CORE model, thanks to a wider geographical scope and hence leveraging more robust generation and transmission capacities, was less prone to this influence and showed higher benefits in terms of mitigated scarcity situations when demand flexibility options were made available, especially in the case of simultaneous availability of EVs and HPs as iDSR. In a next step, the methodology will be implemented in a model covering the whole pan-European perimeter for the electricity system (as in the ERAA). While this approach investigated simplified load-shifting capabilities for iDSR applications, focusing on HPs and EVs in particular, the inclusion of further elements as flexible grid services (e.g. beyond-the-meter batteries, vehicle to grid, smart appliances etc.) will call for new and diverse studies.

6 References

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