Assessment of independent aggregation models

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1 EXECUTIVE SUMMARY

Independent aggregation in electricity markets refers to a third-party entity, called an independent aggregator (IA), that pools the flexible capacity of electricity consumption, storage and/or generation of various consumers or producers independent from the market party that supplies electricity to the aggregator's customers. Fingrid has been tasked with evaluating the detailed implementation of cost reimbursement for demand response activated by an IA and identifying the clarifications needed for practical implementation. DNV has been asked to support Fingrid on this.

This study aims to define how an IA can participate in the day-ahead, intraday, and balancing energy markets, specifically the aFRR and mFRR balancing energy markets in Finland. The assessment has three sub-objectives. First, it aims to support the development of Finland's independent aggregation model by examining the types of independent aggregation models used in other countries for the day-ahead, intraday, and balancing energy markets (aFRR, mFRR, and FCR). Second, possible compensation models are determined, including reference price options for independent aggregation in the different markets. The financial impact of these compensation models and reference price options on key market participants is analysed, focusing on compensation model to be fair and non-discriminatory for all parties involved. Third, it aims to assess the practical implementation of independent aggregation in Finland, focusing on the day-ahead and intraday markets.

The various independent aggregation models are introduced by means of the USEF framework. Three main independent aggregation models are included under the framework: the uncorrected model, the corrected model and the central settlement model. The implementation of independent aggregation models in wholesale markets (DA and ID) as well as FCR, mFRR and aFRR, is analysed by means of a comparative assessment. Eight European countries are selected for this analysis: Belgium, Denmark, Estonia, France, Great Britain, Italy, Poland and Switzerland. The countries are assessed on the basis of their used/proposed independent aggregation model and compensation model.

The comparative analysis shows that the IA Model (IAM) varies by country, but there is a trend towards central settlement in most markets. Most countries first implement independent aggregation in balancing markets, with only Belgium and France having implemented independent aggregation in wholesale markets (in Great Brittain the implementation is planned). Balance responsibility differs widely. In Belgium, France and Great Brittain, IAs must act as or assign a Balance Responsible Party (BRP) in wholesale markets. In balancing markets, some countries require the aggregator to perform/assign the BRP role (Switzerland, Belgium and Estonia, depending on the specific balancing market) and others require only financial balance responsibility (Finland, Great Brittain and France). For the other countries (Denmark, Italy and Poland), the aggregator has no balance responsibility. Approaches to flexibility management and imbalance settlement vary, with reforms aimed at simplifying IA participation.

Regulatory frameworks and technological limitations also impact IA involvement, with barriers like minimum bid sizes and metering requirements still present. However, reforms via the EU's EMD reform and Network Code on Demand Response, aim to reduce these barriers. Data suggests an increasing IA participation in demand-side flexibility, despite challenges. Key issues include the rebound effect (where load reductions or increase cause imbalances in supplier portfolios), and verifying service delivery through audits and smart meters.

The analysis of compensation models in Belgium and France for day ahead and intraday wholesale markets, shows that the ToE price is based on prices in wholesale markets (e.g. DA, forwards), including also the capacity market in France, approximating either the suppliers' sourcing costs or customer's retail price. In balancing markets, all eight countries have implemented (to varying degrees) or started implementing independent aggregation. The reference price is typically either the same as in wholesale markets or equal to the day-ahead spot price.

Different options for the ToE price exist. On the basis of the comparative assessment and based on the principles of creating a level playing field and avoiding potential market distortions, DNV proposes a ToE price that approximates the retail price in the Finnish market. A formula is suggested for fixed price-contracts that includes the various relevant price components and their weights multiplied by a factor of 1.4, to take into account the gross margin of suppliers. For contracts mirroring the day-ahead prices (spot price or dynamic contracts), the formula would be similar the day-ahead price plus a margin representative for such contracts in Finland. The gross margin generally covers all other costs than the wholesale price of electricity itself for a supplier, and its profit. Furthermore, four examples are provided of relevant demand response technologies to illustrate the impact of the ToE price on three key stakeholders: the BRP of the supplier, the BRP of the IA and the retail consumer. The examples illustrate that the impact of the (level of) ToE price formula is limited, or even non-existent when the rebound is close or equal to 100 %. For lower or higher rebound ratios this dependency is more relevant, yet the arbitrage position of the IA still mimics the arbitrage position of a supplier using the integrated aggregator model.

Eight main processes have been identified relevant for the implementation of independent aggregation: Measurements used for flexibility quantification, Determination and verification of baseline methodology, Wholesale nomination, Flexibility quantification and ToE volume calculation, Compensation and financial settlement of ToE, Imbalance settlement, Master data (connection / flex registry) and Prequalification. Three phases are relevant for the consideration of the required processes: contractual phase, ex-ante and the ex-post phase. These phases are linked to processes in order to further detail the required roles and responsibilities for a successful implementation of IA in wholesale and balancing markets. Each of these eight processes involves different roles and responsibilities and DNV has identified the required changes to existing processes and roles to be assigned. Some implementation steps require new processes and some need modifications to existing processes.

DNV provides several recommendations regarding practical implementation of independent aggregation in Finland. For flexibility measurement, DNV recommends using submeters to improve accuracy and allow multiple Independent Aggregators per connection. The Central Flexibility Information System (CFIS) should handle submeter data validation, as well asl flexibility quantification. DNV also suggests that the National Regulatory Authority (NRA) should determine allowed baseline methodologies and their required accuracy, with regular monitoring of baseline quality by the CFIS. Additionally, an ex-ante information exchange through the CFIS should be considered to prevent Suppliers from counterbalancing IA activations, while keeping customer details confidential.

In terms of ToE (Transfer of Energy) volume calculation, DNV proposes that IAs should be responsible for portfolio balance during activation to simplify processes and encourage accurate baseline selection. For financial settlements, DNV recommends that the IA needs to control the rebound effect, and provides suggestions how to enforce this. Additionally, the same ToE price formula should be applied to all markets, including balancing (deviating from the current proposal which is the DA market price for balancing). DNV also notes that separate financial settlements for IA-Balancing Service Providers (IA-BSPs) are unnecessary for wholesale markets, provided IA-BSPs take on the Balancing Responsible Party (BRP) role. The CFIS is recommended to manage master data and provide necessary information to eSett, and prequalification processes should build on existing IA-BSP procedures. Fingrid, the Transmission System Operator (TSO), should oversee prequalification due to its current role in the balancing market.

Final decisions should be taken by the national regulatory authority and other relevant parties on each of the eight processes, as indicated by DNV’s analysis.

2 INTRODUCTION

Independent aggregation in electricity markets involves a third-party entity, known as an independent aggregator, combining the flexible capacity of electricity consumption, storage and/ or generation of multiple consumers or producers. This aggregated capacity is then managed and optimized to engage in various electricity markets, such as day-ahead, intraday, and balancing energy markets.

Aggregation is referred to in the Electricity Market Act (497/2023) as an activity that combines several end-user loads or electricity production for sale, purchase, or auction in the electricity market. An IA is a party who is not tied to the end-user's open electricity supplier. This approach enables smaller consumers or producers, who might not have the scale to participate on their own, to take part in and benefit from electricity markets, also when they are not directly exposed to wholesale prices.

Amendments to the Electricity Market Act (497/2023, 72a) stipulate that the transmission system operator in Finland, Fingrid Oyj, is responsible for defining the independent aggregation compensation calculation method (the compensation model) for the day-ahead market, intraday market, and balancing energy market.

Additionally, the Ministry of Economic Affairs and Employment has tasked Fingrid with evaluating the detailed implementation of cost reimbursement for demand response activated by an IA and identifying the clarifications needed for practical implementation. These clarifications might address the verification of demand response provided by IAs, the inclusion of demand response in imbalance settlement, and the payment of associated financial compensation. Fingrid is required to submit its evaluation to the Ministry by the end of March 2025.

In February 2024, Fingrid established a working group on behalf of the Ministry of Economic Affairs and Employment to evaluate the practical implementation of independent aggregation in the electricity market. The Ministry will use the working group's findings and Fingrid's assessment to draft a Government Decree on independent aggregation. This potential regulation is referenced in Sections 65a and 72a of the amended Electricity Market Act 497/2023.

The objective of this study is to determine how an IA can participate in the day-ahead, intraday, and balancing energy markets, specifically the aFRR and mFRR balancing energy markets in Finland. The assessment has three sub-objectives, that are sequentially addressed in this report.

First, it aims to support the development of Finland's independent aggregation model by examining the types of independent aggregation models used in other countries for the day-ahead, intraday, and balancing energy markets (aFRR, mFRR, and FCR-N).

Second, possible compensation models are determined, including reference price options for independent aggregation in the day-ahead, intraday, and balancing energy markets (aFRR and mFRR). The financial impact of these compensation models and reference price options on key market participants will be analysed. The compensation model should be fair and non-discriminatory for all parties involved.

Third, it aims to assess the practical implementation of independent aggregation in Finland, focusing on the day-ahead and intraday markets. It describes key processes required for practical implementation in these markets. It identifies, describes, and compares implementation options regarding the verification of flexibility, baseline determination, financial compensation payment, electricity balance adjustment, and imbalance settlement. Additionally, it does suggestions on the development needs for the independent aggregation model of the balancing energy markets (aFRR and mFRR) already defined and planned by Fingrid.

3 INDEPENDENT AGGREGATION MODELS

This Chapter focuses on the assessment of independent aggregation models in selected European countries for wholesale markets, FCR, mFRR and aFRR. The selected European countries are: Belgium, Denmark, Estonia, France, Great Britain, Italy, Poland and Switzerland. The selection has been agreed with Fingrid and countries are included either because there is significant progress on implementing independent aggregation models, or because the country chose different approach towards implementation The Chapter starts with a definition of (independent) aggregation and the different models. Afterwards, an international comparative assessment for the selected countries is included based on the following aspects: applied model (based on USEF classification), balance responsibility, participation level and other aspects such as the rebound effect.

3.1 Assessment framework independent aggregation models

Aggregation is referred to in the Electricity Market Act (497/2023) as an activity that combines several end-user loads or electricity production for sale, purchase, or auction in the electricity market. An IA is a party who is not tied to the end-user's open electricity supplier.

Models should be understood as how aggregation is implemented. The USEF publication Recommended practices for Demand Response market design (2017) introduces seven Aggregation Implementation Models (AIMs)[1]. As per the USEF aggregator implementation model classification, the models that do not require a contractual relationship (independent) between aggregator and supplier are the uncorrected, the central settlement and the corrected model. Each model will be briefly explained below. Furthermore, an overview of the models is provided in Figure 3-1.

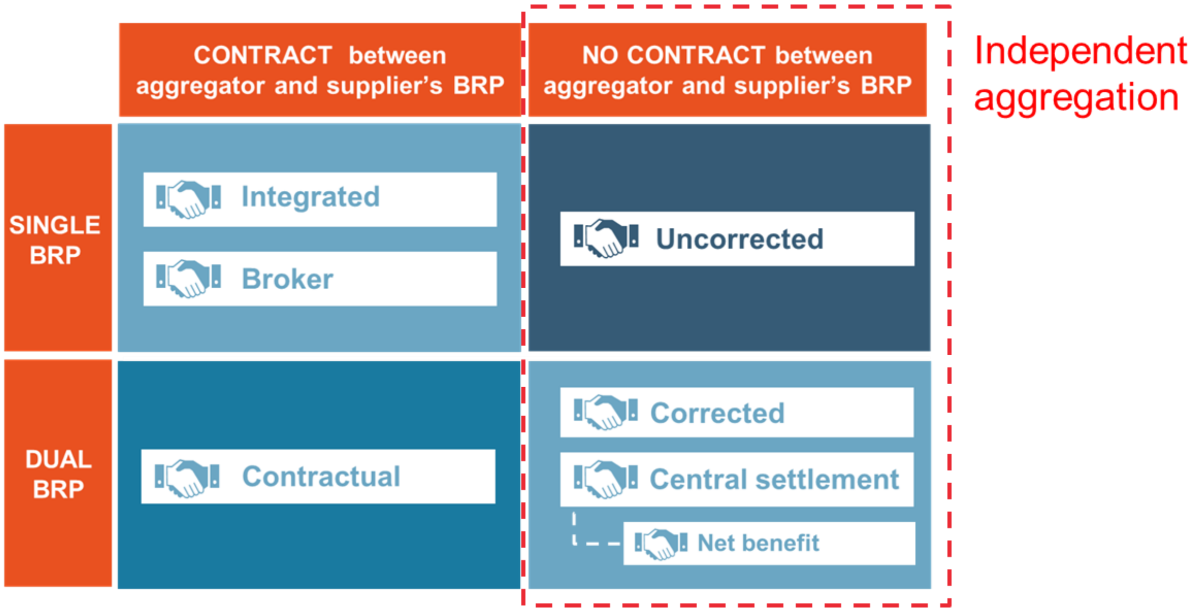


Figure 3-1: Aggregator implementation models determine key aspects of the relation between aggregator and supplier. USEF distinguishes seven models.

3.1.1 Non-Independent Aggregator Models

While this study examines IA models, it is important to also consider non-independent aggregator models, as they are already present in Europe and offer an alternative to independent aggregation.

[1] Flexibility Deployment in Europe White Paper A solid foundation for smart energy futures. (n.d.). Retrieved July 23, 2024, from https://www.usef.energy/app/uploads/2021/03/08032021-White-paper-Flexibility-Deployment-in-Europe-version-1.0-3.pdf

- **Integrated Model:** In this model, the roles of supplier and aggregator are combined within a single market entity.
- **Broker Model:** Here, the aggregator manages flexibility within the supplier's portfolio. The relationship between the aggregator and the supplier is defined by an agreement. Although aggregators do not directly perform the Balance Responsible Party (BRP) role, they coordinate with the supplier’s BRP to address any imbalances caused by the aggregator's actions.
- **Contractual Model:** In this setup, the aggregator and the supplier operate as separate market entities, each with their own BRP. The aggregator assumes balance responsibility during flexibility activation, often limited to specific flexible assets, while the supplier maintains balance responsibility for the connection. Following a flexibility activation, the supplier and aggregator trade the energy at a pre-agreed contractual price.

3.1.2 Independent Aggregator Models

According to the USEF aggregator implementation model classification, three independent aggregation models exist: the uncorrected model, the central settlement model, and the corrected model.

- **Uncorrected Model**
    - Balance Responsibility: In the uncorrected model, the aggregator is not responsible for balance or financial imbalances caused by flexibility activations. The supplier’s Balance Responsible Party (BRP) might experience imbalances after flexibility activations, which are not adjusted by the system operator or Imbalance Settlement Responsible (ISR). However, flexibility activation can aid in system balance, potentially resulting in the supplier’s BRP being compensated as part of the imbalance settlement mechanism due to passive balance contributions.
    - Sourcing Position: This model does not directly balance the sourcing position. However, if the passive balance contribution is remunerated through the imbalance settlement mechanism, the supplier’s BRP will be implicitly compensated for the sourced energy at the imbalance price.
    - Information Exchange & Confidentiality: No specific information exchange is needed beyond market or service participation requirements. The supplier is not informed about the aggregator’s presence, though it might be inferred from customer behaviour analysis through metering data.
- **Central Settlement Model**
    - Balance Responsibility: In this model, the aggregator holds balance or financial responsibility for any imbalances caused by flexibility activations, including potential rebound effects occurring outside the activation window. The central entity, such as a system operator or ISR, corrects the supplier’s BRP perimeter by adjusting for the deviations caused by the aggregator, known as imbalance adjustment.
    - Sourcing Position: Energy transfer is managed through a central entity, with pricing regulated by the National Regulatory Authority. The aggregator pays for the sourced energy at the Transfer of Energy (ToE) price to the central entity, which then compensates the supplier. In cases of load enhancement or generation reduction, energy and payment flow in reverse. If compensation for sourced energy is handled by society or other benefiting entities rather than the aggregator, this model is termed the net benefit model.
    - Information Exchange & Confidentiality: The central entity calculates activated volumes per ISP for each aggregator, typically based on the aggregator’s data (e.g., sub-meter data, activated assets/customers). The central entity does not disclose the identities of customers or aggregators to the supplier, ensuring a level playing field. The supplier is informed about the total amount of activated flexibility within its portfolio per ISP.

- **Corrected Model**
    - Balance Responsibility: Similar to the central settlement model, the aggregator is responsible for imbalances during and potentially after flexibility activations. There are two variations in this model:
        - Type A: A central entity, like a meter data company, adjusts the meter data to reflect the flexibility amount activated during delivery. Hence, the supplier's BRP perimeter remains unchanged since imbalance settlement is based on corrected metering data.
        - Type B: A central entity communicates the activated flexibility volumes to the supplier's BRP, which bills the customer as if no flexibility was activated. The supplier's BRP perimeter is adjusted by the central entity based on the activated flexibility.
        - For both types, the aggregator's BRP perimeter is corrected by the central entity if the aggregator holds formal balance responsibility.
    - Sourcing Position: Energy transfer in this model goes through the customer. The supplier bills the customer as if flexibility was not activated, and the aggregator compensates the customer for the billed but unconsumed energy at the retail price. The differences in sub-models are:
        - Type A: The supplier bills the customer using corrected meter values.
        - Type B: The supplier bills the customer using original meter values, with a specification for the activated flexibility volume.
        - Tax and network tariff calculations should be based on actual consumption rather than corrected meter values.
    - Information Exchange: Information exchange requirements differ by sub-model:
        - Type A: The supplier receives no information on flexibility activations or the presence of an aggregator, preserving confidentiality and preventing detection through meter readings
        - Type B: A central entity informs the supplier of activated flexibility volumes per customer, per ISP. While the identity of the aggregator is not disclosed, it reveals which customers have valorised flexibility, which can be commercially sensitive.

3.2 Analysis of Independent Aggregation Models (IAMs) per country and market

This Section outlines what type of independent aggregation models is applied in different market products across selected European countries: Belgium, Denmark, Estonia, France, Great Britain, Italy, Poland and Switzerland. For each respective country, the different markets in which independent aggregation is applied are assessed: the FCR market, the mFRR and aFRR market and wholesale markets (e.g. day-ahead and intraday).

Belgium presents a relatively advanced independent aggregator framework as IAs can participate in all markets, although with certain limitations. All IA models described in Section 3.1.2 are implemented in Belgium across the different markets:

- In the FCR market, the *uncorrected model* is applicable because FCR is a symmetrical product. It does not entail any energy payments (only power) and has low impact at the perimeter of supplier's BRP in terms of quantity of energy traded. The IA (BSP) is remunerated with the capacity payment already in place for the FCR market.
- For mFRR and wholesale, there are two options for IAs: the *central settlement model* as fall-back if implementation of the contractual model fails, and the *corrected model* for larger consumers. As dictated by the

regulation, aggregator and supplier must first engage in negotiations to try to reach an agreement in an 'opt-out option', which means that a non-independent aggregation model (contractual model) is the first option (in this case, ELIA can perform the ToE (perimeter correction), yet ELIA does not perform the financial settlement). If both parties cannot reach an agreement, independent aggregation under the central settlement model is the fall-back option. When the central settlement model is applied, the IA needs to either perform the BRP role or assign it to a third party to cover the balance responsibility of the flexibility delivery during activations. The Belgian TSO, Elia, corrects the perimeter of the supplier's BRP and organises the transfer of energy (ToE) centrally, against a regulated price. Alternatively, without the need to go through negotiations with a supplier, the aggregator can opt for 'pass-through contracts. This option is only available for large industrial customers that have their own balance responsibility or send schedules with the planned consumption to their supplier. The flexibility activation is charged against the customer's nomination, who pays any deviation at the imbalance price. When there is a flexibility activation, the aggregator would remunerate the customer for the use of their flexibility and for the extra costs charged by the supplier. Thus, the supplier is not affected by the flexibility activation. This model can be considered as *corrected model*, because the transfer of energy goes through the customer.

- For the aFRR market, where the opt-out option is applicable (non-IA contractual model), the options for IA are limited to only the *corrected model* (or 'pass-through' contract), as the fall-back into central settlement model is not allowed.

Denmark is in a preliminary stage of integrating independent aggregation model in the balancing markets. In FFR, FCR and FCR-D, the *uncorrected model* is already in place and the implementation of this model is justified by the limited amount of volume traded in FCR. Following a public hearing in summer 2023, the Danish TSO Energinet published a ruling proposal in on the definition and integration of independent aggregation model expended to FCR-N, aFRR and mFRR (no independent aggregation is yet allowed in the wholesale market). The ruling will become active most probably in the first half of 2026 and a *central settlement model* will be applied, even if the imbalance caused by the aggregator will be corrected for the Supplier's BRP by the TSO. According to Regulation C2 - 'Balance Market and Balance Settlement' of Energinet, the definition of IA is "balancing service provider that provides energy-intensive balancing services to the energy grid but does not itself assume balancing responsibility in connection with the purchase or delivery of the energy in the balancing service." [2].

In 2023, **Estonia** proposed the introduction of independent aggregation model in the mFRR market applying a *central settlement model*. The proposal was based on a revision of the Terms and Conditions for Electricity Balancing Agreement, defining the rights and obligations between the Estonian TSO Elering and the Balancing Authority (BRP) and the responsibilities of the latter for the performance of the Electricity Balancing Agreement. The System Operator must submit to the supplier's Balance Sheet Manager (BRP) the consumption management balancing energy deliveries activated through aggregator(s). In the case flexibility is delivered through the aggregator(s), the SO needs to organise the Transfer of Energy and settle financially with the balancing authority at day-ahead market price: in case of reduction of consumption, the SO purchases the energy imbalance from the balancing authority (BRP), while in case of increase of consumption, the SO sells the imbalance to the balancing authority (BRP). To avoid exchange of sensitive information on aggregated consumers, the SO is explicitly forbidden to transmit data to the supplier's Balance Authority (BRP) on aggregator consumption from the metering point[3]. While IAs are currently active in the mFRR market, their participation in the day-ahead or intraday market is not directly hindered or prohibited, but there is no incentive or commercial benefit for them to do so. A settlement mechanism similar to the one for mFRR is desired by the Estonian government and the TSO Elering has expressed their commitment in starting a business analysis on its implementation as from mid-2025.

[2] Høring over Energinets metodeanmeldelse vedrørende implementering af regler for uafhængige aggregatorer. (2024). Retrieved July 18, 2024, from Forsyningstilsynet.dk website: https://forsyningstilsynet.dk/vejledning-og-indberetning/hoeringer/2024/jan/hoering-over-energinets-metodeanmeldelse-vedroerende-implementering-af-regler-for-uafhaengige-aggregatorer

[3] Elering AS. ELEKTRIENERGIA BILANSILEPINGU TÜÜPTINGIMUSED. 2023.

In **France**, similar to Belgium, there are four models of possible independent aggregation: uncorrected, central settlement, corrected and contractual.

- For FCR, the *uncorrected model* is applied.
- For the other markets mFRR, RR and day-ahead and intraday trading, the other three models are applicable, but the choice is dependent on the characteristics of the connection. If the connection voltage is above 36 kV and has a specific type of contract, where the customer is settled separately for energy and network fees, the *corrected model* is the only viable option, whereas for connections below 36 kV, the model can be either *central settlement* or *corrected* (type A). The reason for this separation is that the correction should only apply to the energy contract, while the network fees should always reflect the real consumption/generation. In addition, correction of meter measurements for residential consumers is not legally allowed in the country, which automatically exclude the corrected model option for smaller connections. Hence, the central settlement model is also applied.
- aFRR was previously allowing the participation of IAs, but little participation has been observed. As from 2023, independent aggregation is not allowed in the market anymore, as the exemption for the TSO to contract secondary reserve is ended. It is probable that in the future this will be updated [4].

In **Great Britain,** two models can be found: *uncorrected* and another model that could be categorised as either *central settlement* or *corrected* depending on customer consensus.

- In balancing markets (such as FCR, which participates outside of the Balancing Mechanism (BM), and the capacity mechanism), the *uncorrected model* is applied.
- For the Balancing Mechanism and RR, aggregators are referred to as Virtual Lead Party (VLP), almost equivalent as Balance Service Provider (BSP), and the imbalance settlement responsible authority is not the TSO (as in all other cases) but a separate entity ELEXON. The current mechanism returns the Supplier to a balanced position, without a price ascribed to that transfer. The result is that the Supplier bills the customer for consumption showing in the meter which the Supplier did not actually purchase. That energy, which was purchased by the VLP in the BM, has been transferred from the VLP to the Supplier unpriced [5]. We classify this as *central settlement model* but with ToE price at 0.
- Ofgem had amended the Balancing and Settlement Code for facilitating access to wholesale markets for flexibility dispatched by VLPs. In the decision, the same model implemented for the balancing mechanism (i.e. central settlement) is considered. A particularity of the proposed implementation is the fact that the compensation of the Suppliers impacted by IAs' flexibility activations will be socialised among all Suppliers active in the market. This model is called *Net Benefit Model* in the USEF framework [6]. Ofgem's decision has been published in October 2023 and is planned to be implemented on November 7, 2024 [7].

Italy made important steps in opening the ancillary service market to pilot projects for distributed resources in 2017 with a resolution from the regulatory authority ARERA[8]. The Italian regulation refers to aggregators as Virtually Aggregated Units (UVAs) and initially made a separation between consumption - UVAC (Virtually Aggregated Consumption Unit), and production - UVAP (Virtually Aggregated Production Unit) moving then in 2019 to the concept of UVAM (Virtually

[4] LCP Delta Subscriber Portal - View. (2023). Retrieved July 18, 2024, from Lcpdelta.com website: https://research.lcpdelta.com/reports/SmartEn_MarketMonitor_2023/files/2023MarketMonitor_V5/Page3?searchHighlight=smarten
[5] *Balancing and Settlement Code (BSC) P415: Facilitating access to wholesale markets for flexibility dispatched by Virtual Lead Parties (P415) Decision: The Authority 1 directs that the modification be made 2*. (n.d.). Retrieved from https://www.elexon.co.uk/documents/change/modifications/p401-p450/p415-ofgem-decision/
[6] *A solid foundation for smart energy futures USEF: THE FRAMEWORK EXPLAINED*. (n.d.). Retrieved from https://www.usef.energy/app/uploads/2021/05/USEF-The-Framework-Explained-update-2021.pdf
[7] *Balancing and Settlement Code (BSC) P415: Facilitating access to wholesale markets for flexibility dispatched by Virtual Lead Parties (P415)*. Retrieved from https://www.ofgem.gov.uk/sites/default/files/2023-10/Ofgem%20decision%20P415%20%27Facilitating%20Access%20to%20Wholesale%20Markets%20for%20Flexibility%20Dispatched%20by%20VLPs_0.pdf
[8] Testo coordinato delle integrazioni e modifiche apportate con le deliberazioni 372/2017/R/EEL e 422/2018/R/EEL DELIBERAZIONE 5 MAGGIO 2017 300/2017/R/EELRetrieved from https://www.energiaflessibile.eu/documenti/300-17ti.pdf

Aggregated Mixed Unit, i.e. consumption and production). UVAs are considered as Balancing Service Provider (BSP) but can be independent from energy suppliers and do not need to be BRPs, even if most aggregators in the Italian landscape coincide with BRPs (and even suppliers, so independent aggregation is still an uncommon practice). The pilot will last until the end of 2024 and from 2025 the definitive regulation (Testo Integrato del Dispacciamento Elettrico – TIDE) will come into force. The pilot projects allowed UVAs to access certain ancillary services, secondary and tertiary reserve services (aFRR, mFRR and RR) and congestion management. FCR market should open to aggregation with the definitive regulation in 2025, while energy wholesale markets are still not included. Currently, the UVA (BSP) is remunerated if the service is correctly delivered but the BSP is still responsible to pay a penalty if the activated flexibility does not correspond with the contracted service volume. This arrangement falls under the definition of *central settlement*, with the only deviation from the model definition, that the UVA (BSP) does not have balancing responsibility but is only responsible to deliver the flexibility services contracted. The perimeter correction and settlement between BSP and BRP is facilitated by the TSO. As this framework is currently under complete revision by the regulator and TSO until the conclusion of the testing phase in year 2024 and implementation of the final regulation as of January 2025, some aspects outlined in the text might not be fully updated, as they reflect the state-of-the-art at the moment of writing.

In **Poland**, a market reform entered into force in July 2023, which amends the Polish Energy Law ('*USTAWA z dnia 10 kwietnia 1997 r. Prawo energetyczne*')[9], makes DSR and, in particular also, independent aggregation eligible to participate in the wholesale electricity markets (including day-ahead and intra-day), as well as the balancing market, providing balancing services, ancillary services (through the so-called service Intervention Reduction of Consumption, '*Interwencyjna Redukcja Poboru'*, IRP) and congestion management [10] [11]. Before, DSR services were contracted in a capacity market dedicated program, which was discontinued in 2021 with changes in regulation to adapt to European requirements. The new amendment of the Energy Law, applicable as from July 2024, comes together with a balancing market reform entering into force in June 2024[12], which changed terms and conditions for balancing market resources, opening the market to a wider range of balancing resources. An IA is simply defined by the law as "an aggregator not affiliated with the customer's electricity seller". In balancing markets, electricity customers can be contracted by a DR (independent) aggregator without the prior consent of the supplier, but the supplier needs to be informed about it. According to the new regulation, the power system operators need to specify in a manual the technical requirements for participation in the so-called off-take response (which refers to demand reduction response) and participation by aggregation in electricity trading, balancing market and system services. So far, the requirements seem to be limited to technical capabilities to deliver balancing services and sharing metering data with TSO for billing and verification purposes[13]. With the currently available information, the aggregation framework applied by Poland for balancing market falls under the *central settlement model* description.

Finally, in **Switzerland**, *uncorrected* and *central settlement model* can both be found. The first is applicable for FCR whereas central settlement applies to aFRR and mFRR. Participation of IAs in wholesale market is not allowed yet, although in 2022 Swissgrid mentioned to have been looking into further opening the wholesale market to aggregators through a central settlement model.

3.3 International comparative assessment

In this Section, an overview is provided of the various IAMs in the selected countries and markets (see Table 1). Besides, the selected countries are compared on the following aspects: balance responsibility, participation levels and other aspects (e.g. rebound effect).

[9] Cabinet Office of the Sejm. Journal of Laws. 1997 No. 54 Item 348 USTAWA of April 10, 1997. Energy Law. 2024.
[10] Polish implementation plan 2. (n.d.). Retrieved from https://energy.ec.europa.eu/system/files/2020-02/polish_implementation_plan_final_0.pdf
[11] Interwencyjna Redukcja Poboru - PSE. (2020). Retrieved July 18, 2024, from Www.pse.pl website: https://www.pse.pl/uslugi-dsr/interwencyjna-redukcja-poboru
[12] Programy DSR w latach 2017-2021 - PSE. (2017). Retrieved July 18, 2024, from Www.pse.pl website: https://www.pse.pl/uslugi-dsr/programy-dsr-w-latach-2017-2021
[13] Dokumenty - PSE. (2020). Retrieved July 18, 2024, from Www.pse.pl website: https://www.pse.pl/uslugi-dsr/dokumenty-dsr

Table 1: Overview IAMs in each country.

	Wholesale	Balancing Market		
		FCR	aFRR	mFRR & RR
Belgium	Corrected* Central settlement	Uncorrected	Corrected*	Corrected* Central settlement
Denmark	*No IAM implemented (only non-IAM)*	Uncorrected	*No IAM implemented (Central settlement as from 2026)*	*No IAM implemented (Central settlement as from 2026)*
Estonia	*No IAM implemented (central settlement under evaluation as from 2025)*	*No IAM implemented*	*No IAM implemented*	Central settlement (complete transition in October 2024)
France	Corrected Central Settlement	Uncorrected	*No IAM implemented (only non-IAM allowed as from 2024)*	Corrected Central Settlement
Great Britain	Central settlement (in implementation)	Uncorrected Central settlement	Central settlement	Central settlement
Italy	*No IAM implemented (aggregation not allowed)*	*No IAM implemented (under discussion as from 2025)*	Central settlement (complete transition in 2025)	Central settlement (complete transition in 2025)
Poland	*No IAM implemented (central settlement in implementation phase)*	Central settlement	Central settlement	Central settlement
Switzerland	*No IAM implemented (central settlement under discussion)*	Uncorrected	Central settlement	Central settlement

*When consumers can nominate their own energy schedule.

3.3.1 Balance responsibilities

In this Section, it is explained how different countries have regulated assigned (or not) the balance responsibility to the IA in each relevant market. Figure 3-2 provides a summary for each country and market. It is important to clarify that, in the IAM examples where the aggregator needs to assign or perform the role of a BRP, the aggregator's BRP is only responsible for balancing in the period in which flexibility is activated, and only for the volume of flexibility delivered (defined as the difference between measurements and baseline). The rest of the time, the balance responsibility is held by the supplier's BRP. See Figure 3-2 for an overview.

Wholesale market

In general, for countries where wholesale markets are open to IAs, such as **France** and **Belgium**, the aggregator needs to assign to a third party or perform itself the role of BRP. However, the role of the IA's BRP (BRPagr) and the supplier's BRP (BRPsup) are slightly different. The BRPsup represents and is responsible for the customer connection at all times, while the BRPagr is only responsible for the potential system imbalance caused by the activation of flexibility.

In the case of **Belgium**, transfer of energy in *central settlement* for the wholesale market works as follows:

1. **Day-ahead:** the BRPagr sells X MWh for a period P on day D to a flexibility requisitioner BRP (BRPfrp). BRPagr nominates X in their programme as a selling trade. BRPagr is in imbalance by X MWh.
2. **Day-ahead:** BRPagr needs to nominate, as a buying trade, the X MWh that will be activated in the aggregator's portfolio so the BRPagr is in balance.

3. **Intraday:** The aggregator activates X MWh of flexibility during period P. The aggregator communicates to the Belgian TSO Elia the delivered volume per connection point, before, during and after activation. At the same time, the TSO communicates to the BRPsup the amount of flexibility that is being activated on their portfolio, to avoid any counterbalancing actions on their side.

4. **After delivery:** Elia quantifies the delivered volumes by comparing the metering at the connection to the baseline. The baseline methodology is defined in the transfer of energy rules. Elia corrects the perimeter of the BRPsup and BRPagr based on the delivered flexibility.

5. Finally, the imbalance settlement is performed and the financial compensation between BRPagr and BRPsup is arranged.

In 2021, Elia published a white paper on a roll-out of Consumer Centric Market Design which aims to remove the necessity of a BRP agreement for wholesale participation by 2023/2024 by easing the "physical balancing obligation which applies for all connection points in the portfolio of a BRP" [14]. The implementation of this CCMD is currently being addressed.

When applying the *corrected model* in **France**, correction aspect differs as this takes place at the level of the meter data. French TSO RTE does not need to perform any perimeter correction on BRPsup's portfolio, while it still needs to perform the perimeter correction on the BRPagr's portfolio.

Balancing Markets

In **Belgium** and **Switzerland**, the aggregator needs to assign/perform a BRP role also in the balancing market services, except for FCR in Belgium. The main difference from the Belgian implementation in the wholesale market is that the perimeter correction of the aggregator's BRP is performed based on the volume of flexibility ordered by the TSO. Therefore, any imbalance will be reflected in the portfolio of the aggregator's BRP.

In **France,** the aggregator does not need to assign a BRP, but it acts instead as a "floating BSP" that is financially responsible for the imbalances caused in the system.

In the examples of the other countries, the IA (BSP) does not need to assign or perform the BRP role but is financially responsible for its imbalances. When applying this in the central settlement or corrected (type B) model, the TSO corrects the BRPsup's perimeter based on the delivered calculated flexibility (per connection, declared ex-post by the aggregator). The aggregator is required to provide the requested amount of flexibility, hence any deviation from the requested amount causes an imbalance in the system and is reflected in a penalty for the BSP. Penalisation for imbalances vary depending on the implementation. A particular example is **Great Britain**, where the BSP (VLP) is only charged for imbalance in case of under-delivery (and if the correction model applies) but not for an over-delivery.

During the **Italian** pilot phase, the UVAs that want to participate need to supply the baseline, their reserve flexibility volume and ultimately the actual measure delivered volume. The UVAs are selected based on a merit order of volume and price offered. Based on this data, the Italian TSO Terna balances the affected suppliers' BRPs' portfolios, informing them that a capacity and a volume of flexibility has been contracted in its portfolio through an aggregator and the BRP will be charged the above-mentioned compensations of the UVA. In case of under- or overdeliver of the UVAs, the supplier's BRP is only responsible for the contracted imbalance of the UVAs, while the latter would need to pay a penalty for not delivery the contracted flexibility volume.

[14] 20210618 Elia Group publishes white paper on a consumer-centric and sustainable electricity system. (2021). Retrieved July 18, 2024, from Eliagroup.eu website: https://www.eliagroup.eu/en/news/press-releases/2021/06/20210618-elia-group-publishes-white-paper-on-a-consumer-centric-and-sustainable-electricity-system

A similar arrangement is currently present in **Poland**: with the balancing market reform of June 2024, the role of BSP and BRP can now exist independently in the Polish balancing market and the IA does not have to contract nor to perform a BRP role. In fact, it is the role of the TSO to correct the supplier's BRP perimeter[15].

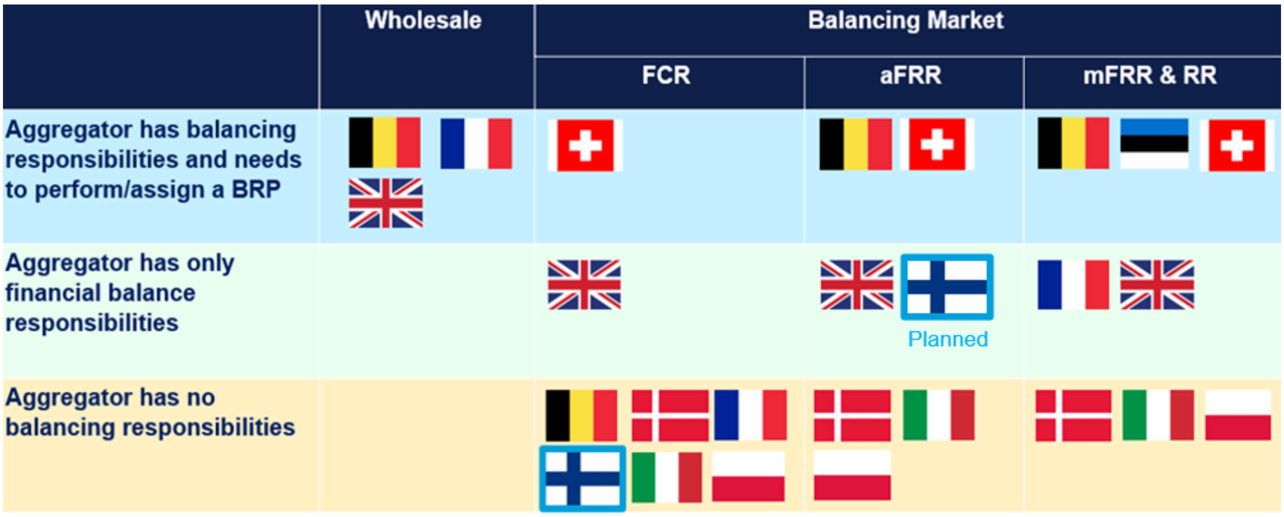


Figure 3-2: Balance responsibilities across the selected countries and markets.

3.3.2 Participation level per market

Different markets show different participation levels of IAs. Reasons are several for a low or high participation: for example, the Italian pilot project only allowed participation of IAs in a later stage (2022), when observing reluctancy for supplier's BRP to allow aggregators' activation. Also, large players in the market can hinder the full-scale development of IAs.

However, there are also several regulatory and market barriers that can hinder the participation of aggregators, especially the aggregators with smaller portfolio encompassing small-scale users. Below, an overview of the limitations to IAM applications in the selected European countries is provided. Limitations observed are those related to specific technologies allowed to participate or not in market products, the limitation of direction of flexibility service (symmetrical or not), limitation at voltage connection levels and other limitations concerning contract types, metering equipment, etc. An overview of the limitations is provided in Table 2.

None of the selected European countries poses limitations to the participation of any technology in an IA's portfolio. There are instead limitations in **France** with regards to the directions of the flexibility service: only downward demand-side flexibility is allowed[16] [17].

In **Belgium** and **France**, limited participation at low voltage level is allowed. In general, this prevents participation of residential consumers through aggregation, because of the limited access to accurate metering data. For France, the limitation is only partial, as low voltage consumers (<36 kV) have been granted an additional independent aggregation model option (central settlement) to overcome the metering device correction practice, which is not allowed for residential (profiled) meters.

Other common limitations are metering capabilities, which in balancing markets need to provide high-frequency communication between the customer's meters and the TSO in **Great Britain** and **Italy**, for example. Other countries have lower requirements for meter participations or are rolling out smart meters in residential assets (i.e. all units in residential sector that can be used for flexibility through a submeter; EVs, heat pumps, batteries etc) as alternative or

[15] Unstructured interview with Polish TSO PSE on August 8, 2024
[16] Polskie Sieci Elektroenergetyczne S.A. - PSE. PSE Development Plan for Meeting the Current and Future Electricity Demand for 2023-2032. 2023.
[17] Interwencyjna Redukcja Poboru - PSE. (2020). Retrieved July 18, 2024, from Www.pse.pl website: https://www.pse.pl/uslugi-dsr/interwencyjna-redukcja-poboru

complementary measures. In **Belgium**, Flanders region's smart meter rollout aims to equip 80% of the residential stock by end of 2024, after net metering has been removed in 2023. This combination of measures is expected to increase flexibility from implicit demand response in residential assets. The regions of Wallonia and Brussels will also see a gradual increase[18]. In addition, Elia allows asset metering (or sub-metering) in mFRR[19] [20] and **Denmark** and **Estonia** are planning to follow.

The next step that some countries are taking is to assess the use of submetering in wholesale market as well. For example, in **France**, RTE launched in the NEBEF mechanism (wholesale market) an experiment on the possibility of monitoring load reductions achieved from measurements obtained at a lower scale than that of the site (i.e. submetering). The experiment has been running since 2021 and will be evaluated in 2025. So far, only Voltalis (an IA), has been approved as Demand Response Aggregators qualified for the submetering experiment. The purpose of the experiment is to identify whether implementing submetering would allow the emergence of new target markets, improve accuracy of the load reduction measurement and not generate risk in terms of load reductions: no effects of "compensation within the same site"[21].

In **Switzerland**, participation in the balancing market has a minimum bid size of 5 MW[22], which excludes the participation of smaller IAs. **Poland** has instead lowered this threshold in the new Balancing Market reform to 200 kW to facilitate smaller market participants[23]. See Table 2 for an overview of the limitations.

Table 2: Limitations of IAM application per selected country: technology, symmetry, voltage and other limitations are covered.

	Technology limitation	Symmetry limitation	Voltage limitation	Other limitations (ex. contract type, meter capabilities, etc.)
Belgium	*None*	*None*	Low voltage assets cannot participate on aFRR and mFRR.	Corrected model generally limited to industrial consumers.
Denmark	*None*	*None*	*None*	*None*
Estonia	*None*	*None*	*None*	*None*
France	*None*	Only downward regulation is considered.	Corrected model is applied for connection voltages above 36 kV and for customer settled separately for energy and network fees. Central settlement is an additional option for connections below 36 kV. Reasons for this are 1) separation of energy and network fees billing and 2) no legal manipulation of metering data allowed.	
Great Britain	*None*	Only in case of over delivery the corrected model is applied. Under delivery is not charged.	*None*	Connections have to be half-hourly / quarter-hourly settled to participate in services and markets, which is not the case for most residential customers.

[18] DELTA-EE. Belgium Consumer Flexibility Potential - Final Report for Elia. 28 Oct. 2022.
[19] Elia Transmission Belgium. Terms and Conditions for Balancing Service Providers for Manual Frequency Restoration Reserve (MFRR) ("T&C BSP MFRR"). 2020.
[20] Elia Transmission Belgium. General Technical Requirements of the Submetering Solutions. 2023.
[21] Participate in the submetering experiment - RTE Services Portal. (2021). Retrieved July 18, 2024, from Portail Services RTE website: https://www.services-rte.com/en/learn-more-about-our-services/participate-in-the-submetering-experiment.html
[22] LCP Delta Subscriber Portal - View. (2023). Retrieved July 18, 2024, from Lcpdelta.com website: https://research.lcpdelta.com/reports/SmartEn_MarketMonitor_2023/files/2023MarketMonitor_V5/Page3?searchHighlight=smarten
[23] Energy Regulatory Office. (2021). Second stage of the Balancing Market reform went live as of June 14. Retrieved July 18, 2024, from Energy Regulatory Office website: https://www.ure.gov.pl/en/communication/news/382,Second-stage-of-the-Balancing-Market-reform-went-live-as-of-June-14.html

	Technology limitation	Symmetry limitation	Voltage limitation	Other limitations (ex. contract type, meter capabilities, etc.)
Italy	*None*	*None*	*None*	BSP must have a time-stamped monitoring point and/ or connected with the TSO communication system, which is not the case for most residential customers.
Poland	*None*	*None*	*None*	*None*
Switzerland	*None*	*None*	*None*	Requirements for availability and size can make it difficult for small aggregators.

Looking at participation volumes in the different market products, it is not always possible to identify the share of IAs to flexibility provided by demand side response. The data publicly available depend on data collection and sharing practices from the TSO. It is however interesting to observe the volume of demand side flexibility in each country per market and try to qualitatively identify where aggregators and IAs contribute to a significant portion.

TSO Elia reports for **Belgium** the capacity contracted in mFRR through aggregation on a yearly basis in the Working Group Balancing. Latest numbers from the meeting in March 2024[24] show the status of 2023 and 2022 in comparison: the mFRR,up contracted in 2023 through independent aggregation is of 132 MW in total, a 3% increase from 2022 with 128 MW. This means that around 7% of the mFRR,up ToE goes via IAs (versus a 9% share in 2022), while the rest is through opt-out agreements (non-IA contractual model) which see the largest increase of 40% from 2022 to 2023. IA contracted capacity went completely through the central settlement model, while the pass-through contracts (corrected model) have in both years not been used. Elia did not provide further explanations for that in the meeting.

In **Denmark**, the TSO Energinet (like many other TSOs) does not distinguish between aggregated and non-aggregated BSPs, so it is not possible to easily provide data on the topic[25].

In **France**, demand response volumes valued with the NEBEF mechanism (wholesale market) can be tracked back to 2016. DSR volumes reached 11 GWh in 2016, 27 GWh in 2018, decreasing to 22.2 GWh in 2019 and then halved in 2020 to 11 GWh[26], although most of the 2019 demand response came from the aggregation of small units (households or professional sites). Since then, volumes have increased significantly with a total of 167 GWh (350 MW) contracted in 2023. A cumulative 1,9 GWh (150 MW) was mobilised by March 2024. When it comes to balancing markets, DSR contributed to FCR market from 18% in 2020 to 20% in 2021 and it remained stable to 45% of mFRR/RR in 2020 and 2021. By April 2022, DSF certified capacity in FCR market was just below 5% with 116 MW, in aFRR remains insignificant, while in mFRR is around 10% with approximately 150 MW, as shown from Figure 3-3 to Figure 3-5.[27] There are currently 18 approved aggregators active in France, of which only two, Flexcity and Voltalis, are qualified for profiled consumers (residential and small C&I).

[24] 20240327 meeting. (2024). Retrieved July 18, 2024, from Elia.be website: https://www.elia.be/en/users-group/wg-balancing/20240327-meeting
[25] Questionnaire's answers from Danish TSO.
[26] The regulation of independent aggregators. (2022). Retrieved July 18, 2024, from Norden.org website: https://pub.norden.org/nordicenergyresearch2022-04/#
[27] RTE report on balancing. (2022). Retrieved from https://www.services-rte.com/files/live/sites/services-rte/files/Balancing_report_2024.pdf

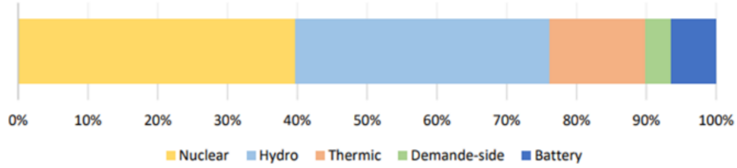


Figure 3-3: RTE certified capacities for FCR as of 1st of April 2022

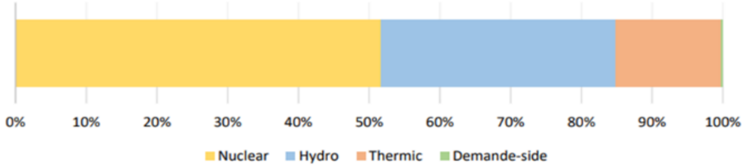


Figure 3-4: RTE certified capacities for aFRR as of 1st of April 2022

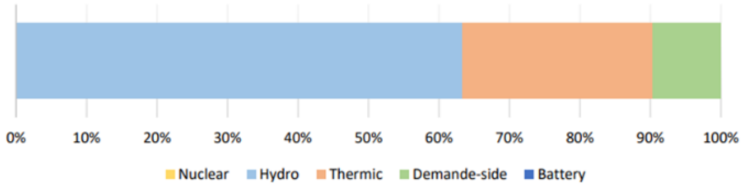


Figure 3-5: RTE certified capacities for mFRR/RR as of 1st of April 2022

Great Britain has seen a significant increase of participation in batteries for provision of flexibility. Still, through additional market products like the Demand Side Flexibility, also DSR has overall increased in balancing markets from 2,3 GW in 2017[28]. In 2023 FFR market, a total DSR capacity of 3 GW was contracted (up from 800-1200 MW of 2020, mainly from storage[29]), with DSF storage batteries covering almost the complete share of it, together with some load reduction in January and March[30]. It is interesting to observe that other flexibility providers such as utility-scale batteries and hydro, are still contracted at lower volume than DSF. In the second launch of the Demand Service of winter 2023/2024, 4,6 GWh of DSR was mobilised. ESO have launched the Demand Flexibility Service (DFS) for winter 2023/24. The service allows the ESO to access additional flexibility when the national demand is at its highest – during peak winter days – which is not currently accessible to the ESO in real time. The service will allow consumers – both domestic and C&I – to be incentivised for voluntarily flexing the time during which they use their electricity.[31] Finally, in the Balancing Mechanism, VLPs show a slight increase of volume from 2022 participation, reaching a total of 35 MWh, shadowed by the substantial growth of utility scale batteries, as shown in Figure 3-6 [32].

[28] Non-BM Balancing Services Volumes and Expenditure Contents. (n.d.). Retrieved from https://www.nationalgrideso.com/document/107511/download
[29] The regulation of independent aggregators. (2022). Retrieved July 18, 2024, from Norden.org website: https://pub.norden.org/nordicenergyresearch2022-04/#
[30] A roundup of developments in demand side flexibility markets in GB. (n.d.). Retrieved from https://www.nationalgrideso.com/document/322181/download
[31] Demand Flexibility Service 2023/24 | ESO. (2023). Retrieved July 18, 2024, from Nationalgrideso.com website: https://www.nationalgrideso.com/data-portal/demand-flexibility-service
[32] A roundup of developments in demand side flexibility markets in GB. (n.d.). Retrieved from https://www.nationalgrideso.com/document/322181/download

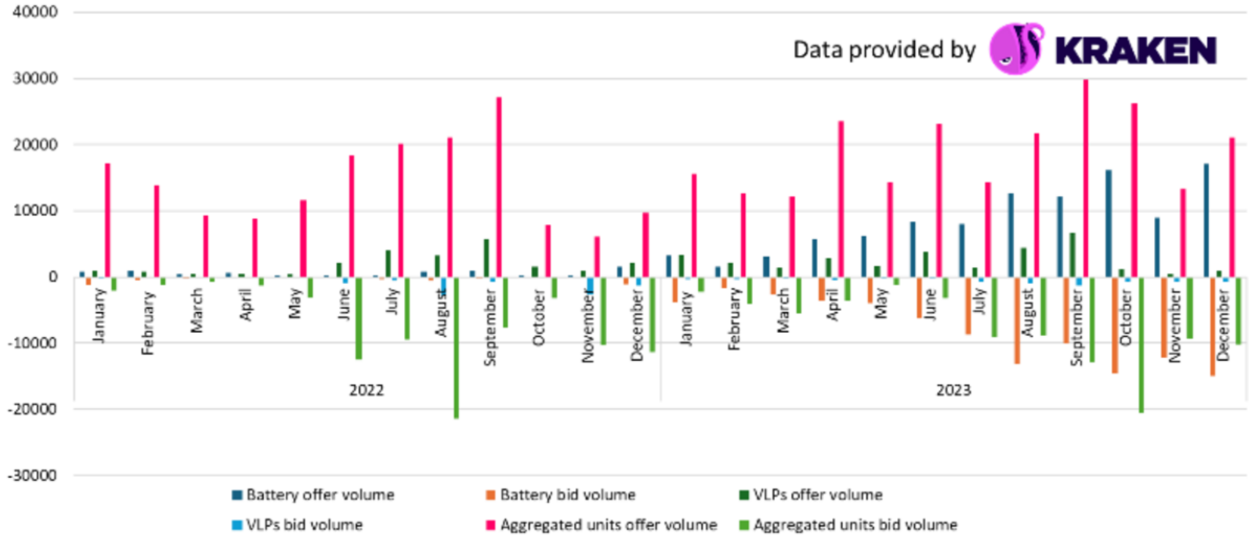


Figure 3-6: Balancing Mechanism dispatched volumes by unit type [MWh]

In **Italy**, where a pilot for inclusion of aggregators in aFRR and mFRR is coming to its end in 2024, there is very detailed data available on contracted capacity in its UVAMs-only monthly capacity auctions. In 2023, the TSO Terna contracted a total of 3.4 GW from UVAMs only. 12% of this volume comes from IAs Flexcity SAS and Ego Energy S.r.l.

Poland currently shows volume numbers for DSR contracted in the capacity mechanism, which amounted to 791 MW in 2023 and to 1029 MW contracted capacity in 2024[33]. No volumes are yet recorded and available online, as the market reform only came into force in June 2024. However, as from the new regulation, a list of aggregators must be publicly available[34]. Based on this list, until March 31, 2024 five aggregators have concluded a contract with the Polish TSO PSE [35]. Among those, no IA can (yet) be found. PSE confirmed that it is expected that with time more market participants will enter the list of contracted aggregated resources [36].

For Switzerland, FCR volumes amounted to 3 MW of DSR in 2017, 18.5 MW DSR in 2017 (8.5 MW industrial), mFRR 49 MW DSR in 2017.

3.3.3 Other aspects

Three other relevant aspects in analysing the implementation of independent aggregation also need to be discussed: the rebound effect, the verification of flexibility service delivery and, to a limited extend, the information flows between parties and the confidentiality aspect. These elements are relevant in completing the picture of how the countries analysed implemented in practice the different IAM in each market.

The term **rebound effect** refers to the phenomenon that the load reduction (or increase) triggered by a demand response event is compensated partly or fully outside the activation period or by other resources. We distinguish three possibilities:

1. Most commonly, the rebound happens (shortly or up to several days) after the demand response event at the same resource that delivered flexibility during activation. An air conditioner that has temporarily been turned off, is likely to start operating shortly after the DR event. An industrial production process may take several days to compensate the loss of production.

[33] Polish implementation plan 2. (n.d.). Retrieved from https://energy.ec.europa.eu/system/files/2020-02/polish_implementation_plan_final_0.pdf
[34] Cabinet Office of the Sejm. Journal of Laws. 1997 No. 54 Item 348 USTAWA of April 10, 1997. Energy Law. 2024.
[35] Agregatorzy i OSD - PSE. (2020). Retrieved July 18, 2024, from Www.pse.pl website: https://www.pse.pl/uslugi-dsr/agregatorzy-i-osd
[36] Unstructured interview with Polish TSO PSE on August 8, 2024

2. The rebound happens before the event, also at the same resource that delivered flexibility during activation. This is the case for events that are scheduled (well) in advance. The pre-cooling of a building before the electricity price peak is an example.
3. The rebound happens during the event but through a different resource than the one that delivered the flexibility during the activation. This other resource may or may not be subject to the same service program and it may or may not be located at the connection. An example is a household with two air conditioning devices, only one subject to a flexibility service program. A flexibility activation may trigger the second air conditioner to increase its load at the same time in which the first one decreases it.[37]

The rebound effect is one of the complexities of DSR, especially in combination with independent aggregation: without further regulation, the rebound ends up in the supplier's portfolio, potentially leading to imbalances. As this aspect is currently unregulated in all countries analysed, the aggregator is (by default) not responsible for the rebound effect, neither with respect to balance responsibility, nor to sourcing position. This might change depending on the new proposed network code for DSR will be released by ACER. France is trying to include the impact of the rebound in the baseline design, by considering a larger period (window before and after) of samples from other (non-activated) households to define the baseline (of activated households).. The rules have not been applied yet, but the rebound effect will be taken into consideration when measuring the accuracy of the baseline by excluding the rebound from the calculations[38]. However, whereas this may improve the quality of the baseline, the impact of the rebound remains with the supplier. In Section 4.2.3, practical options for considering the rebound effect and the consequences of not doing so are further discussed.

When it comes to the **verification of flexibility service delivery**, the use of (smart) meter data is common. Additionally, audits can be conducted by the party responsible for data verification (TSO/DSO, BSP or Metering Device Administrator (MDA)). In Belgium, Denmark, Estonia, Great Britain (for the corrected model), Poland and Switzerland, the TSO can directly verify flexibility service delivery, as it receives data directly from the DSO measurement devices via the TSO-DSO datahub. In Italy, a combined approach is applied, where the TSO Terna receives data through its communication platform and also conducts audits on a monthly basis on a randomised sample, or if triggered by significant deviations between the contracted and the delivered flexibility. This high frequency of audits might not be maintained after completion of the pilot phase. Similarly in France, the TSO RTE, after certifying the demand response units and verifying the delivery via meter measurement data mainly for FCR and aFRR, is responsible for verifying the delivery of the flexibility service via regular, unannounced audits mainly for mFRR. An overview of the verification of flexibility and the rebound effect per country is provided in Table 3.

[37] A solid foundation for smart energy futures USEF: THE FRAMEWORK EXPLAINED. (n.d.). Retrieved from https://www.usef.energy/app/uploads/2021/05/USEF-The-Framework-Explained-update-2021.pdf
[38] The regulation of independent aggregators. (2022). Retrieved July 18, 2024, from Norden.org website: https://pub.norden.org/nordicenergyresearch2022-04/#

Table 3: Comparative assessment for selected countries on verification of flexibility and the rebound effect.

	Verification of flexibility delivery	Rebound effect
Belgium	The TSO can verify flexibility service delivery, as it receives data directly from the DSO measurement devices.	Not considered: the IAM is not responsible for the rebound effect.
Denmark	The TSO can verify flexibility service delivery, as it receives data directly from the DSO measurement devices.	Not considered: the IAM is not responsible for the rebound effect.
Estonia	The TSO can verify flexibility service delivery, as it receives data directly from the DSO measurement devices.	Not considered: the IAM is not responsible for the rebound effect.
France	TSO verifies the delivery of the flexibility service via data received from BSP metering devices (FCR and aFRR) and via regular unannounced audits (in addition for mFRR).	In a regulation that is not yet implemented, the rebound effect is planned to be taken into consideration when measuring the accuracy of the baseline, i.e. the rebound periods will be excluded from the baseline calculations. Yet no consideration in the compensation model or balance settlement.
Great Britain	The TSO can verify flexibility service delivery, as it receives data directly from the DSO measurement devices.	Not considered: the IAM is not responsible for the rebound effect.
Italy	TSO verifies the delivery of the flexibility service via data received from BSP and via audits on a randomized sample monthly and if the delivered flexibility volume differs for the contracted volume.	Not considered: the IAM is not responsible for the rebound effect.
Poland	The TSO can verify flexibility service delivery, as it receives data directly from the DSO measurement devices.	Not considered: the IAM is not responsible for the rebound effect.
Switzerland	The TSO can verify flexibility service delivery, as it receives data directly from the DSO measurement devices.	Not considered: the IAM is not responsible for the rebound effect.

Another aspect analysed in the **information exchange and confidentiality** between the involved parties: the aggregator, the BRP, the costumers, the system operator and, when relevant, an imbalance settlement responsible (ISR, normally the system operator itself). This aspect covers the requirement for aggregators regarding information exchange with other involved parties and the key aspect of confidentiality, which can have an impact in the successful establishment of a level playing field.

In most central settlement models, the exchange of information goes through a centralised Datahub created by the TSO. This is the case for Belgium, Denmark, Great Britain, Italy, Poland and Switzerland.

In Estonia, a change of settlement model is planned for October 2024, when the implementation of the central settlement model will be completed. Currently, the aggregator (BSP) must provide to the TSO a list of metering points involved in demand side response (DSR) management and the clients' authorizations for them to manage these. When the flexibility service is activated in the balancing market, the aggregator communicates the DSR management data for activated points on a D+1 schedule and finalized on an M+3 schedule according to balance portfolios. After October 2024, for the mFRR market, there will be a transition to Datahub. This means that aggregators will register their aggregation contracts directly in Datahub, linking them to the network metering point and the correct balance portfolio, and will themselves submit the activated energy volume. Datahub will calculate the total amounts by balance managers for the system operator.

4 COMPENSATION MODELS FOR INDEPENDENT AGGREGATION MODELS

Compensation models for independent aggregation define the payment mechanism between the IA and the supplier to account for the ToE, which reflects the energy that the aggregator sources from the supplier during flexibility activations, or vice versa. The ToE safeguards the administrative balance of the supplier and allows the aggregator to trade energy. As ToE involves an energy transaction, the compensation mechanism involves a price. In addition to the ToE compensation, a compensation mechanism could also involve administration costs for schedule exchanges.

This Section provides an overview of the compensation models and references prices in Europe, an impact assessment of shortlisted compensation models and a set of recommendations for compensation models and reference price formula suggested for Finland. Note that although the focus of the Section is on independent aggregation, the review of compensation models in Europe also provides examples of a non-independent aggregation model, the contractual model.

In the next Sections, the bidding activity of IA in the wholesale market (DA and ID) is addressed. Participation in the DA market means that the market player submits buy or sell orders to a NEMO (e.g. Nord Pool or EPEX Spot). Buy or sell orders are then aggregated into demand or supply curves which intersection is forming the clearing price in the DA market (per bidding zone). Potential imbalances are settled at imbalance price. In the particular case of the IA,, it could be difficult to understand under which type of bid each flexibility activation (demand reduction/increase, generation reduction/increase) is placed in practice. This is explained as below:

- In case of a flexibility activation that consists of a (net) demand reduction or generation increase (in comparison to the baseline), the IA submits a sell order (or reduces his buy order accordingly).
- In case of a flexibility activation consisting of a (net) demand increase or reduction of generation (in comparison to the baseline), the IA submits a buy order (or reduces his sell order accordingly)

Whether the BRP or the IA itself needs to place a bid depends on the agreement between the IA and his BRP. The bid could be based on the net value (either net sell or net buy order) of the total flexibility activated in the portfolio, but some NEMO encourages separate orders of selling and buying by applying volume fees based on the net position per BZ. Hence the specifics of each trading activity can vary across NEMOs, but the principles remain the same.

4.1 Overview of compensation models in selected countries

In this Section an overview is provided on compensation models in selected countries.

4.1.1 Compensation models and reference prices

Following from the previous analysis, the compensation models for Belgium, France, Great Britain, Switzerland, Estonia, Italy and Poland are analysed to answer the following questions:

1. Which compensation mechanisms can be applied for which markets/products and for which segments, Upwards and downwards, demand and generation?
2. What is the reference price for compensation?

When assessing compensation models, the following aspects should be considered:

- The sourcing position, Transfer of Energy (ToE);
- The financial settlement method (no financial settlement, via the aggregator, through the customer or through a central entity also called the Imbalance Settlement Responsible (often the TSO);
- The reference price;
- The symmetry of the compensation: is the provider of flexibility remunerated for any flexibility direction or not?

There are several methods to set the reference price. In Table 4 are illustrated the most common ones or the models used by the countries and markets assessed in this study (see Table 4).

Table 4: Reference price options

#	Level of compensation	Description
1	No compensation	No payment associated with the ToE.
2	DA price	Hourly price published by the NEMO in D-1 for a given time unit and a given bidding zone.
3	ID price	Hourly price published by the NEMO in D for a given time unit and a given bidding zone.
4	Imbalance price	Hourly price published by the TSOs in D for a given time unit and a given bidding zone.
5	Retail price	The compensation price is based on a formula set by the appointed authority to reflect the retail price. The formula could be based on market indices, typically forward products and day-ahead price.

For **Belgium:**

- When the *corrected model* is applied, the ToE is compensated at the retail energy price.
- For the *central settlement*, the TSO is responsible for arranging centrally the settlement, for which a formula is required defining the ToE price. The regulator is responsible to define the formula which is based on the following principles:
    - The purpose of financial compensation is to prevent the supplier or the aggregator from being negatively affected by the flexibility activations or take advantage by this activation. To resemble the activity of a non-independent aggregator, the Belgian TSO Elia has designed a formula that aims to resemble the retail price of electricity.
    - As retail prices differ among customers and are not publicly available, the formula approximates the average sale price of electricity from a standard portfolio of customers, covering only for the energy component of the bill (i.e., excluding network charges, taxes).
    - The ToE price formula is based on market indices. The formula – as designed by the regulator- is a combination of future markets indices (Cal Y+2, Cal Y+1, M+1) and the day-ahead spot market, on the basis that the energy is sourced at different points in time. Typically, suppliers source the baseload of their energy requirements at Forward Markets for risk hedging. Intraday market prices are not included in the price formula on the basis that ID markets have lower liquidity. The volumes that are traded on ID markets are not representative of sourcing price for the customer supply. The Belgian regulator has included fixed ratios between markets in the price formula. The weight of future markets prices versus the day-ahead prices are based the average ratio between flexible consumption and baseload consumption of industry (i.e., 73% of the industrial load is baseload whilst 27% is considered flexible which is then met by short term markets). Note that IAs are not active with residential customers as no ToE is facilitated at lower voltage levels. If residential customers are part of the IAs' portfolio, then, according to the Belgian approach, the residential baseload and flexible load should also be considered in the formula.
    - The ToE should encourage the application of the contractual model, which is deemed to be the most efficient from the market point of view by the Belgian regulator. For this reason, an uncertainty factor

was introduced on the regulated price during time of negotiation, expressed by the day-ahead element.

The formula that results from these principles is the following:

$$\text{ToE price} = \{[73\,\% \times 1/3\,(\text{Cal Y+2} + \text{Cal Y+1} + \text{M+1}) + 27\,\%\ \text{EPEX spot BE DAM}] \times 1{,}05\} \pm 5\,\%$$

With:

- CAL Y + 2 = the average of the daily quotations published by ICE ENDEX during the year two years before the year of activation for the product baseload.
- CAL Y + 1 = the average of the daily quotations published by ICE ENDEX during the year preceding the year of activation for the baseload product.
- M + 1 = the average of the daily quotations published by ICE ENDEX during the month preceding the month of activation for the baseload product.
- EPEX spot BE DAM = the quotation published by EPEX spot Belgium on the day ahead market for the time during which the activation takes place.
- +/- 5 % = asymmetric element to distinguish between demand turn-up and turn-down.

In **Denmark**, the ToE is compensated at a price indexed at the DA market. The same will happen in **Estonia** after October 2024, when a datahub will be introduced to implement the central settlement model. The TSO will pay the IA the balancing price minus the reference price (equal to the DA spot price) for up-regulation (i.e., consumption reduction) and pay the affected Supplier's BRP the wholesale (DA) spot price. Until then, the system operator pays the aggregator the full amount from the balancing market, and the aggregator settles directly with the related open supplier or consumer (no independent aggregation model currently allowed)[39].

The **French** model follows the same principles for compensation as in Belgium, with a slight difference in the ToE price formula. The formula aims to reflect the average cost for sourcing electricity (whereas in Belgium the retail price is reflected, although the difference is very small for industrial customers) and differentiates between two types of sites: telemetered or half-hourly settled sites (usually industrial and commercial sites) and profiled sites (usually light commercial and residential). Differently than in Belgium, for telemetered sites the French TSO RTE makes prices publicly available for the following year in December and the prices are fixed based on a daily time component (peak/off-peak) and a seasonal component (winter/summer). Also deviating from the Belgian example, the French price formula only considers future market prices (Cal Y+1 and Cal Y+2), ARENH price[40] (regulated price of nuclear energy that EDF is obliged to sell to the wholesale market) and, since September 2023, also capacity mechanism prices. To consider the arbitrage between future markets and ARENH prices, two different formulas are used:

- If the ARNH price is larger than the yearly average future prices, then

$$\text{ToE}(N,S,P) = \text{Cal Avg}(N,P,t) \times \text{pond}(S,P) + \text{aPrice Capa}(S,P)$$

- Otherwise

$$\text{ToE}(N,S,P) = (1 - \text{ARENH rate}) \times [\text{Cal Avg}(N,P,t) \times \text{pond}(S,P) + \text{aPrice Capa}(S,P)]$$

$$+ \text{ARENH rate} \times \{(1 - \text{ARENH cap}) \times \text{ARENH price}$$

$$+ \text{ARENH cap} \times [\text{Cal Avg}(N,P,t) \times \text{pond}(S,P) + \text{imPrice Capa}(S,P)]\}$$

[39] Questionnaire's answers from Estonian TSO.
[40] The ARENH law (2010) obliges EDF to sell part of its nuclear generation (up to 100 TWh/year, i.e., around a quarter of its production) to alternative suppliers on the wholesale market at a regulated price ("ARENH price"), which has been set by the CRE at €42/MWh since 2012.

With:

- N = the year considered
- S = the seasonal component (winter/summer)
- P = the daily time component (peak/off-peak)
- Cal Avg (N,P,t) = the average of the future products on each day t of the period over which the average is calculated, determined by P for the year N.
- pond (S,P) = the weight of half-yearly quotation on the annual quotations (winter/summer).
- ARENH rate = the proportion of off-market electricity offered through ARENH ("ARENH proportion")
- ARENH price = the off-market reference price, equal to the average over years N and N-1 of the prices of electricity sold by Electricité de France to suppliers of final consumers on the continental metropolitan territory or network operators for their losses pursuant to Article 1 of Law No. 2010-1488 of December 7, 2010.
- ARENH cap = the capping rate for ARENH rights, published by CRE at least thirty (30) days before the start of each year N in accordance with article R336-19 of the French Energy Code.
- aPrice Capa (S,P) = auction capacity price for year N, season S and time P.
- imPrice Capa (S,P) = capacity imbalance settlement price for year N as defined by the Capacity Mechanism.

The original formula can be found in the regulation NEBEF 3.5 Chapter 10.2. When it comes to profiled sites, the ToE price is set equal to the cost of supply and differentiated for peak and non-peak hours. The cost of supply is determined and published by the regulator CRE and includes ARENH price, the weighted average wholesale price, and the average of capacity mechanism prices of the previous two years. No formula is provided in the NEBEF regulation. [41]

As from November 2024, **Great Britain** will allow VLPs to participate in wholesale market and will introduce a compensation model classified as *net benefit model* (variant of the central settlement model) to account for the imbalances created by the VLPs actions. The proposed solution is to compensate the Suppliers impacted as a result of VLP action at a ToE price that represents the average supplier sourcing costs. To calculate it, the Price Cap Methodology (PCM) published by Ofgem will be used, which is updated every quarter and is based on wholesale costs, other calculated costs (e.g. network costs), consumer price index (including housing costs) and a percentage allowance. [42] The compensation costs will then be mutualised amongst suppliers. This mechanism applies to demand reduction (generation enhancement), where energy is transferred from the supplier's BRP to the IA's BRP. This mechanism is similar in case of demand enhancement (generation reduction). In this case, the energy is transferred from the IA's BRP to the supplier's BRP against price 0 (i.e. IA is not compensated for ToE).Any benefit that suppliers may face as a result, is mutualised amongst all suppliers, This solution has been chosen by Ofgem after a cost-benefit analysis as the option leading to the greater volumes of additional flexibility deployment, due to lower variable costs, which increases the overall welfare in comparison with the alternative option in which the VLP was liable for compensation costs. [43]

Although practical experience with this model is not available, as it Is not yet implemented, there are several arguments in favour of this variation of the central settlement model:

- A socialised central settlement model can lead to higher market liquidity and flexibility participation. Independent aggregators (VLP for GB) will be more incentivised to enter the market under a socialised

[41] *Règles pour la valorisation des effacements de consommation sur les marchés de l'énergie*. (n.d.). Retrieved from https://www.services-rte.com/files/live//sites/services-rte/files/documentsLibrary/2023-09-01_REGLES_NEBEF_6130_fr
[42] *Price cap -Decision on changes to the wholesale methodology*. (n.d.). Retrieved from https://www.ofgem.gov.uk/sites/default/files/2022-08/Price%20cap%20-%20Decision%20on%20changes%20to%20the%20wholesale%20methodology.pdf
[43] *Balancing and Settlement Code (BSC) P415: Facilitating access to wholesale markets for flexibility dispatched by Virtual Lead Parties (P415) Decision: The Authority 1 directs that the modification be made 2*. (n.d.). Retrieved from https://www.ofgem.gov.uk/sites/default/files/2023-10/Ofgem%20decision%20P415%20%27Facilitating%20Access%20to%20Wholesale%20Markets%20for%20Flexibility%20Dispatched%20by%20VLPs_0.pdf

compensation model as this option lowers costs for independent aggregators who do not have to pay suppliers for their actions in wholesale energy markets.

- High volumes of flexibility and market liquidity in turn can bring more benefits to the consumers by avoiding constraints costs, curtailment of generation, running the electricity system in more efficient and economic high and reducing the need to rely on fossil fuel generation. Moreover, in periods of high renewable generation, when prices are typically low or even negative, VLPs can increase demand to absorb this excess generation.

The proposed compensation model in GB also has several drawbacks, related to not imposing the ToE compensation to the independent aggregator:

- Market distortion is likely to occur, esp. for assets with low marginal costs for activation (e.g. time shifters such as EV charging). This will be further explained in the Section 4.3 on ToE price formula.
- There is no incentive for IAs to perform load enhancement or generation curtailment (unless wholesale prices turn negative).
- This mechanism leads to an uneven market between IAs (VLPs in GB terms) and suppliers (acting as aggregator).
- This mechanism leads to additional costs at suppliers that most likely will be transferred to their customers. This could lead to customers without flexibility “subsidizing” customers with flexibility. It is uncertain whether this is fully compensated by lower energy tariffs.

During the **Italian** pilot phase, that will end in the year 2024, every year and on a monthly basis, the TSO Terna has organised specific tenders for flexibility services through aggregators. In these tenders, UVAs (BSP) would be remunerated in two ways.

1. There would be a capacity availability/reservation payment of around 30.000 €/MW/year, plus a strike price of 200-400 €/MWh (depending on the standardized time interval in which they offer the flexibility service) upon activation.
2. Market price for the volume of flexibility effectively delivered. [44]

These costs are then assigned to the affected supplier’s BRP, while the UVA is responsible to divide the earnings among the single customers by assigning to each of them a percentual contribution to the contracted product. As from 2025, the remuneration 1, based on capacity reservation, will be abolished. It was initially introduced as incentive for aggregators to participate in the pilot. In the permanent implementation of the regulation, aggregators will only be remunerated based on spot market price, even if the details are still under consultation with the market.

The new balancing market regulation in **Poland** does not consider a compensation for the transfer of energy between an IA BSP and the Supplier’s BR, which is settled through the Polish TSO PSE. [45]

In **Switzerland** the compensation between the aggregator and the supplier is organised through a transfer of energy payment. Swissgrid settles the transfer of energy centrally for the volume of flexibility delivered at the day ahead spot price at the time of activation.

InTable 5 and Table 6, an overview of the compensation models per country and per market is provided.

[44] UVAM - Energia Flessibile. (2021, October 4). Retrieved July 30, 2024, from Energia Flessibile website: https://www.energiaflessibile.eu/uvam/
[45] Unstructured interview with Polish TSO PSE on August 8, 2024

Table 5: Wholesale market compensation models for each selected country.

	Contractual model	Corrected model	Central settlement model
Belgium	Not applicable for Independent Aggregations. Compensation mechanism is agreed between the supplier and the Aggregation.	ToE is price is equal to the energy part of the retail contract and imbalance prices. Network fees and taxes are charged for the actual consumption. Available only for large customers ToE goes through the consumer.	ToE compensated via a formula defined by the regulator. Elia corrects the perimeter of the supplier's BRP and organises the ToE centrally. The transfer price should ideally match the price at which the customer buys its electricity from the supplier.
France	Not applicable for Independent Aggregations. Compensation mechanism is agreed between the supplier and the Aggregation.	ToE is price is equal to the energy part of the retail contract and imbalance prices. Network fees and taxes are charged for the actual consumption.	ToE is different depending on the type of customer, and the time of the year. The formula is set by the regulator and the parameters are updated regularly. Price level for the transfer of energy is (an approximation of) the sourcing costs.
Great Britain *(under implementation)*	n.a.	n.a.	Under this solution suppliers that have been commercially impacted as a result of IA action will be compensated by the mutualised suppliers' post based on their Market Share. Market share will be calculated on a Suppliers Final Demand. The value of compensation will be the average wholesale cost for a single rate metering arrangement. Ofgem's published Price Cap Methodology (PCM) will be used to calculate this figure.

Table 6: Balancing market compensation models

	FCR	aFRR	mFRR & RR
Belgium	No ToE, no compensation.	Corrected model: compensation for the ToE only at retail energy price. Contractual model: not applicable for IAs.	Same as wholesale markets.
Denmark	No ToE, no compensation.	Current status: Contractual arrangements, not applicable for independent aggregation. Compensation mechanism is agreed between the supplier and the Aggregator. To be implemented: central settlement model with	Current status: Contractual arrangements, not applicable for independent aggregation. Compensation mechanism is agreed between the supplier and the Aggregator. To be implemented: central settlement model with

	FCR	aFRR	mFRR & RR
		compensation indexed at DA price,	compensation indexed at DA price,
Estonia	n.a.	n.a.	Current status: Contractual arrangements in place. To be implemented: compensation of the supplier at DA spot price.
France	n.a.	n.a.	Same as wholesale markets.
Great Britain	n.a.	n.a.	Balancing Mechanism: Current status: Supplier's BRP position is corrected, and Supplier returns to balanced position but without a price ascribed to the transfer. The energy is transferred from the Supplier to the VLP and vice versa in case of turn up regulation (ToE price at 0). Proposed modification: Same approach as the wholesale market, subject to further assessment.
Italy	Current status: n.a. To be implemented: compensation of the supplier indexed at DA spot price.	Current status: Supplier's BRP position is corrected by the TSO but without a price ascribed to the transfer. Hence, the energy is transferred from the Supplier to the VLP and vice versa via the TSO with a ToE price of 0. To be implemented: compensation of the supplier indexed at DA spot price.	Current status: Supplier's BRP position is corrected by the TSO but without a price ascribed to the transfer. Hence, the energy is transferred from the Supplier to the VLP and vice versa via the TSO with a ToE price of 0. To be implemented: compensation of the supplier indexed at DA spot price.
Poland	Supplier's BRP position is corrected by the TSO but without a price ascribed to the transfer. Hence, the energy is transferred from the Supplier to the VLP and vice versa via the TSO with a ToE price of 0.	Supplier's BRP position is corrected by the TSO but without a price ascribed to the transfer. Hence, the energy is transferred from the Supplier to the VLP and vice versa via the TSO with a ToE price of 0.	Supplier's BRP position is corrected by the TSO but without a price ascribed to the transfer. Hence, the energy is transferred from the Supplier to the VLP and vice versa via the TSO with a ToE price of 0.
Switzerland	No ToE, no compensation.	Compensation of the supplier at DA spot price.	Compensation of the supplier at DA spot price.

4.1.2 Baseline definition

To quantify the actual flexibility delivered, the baseline methodology is key not only for flexibility services but also for the transfer of energy. The baseline methodology for the delivery of the flexibility service should be defined by the system operator and depends strongly on the requirements of the service, such as response time, duration, etc. For day-ahead and intraday markets, however, the baseline methodology for the transfer of energy should be regulated.

There are several baseline methodologies used, as illustrated in Table 7.

Table 7: Baseline methodologies

#	Methodology group	Description
1	Window before a.k.a. Meter Before – Meter After (MBMA)	Single meter reading or average/median/min/max of meter readings before the activation window.
2	Window before and after	As Window before, but now the window after is also taken into account to compensate for direct rebound effects.
3	Historical baseline a.k.a. Rolling baselines	Based on historical data such as 'average interval load of last 5 business days'.
4	Calculated baseline (e.g. weather-based)	Calculation based on external parameters, e.g. generation of a wind turbine base on wind speed and capacity.
5	Regression-based	A regression model is used to calculate the baseline.
6	Control group a.k.a. Peer group	Measurements of similar customers are used as input for calculating the baseline.

Only **France** and **Belgium** have implemented ToE for day-ahead and intraday trading both with corrected and central settlement model.

- In **Belgium**, a historical baseline methodology is applied.
- In **France** the customer can choose between three methodologies window before and after, historical, and nomination baseline. To be eligible for the latter, the requirements are quite strict in terms of timing (e.g. the baseline needs to be submitted two weeks in advance) and accuracy. This makes it difficult for aggregators to comply and therefore to use this methodology.

Great Britain is in the implementation phase for independent aggregation access to the wholesale market. IAs who participate in the wholesale market will be allowed to use historical baselines[46].

4.2 Assessment of various compensation mechanisms

This Section will explore ToE price reference options that could be applied in Finland, taking into account the European examples that were mentioned in Section 3.3 and based on DNV's experience and market intelligence on the topic of independent aggregation. The followed approach principles are explained, together with the criteria that a ToE price reference should meet, and the impact on the main affected parties by the activation if flexibility volume in various examples is explored. The main parties affected are the IA (including its BRP), Supplier (including its BRP) and Consumer.

Before recommending certain compensation mechanisms and ToE price formulas, it is worth considering the need for a ToE and the consequences of implementing such a mechanism. When an aggregator activates flexibility from a customer, it has the intention to sell the activated energy in the wholesale market. Yet without additional measures, only the sourcing position of the supplier is impacted (by either preventing sourced energy to be sold or by triggering energy to be sold that has not been sourced), since the customer resides in the (BRP of the) Supplier's perimeter. In a contractual model, the Supplier would sell the energy that is not consumed by the customer to the IA, ensuring the perimeters of both Supplier and IA are balanced. Without a contractual relationship, the ToE is required exactly for this reason: to correct the perimeter of both the supplier and aggregator. Where in a contractual model, the transfer price is agreed bilaterally, for a centrally organised ToE the price of this energy needs to be regulated. The introduction of any ToE price, impacts the arbitrage position of the IA. Since a supplier acting as an aggregator (*integrated model*) is not

[46] https://www.elexon.co.uk/documents/change/modifications/p401-p450/p415-draft-solution-summary/

affected by the ToE price, this could affect the level playing field, since the IA and Supplier (acting as Aggregator) could end up with different arbitrage positions. The principles outlined in the Section aim to define a proper compensation level that maintain a level playing field for the aggregator.

Another topic to clarify is the meaning of “market distortion”, as in the Sections below scenarios that could distort the market are explored. A market distortion in this context is i) activation of resources which are out of the money (e.g. starting a generator with marginal costs above the relevant market price) or ii) failure to activate resources that are in the money (e.g. not starting a generator with marginal costs below the relevant market price), or similarly for reservation of resources.

4.2.1 Design Principles in DNV’s approach

DNV identified four principles for the design of an adequate compensation mechanism:

1. To avoid market distortion the IA should be incentivized to **activate flexibility when and only when the marginal cost of activation is lower than the market value**. Flexible assets that are brought to wholesale markets though an IA should show a similar behaviour as they would if they were exposed directly to these markets through implicit mechanisms.
2. The compensation mechanism and the price formula should **not create a business case for IA to bring to the DA wholesale market flexibility of customers that are already exposed to DA wholesale prices**.
3. There should be a **level playing field between IA and suppliers acting as aggregators**.
4. Compensation models should be **symmetrical.**

Below, each principle is explained more in details.

Principle 1: IA should be incentivized to activate flexible assets only when the marginal cost of activation is lower than the market value, showing a similar behaviour as if they were exposed to the market through implicit mechanisms.

The compensation mechanisms should ensure IA’s arbitrage should not lead the aggregator to activate flexibility if the market value is below marginal cost.

Typically, flexible assets that participate in implicit mechanisms act upon price signals based on their marginal cost of activation. For example, generation technologies would only turn up if their marginal cost of generation (i.e. activation) is lower than the wholesale price. Similarly, industrial loads with dynamic contracts will need to factor in the cost of turning demand down when they perform load shedding activities to ensure that the cost of reducing demand (e.g., cost of pausing industrial processes) is lower than the savings from not using electricity (based on wholesale market-indexed contract price). The actions that IAs will take upon flexible loads should follow the same patterns and ensure load-shifters to be always shifted from periods with high prices to periods with low(er) prices, the higher the price spread, the better. Deviation from these patterns means that the IA takes arbitrage positions that distort the markets.

Principle 2: There should be no business case for IA to bring to the DA wholesale market flexibility of customers that are already exposed to DA wholesale prices.

Principle 2 implies that IAs should not be able to create a business case by aggregating customers with dynamic contracts on the basis that these customers already take benefits of the day-ahead prices through so-called implicit flexibility. A similar principle would apply to ID trading, for customers exposed to ID prices, but the latter is uncommon. This is an important aspect as a significant share of Finnish consumers have chosen spot (DA) or hybrid contracts, which both create a linear relation between the wholesale day-ahead market and the customers’ bills.

For the scope of this exercise the focus is therefore on customers with fixed supply tariffs (or dual price tariffs) where settlement is based on smart meter data and not synthetic data.

Principle 3: There should be a level playing field between IA and suppliers acting as aggregators.

Non-independent aggregators and IAs should have the same access opportunity to wholesale (DA and ID) markets. Principle 3 aims to ensure a level playing field between non-IA and IA: it implies that there should not be an incentive for Suppliers that perform aggregation to separate their aggregation activities in a stand-alone IA. IAs should be able to generate similar revenues from their operations as with the suppliers acting as aggregators. In the scope of this report, the creation of a level playing field is mainly linked to the regulation of the ToE price, as this affects the arbitrage decisions of the IA.

Principle 4: Compensation models should be symmetrical.

Compensation mechanisms should ensure that there is both value in decreasing load (enhancing generation) during scarcity times, and in enhancing load (decreasing generation) during times of oversupply (integration of renewables).

It is relevant to mention that these four principles focus on optimal market functioning and on creating a level playing field, not necessarily on boosting participation of demand-side flexibility. In the international benchmark, it has been observed how other countries – with the GB as the most relevant example – seem to focus on designing a compensation model aimed at (over-)incentivising demand side flexibility in wholesale and balancing markets, in order to kick-start / accelerate customer participation, with a reference to the net benefits DSF can bring to the society. A further reflection to this aspect is provided in section 4.3.4.

4.2.2 Assessment Methodology

The priority for this Section is to provide compensation mechanism recommendations in the **wholesale market** (day-ahead and intraday) that could be applicable for Finland. The wholesale market provides a first challenge due to the higher arbitrage options, larger volumes of energy traded and its consequence higher volatility. There are also fewer examples of successful implementation in other European countries. Once a satisfactory compensation mechanism is identified for the wholesale market, its efficacy will be tested for the balancing markets as well, to come to a comprehensive final recommendation.

In addition, the Section further focuses the scope of compensation models assessment on **residential flexibility** on the basis that:

1. Residential flexibility presents the most challenging case compared to most large Commercial & Industrial (C&I) customers and Distributed Generation (DG). The challenge with the residential flexibility lies in the fact that marginal cost of activation is very difficult to estimate and generally agreed to be very low, close to zero or even zero in many cases. This allows more arbitrage opportunities for the Independent Aggregation, that does not have any marginal activation costs, which in turn could create market distortions more frequently if the ToE price is not set at the right level. In addition, residential flexibility is on one side characterised by small volumes of power per customer but still also by high activation frequencies. Compensation and ToE price remains therefore crucial.

2. Experiences with (explicit) residential flexibility and independent aggregation are very limited. Only a limited number of countries has a regulatory framework in place (with GB under implementation) allowing access to residential flexibility through IAs applying the uncorrected and central settlement model. In Switzerland this is only applicable in balancing markets and for large, aggregated portfolios, while in France access is limited to demand turn-down (generation enhancement), whereas residential flexibility is also well-suited to absorb renewable energy such as EV charging or electric heating when prices are low. In Belgium independent aggregation for low-voltage flexibility has not been implemented yet, while in other countries, like Italy and GB (until now), the barriers for small consumers are higher. The frameworks implemented or in implementation in balancing market in Estonia, Denmark and Poland are more open to participation but still in early stage.

3. Finally, focusing on residential flexibility, which is argued to be the most complex and difficult to integrate in a compensation model for IA, would allow to more easily extend the same solution to other consumer groups, under the principle that if the solution is feasible for residential flexibility and adheres to the design principles that we set earlier in Section 4.2.1, then the recommendations will also work for C&I customers, characterized by large volumes (power) per customer, typically high activation costs and low activation frequencies.

4.2.3 Rebound effect considerations

The rebound effect and how to deal with it is one of the complexities of DSR, especially in combination with independent aggregation. Without further regulation, the rebound can potentially cause imbalances to the supplier’s portfolio and needs therefore further attention when performing an impact assessment. When not properly addressed and when IA activations significantly scale up, the rebound effect could even lead to system instability, assuming rebound effects per technology shows high simultaneous behaviour.

As already introduced in Section 3.3.3, in case an IA operates either a DR or storage within its portfolio, most (if not all) of the reduced / enhanced load will be shifted to another period. E.g. charging an EV can be halted for a period, but the battery of the EV will need to be charged at a later time. Also, industrial processes like manufacturing can be halted, but the manufacturing process will likely be scheduled at a later time. As outlined in these examples, the rebound effect typically occurs after the flexibility activation event, but there are some cases in which it occurs before (e.g. pre-heating or pre-cooling). The rebound effect happens rarely during the event (using other assets).

Assuming that the IA does not control the rebound effect and does not (need to) take responsibility for the rebound (which is the current situation in all countries’ aggregation model regulations), the effect of the rebound is inevitably reflected in the supplier’s portfolio in the following manners:

- **Sourcing position:** the Supplier’s BRP sourcing position is bound to a specific time, which means that the Supplier’s BRP still needs to source the additional energy that is required by the rebound for the period(s) that it occurs (when the rebound is not controlled by the IA, the ToE does not occur in the opposite direction during the rebound period, as illustrated in the example below of ToE for load-shifting in). When the rebound is sourced to the customer by the IA, there is an open sourcing position for the Supplier, which will run through the imbalance settlement and sourced by the Supplier at balancing prices (much higher than other sourcing prices).
- **Balancing position:** since the rebound effect is strongly depending on the asset type (e.g. electric vehicle, heat-pump, industrial process, etc.), the consumer and the specific circumstances, it is in general hard to predict. Therefore, the rebound is likely to create additional uncertainties in balancing the suppliers’ perimeter.
- **Administrative costs:** the supplier may mitigate the impact on its balancing position by enhancing its forecast and/or monitoring capabilities.

In the below example, it is explained how unregulated rebound effect can lead to possible market distortion. In this example, an EV charging activity is interrupted between 15h and 17h to respond to a flexibility activation product. It is assumed that in this period, the wholesale price is higher than the sum of ToE price and any potential marginal cost for activation. The assumption is that the flexibility activation is managed by an IA that does not have responsibility for the rebound effect.

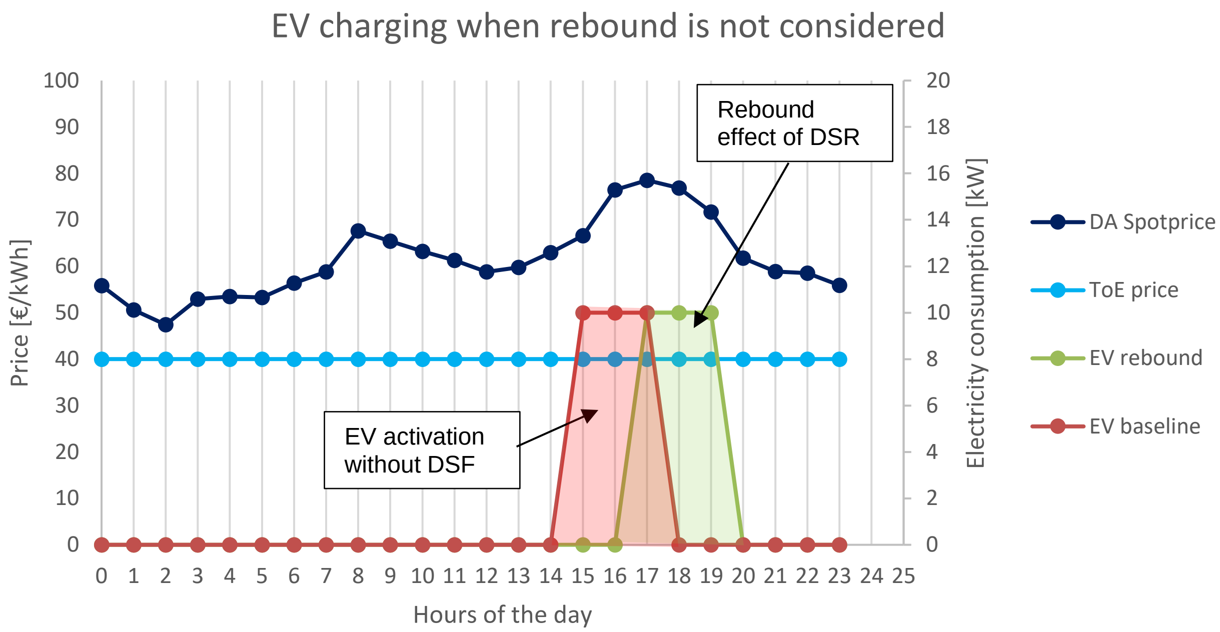
In general, as underlined in Principle 1 of Section 4.2.1, for efficient market functioning, it’s not only important that load is reduced during peak hours, but also that load shifting results in load being shifted from periods with high prices to periods with low(er) prices, the higher the price spread, the better. Following this principle, high wholesale prices should stimulate DR activations (IA arbitrage against ToE price). For example, if the evening peak occurs between 17:00h and 19:00h, an aggregator can generate revenue by reducing the total load of an EV-charging portfolio from 17:00 to 18:00. If that load is fully shifted to the next hour, the peak in that hour is only aggravated.

From the Supplier's perspective, this has several consequences which could (in extreme cases) even lead to higher system costs, as outlined as following.

- During activation period (15h to 17h), the Supplier records lower revenues due to reduction in consumed load at retails price.
- The Supplier receives compensation for the energy that was reduced during the activation period through ToE from the aggregator.
- However, after the activation period, the rebound starts (17h to 19h). In this period the Supplier records higher revenues from retail sale.
- The Supplier will face imbalance during the period in which the rebound occurs. In general, this energy will be sourced through the imbalance settlement mechanism against balancing prices. Only when the supplier gains sufficient insights in the behaviour of all IAs in its portfolio, and in the rebound effect of their portfolios, will it be able to source (part of) this energy on the wholesale market peak price (at €77, instead of at €75). Since there is no financial incentive to be exposed to balancing prices, we can assume the associated costs for the supplier are at least €77.
- In our example, even when the rebound can be scheduled against the lowest wholesale price, the IA will still be faced with costs for controlling the rebound, since wholesale prices exceed the retail price during the full day. Without an incentive (or obligation) to control the rebound, the IA can still technically schedule the rebound, but not trigger the ToE, and thus not incur additional costs.

At the end of the rebound, the supplier is faced with costs: in principle the difference between the ToE price and the imbalance prices, which are unpredictable.. In this way, the revenue obtained by the IA is fully paid by the supplier and the system has lost €2 in overall efficiency. This loss represents a lower bound of the potential additional losses if the rebound needs to be settled by the Supplier at imbalance price.

Rebound effect can also have consequences for system balance. An example is the increasing installation of home batteries at residential consumers. Home batteries are sometimes managed by the electricity suppliers, but may as well be operated by an IA having a contract with the costumer to schedule the dispatching of the battery. If the IA is not responsible for the rebound effect, it could lead to a situation where all rebound happens at the very same time, not only creating challenges for the Supplier's portoflio, as explained before, but also causing serious problems in system balancing (see Figure 4-1).



	Period 15-17h	Period 17-19h
Supplier	**Revenues = ToE price (40€/kWh)** **Costs = Missed retail revenue (40€/kWh)**	**Revenues = additional retail revenue (40€/kWh)** **Costs = Energy sourcing cost (at least €77/kWh)**
IA	**Revenues = Wholesale price (75€/kWh)** **Costs = ToE price (40€/kWh)**	**N.a.**

Figure 4-1: Example of an EV charging profile without consideration of the rebound effect

From the considerations outlined in this Section, DNV recommends regulating the rebound effect, in particular making the **IA responsible for the imbalance created by the rebound effect of any flexibility activation**. The responsibility of rebound effect ensures that the level playing field between non-IA and IA is maintained, as it will force the IA to perform arbitrage between peak and off-peak prices, as illustrated in Figure 4-2. The re-establishes the same rebound position for the IA compared to the supplier acting as an aggregator, and will fully remove the dependency from the ToE price level for the rebound volume, as we will also demonstrate in the examples in section 4.3.5. ToE price level is then only relevant for the volume that has no rebound, the right choice of ToE price for load shedding is further discussed in Section 4.3.

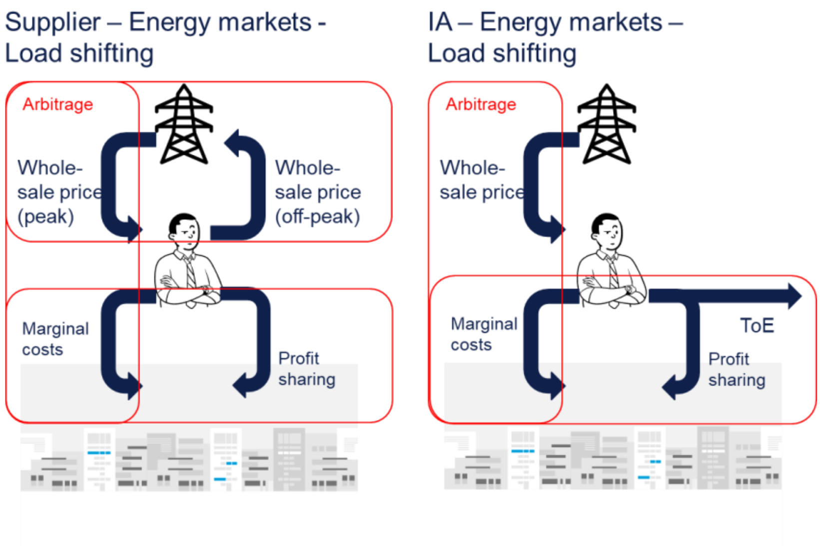


Figure 4-2: Non-IA and IA arbitrage positions for load shifting (without IA responsibility for the rebound)

However, when it comes to the implementation of responsibility for rebound effect, there are several challenges. The rebound effect is very difficult to predict, measure or calculate, as it is determined by many factors:

- **Technology:** across demand response technologies, the literature recognises different rebound behaviour. For example, industrial load could have a rebound as low as 0%, EV charging is usually 100%, electric heating is (presumably) between 80 and 100% depending on efficiency effects, while battery is considered at 110% due to roundtrip inefficiency.
- **Location:** rebound can also be location-dependent, e.g. a customer whose charging activity was delayed at home could decide to complete the charging in another location, for example at the office.
- **Timing:** Another aspect is the timeline of the rebound. Sometimes rebound happens directly after the DR event, most often it is spread over the next 12-24 hours after the event, sometimes even over multiple days, also strongly depending on the technology. The rebound can also happen before the DR event (although it is typically controlled in this case).

These different facets of the effect make it very challenging for the implementation of the recommendation above: how to make the IA responsible for all these facets, without impacting its market participation with excessive administrative and uncertainty burdens? In the following Section, two options are provided on how this responsibility can be implemented and regulated.

4.2.4 Options for assigning rebound responsibility to IA

Rebound responsibility is defined as the situation in which an IA that reduces (or enhances) the load during the DR event, is also responsible for scheduling the rebound. This implies that every DR event should be followed by a second event in the other direction which includes an additional ToE for the second period.

DNV has recognised two possible options to effectively implement a responsibility requirement for the IA on the rebound effect.

1. **Extension of the demand response event:** the initial DR event, which normally terminates when the service window ends (e.g. after the final ISP of the corresponding wholesale trade) is extended to include the full period when the rebound is expected to happen (depending on technologies included in the activation, for example). Some complexities in the implementation of this option are in the length of the period, the technology-dependency and the quality of the baseline for such a long period.

2. **Scheduled rebound:** the IA determines when the “rebound event” occurs and during such event the same compensation model apply (baseline, ToE). The main complexity of this implementation option is in the validation that the full volume is actually recovered during the period of rebound activation.

In this Section, the two options are further examined and examples are provided.

Option 1: extension of the demand response period.

Since rebound periods can take up to 12 hours in residential environments, it is reasonable to assume that the IA should have 24h responsibility frame after the activation of the DR. This would lead to a technology-specific, synthetic profile that would represent the baseline for the DR activity and forms the basis for the energy sourcing by the Supplier. The synthetic baseline can be created for example based on a reference group of (non-controlled) assets of that specific technology. In this way, the technology and time aspects of the rebound effect, as described in the previous Section, can be included. Any deviation from this synthetic baseline would be settled through the ToE. Any deviation ends up in the IA portfolio and he can (and must) bring this to any market he wants to participate in. This option corresponds to USEF’s description of Aggregator Implementation Models based on reference profiles.

An example of this option is illustrated in Figure 4-3, where the measured profile of an EV charger is plotted against the synthetic baseline over a 24h period. This EV charger is assumed to have a 100% rebound. The Supplier needs to source the energy below the synthetic baseline, and bears imbalance risk only on the total volume, not profile, within the 24 hours extended DR period. It is also responsible to deliver the energy to the costumer. In yellow it is highlighted the DR event activated by the IA until 5am. After 5am, the IA is still responsible for any difference between the measured and the synthetic profile for the extended period up to 24 hours, as it is assumed that such deviation corresponds to the rebound effect, indicated with the purple area. Also, in the case of the rebound effect, the IA needs to buy the energy through the ToE from the supplier and sell it to the wholesale market. As the total energy (orange and green areas) cumulates to zero, all these transactions happen in the wholesale and there is no need to arrange energy supply between IA and the consumer.

The main challenge of this implementation option is that while the (normalised) profile may be known, the daily energy volume is not. In order to ensure the supplier delivers the correct volume, this calculation has to be performed on a daily basis. As a consequence, during the day, the IA does not know the exact baseline, although these effects may even out on portfolio level. In any case, this option leads to a highly complex calculation and re-introduces synthetic profiles. In addition, it does not solve completely the locational aspect of the rebound effect.

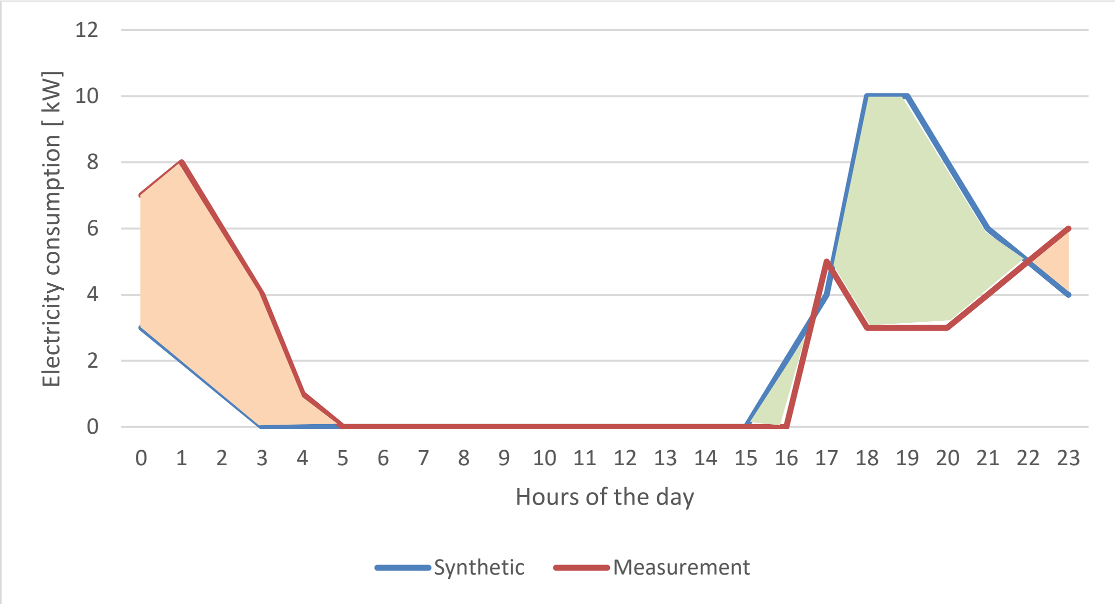


Figure 4-3: Example of IA rebound responsibility through extension of DR period

Option 2: scheduled rebound.

In this solution, it is left to the discretion of the IA to control the rebound and decide when the associated DR (rebound) events will take place. During these events the same compensation model applies (baseline, ToE). The main complexity of this solution is the validation that the full volume is actually recovered. Rather than validating this physically, this can also be achieved by stipulating that ToE volumes in both directions need to level out (e.g. on a monthly basis) – either on customer or portfolio level. Disincentives could be created when there are large discrepancies between the two volumes (e.g. the introduction of penalties).

The same example as in Option 1 is illustrated in Figure 4-4 for Option 2. The IA activates a DR event, increasing the consumption between 0h and 4h, sourcing the energy through the ToE and selling it to the wholesale market. Afterwards, the IA schedules a second DR event and reduces the load between 17h and 20h by the same volume activated during the first DR event. In this way the total ToE is levelled out.

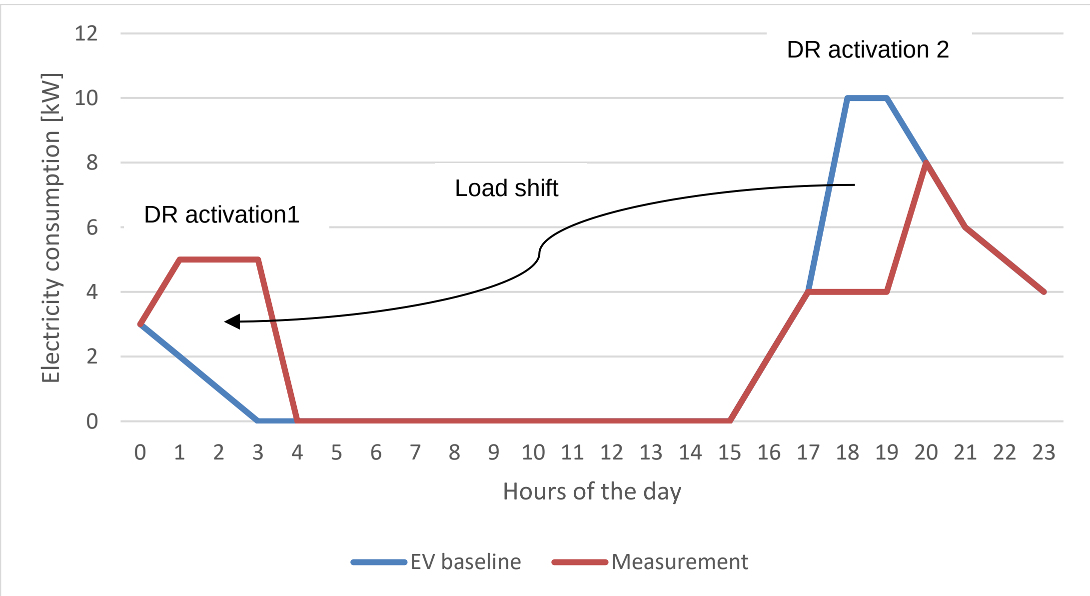


Figure 4-4: Example of IA rebound responsibility through scheduled rebound

We recommend the implementation of Option 2 (scheduled rebound) as it incentivises the IA to schedule the rebound when there is the correct market signal to do so. In Section 4.3.4, this consideration is illustrated with its effects. A simplification that this solution brings is that in case the ToE formula is not time dependent (similar to retail price), and the net energy volume is 0, there is no need for a compensation (although perimeter corrections are still needed).

However, several other challenges remain.

- Rebound effect remains very difficult to predict, measure or determine/calculate.
  This is especially true when the rebound is not controlled by a market party (IA or Supplier). When e.g. the charging of an EV is delayed, the rebound may occur at different times (or even places). Yet when the rebound is controlled / planned by the market party, it is quite apparent when this occurs. With respect to technologies for which rebound is more difficult to control, the IA has two options:
    - Extend the duration of the DR event (ToE period) – and as such assuming balance responsibility for a longer period, ensuring the rebound effect is captured (this would move closely to option 1 described above).
    - Refrain from controlling this specific technology since it is not suitable for IA models.
- What if rebound does not equal 100%?
  This can be addressed by introducing a technology-dependent rebound factor. If e.g. heat pumps have 80% rebound, this means that the IA upward volume needs to equal 0,8 * downward volume. In case of a mixed portfolio, it needs to be broken down per technology, and the ratio should be applied per technology.
- The assumptions on rebound percentage and rebound time could be too approximative for all the technologies available in the market. The concept of rebound ratios is meant to provide a means to validate whether IAs take responsibility on the rebound. There may be other, more qualitative ways, to validate this requirement. If/ when IA volumes increase and more experience is gained, quality of these ratios will also increase.
- How to select the correct baseline, given the high dependency on its accuracy that this solution requires? Especially when rebound period is long (e.g. 12h), baseline methodologies such as MDMA are inappropriate. For this, peer groups not subject to aggregation may be the best way forward.
- How to tackle the locational aspect of rebound effect? The problem arises whenever the location in which the rebound happens is not included in the same IA portfolio and in the same supplier's BRP portfolio.
  This aspect is likely to level out within a larger portfolio. If there is some structural bias preventing this from happening, the IA may apply for a different rebound ratio during prequalification.

In any case in which the rebound responsibility is implemented, there will be immediate effects on the system and business model of IA and Suppliers. This is why DNV suggests taking a staged approach in tackling the recommended implementation option as well as the remaining challenges. This means that the responsibility can be introduced from the start, yet enforcing this requirement can be implemented gradually.

4.3 Recommendations for a reference price formula and impact assessment

In this Section, recommendations for a reference price formula in Finland are presented. First, the considerations for a ToE that approximates the retail price are provided, then the proposed ToE formula is explained and finally the impact is illustrated by means of four examples.

The reason we aim for a ToE price that approximates the retail price(s) is to ensure a level playing field and to ensure that decisions to activate flexibility are efficient. The level playing field argument considers that the energy that an IA sells to or buys from the wholesale market (because of the activation) is effectively netted against the balance of the retailer. The relevant costs for the retailer are the wholesale procurement costs, including relevant risks and costs of capital associated with supplying the customer based on the type of contract chosen by the customer. The best available proxy for these costs is the retail price agreed in the retail contract. The level playing field argument can also be considered by comparing two different aggregator implementation models: the integrated model, where the supplier performs the aggregator role, and the central settlement model, where the IA is facilitated by the ToE. A level playing field can only be obtained if the aggregator role has the same arbitrage position, this is visualised in the picture below. For load shedding, this can only be achieved by setting the ToE at the retail price. For load shifting, an additional measure us needed, as described in section 4.2.3 and see Figure 4-5.

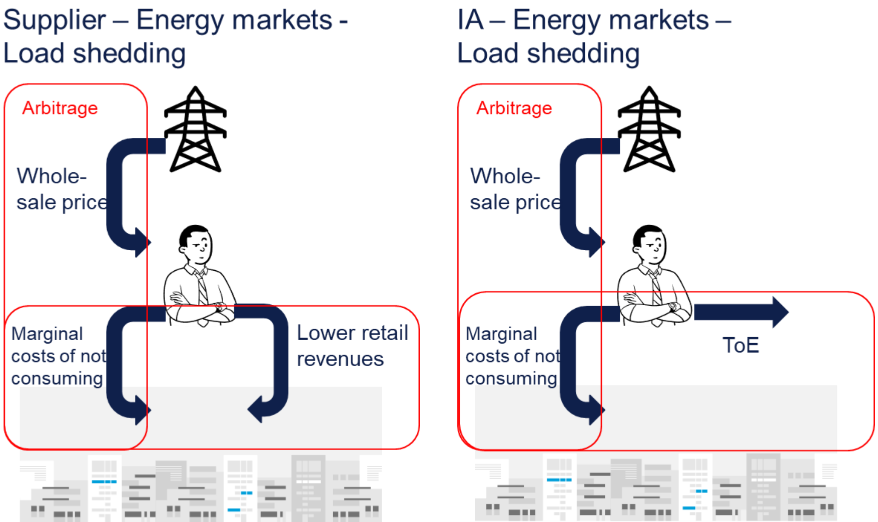


Figure 4-5 : Non-IA and IA arbitrage positions for load shedding

The efficiency argument for a central settlement model leads to the same conclusion, but is more complex: with central settlement, the customer will pay less to his retail supplier when the flexibility is activated (due to the perimeter correction). Hence, we need to consider the retail price when defining a ToE price that ensures efficient activations only. Suppose the customer pays a retail price RP and incurs non-negative activation costs AC when the IA activates the customer's flexibility. For simplicity, assume also that the quantity activated is 1 (e.g., 1 kWh).

- We would like the IA only to activate this flexibility when the wholesale price (e.g., the DA price) exceeds the socioeconomic costs of activation. The only socioeconomic cost in this setup is the activation costs, AC.[47] Hence, we are looking for when this is satisfied; AC = DA (or AC < DA).
- When activated, the customer incurs AC, but also receives a benefit RP via a reduced bill from his supplier. If the IA compensates the customer for AC, it is natural that customer's benefit is also considered.

[47] If the retail competition is highly inefficient, e.g., due to monopoly power by a major supplier, there might be additional socioeconomic impacts of activation of flexibility. To DNV's knowledge, this is not the case in Finland.

- The IA, faced with a ToE cost, will only activate the flexibility if the wholesale price exceeds his costs, which are the ToE plus AC minus the RP.
- The question is then when is ToE + AC – RP = DA. If DA = AC, this only happens when ToE = RP

4.3.1 Customer impact of reference price formula

Since the compensation formula primarily affects the IA and the Supplier (and/or their BRPs), impact on the customer is indirect. This section will reflect on the possible impact to the customer.

It is important to distinguish between two types of customers, those that have contracts with IAs and benefit from their market operations, and all (other) customers.

Impact on customers participating in IA services

In general, the impact on these customers strongly depends on the contractual relationship between the IA and the customer, i.e. the customer proposition. Since the customer proposition is unknown and can differ strongly, the precise impact cannot be described. In section 4.3.5, several examples (that we deem realistic) are provided indicating the impact for the compensation model that is proposed in the next section (i.e. approximation of the retail price).

The following can be stated about customer impact for compensation models that (strongly) differ from the proposed formula:

- Customers are represented in the market by the IA. This means that when revenue options increase for the IA, this is (in general) beneficial for the customer. When revenue options deteriorate, this has negative impact on what the IA is able or willing to offer the customer, and thus on the customer.
- The impact of alternative compensation models on the IA is often unclear, as this may depend on unknown, future market conditions. E.g. if the DA market price is used for ID trading related to customers with fixed price retail contracts, the impact depends on the level of DA market prices relative to the retail price. When these market prices are structurally higher (e.g. during the recent energy crisis), the IA benefits when turning demand down; one could expect that also the customer will benefit in this situation. Yet when DA prices are structurally lower, the IA will be negatively impacted, and so will the customer. [48]
- The impact of alternative models on the IA also depends on the direction (demand enhancement vs. reduction). Most of the applied compensation models are symmetrical, this means that an alternative model resulting in a positive impact for customers in one direction, results in a negative impact in the other direction. This can e.g. be observed in the GB model, where demand enhancement (absorbing excess renewable power) is hardly economically feasible, and will not allow customers to benefit from low market prices.

Impact on all (other) customers

Since the compensation model informs the arbitrage position of the IA and, as such, its market behaviour, any compensation model (when sufficiently scaled up in the market) will influence the overall market functioning and thus all customers (independent if they are active themselves or represented by suppliers). A fully efficient market will lead to the lowest prices, both on the short term and (by providing correct investment incentives) on the long term.

The following can be stated on customer impact for compensation models that (strongly) differ from the proposed model:

- Alternative models can lead to market distortions that will decrease market efficiency, leading to negative impact to all customers.

[48] Please note that, when our recommendation on rebound is adopted, the dependency on the ToE price formula will weaken, and may even become fully independent for 100% time shifters

4.3.2 Considerations for a ToE price formula that approximates the retail price

The retail price is essentially an individual commercial agreement between supplier and consumer, not known to others. In a competitive market, however, it should be possible to develop a proxy for the retail price (excluding taxes and network charges). This could be done by considering the following:

1. The retail price is inextricably linked to the sourcing costs of the supplier, which in turn depends on the wholesale price;
2. The supplier sources energy during different times of the year and the day;
3. A formula needs to reflect previous market prices, to the extent these reflect the sourcing costs for the supplier (e.g., fixed price contracts);
4. The formula must also reflect the gross margin for the supplier, to cover costs associated with volume risk, profile risk, credit risk, cost of collaterals, other procurement costs, and profit;
5. The formula must also consider whether there are single vs dual retail prices in Finland, or other forms of price differentiation across time or volume;
6. Another consideration is retail price differentiation in Finland. If retail prices vary a lot by supplier and by customer segments, a single ToE will create distortions for at least some customer, if not all.

In order to have a better understanding of the Finnish market, DNV has interviewed representatives from three retail suppliers as well as the regulator. DNV concluded the following on the basis of these interviews:

- About 40% of customers want a fixed period contract (was 45% end of 2023):
  - 24 months (~75% out of 40%), 12 months (~20%), or 3-6 months (rest i.e. 5%);
  - The rest is split between «spot» and «open ended»; the latter is «fixed price until further notice» and essentially not very different from fixed price contracts within the scope of this analysis;
  - The sale of contracts is relatively stable during the year.
- For the fixed price contracts, the suppliers either hedge the sales themselves or via a portfolio manager (PM). New sales ‘today’ is based on forward prices ‘today’ (or the day before):
  - PMs offer prices to their retail sales customers daily (or weekly), the retailers then add a margin to cover their own costs
  - Comparing current fixed price contracts with current forward prices suggests a gross margin around 40%.
- This suggests a ToE formula reflecting the current retail prices of the existing customer portfolio:
  - A moving average of 2 and 1 year forward contract prices, all multiplied with 1.4;
  - The moving average should reflect the structure of the typical contract portfolio.

  For customers on dynamic or spot contracts the ToE retail price would then equal the DA market price to which the contract is linked, plus a margin reflecting retail suppliers costs beyond the day-ahead prices and the profit..

Since the Russian full-scale invasion of Ukraine and the surge in wholesale prices, a ‘hybrid fixed price’ contract has received quite some interest in Finland. The hybrid is essentially a fixed price contract with an individual adjustment based on the customer’s volume per hour and the day-ahead price per hour. Customers with a majority of its consumption during periods in which the day-ahead price is below the (arithmetic) average day-ahead price will receive a discount, while customers with opposite consumption patterns will be invoiced an extra amount. In essence, this arrangement moves the profile risk from the supplier to the consumer, and the consumer will have incentives comparable with those of customers having opted for spot-based contracts.

4.3.3 Proposed ToE formula

DNV proposes applying the following ToE price formula for customers with fixed price contracts, with as a basis:

$$\boldsymbol{Basis} = \mathbf{75\%}\left(\frac{\boldsymbol{Y_{+1}} + \boldsymbol{Y_{+2}}}{\mathbf{2}}\right) + \mathbf{20\%}\boldsymbol{Y_{+1}} + \mathbf{5\%}\left(\frac{\boldsymbol{Q_{+1}} + \boldsymbol{Q_{+2}}}{\mathbf{2}}\right)$$

Hence, this would translate to:

$$\mathbf{37.5\%}\boldsymbol{Y_{+1}} + \mathbf{37.5\%}\boldsymbol{Y_{+2}} + \mathbf{20\%}\boldsymbol{Y_{+1}} + \mathbf{2.5\%}\boldsymbol{Q_{+2}} + \mathbf{2.5\%}\boldsymbol{Q_{+1}}$$

Hence, including the gross margin of 40%, this would lead to a ToE price formula of:

$$\boldsymbol{TOE} = \left(\mathbf{37.5\%}\boldsymbol{Y_{+2}} + \mathbf{57.5\%}\boldsymbol{Y_{+1}} + \mathbf{2.5\%}\boldsymbol{Q_{+2}} + \mathbf{2.5\%}\boldsymbol{Q_{+1}}\right) \times \mathbf{1.4}$$

It should be noted that:

- Here, Y+2 refers the average of the daily closing prices published by Nasdaq for a one-year contract (SYS+EPAD) two years out in time, and Q+2 refers similarly to closing price of a one-quarter contract two quarters out in time
- Since 75% (of 40%) have a 2-year contract, and 2-year contracts are not traded but are instead composed of a 1-year contract and a 1-year contract one year from now, half of 75% is linked to the Y+2 . The other half is added to the 20% 1-year contracts, hence 57.5%. The quarterly contracts are split equally between $\boldsymbol{Q}$_$(+\mathbf{2})$ and $\boldsymbol{Q}$_$(+\mathbf{1})$, hence both 2.5%.
- For October 2024, this Y+2 means closing prices for the 2024-contract registered from October to December 2022, closing prices for the 2025-contract registered throughout 2023 and closing prices for the 2026-contract registered from January to September 2024. For November 2024, the observation period would be adjusted to November 2022 to October 2024, etc.
- Note: the actual months covered by a two-year contract thus depend on when the contract started; this partly explains the high gross margin (perfect hedges not available)
- Similarly, Y+1 mean closing prices for the 2024-contract registered from October to December 2023 and closing prices for the 2025-contract registered from January to September 2024.
- The price formula is updated monthly. The price data is publicly available.
- Whether a gross margin of 40% is a reasonable proxy for the Finnish retail market should be verified (regulator)
- The 40% should cover costs related to collaterals for wholesale trading, profile and volume risk, credit risk, and all other sales costs
- For customers with spot-based contracts, a different approach should be taken, as for these, the forward prices are not relevant, and the gross margin would need to cover less cost items than the gross margin for fixed price customers (no costs related to profile risks, and no costs related to collaterals from trading in the forward markets). See also section 5.3.5 below.

Example of price inputs required for one day as part of the monthly updated ToE price are provided in Figure 4-6 (the remaining days that month should be included in the rolling average to construct the right ToE).

As already mentioned, for contracts mirroring the day-ahead prices (spot price contracts), the formula would be simpler; the day-ahead price plus a margin representative for such contracts in Finland. The retailers' costs that are supposed to be covered by the gross margin is essentially lower for spot price contracts as compared to fixed price contracts. For illustrative purposes we have suggested a 20% margin in the formula below. Whether a gross margin of 20% is a reasonable proxy for spot price contracts should be verified, e.g., by the regulator:

$$\boldsymbol{TOE} = (\boldsymbol{D}_{+1}) \times \mathbf{1.2}$$

Market Prices

Market: Electricity Nordic | Types: All | Product: All

Export to Excel | Traded

Aggregated volume (GWh): 2222.54 — * MW ** HOURS

Updated: 2024-09-16 16:27:28

PRODUCT SERIES	BID	ASK	LAST	+/-	%	HIGH	LOW	ON*	OFF*	VOL*	DAILY FIX	OI	SIZE**	UPD*	MORE...
ENOAFUTBLMOCT-24	21.75	22.00	21.80	1.05	5.06	22.00	20.00	125	24.0	149.00	20.75	1232	745	16:00:00	
ENOAFUTBLMNOV-24	38.00	38.80	38.00	1.00	2.70	38.00	36.75	24		24	37.00	378	720	16:00:00	
ENOAFUTBLMDEC-24	49.00	50.00	49.65	0.75	1.53	49.65	48.00	14		14	48.90	406	744	16:00:00	
ENOAFUTBLMJAN-25	58.75	61.50	60.50	-1.25	-2.02	60.50	60.50	1		1	61.75	163	744	16:00:00	
ENOAFUTBLMFEB-25	60.50	63.50	62.25	-1.00	-1.58	62.25	62.25	5		5	63.25	56	672	16:00:00	
ENOFUTBLQ4-24	36.60	36.70	36.60	0.87	2.43	36.67	34.75	56	109.0	165.00	35.73	5842	2209	16:16:10	
ENOFUTBLQ1-25	55.40	55.59	55.35	-0.55	-0.98	55.75	54.45	57	116.0	173.00	55.90	2046	2159	16:17:42	
ENOFUTBLQ2-25	29.15	29.25	29.05	-0.35	-1.19	29.10	29.00	7	7.0	14.00	29.40	560	2184	16:00:00	
ENOFUTBLQ3-25	23.60	23.95	24.00	-0.05	-0.21				7.0	7.0	24.05	565	2208	16:00:00	
ENOFUTBLQ4-25	45.40	45.60	45.45	-0.25	-0.55	45.60	45.45	3		3	45.70	739	2209	16:00:00	
ENOFUTBLQ1-26	63.05	66.85	63.05	-0.30	-0.47	63.05	62.90	3	1.0	4.00	63.35	508	2159	16:00:00	
ENOFUTBLQ3-26	22.40	26.45	22.70	-0.25	-1.09	22.75	22.70	9		9	22.95	141	2208	16:00:00	
ENOFUTBLQ4-26	44.75	46.00	46.00	-0.90	-1.92				1.0	1.0	46.90	150	2209	16:00:00	
ENOAFUTBLW39-24	22.50	24.50	22.50	2.13	10.46	22.50	22.00	20	10.0	30.00	20.37	374	168	16:00:00	
ENOFUTBLYR-25	38.25	38.40	38.30	-0.35	-0.91	38.30	38.00	30	16.0	46.00	38.65	5400	8760	16:00:00	
ENOFUTBLYR-26	40.00	40.30	40.10	-0.30	-0.74	40.10	39.90	9	19.5	28.50	40.40	2283	8760	16:00:00	
ENOFUTBLYR-27	41.45	42.75	41.50	-0.40	-0.95	41.50	41.50	1	23.0	24.00	41.90	1111	8760	16:00:00	
SYHELFUTBLQ1-25	19.00	25.00	20.00	-3.00	-13.04				4.0	4.0	23.00	155	2159	16:00:00	
SYHELFUTBLYR-25	11.00	15.75	16.00	1.00	6.67				7.0	7.0	15.00	781	8760	16:00:00	
SYSTOFUTBLQ4-24			-4.50	-0.50	12.50				1.0	1.0	-4.00	1766	2209	16:00:00	
SYSTOFUTBLQ1-25		-3.00	-4.20	-1.20	40.00				4.0	4.0	-3.00	359	2159	16:00:00	
SYSTOFUTBLYR-25	-4.15	-3.50	-4.00	-0.17	4.44				12.0	12.0	-3.83	1349	8760	16:00:00	
SYSTOFUTBLYR-26	-3.55	-3.10	-3.30	0.25	-7.04				11.0	11.0	-3.55	689	8760	16:00:00	
SYSTOFUTBLYR-27		-2.00	-1.35	1.05	-43.75				10.0	10.0	-2.40	270	8760	16:00:00	

Figure 4-6: Market prices on the Finnish wholesale market.[49]

4.3.4 Net benefit considerations

Some may perceive DNV's recommendation for the ToE reference price formula as a barrier to allow a large and fast emergence of IAs. As explained, the proposed IA compensation mechanism ensures fair market access, a level playing field and avoids market distortions. Net benefit arguments may be used to justify an alternative compensation model (as can be seen in GB), yet with respect to the societal net benefits that IAs can bring we observe:

- Both IAs and suppliers acting as aggregators contribute to any societal benefit, just as implicit flexibility (dynamic contracts) can provide these benefits. When net benefit effects are included in the ToE price formula, this would not stimulate the contribution of suppliers in the same way and would affect the level playing field.
- It can also be shown theoretically that inclusion of benefits that are already reflected in market prices will create inefficient incentives and suboptimal allocation of resources. Even if an approach is legal, it does not necessarily lead to an efficient allocation.

[49] Market Prices. (2024). Market Prices. Nasdaq. https://www.nasdaqomx.com/commodities/market-prices

- If a member state wishes to take the net benefits into account, we recommend including those as capacity payments (for all market parties that operate/activate demand-side flexibility), rather than through the (ToE) compensation mechanism to minimise market distortion. The EMD reform provides ample room for these type of capacity payments (either within existing CRMs or as a separate mechanism).

Since this report focuses on the compensation mechanism, no recommendations will be provided on these capacity payments.

4.3.5 Impact illustration

In this Section, four examples are provided to illustrate the impact of the recommended compensation model on the BRP-IA (the BRP of the IA, in the example referred to as IA for simplicity), the BRP-SUP (the BRP of the Supplier, in the examples referred to as Supplier for simplicity) and the Consumer. The examples outline the consequence of a certain ToE price (with a formula approximating retail price, as suggested in this report). The main focus of the analysis of such examples is to show that the market can function correctly and that the recommended ToE price allows maintaining a level playing field between IA and non-IA.

The following four situations of activation of flexibility products are considered:

1. Electric Vehicle (EV) in Figure 4-7.
2. Heat pump in Figure 4-8
3. Li-ion battery in Figure 4-9
4. Diesel generator in Figure 4-10

In the examples, the following assumptions are made (see Table 8 for cost assumptions):

- DR activation planned by the IA is 10 kW for a period of 1 h (10 kWh)
- ToE price is calculated as 0.095 EUR/kWh
- The retail contract is a single-tariff contract at retail price of 0.12 EUR/kWh
- DA prices are obtained from the curve in the example extracted from Nord Pool market data
- The customer proposition (in our example) differs per technology operated by the IA:
    - For EV or BTM generator trading, profits are shared on a 50/50 basis between IA and customer (for example purpose only)
    - For heat pump the IA keeps the trading profits, as the customer benefits from energy savings
    - For batteries, the IA compensates the customer for energy inefficiency, and shares trading profits 50/50
- Rebound effect differs for each technology:
    - 100% for EV
    - 90% for heat pump (due to energy efficiency)
    - 110% for Li-ion battery storage (due to round-trip inefficiency)
    - 0% for diesel generator
- IA knows the retail price of the customer (only relevant for example 1 and 4)
- The IA controls the full “rebound event” by dispatching the flexible units.

The examples indicate costs and revenues relative to the situation without DR activation and, while only DA trading is considered in this case, the same results are valid for the same examples considered for ID trading. The examples illustrated below do not aim to provide recommendations on the business agreement between customers and IA (i.e. the profit distribution), but to provide realistic examples for the sake of explaining the impact of ToE compensation between IA and Supplier, providing also an insight on the potential impact on consumers.

Table 8: Summary of assumed values for the calculation of the financial result.

Values	[€/kWh]
DA price A	0.225
DA price B	0.000
DA generation activation price	0.750
Retail price	0.120
ToE	0.095
Fuel price	0.740

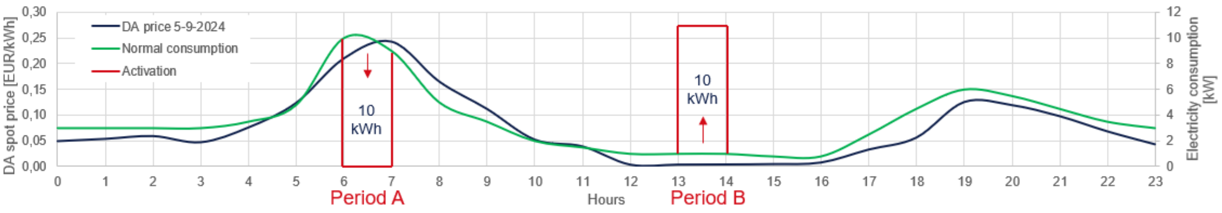
4.3.5.1 Impact illustration 1: EV charger

In this example, the IA activates an EV charger. The IA can sell the reduction of load at peak price (period A) in the energy market but is also directly responsible to buy the increased consumption that occurs later (the rebound effect, period B). Hence, the IA will activate the flexibility product when the spread of DA price between period A and B is large enough, considering administrative costs and profit share with consumers. The specific trading strategy is determined by the IA, just like any other market participant. The IA could e.g. place the sell and buy offers as linked bids on the DA market, or it can sell the energy on the DA market and procure the energy (for rebound) in the ID market.

The Supplier incurs costs in period A caused by the loss in retail energy sold to the customer, but in the assumed case of a fixed-price retail contract, these losses are recovered in period B where the consumption is shifted.
A similar argument holds for the costs associated with the ToE. The Supplier incurs revenues in period A through the ToE, but since the recommended ToE price is the same for both periods, these revenues are neutralised in period B where the ToE is applied to the same volume, in the opposite direction. Hence, the flexibility activation event has no impact on the Supplier in case of a 100% rebound.

Similarly to the Supplier, the Customer has an initial saving from its electricity bill in period A, which is then balanced by the increase consumption in period B. The Customer then receives a remuneration from the IA as bilaterally agreed (in this case with a 50% profit share) for the participation in the DR event.

In any load shedding event with 100% rebound (hence become a load-shifting event), there is in fact no need for a financial compensation, as the Supplier is not impacted by the IA activation. Perimeter corrections are still needed in both periods. In Figure 4-7, the example is further illustrated.



	Period A: Activation of the flexibility	Period B: activation of rebound	Financial results from DR activation
BRP-IA	Revenues = DA price A x 10 kWh Costs = ToE price x 10 kWh	Revenues = ToE price x 10 kWh Costs = DA price B x 10 kWh	**= 10 kWh x (DA price A – DA price B)** **= 2.25 €**
BRP-SUP	Revenues = ToE price x 10 kWh Costs = retail price x 10 kWh	Revenues = retail price x 10 kWh Costs = ToE price x 10 kWh	**= 0 €**
Customer	Revenues = retail price x 10kWh Costs = 0	Revenues = 0 Costs = retail price x 10 kWh	**= 0 €** Customer receives profit from IA according to the bilateral agreement between the customer and the IA.

Example: IA shares 50% of profit with customer 1.13 €

The ToE occurs twice in this example, in opposite direction. Yet, since the ToE price is constant throughout the day, the ToE compensation in the different periods level each other out. Therefore, there is **no need for a financial compensation when rebound is 100%.**

Figure 4-7: Impact illustration example (1/4) EV charger.

4.3.5.2 Impact illustration 2: Heat pump

In this example, the IA activates a heat pump with 90% rebound. Similarly to the previous example, the IA sells the reduction of load in period A and buys the rebound energy in period B. However, in this case, the volume bought in period B is 90% of the volume sold in period A. This difference is also reflected in the compensation to the Supplier via ToE. In this case activation by the IA is still predominantly determined by the price spread between period A and B, yet the ToE price also enters the equation, but only as a second order.

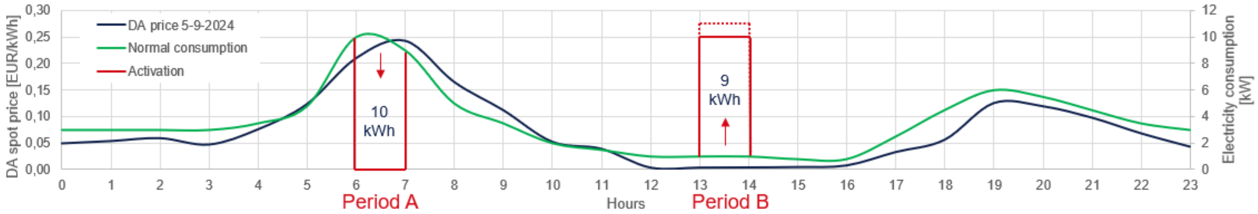
The Supplier incurs an initial net cost due to the loss of 10% revenues from the consumer's retail contract, yet is compensated by the IA at ToE price for this amount. The example shows that how closer the ToE price approximates the actual retail price of the consumer's contract, the more the Supplier is neutralised for IA's activities. Hence, the activation of a flexibility event with lower than 100% rebound could result in losses or gains for the Supplier, but these are second order effects and reduced the better the ToE price approximates the retail price.

In this example, the Customer has a final net saving through its electricity bill and is therefore benefitting from the DR activation. Depending on its bilateral contract with the IA, the Consumer could be remunerated additionally for the participation in DR event.

In any DR activation event with high rebound effects, yet lower than 100%, the ToE price definition (more precisely: any difference between ToE price and retail price for a specific customer)

- could impact the arbitrage of the IA, but only as a second order effect,
- could impact the remuneration of the Supplier, both positively or negatively, but only as a second order effect.

Figure 4-8 illustrates further the example.



	Period A: Activation of the flexibility	Period B: activation of rebound	Financial results from DR activation
BRP-IA	Revenues = DA price A x 10 kWh Costs = ToE price x 10 kWh	Revenues = ToE price x 9 kWh Costs = DA price B x 9 kWh	**= 10 kWh x DA price A – 9 kWh x DA price B – 1 kWh x ToE** **= 2.16 €**
BRP-SUP	Revenues = ToE price x 10 kWh Costs = retail price x 10 kWh	Revenues = retail price x 9 kWh Costs = ToE price x 9 kWh	**= 1 kWh x (ToE price – retail price)** **= - 0.03 €** Supplier incurs (limited) costs, this may level out on portfolio level.
Customer	Revenues = retail price x 10kWh Costs = 0	Revenues = 0 Costs = retail price x 9 kWh	**= retail price x 1 kWh** **= 0.12 €** The customer benefits from energy savings.

The ToE occurs twice in this example, in opposite direction. The net ToE volume from BRP-IA to BRP-SUP equals 1 kWh.
The BRP-SUP is compensated for this 1 kWh against ToE price (missed revenue since customer is consuming 1 kWh less).

Figure 4-8: Impact illustration example (2/4) Heat pump.

4.3.5.3 Impact illustration 3: Behind the meter (BTM) home battery

In this example, the IA activates a BTM home battery. Like in the other examples, the IA conducts arbitrage between market prices in period A and B. Similar to the previous case, the volume bought in period B is not equal to the one sold in period A. In the case of a home battery, the volume bough in period B is 110% of the volume sold in period A, this is due to roundtrip inefficiency of the battery being around 90%. This difference is also reflected in the compensation to the Supplier via the ToE. In this case activation by the IA is still predominantly determined by the price spread between period A and B and the round-trip inefficiency, yet the ToE price also enters the equation, but only as a second order. When the ToE price approximates the retail price, the IA's arbitrage decision is reduced to only a consideration of price spread, similar to the arbitrage decision of an Aggregator using the Integrated model (in line with our design principles).

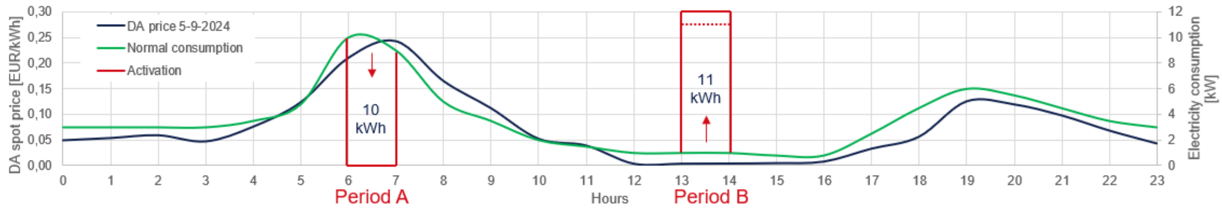
Opposite to the previous example, the Supplier incurs an initial net benefit due to the additional 10% revenues through the consumer's retail contract. However, it has to compensate the same volume at the ToE price to the IA. Again, it underlines the relation between ToE and retail price approximation in order to minimize the impact on the Supplier. The activation of a flexibility event with higher than 100% rebound can lead to total net benefits or costs for the Supplier, but these are reduced to the extent the ToE price is close to the retail price. In a large portfolio, these costs and benefits may be partly balanced out.

Opposite to the previous example, the Consumer has a 10% increase of consumption in period B. The Consumer is compensated by the IA for this additional consumption caused by the DR activation. In addition, it will receive remuneration from the IA as bilaterally agreed (in this case with a 50% profit share) for the participation in the DR event.

In any DR activation event with rebound (slightly) higher than 100%, the ToE price definition (more precisely: any difference between ToE price and retail price for a specific customer)

- could impact the arbitrage of the IA, but only as a second order effect,
- could impact the remuneration of the Supplier, both positively or negatively, but only as a second order effect.

Figure 4-9 illustrates further this example.



	Period A: Activation of the flexibility	Period B: activation of rebound	Financial results from DR activation
BRP-IA	Revenues = DA price A x 10 kWh Costs = ToE price x 10 kWh	Revenues = ToE price x 11 kWh Costs = DA price B x 11 kWh + retail price x 1 kWh	**= 10 kWh x DA price A + 1 kWh x ToE – 11 kWh x DA price B – 1 kWh x retail price** **= 2.23 €**
BRP-SUP	Revenues = ToE price x 10 kWh Costs = retail price x 10 kWh	Revenues = retail price x 11 kWh Costs = ToE price x 11 kWh	**= 1 kWh x (retail price –ToE price)** **= 0.03 €** The supplier has (limited) profit.
Customer	Revenues = retail price x 10kWh Costs = 0	Revenues = retail price x 1 kWh Costs = retail price x 11 kWh	**= 0 €** Customer receives profit from IA according to the bilateral agreement between the customer and the IA.

IA com-pensates customer

Example: IA shares 50% of profit with customer 1.11 €

Again, the ToE occurs twice, in opposite directions; the net ToE volume from BRP-IA to BRP-SUP equals a negative value of -1 kWh.
The BRP-SUP compensates the BRP-IA for this 1 kWh against ToE price (additional revenue since customer is consuming 1 kWh more).

Figure 4-9: Impact illustration example (3/4) Home battery.

4.3.5.4 Impact illustration 4: BTM diesel generator

In this example, the IA activates a BTM diesel generator, which does not have a rebound effect. Hence, the IA conducts arbitrage between market prices in the activation period and its costs for the activation, which amount to:

- The compensation of the Supplier at ToE price for the loss in the retail contract,
- The fuel price to be paid to the Consumer, minus the saving of the Consumer through its retail contract.

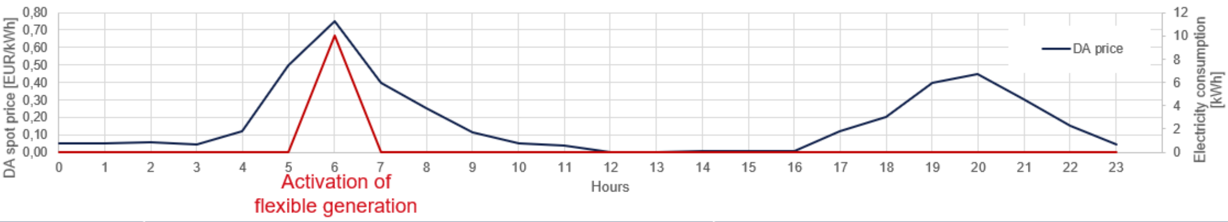
When the ToE price approximates the retail price, the IA's arbitrage decision is reduced to the difference between DA revenues and fuel costs, similar to the arbitrage decision of an Aggregator using the Integrated model (in line with our design principles).

The Supplier incurs a loss from the retail contract, compensated by the ToE from the IA, while the Consumer is compensated by the IA the difference between the fuel costs and the retail contract savings. In addition, it will receive remuneration from the IA as bilaterally agreed (in this case with a 50% profit share) for the participation in the DR event.

In any DR activation event with no rebound effect, the ToE price definition (more precisely: any difference between ToE price and retail price for a specific customer)

- could impact the arbitrage of the IA, as a first order effect,
- could impact the remuneration of the Supplier, both positively or negatively, as a first order effect.

Figure 4-10 illustrates further this example.



	Increase of diesel generation	Financial results from DR activation
BRP-IA	Revenues = DA price A x 10 kWh Costs = ToE price x 10 kWh + (fuel price – retail price) x 10 kWh	**= 10 kWh x DA price A – 10 kWh x fuel price + 10 kWh x retail price – 10 kWh x ToE price** **= 0.35 €**
BRP-SUP	Revenues = ToE price x 10 kWh Costs = retail price x 10 kWh	**= 10 kWh x (ToE price - retail price)** **= -0.25 €**
Customer	Revenues = retail price x 10 kWh + (fuel price – retail price) x 10 kWh Costs = fuel price x 10 kWh	**= 0 €** Customer receives profit from IA according to the bilateral agreement between the customer and the IA.
In this example, there is only one ToE and its net volume from BRP-IA to BRP-SUP equals the full activated volume of 10 kWh, which is compensated by the BRP-IA to the BRP-SUP at ToE price.		

IA compensates customer

Example:
IA shares 50% of profit with customer
0.18 €

Figure 4-10: Impact illustration example (4/4) Behind the Meter (BTM) generation increase.

Conclusions from the impact illustrations:

- For the arbitrage by the IA when **rebound effect is closer to 100%,** the comparison with the volatility (or price spread) of the DA prices is the most relevant factor. The ToE price level is less relevant, nor the absolute DA/ID prices. Marginal costs / benefits of activation, when relevant, also need to be taken into account.
- When the **rebound effect is closer to 0%,** the arbitrage by the IA mainly depends on the difference between DA price, activation costs and ToE price (marginal costs of activation / fuel price – retail price + ToE price). In this case, the ToE price definition becomes more relevant in respect to DA price and retail price although the marginal costs of activations are typically dominant in case of load shedding (or generation enhancement).
- When examining the required price spread ($\frac{price\ A - price\ B}{price\ A}$) for the IA to activate flexibility is, in our examples, we observe that the IA will face the same market position as a supplier acting as an aggregator (integrated aggregation model):
    - For time shifters (high rebound ratio), only small price spreads are needed, which would typically lead to daily activations. E.g. for EV charging, any price spread > 0 would incentivize the IA to shift load, for a battery a 10% price spread is needed to account for the round-trip inefficiency costs.
    - In all time shift cases, the IA will be incentivized to take advantage of the largest price spreads (move load away from the most expensive hours and shift this load to the cheapest hours).
- In the activation of flexibility services, the supplier should not incur any losses nor gain profits. However, this is only possible if the ToE has the exact same price as the individual retail contracts. With our ToE price recommendation, the supplier will still incur losses and gain profits. With a rebound closer to 100%, these are **very limited** and could be **balanced out in a large portfolio of customers**.

Caveat: the customer impact, but also the behaviour of the IA, depends strongly on the commercial agreement between both parties. **Our examples are not exhaustive but aim to provide realistic customer propositions.** The choice for profit sharing ensures the trading behaviour of the IA is not affected. The main purpose of these examples is to show that the impact of the (level of) ToE price is limited, or even non-existent, for time shifters. **We do not intend taking any position on the commercial agreement between IA and customer.**

5 PRACTICAL IMPLEMENTATION IN FINLAND

This Chapter covers the assessment of the practical implementation options of independent aggregation models in Finland. It starts with a short description of the current implementation design for FCR, aFRR and mFRR.

Section 5.2 focuses on the day ahead and intraday markets. Finding suitable implementation models for IA is most challenging in wholesale markets, esp. for assets with low marginal costs, that are typically operated on a daily basis. Consequence of low marginal costs is that the activations are very sensitive to the ToE price, as shown in the previous section. Also these type of assets typically have high rebound effects. These challenges might have so far slowed down the implementation of IAM in wholesale markets in other European countries, where even the two existing implementation are incomplete (France not supporting demand enhancements and Belgium not supporting the residential segment).

Based on the recommended implementation for DA and ID markets, section 5.4 will provide recommendation on possible modification for the current design for balancing services, for two reasons

- One model covering both DA/ID market and balancing services is preferred to two separate models, for cost efficiency reasons and transparency reasons
- Arguments leading to specific recommendations for DA/ID markets may also be valid for balancing services and would lead to an enhancement of the current design for balancing services.

5.1 Implementation design for FCR, aFRR and mFRR

FCR and FFR

Frequency Containment Reserve (FCR) refers to a reserve that is available for the containment of frequency during an imbalance between electricity production and consumption. It is divided into 3 products: FCR-N, FCR-D up and FCR-D down. FCR for Normal Operation (FCR-N) is a Frequency Containment Reserve that aims to keep the frequency within the normal frequency range of 49.9–50.1 Hz. While FCR-N is procured symmetrically in the Finnish market, FCR for Disturbances has two separate products for upwards and downwards regulation. FCR for Disturbances, up-regulation product (FCR-D Up) aims to contain the frequency to at least 49.5 Hz if the frequency falls below the normal frequency range of 49.9–50.1 Hz, while FCR for Disturbances, down-regulation product (FCR-D Down) aims to contain the frequency to at least 50.5 Hz if the frequency is above the normal frequency range of 49.9–50.1 Hz. FCR is contracted by Fingrid in a yearly, D-2 and hourly market and is remunerated via a Capacity Fee based on merit order clearing price [50]. Fast Frequency Reserve (FFR) is procured from a national market by Fingrid to handle low-inertia situations. Inertia means the ability of the kinetic energy stored in the rotating masses in the electricity system to resist changes in frequency. The needed volume of FFR depends on the prevailing inertia in the power system and the size of the reference incident. Independent aggregation is allowed in both FCR and FFR markets: *uncorrected model* is applied for FCR-D and FFR, while *central settlement model* is in place for FCR-N [51] For both products, the IA does not need to perform or assign the BRP role. As of October 2024, in the FCR-N, the BRP of the reserve resource's supplier receives the energy payment at the imbalance price and an imbalance adjustment is done for the BRP. In FCR-D and FFR, there is no energy payments and no imbalance adjustments.

aFRR

Fingrid is planning to open the market of automatic Frequency Restoration Reserve (aFRR) to IAs, following public consultation in March 2024 [52]. The IA model in aFRR is expected to go live in March-April 2025. In the proposal

[50] Oyj, F. (n.d.). *Appendix 1 to the Market Agreement of Frequency Containment Reserves Unofficial translation Terms and conditions for providers of Frequency Containment Reserves (FCR)*. Retrieved from https://www.fingrid.fi/globalassets/dokumentit/fi/sahkomarkkinat/reservit/terms-and-conditions-for-providers-of-frequency-containment-reserves-fcr-as-of-22-may-2023.pdf

[51] The regulation of independent aggregators. (2022). Retrieved August 11, 2024, from Norden.org website: https://pub.norden.org/nordicenergyresearch2022-04/#99954

[52] Public consultation on independent aggregation in the Automatic Frequency Restoration Reserve market. (2024, February 29). Retrieved July 22, 2024, from Fingrid website: https://www.fingrid.fi/en/news/news/2024/public-consultation-on-independent-aggregation-in-the-automatic-frequency-restoration-reserve-market/

submitted to the regulator, the IA assumes the role of BSP but does not have to be a BRP nor must have a contract with a BRP. However, the BSP is financially responsible for the imbalances caused to the power system and for non-compliance of delivery of flexibility services at the imbalance price. Fingrid proposes the compensation of the supplier's BRP at the DA market price during the relevant imbalance settlement period. The BSP is responsible to provide information to eSett on the balancing energy delivered , to allow the determination of the compensation fee and imbalance adjustment of the BRP of the reserve resource [53]. Fingrid checks the baseline and delivered energy calculation in the prequalification phase and may ask for additional information also after prequalification.

mFRR

Fingrid aims to implement a similar IA model as planned in aFRR, to mFRR (balancing energy and balancing capacity markets) during 2026. Fingrid's pilot project for testing IAs' participation in mFRR between 2018 and 2021 applied a central settlement model, where both options where tested: when the IA BSP needs to assign or perform the role of BRP and when it holds financial responsibility but does not have to take a BRP role.

An overview of the status of the practical implementation of IAM across balancing markets is provided below.

Table 9: Overview status practical implementation IAM across balancing markets.

[53] Oyj, F. (n.d.). Background document on changes in the aFRR terms and conditions applying to independent aggregators 2/2024. Retrieved from https://www.fingrid.fi/globalassets/dokumentit/en/news/electricity-market/background-document---public-consultation-of-changes-to-terms-and-conditions-of-afrr-unofficial-english-translation.pdf

	Balancing Market		
	FFR and FCR	**aFRR**	**mFRR**
Verification of delivered flexibility	Prequalification test of BSP every 5 years. Real-time measurements from BSP. Audits conducted by Fingrid.	Prequalification test of BSP every 5 years. Real time measurements from BSP. Audits conducted by Fingrid. *Proposal:* *Description of determination of delivered energy per BRP-SUP-MGA is provided by IA for Fingrid in prequalification phase.* *Fingrid sets accuracy requirement for delivered energy calculations. Accuracy checked during prequalification.* *Proposal:* *BSP must communicate information on final balancing energy delivered ex-post (within 13 days).*	Prequalification of BSP Real time measurements from BSP. Audits conducted by Fingrid. Similar concept for verification of flex. provided by IA planned by Fingrid as proposed in aFRR.
Determination of baseline	There is no baseline methodology defined/prescribed by the TSO. Following some general guidelines, BSP presents its calculation to Fingrid, which evaluates it and approves it or not. Currently in FFR, FCR and aFRR, Fingrid applies accuracy requirements for baselines (referred as reference power) in the prequalification phase.		
Compensation	For FCR-N, no compensation model. However, as of Oct. 2024, energy payment (at imbalance price) is done towards the BRP of the reserve resource. In 2025, this is planned to change: energy payment (at imbalance price) is done towards the BSP. Imbalance adjustment still done for the BRP of the reserve resource (at 0 price). FCR-D and FFR: no compensation.	Currently n.a. *Proposal:* *Compensation based on DA market clearing price in the Finnish bidding zone.* .	Currently n.a. Similar compensation model as proposed in aFRR planned for mFRR by Fingrid with go-live target in 2026.
Aggregator's balance responsibility	No need to perform/contract a BRP. This applies to all BSPs.	*Proposal:* *No need to perform/contract a BRP. The BSP is financially responsible for imbalance caused at the imbalance price of the ISP plus the imbalance fee EUR 1.15 /MWh.*	Similar as in aFRR planned by Fingrid.

Imbalance settlement	FCR-N: Imbalance adjustment done to the BRP of the reserve resource. FCR-D and FFR: no imbalance adjustment.	*Proposal:* *The IA communicates the balance energy delivered to the supplier's BRP through eSett.*	Similar as in aFRR planned by Fingrid.

Balance responsibility of IA in Finland in FCR-D, FCR-N, FFR:

- FCR-D: no balance responsibility and no financial balance responsibility for any BSP, product based on capacity, no imbalance adjustments or compensation to BRPs
- FFR: no balance responsibility and no financial balance responsibility for any BSP, product based on capacity for BSP, no imbalance adjustments or compensation to BRPs
- FCR-N: no balance responsibility and no financial balance responsibility for any BSP, product based mainly on capacity payments for BSP. Imbalance adjustments done to BRP.
    - Currently: energy fee and imbalance adjustment towards BRP at imbalance price
    - Proposed (expected to come into force during 2025): Energy fee towards the BSP at imbalance price. Imbalance adjustments still done to BRPs (at 0 price).
    - Processing of balancing energy in FCR-N is further explained in Fingrid's terms and conditions (Chapter 10, document currently in force). [54]

5.2 Implementation options in day ahead and intraday markets including roles and responsibilities

In this Section, the implementation options in terms of roles and responsibilities are described.

5.2.1 Roles and responsibilities in the wholesale market

In the graphs below we provide a high-level overview of the roles, responsibilities and processes associated with the IA model integration in the wholesale market.

We divide the roles and responsibilities in 3 phases:

1. **Contractual phase** – this includes one-off procedures that are completed when the IA is established (see Figure 5-1).
2. **Operational / ex-ante phase** – this phase includes the roles of the different parties during the operational phase, before the activation / delivery of the flexibility service (see Figure 5-2, Figure 5-3).
3. **Ex-post phase** – roles & responsibilities after the delivery of the flexibility service and mainly focused on imbalance settlement and ToE financial settlement (see Figure 5-2, Figure 5-3).

In the following sections, the major aspects of implementation of the recommended IA model are described in detail. For each phase and for each implementation aspect, the roles and responsibilities of each actor are depicted in flow charts. Focus is on new processes, and existing processes that need modification. In **blue** are indicated the roles and processes that are necessary. In **green** we highlight the options that need further discussion or are dependent on future decisions.

Each section is characterized by implementation questions and outlines several options when applicable and our motivated recommendation when there is a strong preference based on our experience and expertise.

[54] Oyj, F. (2024). Appendix 1 to the Market Agreement of Frequency Containment Reserves Unofficial translation Terms and conditions for providers of Frequency Containment Reserves (FCR). Retrieved September 24, 2024, from https://www.fingrid.fi/globalassets/dokumentit/en/electricity-market/reserves/terms-and-conditions-for-providers-of-frequency-containment-reserves-fcr-id-391152.pdf

Contractual phase

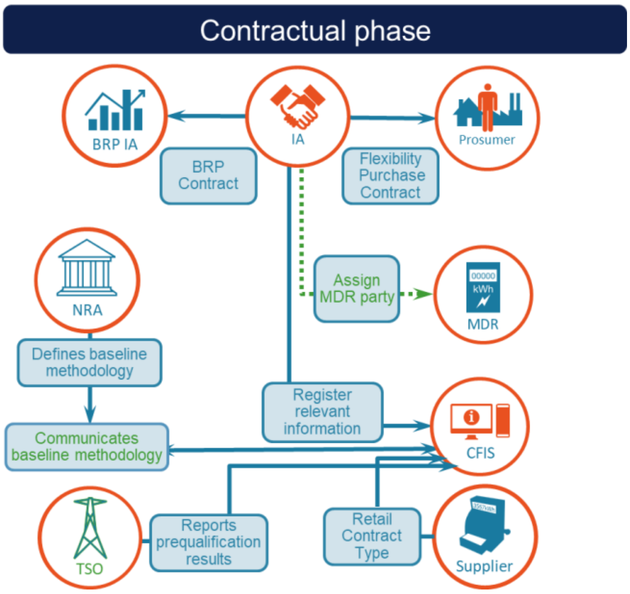


Figure 5-1: Roles and responsibilities in contractual phase.

In relation to the contractual phase, the are several implementation topics to be addressed:

- **BRP responsibility:** we recommend that the IA must assign or perform a BRP role in the wholesale market. This is in line with current wholesale design where all participants need to perform the BRP role. Also, the network code proposal for Demand Side Response published by the DSO Entity and ENTSO-e requires all IAs to assign (or perform) a BRP role, facilitated by the transfer of energy with the Supplier's BRP. The proposal was reviewed by ACER, which published its own draft proposal and opened a public consultation that will close on October 30th, 2024. The ACER review does not (yet) mention this requirement.
- **Qualification of IA:** we recommend establishing a prequalification process for the IA. The prequalification process design and execution should be assigned to a responsible party (see dedicated section 5.3.8). After the prequalification process the relation between the BRP and IA should be registered in a Central Flexibility Information System (CFIS) and eSett. This to facilitate the processes in the following phases. The information that should be registered in CFIS by the IA is:
    - Contracted customers/assets (portfolio)
    - Meter IDs and metering contracts (when dedicated measurement devices (DMDs) are used for settlement)
    - (if applicable – see Section 2) Baseline Methodology selected
    - Balance Responsibility agreement.

  When we refer to the so-called *Central Flexibility Information System* ("flexibility register"), the term is taken from ACER's draft NC DR network code. It is a national decision how and where the flexibility register will be implemented in the future.

Operational / ex-ante phase and Ex-post phase

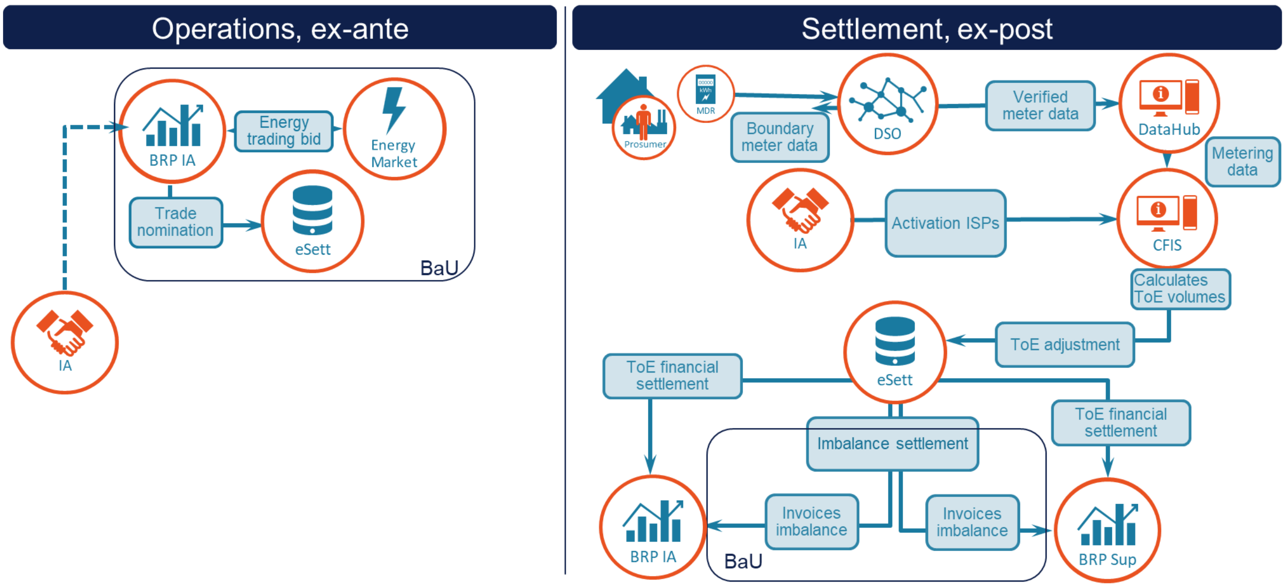


Figure 5-2: Roles and responsibilities in ex-ante and ex-post phases – necessary processes.

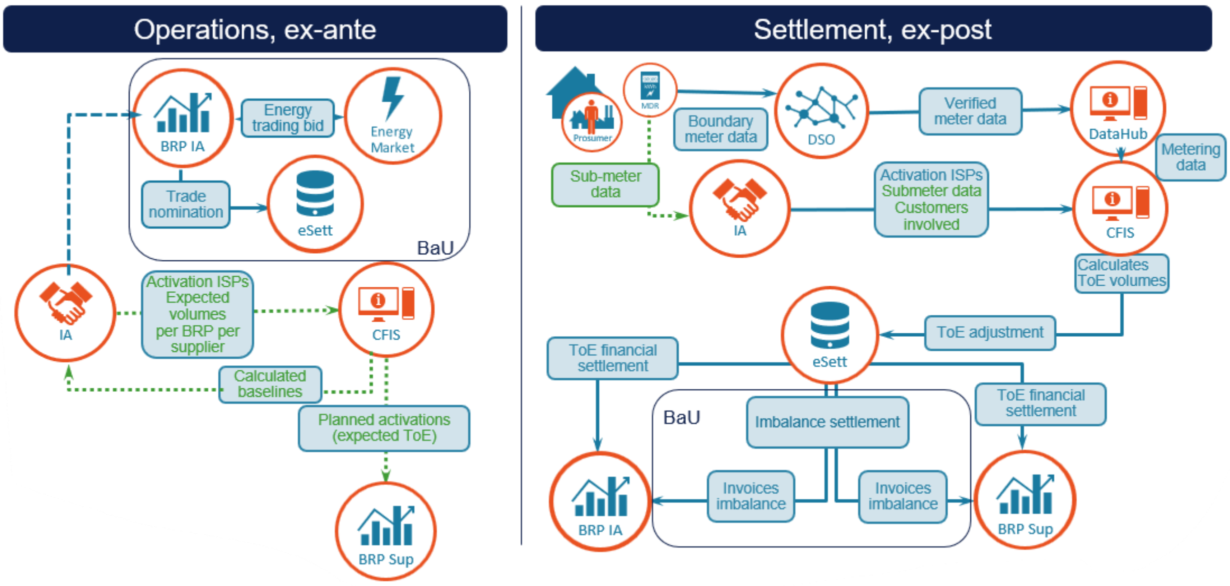


Figure 5-3: Roles and responsibilities in ex-ante and ex-post phases – decisions to be made (options).

The operational and ex-post phases will be further described in the next sections.

5.3 Practical implementation in day ahead and intraday markets including new and enhanced processes

DNV has identified eight key processes and its associated challenges. These are depicted in Figure 5-4 and represent the content structure of the following sections.

Main process	Main challenge
1. Measurements used for flexibility quantification	•Use of boundary meter only or boundary + sub-meter •Allow multiple IAs per customer/connection
2. Determination and verification of baseline methodology	•Roles and responsibilities for designing, selecting and verifying BM
3. Wholesale nomination	•Need for ex-ante ToE •Information exchange with supplier's BRP
4. Flexibility quantification and ToE volume calculation	•IA (balance) responsibility for full portfolio, or only activated part •Trigger for perimeter correction (nomination?)
5. Compensation and financial settlement of ToE	•Which price formula to apply? Same formula for different markets (DA, ID, balancing) •Rebound effect
6. Imbalance settlement	•Impact of ToE on imbalance calculaion •How to make the IA responsible for imbalance caused by (incomplete) DR activations
7. Master data (connection / flex registry)	•Register relation between IA and customer and between IA and BRP-IA •Register metering point + MRP •Enable / disable (in case of full responsibility)
8. Prequalification	•Selection and validation of baseline •Rebound level •Assignment of BRP

Figure 5-4: Main processes and challenges to consider for practical implementation.

5.3.1 Measurements used for flexibility quantification

The first implementation aspect to consider is the measurement used for the quantification of the delivered flexibility. Below we list the two main challenges that need to be addressed: 1) the measurement equipment allowed to be used for quantification and 2) who should be responsible for data processing and verification. A process description is shown in Figure 5-5Figure 5-5.

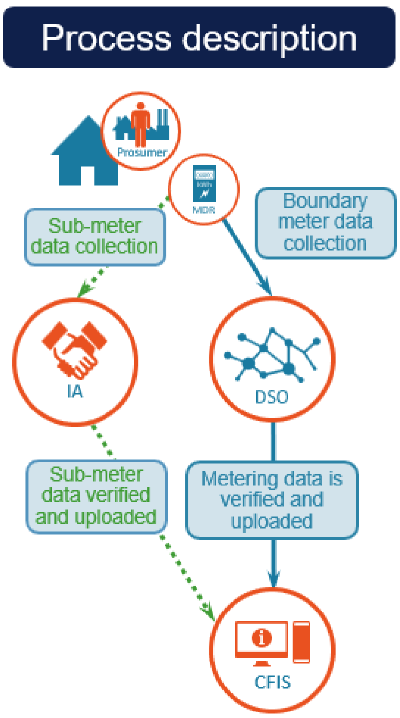


Figure 5-5: Process description measurements used for flexibility quantification process description.

Main challenges and options

- **Measurement equipment:** The main challenge is if the validation of the delivered flexibility should be allowed to be based on the boundary meter only, or if the use of a submeter / asset meter ("dedicated measurement device") should be permitted. Related to this is the question, if only one IA per connection should be allowed, or multiple.

  We recommend allowing the use of submeters for quantification and validation, as the use of a submeter not only allows multiple IAs per connection, but it will also improve the quality of the flexibility quantification / baseline methodology (no noise included from non-controlled appliances). In addition, submetering (as "dedicated measurement device") data is included in the EMD reform.

- **Responsibility for data verification:** in case submetering is allowed, who is responsible for data collection, cleansing and verification of the measurement data? There are a few options to distribute these roles over IA, DSO and CFIS:

  Option 1: Meter data is collected by the DSO (boundary meter or submeter), which sends it to CFIS. Validation is performed either by DSO or CFIS.

  Option 2: Meter data (submeter) is collected by the IA, validation is performed either by DSO or CFIS.

  Option 3: Meter data (submeter) is collected and validated by the IA, and directly uploaded to CFIS.

  We recommend that the data collection is performed by the IA, yet the validation of the data is not performed by the IA (Option 2). This ensures that the verification is conducted by an independent party.

  Within Option 2, we recommend that the validation of meter data is performed within CFIS, for cost efficiency reasons.

- **Handling of submetering data:** when allowing submetering, the data collection process must be adapted, as the DSO does not have access to meters behind the boundary meter. The following data handling procedure is recommended instead:

  1. IA extracts data and provides bulk measurement data through back-office
  2. The raw data is delivered directly to the CFIS which performs a centralized validation (see dotted line in Figure 5-6).
  3. For ToE calculation and financial settlement, validated data is forwarded to the CFIS.

  We recommend implementing this option, as the collection of submetering data is a new process to all market parties and it will be better handled centrally (see Figure 5-6).

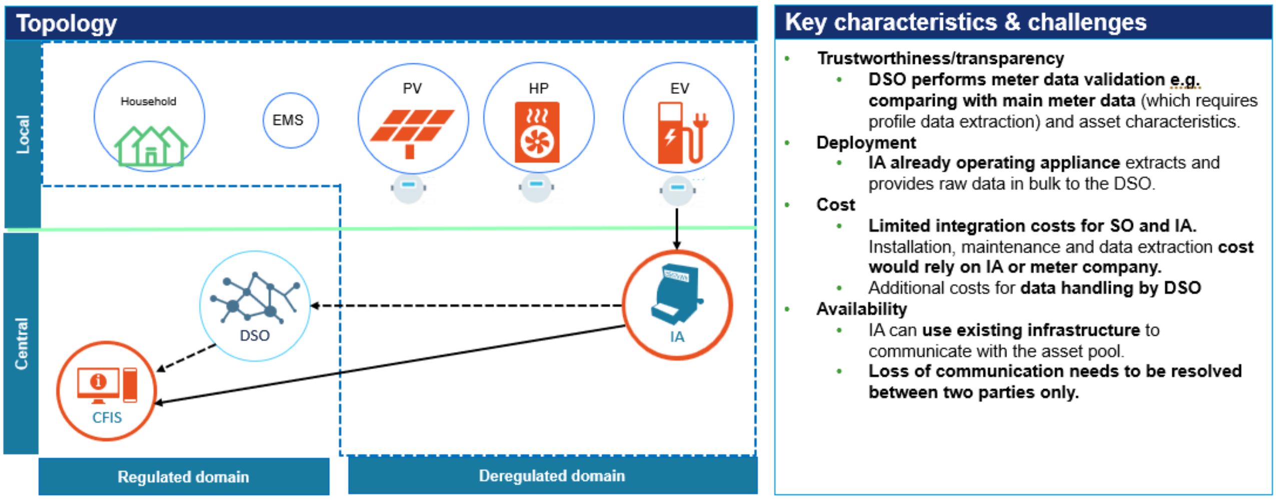


Figure 5-6: Recommended data handling for submetering.

Relation to existing processes

There are some aspects in already established processes where the new recommendations can be integrated

1. The data gathering by the IA can be similar to the proposed solution for the IA integration in aFRR market, where the BSP is responsible to deliver the final balancing energy data ex-post. However, the verification responsibility in the case of wholesale markets is assigned to the CFIS.
2. For boundary meters, the regular path for data collection and validation can be followed.
3. Strong similarities with solution for multiple suppliers per connection (CFIS)

5.3.2 Determination and verification of the baseline

When determining the allowed baseline methodology (BM), the following aspects should be considered:

- **Responsibility of BM definition:** the allowed baseline methodology(-ies) need to be defined, since the wholesale market has no associated BMs (unlike e.g. balancing products). We suggest that the National Regulatory Authority (NRA) holds this responsibility for its determination, since wholesale markets are not governed by the TSO Fingrid.
- **Selection the BM:** if multiple BMs are allowed, we suggest that the IA is responsible for choosing the most suitable BM, provided the IA can demonstrate that the BM is sufficiently accurate. The selection is performed on asset/connection level, and this choice needs to be registered in CFIS.
- **BM accuracy:** the NRA should define the accuracy requirement; there is no need to define different levels for different technologies or different baselines methodologies.
- **Baseline calculation:** once the BM is determined and selected, the options for its calculation are mainly three:

  Option 1: **Calculation is performed by IA and shared (either ex-ante or ex-post) with CFIS:** Certain baselines methodologies can only be calculated by the IA (e.g. nomination baseline methodology).

  Option 2: **Calculation is implemented in CFIS and shared with IA ex-ante (example GB DSO products).** For baseline methodologies that can be calculated by a neutral party, the CFIS is the most logical place for its implementation. Publishing the calculated baseline ex-ante guarantees that the IA knows exactly how much DR needs to be activated.

Option 3: **Calculation is implemented in CFIS and only shared ex-post:** this option avoids additional information exchange, assuming that the IA can calculate the baseline itself. The calculated baselines may be shared ex-post with the IA as part of the ToE settlement transaction.

The choice finally depends on the type of BM allowed, e.g. options 2/3 are not feasible for a nomination baseline.

- **Baseline accuracy monitoring:** we recommend that the quality of the selected BM is regularly checked for each IA. This responsibility should be assigned to CFIS, as the CFIS receives measurement data and will already be responsible (according to our recommendation) for ToE calculation.

  Accuracy monitoring for baselines is relevant for service delivery and also when the baseline is used as the basis for the ToE. Suppliers and BRPs are not able to verify if their perimeter correction is precise, or whether it introduces an imbalance in their portfolio, so they must rely on the baseline methodology, of which the quality should be quantifiable.

  To monitor accuracy of the baseline methodologies, it is recommended to check the baseline accuracy continuously on non-event days, comparing the baseline with the measurements. Accuracy should be primarily monitored on connection/asset level (prequalification), yet also BRP level can be considered (relevant for ToE). Once minimum accuracy requirements are set, asset/BM combinations that do not meet these requirements, either need to switch to another BM, or should be removed from the IA's portfolio.

  The facilities needed for accuracy monitoring are also important for gaming monitoring, to avoid consequent market distortions, and for prequalification, especially when more baseline methodologies become available to the IA.

  We do not recommend including pre-defined BM accuracy requirements from the start, it would be better to first obtain visibility on the accuracy of the assets that are participating. Outliers can first be discussed with the IA. In time, pre-defined thresholds can be defined, when IAs have gained more experience, volumes are increasing and the impact on product effectiveness increases.

  In Figure 5-7 the process description is provided.

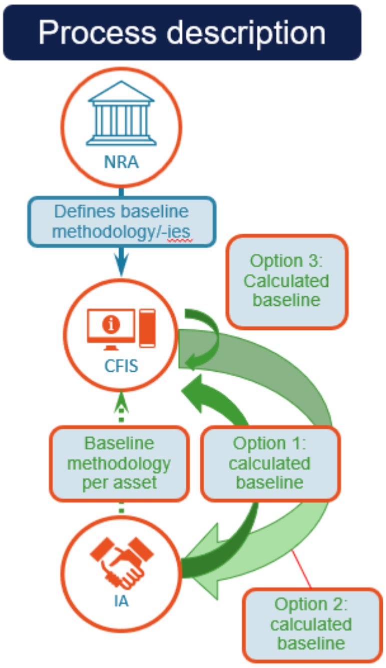


Figure 5-7: Determination and verification of the baseline process description.

5.3.3 Wholesale nomination

Like other market parties, the IA needs to nominate to eSett its planned activations and trades for the consequent calculation and settlement of imbalance. Because the activation plan is prepared in advance by the IA, it could be shared with the CFIS in advance to inform the CFIS and potentially already estimate the ToE volume.

Regarding wholesale nomination, we provide the following recommendations:

- **We recommend not to implement an ex-ante Transfer-of-Energy** (as seen in France).
  The BRP-IA should initially only nominate the (DA) energy trade to eSett and only subsequently, the measurements and ToE calculation by CFIS are used for the ex-post correction of the perimeters. This is similar to a BRP Sup only nominating the energy it sources on the spot market, not the energy consumed by its customers, which will also be added to the balancing settlement by metering data collected in the Data Hub and aggregated per BRP, per Metering Grid Area (MGA).
- **Should the (BRP of the) Supplier be informed about the intended activation of DR?**

  Arguments in favor of ex-ante information exchange:

  - Measurements are often used for short—term forecast. ToE volumes should be excluded from these measurements as they are not sourced by the Supplier.
  - DR activations may be noticed by Suppliers through on-line monitoring. This information could prevent these suppliers for (inefficient) counter-balancing the DR activations.

  Arguments against ex-ante information exchange:

  - It creates administrative burdens for IA, CFIS and BRPs of Suppliers.
  - IA often decide (close to) real-time which assets to activate, indications may have poor quality
  - Transfer of Energy volumes are communicated ex-post, thus can be used for forecasting/ nominations.
  - On-line monitoring by the Supplier (or its BRP) is uncommon for most customer groups
  - When on-line monitoring is in place, DR activations are noticed on customer level, whereas expected ToE volumes are only shared on BRP, Supplier and MGA level – therefore difficult to link to the right customers.

  We recommend Finland to nationally consider an **ex-ante information exchange about intended activations**. Main reason for providing this information to the Supplier is that if a Supplier is monitoring its portfolio in real time and is timely informed about a DR activation, it will not counterbalance the activation by IAs. If not informed, the Supplier could interpret the large deviation from the consumer's baseline as an unplanned outage or a not-communicated variation in the consumer activities and it would try to counteract it to avoid or at least reduce its imbalance. For confidentiality reasons, the information exchange needs to be routed through the CFIS (not disclosing the involved IA to the Supplier), and the data needs to be aggregated (not disclosing the customers involved) per MGA, per BRP.

Relation to existing processes

The nomination of IA's BRP can follow the existing nomination processes (indicated as Business as Usual in the process flow in Figure 5-8).

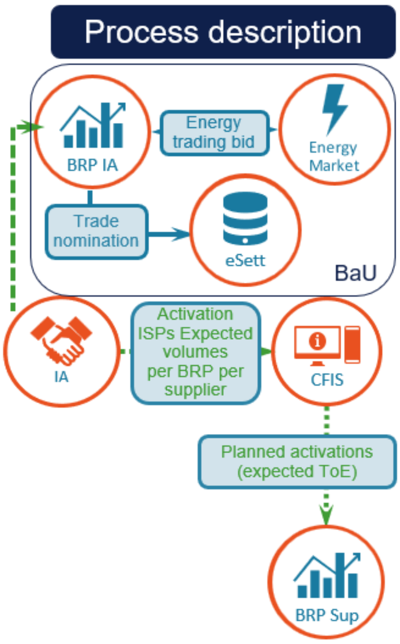


Figure 5-8 Wholesale nomination process description.

5.3.4 Flexibility quantification

When the quantification of the delivery flexibility needs to be finalised, there is a need for clarity on what is the extent of the IA's responsibility on deviations form baseline in its portfolio, but also who and how is responsible to calculate the final ToE. We outline these specific challenges in the section below, together with our recommendations.

The process description is in Figure 5-9.

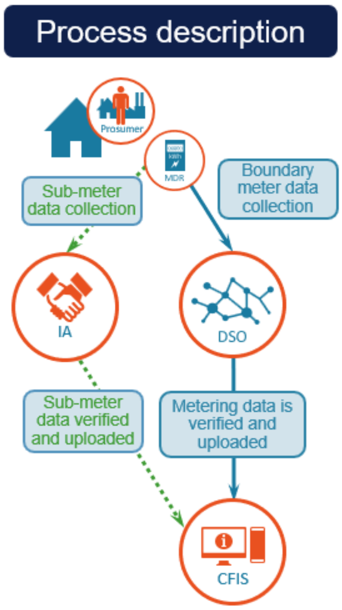


Figure 5-9: Flexibility quantification process description.

Main challenges and options

- **Is the IA responsible for the balance of its whole portfolio during flexibility delivery or only for the activated/nominated units?**

  Arguments in favour and against are outlined in Table 10.

Table 10: Pros and cons of full portfolio versus only activated flexibility assets.

IA's balance responsibility	Pros	Cons
Full portfolio	• Lower risk of gaming (the IA could otherwise "cherry-pick" only those assets that are needed to balance its portfolio ex-post). • Baselines are usually better defined at portfolio level, higher accuracy for portfolio of assets instead of smaller pools (law of large numbers)	• More difficult for IA to maintain the portfolio balanced, more uncertainties. • Non-controlled assets are subject to baseline methodologies whereas their non-controlled consumption is the "real" counterfactual. • Enabling/disabling of assets may be needed, incl. information exchange.
Only activated flexibility assets	• Easier for the IA to maintain the portfolio balanced. • More transparent process	• Risk of gaming behaviour: the IA could ex-post decide which assets were activated and which not (e.g. to reveal over- or underdelivery). • Additional information exchange needed (ex-post) which assets have been used for DR activations.

We recommend that the **IA should be responsible for the balance of its whole portfolio during activation period**. Although no current regulation is mentioning this, we believe that this arrangement will reduce (administrative) complexity and gaming options. It will also stimulate further the selection of a high-quality baseline methodology. Note that for balancing services, it is planned instead to make IA responsible only for nominated and activated assets.

- **Calculation of ToE:** we recommend that the **calculation of the ToE volumes is implemented in the CFIS**. The CFIS needs information from the connection / flexibility register , informs the financial settlement of the Transfer of Energy performed by eSett (see Section 5.3.5), and provides the ToE volumes to eSett to inform the imbalance settlement calculations (see Section 5.3.6).

  The process of calculating the ToE volume in CFIS should be triggered whenever an IA indicates a DR event activated during a specific ISP. The volume should be calculated
  - For each IA that triggers the ToE (by declaring ISPs during which DR has been activated)
    - For each ISP
      - For each customer/asset (all, or those declared by the IA)
        - Activated volume is calculated by comparing the meter reading with the calculated baseline

  Volumes are then aggregated per ISP, per IA, per BRP-IA, per affected Supplier, per affected BRPs, per contract type (dynamic/static), and finally per MGA1 before being delivered to eSett.

Relation to existing processes

- The process of quantification can be similar to the current one used for IA-BSP active in balancing services.

5.3.5 Compensation and settlement of ToE

The compensation model encompasses several aspects to defined: 1) the price of the ToE and 2) the most suitable pricing method considering different markets of implementation. In addition, we outline our recommendation on if/how to manage the rebound effect in the compensation model, as already extensively explained in Section 4.2.3. The process description is in Figure 5-10.

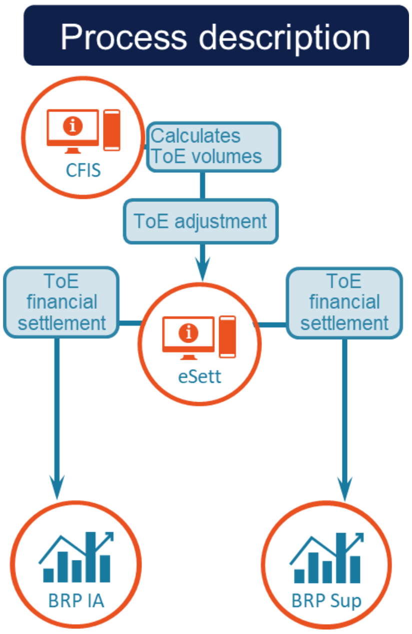


Figure 5-10: Compensation and settlement of ToE process description.

Main challenges and options

- **How to price the ToE?** As explained in Section 4.3, the ToE should based on the retail price, to ensure a level playing field. Since the retail price is not publicly available, the ToE should be based on a formula that approximates the retail price. Given the strong differences in statis and dynamic retail contracts, different price formulas should be applied for these different retail contract types.
  - **For static retail contracts,** we recommend a **price formula similar to the ones used in Belgium and France that has the optimal fit with the Finnish market and sourcing strategies**.
  - **For dynamic retail contracts** (typically based on DA spot prices), the ToE price should equal the DA price plus a representative surcharge corresponding to suppliers' gross margin on such contracts. As a consequence, the IA can hardly make any profit via DA participation with customers on dynamic DA-priced contracts, ensuring a level playing field, since there is no additional revenue to be gained by the IA on customers/assets that are already exposed to the DA spot market. Alternatively, the IA could agree on a service agreement with the customer for the optimization of its electricity consumption, where the customer keeps the potential cost saving and the optimization service revenues are sufficient to make a business case for the IA. In this case, the IA no longer acts as an aggregator, trading the consumers' energy in the market, but rather as an energy service company, optimizing the energy consumption of the customer.
    The IA could still create additional revenues for this customer group by trading on ID markets, or by participating in balancing and congestion services.
  - **For hybrid retail contracts** (combination of static and dynamic), it is reasonable to assume that dynamic prices are applied to flexible assets. Hence these should be treated as dynamic contracts.
- **Should the same formula be used for balancing services and DA trading?** We recommend using the same formula, based on the following arguments:

1. **Facilitation of value stacking:** from a conceptual point of view, ToE is used by the IA to balance its portfolio, not to balance individual assets or individual trades / services. As an example, when an IA sells 100 MWh on the DA market and buys the same volume in real-time in a balancing product, the IA could avoid any DR activation. Applying different formulas would still lead to two transfers, opposite in volume, but against different prices. This would affect the level playing field of the IA compared to the Supplier that would not face this price difference.

2. **Costs and simplicity:** having one formula for dynamic/hybrid contracts and one formula for static contracts regardless of the market in which IA is participating means one single process, and there is no need to assess which asset has been used to deliver which service, especially in case of over-/under delivery. Even if the ToE is combined for wholesale and balancing, the verification of the delivery of balancing services can/should still occur.

3. **Transparency:** The impact to the Supplier is indifferent from the market where the IA trades the flexibility. The Supplier should therefore not be faced with different compensation levels. It could also provide information on which markets flexibility is generally traded, which does not need to be shared with the supplier.

Table 11 summarizes our recommendation on compensation models for each service and consumer's type of contract. A possible simplification that could be applied to the process, consequent to the recommendation to apply the same ToE formula for all services, is that the IA also should need to assign a BRP for balancing services (currently not in the proposal for aFRR market). In this way, the IA could manage all stacked revenue sources within one BRP without any further complication from different service pricing.

Table 11: Compensation model recommendations.

Market/ service	Model (static supply contracts)	Model (dynamic /hybrid supply contracts)
DA markets	Central Settlement with ToE price formula that approximates retail price (mainly based on futures)	Central Settlement with ToE price formula that approximates retail price (mainly based on DA price)
FCR*, FFR	Uncorrected	Uncorrected
mFRR & RR	Central Settlement with ToE price formula that approximates retail price (mainly based on futures)	Central Settlement with ToE price formula that approximates retail price (mainly based on DA price)
aFRR	Central Settlement with ToE price formula that approximates retail price (mainly based on futures)	Central Settlement with ToE price formula that approximates retail price (mainly based on DA price)

*FCR-D is uncorrected and FCR-N is perimeter corrected

- **Rebound effect:** indifferently from if/how the rebound effect is managed, no additional changes are needed to the regular process:
    - When the rebound is not controlled by the IA, no ToE calculation is triggered for the period when the rebound occurs.

- When controlled by the IA, this will lead to another DA trade with associated ToE, that follows the "regular" process.

However, when the IA is made responsible for rebound, and this is enforced by comparing the ToE volumes in both directions, this comparison needs to be included in this process, including potential penalties for non-conformance.

We recommend that the **ToE mechanism includes the requirement for the IA to control the rebound effect**, as explained in Section 4.2.3. Two exceptions may be foreseen:

- Assets for which no (noticeable) rebound occurs, such a gen-sets and certain types of industrial load shedding
- Assets that are only utilised for capacity-based products, typically with high marginal costs

For assets that have 0% rebound, this implies that the ToE is only performed in one direction.
If the IA does not meet this requirement (i.e. volumes in both directions are not in line with the pre-qualified rebound ratio), then the ToE is facilitated, but only for the part that matches the rebound ratio. Any deviation should be penalized to the extent the IA is sufficiently stimulated to meet this requirement, yet not taken out of business when this occurs. The impact illustration in Section 4.3.4 shows different examples of how ToE is supported in different rebound situations.

- The implementation of the recommended compensation model should also include the following aspects:
  - **Symmetry:** we recommend making the compensation symmetrical, which means that in the compensation between Supplier and ToE is implemented in both cases of demand enhancement / generation reduction and demand reduction / generation enhancement.
  - **Financial settlement:** we recommend that the ToE financial settlement is implemented in eSett, as the platform is already responsible for settlement and invoicing of BRPs.
  - **Information registry:** if, as recommended, different price formula are applied depending on retail contract type, it is important that this information is registered by the Supplier in the connection / flex registry.
  - **Compensation between BRPs:** compensation should be done between BRP-IA and BRP-SUP. The BRP-SUP and the Supplier, as well as the BRP-IA and the IA, should bilaterally agree on how to handle the compensation related to IA activations in their contractual relations. This report does not provide any recommendations on these bilateral arrangements.

5.3.6 Imbalance settlement

Typically, IAs need to bear balance responsibility for imbalances associated with (incomplete) DR activation. The proposed mechanism achieves this objective, since ToE volumes are calculated based on measurements ("physical settlement"). If the IA is unable to activate the volume sold on the DA market (situation of under delivery), this will result in a lower ToE volume, and thus in an imbalance position for the IA-BRP. The same holds true if over delivery occurs. The process description is in Figure 5-11.

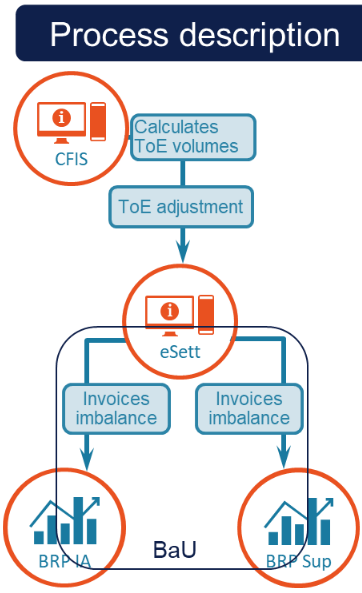


Figure 5-11: Imbalance settlement process description.

Figure 5-12 shows how a ToE adjustment needs to be implemented in the imbalance calculation in eSett, quite similar to the imbalance adjustment already present. The ToE volumes should be provided by the CFIS (as explained in 5.3.4) and the sum of all ToE adjustments over BRPs should equal zero. Whether imbalance caused by the rebound effect ends up at the IA, depends on the question whether the IA controls the rebound effect (either voluntary or mandatory).

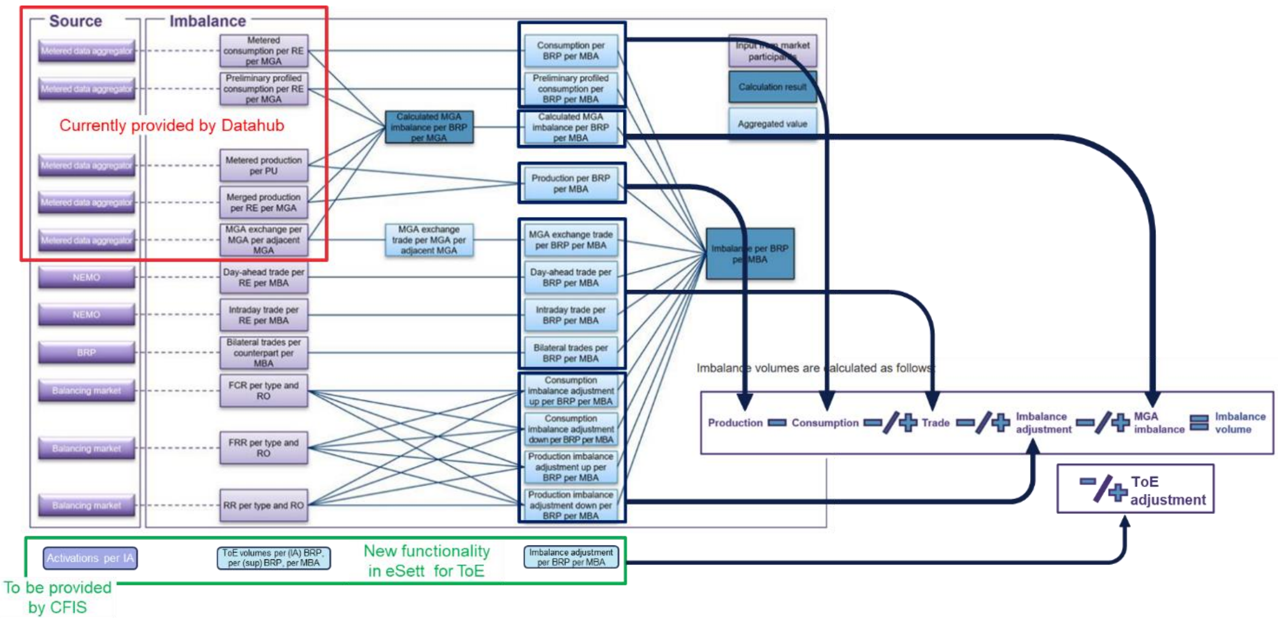


Figure 5-12: Imbalance settlement – necessary changes.

Relation to existing processes

- In the current proposal for IA integration in aFRR market, a separate financial settlement is needed for BSP-IAs that cause an imbalance. This is not needed for wholesale market and could even be made obsolete when IA-BSP's perform/assign the BRP role, as suggested in Section 5.3.5.
- Perimeter correction is similar to the one for balancing services under the Balancing Guidelines. Yet, for ToE also the BRP-IA's perimeter needs to be modified.

5.3.7 Master data (connection /flex registry)

The IA needs to submit the following information to the CFIS (connection / flex registry):

- Register relation between IA and customers (portfolio):
    - This can be similar to the registration of the relation between IA-BSP and customer
    - It should contain a reference to the metering point (and possibly meter data responsible party) when submetering is allowed
    - It should describe which baseline methodology will be applied for this customer / asset (only when multiple BMs are allowed).
- Register relation between IA and BRP
    - This can be similar to the relation between Supplier and BRP
- Possibility to temporarily enable / disable a customer (in case of balance responsibility for full portfolio)
    - This would make sense, to allow for maintenance, communication failures etc.
    - Should not be (mis)used by the IA on a daily basis to create a dynamic portfolio

The Supplier needs to submit the following information to the CFIS the contract type (static / dynamic / hybrid), as depending on the contract type, different price formulas will be applied to the ToE. See Figure 5-13 for an illustration of the process.

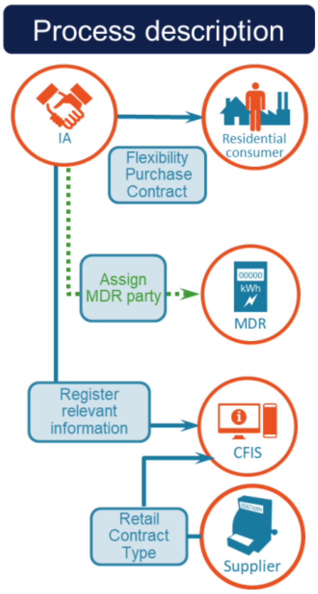


Figure 5-13: Master data (connection /flex registry) process description.

Relation to existing processes

- The recommended process is similar to the one applied for IA-BSP's master data.

5.3.8 Prequalification of the IA for wholesale market

As mentioned in Section 5.2.1, we recommend the **IA to run through a prequalification process**. The IA prequalification process should verify the capabilities of IA to meet defined requirements – which partly depends on the process choices to be made nationally in Finland, in particular:

- collection and verification of sub-metering data (if not assigned to separate MDR)

- communication and data exchange with CFIS
- baseline methodologies applied and rebound characteristics

The IA-BRP prequalification follows the regular process for any BRP (the IA may contract an existing BRP as well) and the following aspects should be considered:

- IA needs to be prequalified and registered in CFIS once the prequalification has been passed
- This leads to several information exchange needed:
    - Relation IA – BRP needs to be registered in CFIS
    - The portfolio information of the IA needs to be communicated to CFIS
    - (If applicable) IA needs to select the baseline methodology (if multiple BMs are allowed), and demonstrate its accuracy during prequalification test
    - (if applicable) IA needs to demonstrate the rebound ratio per technology

The responsibility for the prequalification should be assigned to a prequalification responsible party. We recommend that **the TSO is responsible for conducting the prequalification test and sharing the results with CFIS**, as it is a similar process as the BRP and BSP prequalification. It is also likely that the IA active in wholesale market will also be active in the balancing market. If the TSO is responsible for both qualifications, the process is simplified.

Relation to existing processes

Prequalification of IA can be based on the already existing prequalification process of IA-BSP as proposed by Fingrid for the IA integration in the aFRR market. In addition, the registration of IA-BRP relation is similar to registration of the Supplier-BRP relation.

In illustration of the process is in **Figure 5-14**.

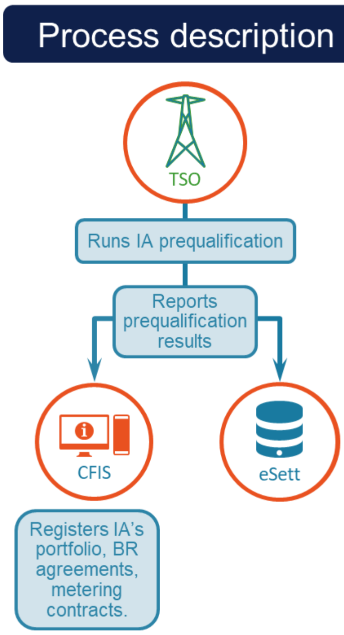


Figure 5-14: Prequalification of the IA for wholesale market process description.

5.4 Implications for balancing markets

As mentioned at the beginning of this Section, the recommendations presented for implementing IA in wholesale market, together with their reasoning and arguments, are similarly applicable to the IAM in balancing services.

In Table 11 Section 5.3.5, we summarise the recommended IAM and compensation models across wholesale and balancing services. With the exception of FCR and FFR, where an uncorrected model is recommended, in line with the majority of other European examples and for practical reasons related to low volume exchange, for all other considered markets a central settlement model is recommended with a regulated ToE price that approximates the electricity retail price. The use of one single mechanism for both wholesale and balancing markets not only allows simplicity and transparency, but also ensures level playing field in trading across markets and avoids market distortions. In fact, the same principles demonstrated in the impact illustration (Section 4.3.4) applies if the IA is active in balancing markets: by setting the ToE price to an approximation of the retail price, the arbitrage position of the IA mimics the arbitrage position of the integrated model (and the arbitrage position of the customer exposed to wholesale prices) and avoids potential market distortions in balancing services.

To allow and facilitate value stacking by IAs, the ToE should not be applied to different markets separately. In stead, the ToE should be applied to balance the net position of the IA resulting from all (buy and sell) activities in the different markets (DA, ID, balancing and -in the future- congestion management). This implies that only one ToE price formula is needed (per our recommendation), also that the Supplier is ignorant of the markets where the IA participates. Since the ToE is performed between BRP/IA and BRP/SUP combinations, another logical consequence is that IA-BSPs should assign a BRP. Impact of this recommendation is low, since IAs active in different markets including wholesale, will already need to assign a BRP.

This also implies that our recommendation for the IA to hold balance responsibility for its full portfolio should be extended to balancing services.

It is important to mention that the current recommendations do not impact the existing process of validating the delivery of balancing services, as explained in Section 5.3.4. It could however lead to different baseline methodologies being applied for balancing services and in wholesale markets. Also, the verification and quantification of flexibility delivery is recommended for wholesale market to be handled by the CFIS, while for balancing markets the responsibility is still (and can remain) within the system operator.

Another important recommendation focuses on regulating the responsibilities of rebound effect and in particular it is recommended to assign such responsibility to the IA. This aspect is also relevant for balancing services. We recommend that also the **ToE mechanism for balancing services includes the requirement for the IA to control the rebound effect**, following the explanation in Section 4.2.3. The recommendation is not impacted by the fact that IA is allowed to trade across different markets. In fact, the same arbitrage strategy is already in place for batteries active both in balancing and wholesale markets; making the IA responsible for rebound effect will create a very similar activity. However, as for wholesale market, there are exceptions to the application of this recommendation. These are even more relevant in balancing markets, where capacity payments apply:

- Assets for which no (noticeable) rebound occurs, such as gen-sets and certain types of industrial load shedding
- Assets that are only utilised for capacity-based products, typically with high marginal costs

6 CONCLUSIONS AND RECOMMENDATIONS

The main conclusions from this study are listed below:

- The assessment framework defined by USEF includes seven aggregator implementation models. Models differ based on whether there is a contractual relationship between the aggregator and the supplier's BRP, and whether the Aggregator has BRP responsibilities. Three key models focus on independent aggregation: the uncorrected model, the central settlement model, and the corrected model.
- International comparative assessment
    - It can be concluded that the IAM varies by country, yet there is a convergence perceived towards central settlement across markets. Most of the assessed countries opened participation of IAs first to balancing markets and capacity mechanisms, while the wholesale market remains untapped or is left to a second stage of the implementation plan. Several countries have implemented multiple IAMs, often for different markets/products or customer segments.
    - Balance responsibility in relation to IAs varies significantly across countries and markets, depending on whether the aggregator is required to perform or assign the role of a BRP.. Overall, in balancing markets, most countries have opted for not assigning balance responsibilities to the IA, especially in FCR, with some exceptions in aFRR and mFRR: Belgium and Switzerland impose similar requirements in balancing markets, with the aggregator's BRP being held accountable for any imbalances due to over- or underdelivery of the agreed balancing volume. However, other countries like France of GB adopt a different model in some balancing markets where the aggregator acts as a "floating BSP," assuming financial responsibility for imbalances without the need to perform the BRP role. When it comes to balance responsibilities in wholesale markets, it is unanimous the choice of assigning the balance responsibility to the IA.
    - The participation of IAs is impacted by regulatory frameworks, market dynamics, and technological limitations. Minimum bid sizes and specific technological requirements also limit participation, as seen in Great Britain and Switzerland. However, ongoing reforms in countries like Poland aim to lower these barriers and it is expected that the upcoming Network Code on Demand Response will require such changes. Submetering still represents a challenge in most of the analysed IA markets, first adopters are Belgium and France experimenting with this. Although tracking IA participation volumes in demand-side flexibility is challenging due to transparency limitations, reports from countries like Belgium and Great Britain indicate an upward trend, while France is experiencing a decline of activations. Overall, overcoming these challenges is crucial for unlocking the full potential of IAs and enhancing demand-side flexibility across markets.
    - The current lack of accountability for the rebound effect, especially relevant for time shifters such as EV chargers and heat pumps, creates an arbitrage position for the IA that is fundamentally different than the arbitrage position of market parties controlling such an asset when directly exposed to the market. This can lead to serious market distortions when not properly managed. Furthermore, load reduction or increase may (due to the rebound effect) inadvertently create imbalances in the supplier's portfolio, highlighting an urgent need for regulatory clarity.
    - Verification of flexibility service delivery, relying on audits and smart metering, is crucial for maintaining the trustworthiness of DSR mechanisms. Countries such as Belgium have established robust systems enabling TSOs to verify service delivery directly via data from distribution system operators (DSOs) and countries like Denmark and Estonia have implemented or are implementing DataHubs for measurement data collection and management.
    - Lastly, information exchange and confidentiality between parties—such as aggregators, BRPs, and system operators—are crucial for fostering transparency and competition in the market. Most countries are moving towards centralized data hubs to streamline this exchange, but careful attention must be paid to confidentiality to ensure a level playing field for all participants.

- Compensation models
    - The comparison of compensation models in selected countries shows that the ToE price formula differs significantly between countries. Most commonly, for balancing services, the price assigned for the compensation is the DA spot market price, but countries that opened the wholesale market to IA (next to balancing) have moved to more complex pricing in order to ensure a level playing field for IA.
    - The Belgium model for ToE compensation focuses on compensating ToE at a reference price based on a regulated formula. The formula aims to approximate the retail energy prices to minimise losses or profits in the Supplier's portfolio due to flexibility activation. The Transmission System Operator (TSO) facilitates the central settlement.
    - DNV proposes a ToE price that resembles the retail price of (residential) customers in Finland. For customers with fixed price contracts, the ToE price should consider the long- and short term electricity supply contracts in Finland, weighted based on the respective market share. The total is multiplied by a factor of 1.4 to take into account other costs than wholesale baseload electricity, i.e., the gross margin of suppliers. For customers with contracts based on day-ahead prices, the ToE price should essentially be based on the day-ahead price (per hour) plus a margin corresponding to the lower costs for servicing such customers (reduced need for collaterals with the power exchanges, the customers are carrying the profile risks themselves). For illustrative purposes DNV suggests to multiply the day ahead price with a factor of 1.2 (i.e. 20%) to take this margin into account.
    - The ToE impact assessment shows that the impact of the (level of) ToE price formula is limited, or even non-existent when rebound is close or equal to 100%, provided the IA controls the rebound. For low rebound ratios this dependency is stronger, yet the arbitrage position of the IA still mimics the arbitrage position of a supplier using the integrated aggregator model.
- Practical implementation in Finland
    - Eight required processes are identified and explained. Each of these eight processes involves different roles and responsibilities and DNV has identified the required changes to existing processes and roles to be assigned.
    - On **Measurements used for flexibility quantification** DNV recommends allowing the use of submeters for quantification and validation, as the use of a submeter not only allows multiple IAs per connection, but it will also improve the quality of the flexibility quantification / baseline methodology. DNV recommends implementing the verification of submeter data in the CFIS, as this needs to be conducted by an independent party.
    - On **Determination and verification of baseline methodology**, DNV suggests that the NRA holds the responsibility for defining allowed baseline methodologies, since wholesale markets are not governed by the TSO Fingrid. The NRA should also define the accuracy requirement of the baseline. DNV does not see the need to define different accuracy levels for different technologies, nor for different baseline methodologies. The selection of the BM (if multiple BMs are allowed) should be the responsibility of the IA. DNV identified three different options concerning which party should perform baseline calculation, depending on the type of BM allowed. For baseline accuracy monitoring, DNV recommends that the quality of the selected BM is regularly checked for each IA. This responsibility should be assigned to the CFIS, as the CFIS receives measurement data and will already be responsible (according to our recommendation) for ToE calculation.
    - On **Wholesale nomination**, DNV recommends to nationally consider an ex-ante information exchange to the Supplier about IA's intended activations. Main reason for providing this information is that if a Supplier is monitoring its portfolio in real time and is timely informed about a DR activation, it will not counterbalance the activation by IAs. For confidentiality reasons, the information exchange needs to be routed through the CFIS (not disclosing the involved IA to the Supplier), and the data needs to be aggregated (not disclosing the customers involved) per MGA, per BRP.

- On **Flexibility quantification and ToE volume calculation**, DNV recommends that the IA should be responsible for the balance of its full portfolio during activation periods. DNV believes that this arrangement will reduce (administrative) complexity and gaming options. It will also stimulate further the selection of a high-quality baseline methodology. DNV recommends that the **ToE mechanism includes the requirement for the IA to control the rebound effect**, as explained in Section 4.2.3. with two exceptions: assets for which no (noticeable) rebound occurs, and assets that are only utilised for capacity-based products, typically with high marginal costs. If the IA does not meet this requirement, then the ToE is facilitated, but only for the part that matches the rebound ratio. Any deviation should be penalized, to a fair extent.
    - On **Imbalance settlement**, the current proposal for IA integration into the aFRR market necessitates a separate financial settlement for IA-BSPs that create imbalances. This additional step is not required for the wholesale market and could potentially be eliminated if IA-BSPs take on or are assigned the BRP role (which they may already if they are active in both balancing and wholesale markets). Additionally, while perimeter correction for IAs follows a similar approach to that used in balancing services under the Balancing Guidelines, it is essential that the IA-BRP's perimeter is also adjusted for the ToE to facilitate wholesale trading by the IA.
    - On **Master data (connection / flex registry)**, DNV recommends storing master data in CFIS. Information needs to be sent by both IA and Supplier to the CFIS, which will then provide the necessary and aggregated information to eSett.
    - On **Prequalification**, DNV recommends basing this process on the already existing prequalification process of IA-BSP as proposed by Fingrid for the IA integration in the aFRR market. In addition, the registration of IA-BRP relation should be kept similar to the registration of the Supplier-BRP relation. Still to be assigned is the role of the party that will run and assess the prequalification process. DNV recommends assigning this responsibility to Fingrid, as it is already responsible for this activity in the balancing market.
- Implications for balancing services
    - For balancing services where the central settlement model is / will be implemented, we recommend applying the same ToE price formulas as in wholesale. Not only because of simplicity and transparency, also because the same reasoning holds with respect to level playing field and market distortions (i.e. using e.g. only the DA price as a reference price could lead to market distortions in balancing services for customers with fixed retail contracts).
    - The requirement for IAs to control the rebound effect should also be applied to balancing services (with the same exceptions).
    - When the recommendation for the IA to hold balance responsibility for its full portfolio is adopted for wholesale market, this should be extended to balancing services.
    - For further streamlining settlement processes, we recommend that IA-BSPs should assign a BRP when IA is introduced in DA and ID in addition to balancing energy markets. In the future it is quite likely that IAs will enter different markets including wholesale, which will require them to assign a BRP anyway.
    - Our recommendations do not impact the current process of validating the delivery of balancing services. It could however lead to different baseline methodologies being applied for balancing services vs. the Transfer of Energy.

7 GLOSSARY

Term	Definition
Adequacy	The state or quality of being adequate; sufficiency for a particular purpose. In energy markets: whether the generation capacity is sufficient to meet the demand.
Adequacy Product	Product intended to increase the adequacy of the system; one of the possible flexibility products.
aFRR	Automatic Frequency Restoration Reserve.
Allocation	Allocation of measured energy consumption in a certain control area to the different BRPs.
Ancillary and Balancing Services	Functions contracted by TSOs to guarantee system security, including black start capability, frequency response, fast reserve, provision of reactive power, etc.
aPrice Capa	Auction Capacity Price
Arbitrage	The practice of taking advantage of a price difference between two or more markets: striking a combination of matching deals that capitalize upon the imbalance, the profit being the difference between the market prices.
ARENH	Accès Régulé à l'Énergie Nucléaire Historique (Regulated Access to Historical Nuclear Energy)
ARERA	Regulatory Authority for Energy, Networks and Environment (Italy).
Balancing	The act of reducing/increasing load/generation to restore system imbalance. TSOs use balancing services after markets have closed to ensure demand equals supply in real time.
Baseline	The best approximation of energy consumption or production that would have occurred if no demand response (DR) event had been triggered. Used to quantify delivered flexibility.
BM	Baseline methodology.
BRP	Balancing Responsible Party.
BSP	Balancing Service Provider.
BTM	Behind-the-Meter.
C&I	Commercial and Industrial.
CAL	Calendar
Contracted Bidding	Placing bids on a market which was committed beforehand via a contractual obligation. Ensures certain market volume for the contracting party. Opposite of free bidding.

CRE	Commission de Régulation de l'Énergie (French Energy Regulatory Commission)
DA	Day-Ahead.
DAM	Day-Ahead Market
DER (Distributed Energy Resource)	Distributed Energy Resource.
Dispatch	Turning on or off a power generation unit or adjusting their power output according to an order, generally at the request of power grid operators or plant owner to meet demand based on merit-order. Opposite of intermittent energy sources.
DR	Demand Response.
DSO	Distribution System Operator.
DSR	Demand-Side Response.
eDSO	European Distribution System Operators.
EPAD	Electricity Price Area Differential.
EPEX	European Power Exchange
EU	European Union.
EUR	Euro (currency).
EV	Electric Vehicle.
Ex-ante	The term ex-ante is a phrase meaning "before the event". Ex-ante is used most commonly in the commercial world, where results of a particular action, or series of actions, are forecast in advance (or intended). The opposite of ex-ante is ex-post (actual).
Explicit Distributed Flexibility	Form of flexibility where customers make an explicit change in demand/generation in response to a signal, and are specifically rewarded (remunerated) for that change.
Ex-post	"Afterward", "after the event". Based on knowledge of the past. Measure of past performance.
Ex-post Nomination	The possibility for BRPs to include transactions after the Operation phase (i.e., after the associated ISP) by a change in their approved E-programs. This change is processed by the TSO before the allocation. Via this mechanism, BRPs can mutually settle imbalances and avoid the imbalance penalties raised by the TSO.
FCR-D	Frequency Containment Reserve - Disturbance.
FCR-N	Frequency Containment Reserve for Normal Operation.

Flexibility Service Quantification	Determination of the amount of load/generation reduction/increase in terms of instantaneous power [W] or energy during a certain time interval [Wh]. To determine whether the service was actually delivered with the right quantity. A baseline is needed for this purpose.
Free Bidding	The act of placing bids on a market without a (contractual) obligation to do so. Opposite of contracted bidding.
Gaming	Using the rules and procedures meant to protect a system in order to manipulate the system for a desired outcome. Gaming is a form of abuse. See also arbitrage.
Grid	Network for the transport and distribution of energy.
GWh	Gigawatt-hour.
IA	Independent Aggregator.
IAM	Independent Aggregator Model.
ID	Intraday.
Implicit Distributed Flexibility	Situation where customers are exposed to varying energy prices and/or grid tariffs and respond by adapting their energy demand profile. In general, consumers exposed to such tariffs might have an automated system or a 3rd-party (ESCO) service that helps them to consume their energy at optimal prices.
imPrice Capa	Imbalance Settlement Price
IRP	Interwencyjna Redukcja Poboru (Intervention Reduction of Consumption).
kV	Kilovolt.
M	Month
Merit-order	The merit order is a way of ranking available sources of energy, especially electrical generation, based on ascending order of price (which may reflect the order of their short-run marginal costs of production) together with the amount of energy that will be generated. In a centralized management, the ranking is so that those with the lowest marginal costs are the first ones to be brought online to meet demand, and the plants with the highest marginal costs are the last to be brought online. Dispatching generation in this way minimizes the cost of production of electricity. Sometimes generating units must be started out of merit order, due to transmission congestion, system reliability, or other reasons.
mFRR	Manual Frequency Restoration Reserve.
MGA	Metering Grid Area.

MW	Megawatt.
MWh	Megawatt-hour.
N	Year
n.a.	Not applicable.
NEBEF	Mechanism for wholesale market monitoring and load reduction.
NEMO	Nordic Electricity Market Operator
Nomination	The act of informing the counterparty about the forecasted energy profile for the near future. For example, a day-ahead nomination for the full next day, an intra-day nomination for the remainder of the day, or short-term nomination for one or more ISPs.
Notification	Activation request by the system operator towards the flexibility service provider. In case of wholesale trading: closure of wholesale trade.
NRA	National Regulatory Authority
Ofgem	Office of Gas and Electricity Markets.
P	Daily time component (peak/off-peak)
Passive Balancing	A BRP helps reduce the imbalance for the whole control area by deviating from its own electricity program. If this contributes to reducing the total imbalance, the BRP may receive remuneration for its passive contribution, depending on market design.
PCM	Price Cap Methodology
Perimeter Correction	Adjustment of the imbalance volume of the corresponding BRP. Normally performed by the ISR role to avoid that flexibility activation would result in an imbalance due to the changed energy volume.
PM	Portfolio Manager.
PSE	Polskie Sieci Elektroenergetyczne (Polish Power Grid)
Rebound Effect	The phenomenon that the load reduction (or increase) triggered by a demand response event is compensated partly or fully outside the activation period or by other resources.
Resolution	The resolution of a flexibility product refers to the time intervals of the measured load/generation profile, which should also align with the resolution of the baseline.
RR	Replacement Reserve.
S	Seasonal component (winter/summer)
SDAC	Single Day-Ahead Coupling.

Service Window	Time of the year/week/day that a certain service is active (e.g., strategic reserves are typically limited to the winter period).
Settlement	Determining the energy production and consumption and used flexibility as preparation for the billing process.
SIDC	Single Intraday Coupling.
Sourcing (of Energy)	Purchasing of energy.
Spot Market	A spot market is a public financial market in which financial instruments or commodities are traded for immediate delivery. Day-ahead markets and intra-day markets are both spot markets.
SYS	System Price (from Nasdaq electricity markets).
Transfer of Energy (ToE)	Energy volumes transferred between the BRP of the Aggregator and the BRP of the Supplier. In this context, the Transfer of Energy is used to compensate the BRP of the Supplier for the effects of flexibility activation.
TSO	Transmission System Operator.
UVAC	Virtually Aggregated Consumption Unit.
UVAM	Virtually Aggregated Mixed Unit.
UVAP	Virtually Aggregated Production Unit.
UVAs	Virtually Aggregated Units.
VLP	Virtual Lead Party.

8 ABOUT DNV

DNV is the independent expert in risk management and assurance, operating in more than 100 countries. Through its broad experience and deep expertise DNV advances safety and sustainable performance, sets industry benchmarks, and inspires and invents solutions.

Whether assessing a new ship design, optimizing the performance of a wind farm, analyzing sensor data from a gas pipeline or certifying a food company's supply chain, DNV enables its customers and their stakeholders to make critical decisions with confidence.

Driven by its purpose, to safeguard life, property, and the environment, DNV helps tackle the challenges and global transformations facing its customers and the world today and is a trusted voice for many of the world's most successful and forward-thinking companies.