WHEN TRUST MATTERS

Operational Metering Requirements

WP5: Final Report

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Contents

Acronyms

Abbreviation	Meaning	Abbreviation	Meaning
AMQP	Advanced Message Queuing Protocol	IEC	International Electrotechnical Commission
ANM	Active Network Management	ISO	International Organization for Standardization
AP	Access Point	MID	Measuring Instruments Directive
BM	Balancing Mechanism	MPAN	Meter Point Administration Number
BMU	Balancing Mechanism Unit	MQTT	Message Queuing Telemetry Transport
BOA	Bid Offer Acceptance	MVAR	Megavolt-Ampere Reactive
BSP	Balancing Service Provider	NCMS	National Control and Monitoring System
CER	Consumer Energy Resources	NESO	National Energy System Operator
COP11	Code of Practice 11	NETS	National Electricity Transmission System
DA	Day-Ahead	NIV	Net Imbalance Volume
DER	Distributed Energy Resources	NHH	Non-Half Hourly
DERMS	Distributed Energy Resource Management System	OBP	Open Balancing Platform
DFS	Demand Flexibility Service	OM	Operational Metering
DIN	Deutsches Institut für Normung	OMD	Operational Metering Data
DNO	Distribution Network Operator	PNA	Power Network Analysis
DSO	Distribution System Operator	PN	Physical Notification
EIP	Energy Information Platform	PoC	Proof of Concept
ENCC	Electricity National Control Centre	RoC	Report on Change
NESO	Electricity System Operator	RT	Real-Time
EV	Electric Vehicle	SLA	Service Level Agreement
FES	Future Energy Scenarios	SO	System Operator
FRCR	Frequency Risk and Control Room	SoE	State of Energy
GSP	Grid Supply Point	SP	Service Provider
HH	Half-Hourly	SQSS	Security and Quality of Supply Standard
HNDFUE	High Normal Demand for Uncertain Event	STOR	Short-Term Operating Reserve
IA	Impact Assessment	TSO	Transmission System Operator
ID	Intraday	VLP	Virtual Lead Party
		WA	Week-Ahead

Executive Summary

Report Overview

Background: This project, commissioned through Power Responsive with the NESO, reviews operational metering requirements for the Balancing Mechanism and sets out how to modernise them. The legacy framework was built for large, centrally dispatched generation. With Customer Energy Resources projected to contribute approximately 31GW of flexible capacity by 2035 and up to 77GW by 2050[1], the metering paradigm must shift to the aggregated portfolio, rather than individual devices. . The section outlines objectives, scope, evidence sources and the reliability goal under the Security and Quality of Supply Standard (SQSS).

Why change is needed: Current rules create barriers for CER portfolios, including high accuracy targets, one-second data requirements and a 1 MW minimum portfolio size. Scaling device-level monitoring is costly and operationally complex without proportional reliability benefits. Analysis and stakeholder input support a move to portfolio-level requirements that maintain SQSS while unlocking cost-effective flexibility.

Operational Metering Options: Three main options are considered ranging from minor adjustments to current requirements through to advanced solutions such as report-on-change and adjustment of metering feed. Design parameters include required meter accuracy, permissible measurement intervals, latency and data reporting methods.

Impact Assessment: Evidence from synthetic datasets, scenario analysis, and industry interviews informs feasibility, and options are assessed against guiding principles considering reliability impact, market operability, implementation effort, cost to consumer and provider inclusivity.

Recommended Solutions: The report recommends adopting a portfolio-level approach to operational metering, beginning with setting a 30s meter read interval on asset level, and incentivising report-on-change metering for suitable asset types to support immediate participation and reliability. As CERs participation in the BM expands, the strategy should evolve by progressively integrating adjusted metered feed solutions to strengthen system resilience and optimize long-term cost efficiency.

Implementation: Deliver changes in phases across process, data and systems, with defined guidance for providers and aggregators and clear contractual, validation requirements. Use milestones, feedback cycles and governance to manage risk and resolve issues early. Coordinate regulatory alignment and continue industry engagement to support adoption at scale, with success measured by reliability outcomes and increased participation in balancing services.

[1]FES 25 Holistic Transition

The current OM requirements constitute barriers and constrain critical balancing market participation for CERs

Accuracy: 1% accuracy requirements on asset level
Although engagement with external stakeholders revealed that some current EV charger meters and smart meters can achieve 1% accuracy, many CERs do not meet this standard. While the metering component cost to achieve ±1% accuracy is relatively small compared to the overall asset cost, redesigning and recertifying the assets would be expensive.
Frequency: 1-second meter read frequency
The primary barrier to 1-second meter read frequency at the asset level is the high cost of data transmission, especially when using cellular networks, combined with the expenses of cloud computing resources and data storage required to process and store data at 1-second intervals. Additionally, many legacy assets are not capable of 1-second communication frequency. Aggregators have suggested that 10-30 second intervals would be more feasible and cost-effective, however reducing the meter read frequency of assets results in reduced accuracy of the aggregated meter signal caused by the additional latency for some assets. This results in the aggregated meter signal lagging behind real power delivery, or "meter lag".
Latency: Maximum 5-second latency from the CER asset to NESO
In general, the 5-second latency requirement has not been widely raised as a concern by industry. In part this is likely because there is currently no mechanism in place to test portfolio communication latency, aggregators expressed concern that if this requirement were to be enforced and future testing showed non-compliance then the cost of dedicated communication systems to reduce latency could be significant. Communication latency for CERs is also unique in that it can be highly variable between similar assets depending on signal strength and other network factors e.g. network congestion, it is also dependent on the number of intermediate processing steps by different parties in metering chain (e.g. asset manufacturer, aggregator, virtual lead party). Therefore, latency is usually outside the control of any single party. The extent to which latency will be a barrier in future therefore depends on gathering more evidence on latency performance and NESOs enforcement approach.

Market participation for CERs is crucial so that NESO can observe and control the behaviour of CER portfolios, which will have increasingly significant system impacts as the adoption of CERs progresses

Even under the most conservative scenarios, CERs will have a significant system impact in future, DNV analysis of NESO FES 24 data reveals that peak change in hourly CER net demand in 2035 ranges from 37.3 GW/h in the Holistic Transition (HT) scenario to 29 GW/h in Electric Engagement (EE), 16 GW/h in Hydrogen Evolution (HE) and 6.6 GW/h in Counterfactual (CF).

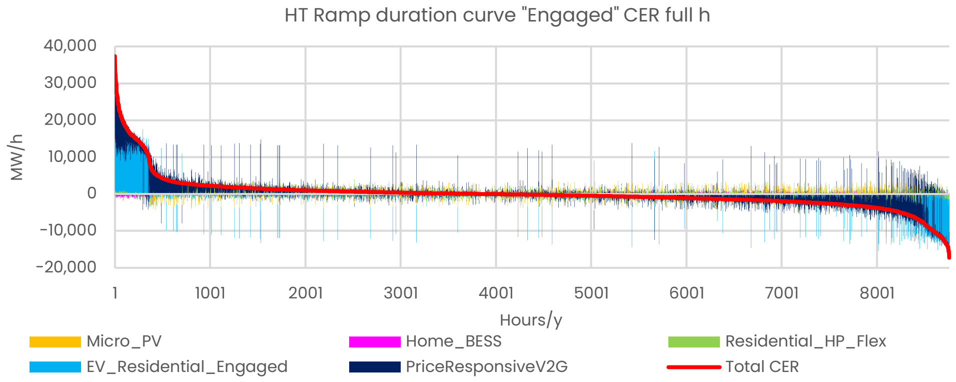


Figure 0.1 – Future Energy Scenarios Holistic Transition scenario: Net hourly CER step change for all hours in 2035 sorted by magnitude

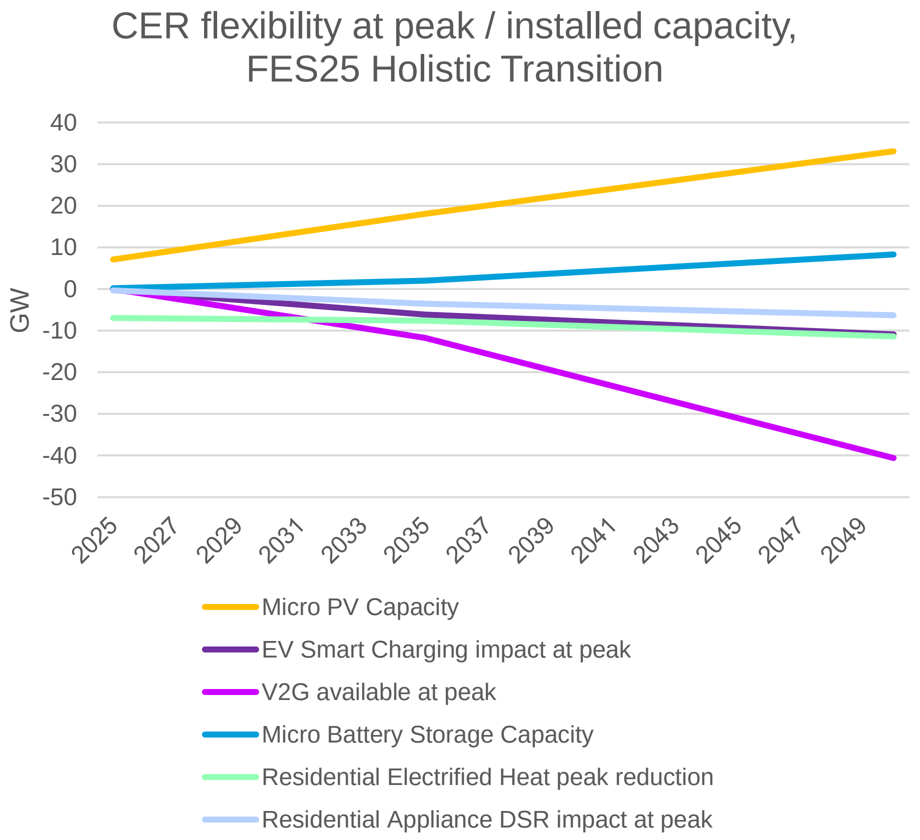
Highlighted CERs could provide around 31GW of flexible capacity by 2035 and 77GW by 2050*

Highlighted CERs are expected by aggregators to be predominant asset types in portfolios

Technology Type		Micro PV **Capacity**	EV Smart Charging impact at peak	V2G available at peak	Micro Battery Storage **Capacity**	Residential Electrified Heat peak reduction	Residential Appliance DSR impact at peak
Unit power (range)		1-12kW residential (avg. 3.5kW) 10-100kW commercial	7kW	7-1000kW	10-30kW	4-16kW	2kW (avg. delivered)
Typical Connection Point		415V and below	415V and below	415V and below	415V and below	415V and below	230V
Capacity (GW)	**2024**	7.1	-0.25	0	0.19	-6.95	-0.34
	2035	18.1	-6.17	-11.79	2	-7.61	-3.5
	2050	33.1	-10.9	-40.6	8.3	-11.39	-6.3

Table 1.4 – Aggregated Consumer Energy Resources Projected Growth, Source: FES25 Databook Sheets ES1 and FLX1.

*** Sum of installed capacities for battery storage, plus peak flexibility for EVs, electrified heat, and residential appliances is 31GW in 2035 and 77GW in 2050.**



Sources:
NESO FES 25
https://www.sunsave.energy/blog/demand-flexibility-service
https://www.glowgreenltd.com/solar-advice/commercial-solar-panels
https://www.greenmatch.co.uk/solar-energy/solar-panels
https://energysavingtrust.org.uk/advice/solar-panels/

We assessed three high-level options for new CER Operational Metering requirements

#	Option	Description	Variant
1	Keep (close) to Current Requirements	Maintain current latency requirements, however measure Meter Accuracy on portfolio level, provide an option for assets capable of report-on-change to do so thus minimising data costs for aggregators.	a- Meter Accuracy= 1%, MR=1 sec (portfolio-NESO), Latency =5 sec (Counterfactual)
			b- Aggregated Meter Accuracy= 1%, Report On Change on asset level, Latency =5 sec
2	Use delayed CER OMD as real-time data	Allow CER portfolios to submit meter data with an induced delay from meter read interval of assets being >1s. Treat this delay as an error between the true state of the portfolio and the meter reading received by NESO. This error distorts demand forecasts, potentially leading control engineers to act on inaccurate information. Set limits on meter read interval* performance and increasing reserve and response levels to mitigate the impact on NESO system. **This option introduces an error into NESO systems relying on OM data, even when CER BMUs follow their PN/BOA.**	a- Allow error by mitigating its impact, set a 30s maximum meter read interval
			b- Allow error by mitigating its impact, set a 10s maximum meter read interval
			c- Allow error by mitigating its impact, set a 5s maximum meter read interval
			d- Ramp rate control (suitable to all range of MR). Aggregators must comply with an accuracy requirement by limiting the ramp rate of their portfolio according to its meter read interval, thus preventing high magnitude errors
3	Consider CER OMD, invest in systems to mitigate risk	Allow CER portfolios to submit meter data with an induced delay from meter read interval of assets being >1s. Treat this as delayed data and attempt to mitigate the impacts by upgrading NESO and aggregator systems to quantify the delay and limit its impact on operational decision making. **This option introduces an error into NESO systems relying on OM data only when CERs do not follow their PN / BOA, or the forecasted behaviour is inaccurate.** The error persists until the timestamped OM feed is received (likely 15-30 seconds). This error can be further reduced through different advanced forecasting methods (e.g. historical behaviour)	a- Aggregators timestamp OM data, NESO create real-time estimation and update with delayed OM feed
			b- Aggregators send synthetic data that best reflect the current real-time situation

Table 0.1 – Overview of Operational Metering Options

*The 60-second MeterRead interval was not modelled, as the 30-second results already significantly exceeded NESO's risk tolerance thresholds. Moreover, all aggregators indicated they were comfortable meeting the 30-second requirement, as confirmed by the WP1 survey.

DNV recommends that a combination of options are implemented in a phased approach

PHASE 1: The best short-term solution is 2a combined with event-driven reporting for specific assets, which achieves feasibility, and maintain transparency however not scalable. Option 1b remains viable for specific asset types but has limited scalability.

Phase 1 – options which can be implemented within 12 months

- **Implement Option 2a: Set a maximum asset MR interval of 30s –** reasonable as a short-term solution since it enables mass participation from consumer assets – most of which can achieve 30s (those that cannot can still access the derogation). Cannot be an enduring solution because it becomes very expensive (up to 10x increase in reserve and response costs(i.e. capacity required)) in medium-long term as the impacts of systematic error in control room increase. At this point 2a must either be supplemented with 3 a/b, or replaced with a lower MR interval (e.g. 2b, 2c)
- **Incentivise higher OMD quality:** NESO can incentivise higher-quality OMD by applying performance metrics that reward accuracy with increased market access to ancillary services. By increasing accuracy, NESO reserve costs can be reduced. Aggregators using event-driven reporting can lower data costs while meeting accuracy thresholds, enabling broader market participation and operational efficiency

Guiding Principles

Ensure solutions are reliable, feasible within current systems, scalable for future growth, transparent and accountable, and cost-effective for consumers.

Important Considerations:

1. Incentivises higher PN or forecasting accuracy: by assessing the performance of PNs. Improved accuracy reduce the need for corrective actions and contribute to greater overall system efficiency and reliability.

2. Incentivise higher meter quality: by linking performance to metering standards, the framework should motivate stakeholders to invest in higher-quality meters.

DNV recommends that a combination of options are implemented in a phased approach

PHASE 2: Option 3a/b should be considered as a final solution pending further development, as it requires a proof-of-concept and significant system changes. Option 1b remains viable for specific asset types but has limited scalability.

Phase 2 – options to be developed and implemented later, *to supplement Option 2a*

- **Incentivise 1b - Report on Change metering:** Optimal for national balancing activities but only works for specific asset types (e.g. EV, V2G) so cannot be a broad requirement on industry since it is against principles of technology agnostic regulations. Requires changes to comms protocols and incentivises for aggregator investment in metering upgrades to enable this especially because it increases data submission volumes compared to 2a*.
- **Evaluate Options 3a and 3b and implement the best performing approach:** 3a and 3b mitigate errors using an additional adjusted metering feed (developed by NESO (3a) or by aggregators (3b)) which anticipates the behaviour of CER portfolios within the coming 30 seconds. Likely best medium-long term solution because it is technology agnostic, presents no restrictions on market entry, CER performance, or CR resources, and limits impact on situational awareness to instances where BMUs behave unexpectedly. Feasibility and benefits of 3 should be explored in an innovation project.
  - **3a – NESO constructs synthetic meter feed:** requires significant investment to update NESO systems, and to a lesser extent aggregator systems. Requires estimation methodology to be developed and PNs to be accurate. Does not lead to larger reserve and response costs as CER population increases. Does not incentivise aggregator investment in metering. Scalability potentially limited by NESOs resource and system capacity to predict the behaviour of a large number of CER BMUs.
  - **3b – aggregator constructs synthetic meter feed in addition to real-time feed:** investment required by NESO is significantly reduced however is still needed for NESO to verify quality of metering submitted by aggregators in real-time. Likely more resource-intensive than 3a overall, since all market participants must implement their own solution. Aggregator responsibility for synthetic profile may have lower confidence by the ENCC compared to 3a, however aggregator has a better understanding of its portfolio and therefore is more able to construct an accurate meter feed, this option is likely more scalable than 3a and with proper validation the performance of synthetic feeds could be managed.

Guiding Principles

Ensure solutions are reliable, feasible within current systems, scalable for future growth, transparent and accountable, and cost-effective for consumers.

Important Considerations:

1. Incentivises higher PN or forecasting accuracy: by assessing the performance of PNs. Improved accuracy reduce the need for corrective actions and contribute to greater overall system efficiency and reliability.
2. Incentivise higher meter quality: by linking performance to metering standards, the framework should motivate stakeholders to invest in higher-quality meters.

DNV's Recommendation

Following the feedback received from NESO's external stakeholders and NESO and informed by DNV's independent evaluation of the available options, it is recommended that new **operational metering requirements for CERs be implemented through a phased approach**, with requirements for other asset types remaining unchanged.

New requirements are needed for CERs since these assets have the highest barrier to entry to the balancing mechanism due to their high cost of metering relative to potential flexibility revenue per asset, in addition to the lack of clarity in the current requirements whether performance should be measured at the asset level or the portfolio level. Industry feedback indicated that assets >1MW had no barriers to entry, and assets between 100kW and 1MW had marginal barriers which were expected to be resolved with new lower cost metering technology.

Specifically, **the rollout should begin with Option 2a**, establishing a foundational level of compliance. **Over time, Option 2a should be supplemented with Options 3a/3b**, to enhance system robustness and reduce overall costs (pending further development to confirm their ability to deliver the anticipated benefits and effectively mitigate associated risks).

Concurrently, **efforts should be made to promote improvements in the quality of operational metering data**, as outlined in Option 1b (e.g. RoC or event-driven), to support long-term performance and reliability.

The new requirements should apply to aggregated portfolios of assets connected at voltage levels of 415V and below.

CER Operational Metering Requirements

Option 2a:

- Meter Accuracy (KW)
  - Asset Level: No extra requirement, as per applicable British Regulation*.
  - Portfolio Level: 1% (calculated based on accuracy of underlying assets considering effect of the law of large numbers) AND Min Asset Number in Portfolio = 30. (If the number of assets in the portfolio is above 100 the portfolio can be assumed to meet the minimum accuracy requirements given that COP11 and EV Smart Charing regulations already require accuracy +/- 10%)
- Meter Read Frequency & Latency (seconds):
  - Asset Level[1]: every 30 seconds
  - Portfolio Level: every 1 second
  - Latency[2] : 5 seconds (end to end latency from the asset to NESO's platform)
- [1] For assets unable to meet the specified MR interval requirements, alternative route if offered though the existing BM derogation pathway.
- [2] For aggregators not able to meet the 5-second latency requirement, compensation will be applied via the MR interval, using the formula: MR interval = 30-2*ΔLatency, where ΔLatency= Latency Actual – Latency Requirements. This formula accounts for the fact that 1s of communication latency has 2x the impact of 1s of additional MR interval.
- * Refer to recommendation 7.5

DNV

Additional Operational Metering Signals

CER portfolios should initially be required to submit only Active Power and Power Available measurements:

According to the Grid Code, in addition to active power, other signals are required to be submitted, however these are either not relevant for distributed assets, or are currently not feasible for CERs:

Relevant:

- ✓ ActivePower
- ✓ Power available (calculated on portfolio level)

Not relevant:

- X ReactivePower
  - While the reactive power signal is crucial for voltage control, its impact is limited for assets connected to the lower voltage levels of the distribution network due to the localised nature of voltage. Aggregation of a voltage signal from distributed CERs would therefore have limited value.
- X Circuit breaker status
  - Not relevant for distributed assets
- X Temperature
  - Not relevant for distributed assets

Not technically feasible yet:

- ◊ State of Charge (Import/Export)
- ◊ Energy Available (Import/Export)
  - Energy Available and State of Charge, where applicable to the relevant asset technology type, are not currently feasible for aggregators to submit (e.g. due to lack of visibility of vehicle state-of-charge by charge points). **Should aggregators have access to this information in future these parameters should be re-considered as requirements for CER submission.**

Appendix F5 – Schedule 2 *(Use this version of schedule 2 for all Small and Medium)*
Site Specific Technical Conditions – Operational Metering requirements (ECC.6.4.4, ECC.6.5.6)

Signals (Generators ≥ 1MW)	Range	Scale (Unit)	Accuracy	Resolution	Refresh Rate
Active Power	-100 MW to +100MW	MW	1% of meter reading	1kW	1 per second
Reactive Power	-100 MVAr to +100MVAr	MVAr	1% of meter reading	1MVAr	1 per second
EU Code User System Entry Point Voltage	0 – 100%	kV	1% of meter reading	1kV	1 per second
Controlling Breaker	Open/Closed	0/1	Not applicable.	Not applicable.	On Change.
Tap Position	1 – 64	Value	Not applicable.	Not applicable.	On Change.
Additional requirements for wind farms only					
Wind Speed	0 – 50m/s	m/s	5%	1m/s	1 per minute
Power Available	0 – 100%	MW	1% of meter reading	1kW	1 per second
Wind Direction (0° denotes FROM due North)	0 – 360°	5°	±15°	5°	1 per minute
Additional requirements for Solar PV only					
Power Available	0 – 100%	MW	1% of meter reading	1kW	1 per second
Global Radiation	0 – 2000W/M²	W/m²	1% of meter reading	1W/m²	1 per minute
Ambient Temperature	-100 – +100°C	°C	1% of meter reading	1°C	1 per minute
Additional requirements for Tidal only					
Tidal Flow	0 – 5m/s	m/s	1%	0.1m/s	1 per minute
Tide Direction (0° denotes TO due North)	0 – 360°	°	±15°	5°	1 per minute

Aggregated Signals (including sub units <1MW)	Range	Scale (Unit)	Accuracy	Resolution	Refresh Rate
Active Power	-1000MW to +1000MW	MW	1% of meter reading	1MW	1 per second
Reactive Power	-1000MVar to +1000MVar	MVar	1% of meter reading	1MVar	1 per second
Power Available	0 – 100MW	MW	1% of meter reading	1MW	1 per second
State of Charge (Energy) (Export)	0 – 100%	%	1% of meter reading	1%	1 per second
State of Charge (Energy) (Import)	0 – 100%	%	1% of meter reading	1%	1 per second
Energy Available (Export)	0 – 1000MWh	MWh	1% of meter reading	1MWh	1 per second
Energy Available (Import)	0 – 1000MWh	MWh	1% of meter reading	1MWh	1 per second

Table 1.3 – Site Specific Technical Conditions – Operational Metering Requirements

Major findings

- NESO must begin evaluating the feasibility of Options 3a/3b immediately, as DNV modelling indicates that the NESO risk profile is exceeded when CER swings reach 420MW, expected by 2028 at the latest. As the participation of consumer energy resources in the BM scales up Option 2a alone becomes prohibitively expensive (up to 10x increase in reserve and response costs).
- NESO Impact Assessment revealed that Option 2a has the highest impact on control room while options 3a/3b requires substantial system development but offer better long-term cost management and scalability.
- All options require updating contractual agreements and developing compliance process regardless of chosen approach.
- Stakeholder engagement with Power Responsive members revealed strong industry preference for Options 3b and 2a , with Option 3b achieving the highest combined technical and commercial feasibility score.
- Industry overwhelmingly rejected maintaining current requirements (Option 1a) due to prohibitive costs and technical barriers. This option would have a negative impact on NESO’s visibility and flexibility required to achieve 2030 goals.
- DNV advises that several additional actions are taken to align the industry and integrate the recommendations appropriately as shown on the right:

Complimentary reforms & recommendations

- **Legislation:** NESO should engage with Department for Business and Trade to raise awareness of it’s future needs for report-on-change capability and to ensure that Energy Smart Appliances have the capability to measure and communicate electrical power data every one second even if this is not enabled by default. Inverter losses should be addressed through AC-side metering.
- **Standardization:** NESO should engage in standardisation bodies like BSI, IEC, and CENELEC to promote advanced protocols that support report-on-change. It should advocate for real-time, event-driven communication and collaborate with industry to pilot and validate emerging standards.
- **System Planning:** NESO should refine CER modelling assumptions with industry input and make reserve and response dimensioning required for CERs a regular activity to reflect annual CER growth and maintain SQSS compliance.
- **Balancing Mechanism Rules:** NESO should engage new entrants on PN accuracy and BOA precision, review the 1 MW minimum bid size to enable CER participation, and explore requirement for single-technology BM portfolios once scale allows for better forecasting.
- **Forecasting:** NESO should integrate flexible demand and embedded generation, including BMUs currently on iHost, into forecasting processes as part of system upgrades.
- **Grid Code:** NESO should assess whether ramp rate limits for CER portfolios are needed as penetration grows to manage frequency risks without limiting flexibility.
- **Market and Settlement Rules:** NESO should work with Elexon, ENA, and FMAR to standardise flexibility products, harmonise baselining, and align data requirements. It should also harmonise metering standards, ensure visibility of rebound effects, and support more granular DNO forecasting to improve market efficiency and system reliability.
- **Operational Metering:** NESO should move from GSP Group-level to GSP-level aggregation for CER metering, consider line loss correction factors, and implement robust testing and compliance processes similar to those for large generators.

Strategic implementation journey: delivering change through key phases, milestones & industry engagement

NESO working closely with the PR stakeholders to harness the value of CERs

1. DNV Recommendations *(By Sept 25)*

Review and incorporate change to OM requirements based on DNV's recommendations

Align OM recommendations with contractual revisions and stakeholder feedback

2. Updated OM Requirements (*Sept 25 – Jan 26)*

Revise contractual agreements.

Design market monitoring framework for compliance.

Update operational metering requirements

Scope and secure approval for Feasibility Option 3.

Engage with industry to ensure alignment on updated requirements and policy changes.

Engage with industry to support implementation of 1b (ongoing)

3. Feasibility Option 3 (*Feb 26 – Aug 26)*

Launch and manage feasibility project.

Assess and select suitable estimation methodologies.

Scope and obtain approval for 3.

Engage with industry to test feasibility assumptions and gather input on estimation approaches.

4. PoC Option 3 *(Aug 26 – Aug 27)*

Build PoC monitoring capabilities.

Validate performance using ex-post data.

Scope and gain approval for Execute Option 3.

Engage with industry to review PoC results and refine execution plans.

5. Execute Suitable Option (*Aug 27 – Aug 29)*

Develop and deploy IT systems.

Integrate systems across platforms.

Define and implement fall-back strategy.

Plan and execute BAU transition strategy.

Lead change management activities.

Engage with industry to coordinate rollout and support adoption.

6. Transition to BAU (*By Jan 29)*

Complete transition to Business-As-Usual operations.

Engage with industry to monitor performance and ensure long-term compliance.

1. Background

Section Contents

Introduction

Operational metering is crucial for the secure operation of the GB transmission system, but existing requirements are complex and not designed for today's distributed assets.

This report was commissioned through Power Responsive with the NESO to review and update operational metering requirements for the Balancing Mechanism. The current Operational Metering Requirements were designed around large, centrally dispatched generation. However, increasing electrification and development of flexibility markets integrating smaller distributed assets means that new standards are needed to accommodate the unique characteristics of CERs. These standards need to allow CERs to participate in NESO markets, whilst complying with the Security and Quality of Supply Standard.

In this section we cover what operational metering is and why it is critical to system security. We also define Consumer Energy Resources and the asset types we consider throughout the report.

1.1 The Importance of Operational Metering

NESO is responsible for keeping the lights-on

NESO is responsible for ensuring that **electricity supply meets demand on a second-by-second basis**, which is referred to as "**balancing" the grid**. This task **is highly complex and involves managing various factors, including inertia, frequency, voltage and thermal constraints**. The NESO must account **for fluctuations in demand** throughout the day, seasonal changes, and **unpredictable supply variations**. To achieve this, they employ a range of tools and work with industry partners through **NESO Balancing Services** to **maintain a reliable, affordable, and safe electricity supply**.

License obligations

NESO has a licence provided by Ofgem and a requirement to operate a safe, reliable and efficient network translated into **a set of standards** that the ENCC must meet. As part of our licence, NESO is required to plan, develop and operate the National Electricity Transmission System (NETS) in accordance with the **System Security and Quality of Supply Standard (SQSS**) and comply with the **Grid code.**

Security and Quality of Supply Standard (SQSS)

The Security and Quality of Supply Standard (SQSS) is a **set of guidelines and requirements that govern the planning and operation of Great Britain's electricity transmission system.** It aims to ensure the security of the transmission system and the quality of electricity supply to consumers.

The SQSS covers various aspects of the electricity network, including planning criteria for the transmission system, operational standards for voltage and frequency control, and requirements for system stability and resilience.

The ESO's license obligations include:

1. Adhering to the SQSS guidelines by maintaining **frequency within the range of 49.5 Hz to 50.5 Hz** under normal operating conditions and maintaining voltage on the 400, 275 and 132 kV Network within -10%/5%, -/+10%, -/+6% respectively.
2. Regularly reviewing and proposing updates to the SQSS to reflect changes in technology, market conditions, and regulatory requirements

Grid code:
The Grid code is the technical **code for connection and development of the NETS**. This sets out the detailed operating procedures and principles that govern the relationship and interactions between the NESO and users of the NETS, such as generators and other users.

Balancing Mechanism:
The BM is a core tool the NESO uses for managing the GB electricity system, **accounting for 5-15% of all contracted electricity volumes over a year.** The Balancing mechanism is a platform used to ensure electricity supply and demand is balanced in real time. Since BM dispatch systems are compatible with integer values, the current minimum size to enter the BM is 1 MW (1MW per GSP group for aggregated assets). Units must respond to instructions from the ENCC within a period of 1 minute to 89 minutes following instruction. To balance supply and demand, system frequency should be kept close to 50 Hertz. During unexpected events like sudden power generation loss or demand spikes, the NESO uses balancing services to ensure cost efficiency and maintain supply reliability, as required by the Frequency Risk and Control Report (FRCR) and SQSS.

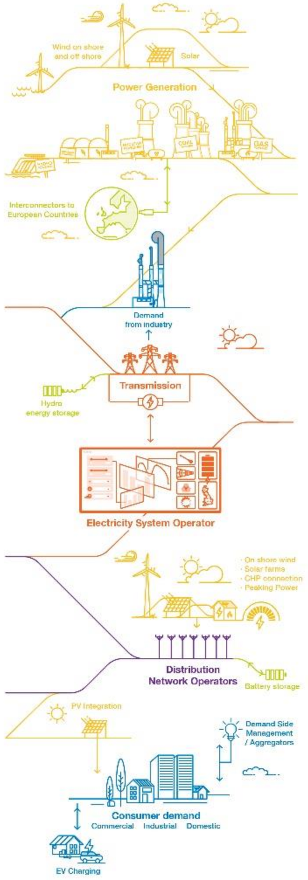


Figure 1.1 – UK Power Network Representation

SQSS: download (nationalgrideso.com)
Grid Code: Grid Code (GC) | NESO (nationalgrideso.com)
Contracted volumes: NESO Wider Access to Balancing Mechanism

ENCC Overview of Operational Metering – National View

Operational metering and predictive analytics are crucial for real-time system balance and stability, using current and historical demand data to proactively manage frequency deviations.

Operational metering provides the control room with a view of the overall 'demand' at any point in time, represented by the white line, with a resolution of one minute. This real-time data is crucial for understanding the immediate power needs of the system.

The predicted demand, depicted by the blue line, is based on the operational metering and updates every minute. This prediction allows for proactive adjustments to maintain system balance. The program set, shown by the red line, aims to meet the predicted demand. This plan filters down to target programs for each zone, with instructions ultimately trying to meet these requirements at a national level. The goal is to ensure the system remains balanced and to reduce frequency deviations in real time.

Historical data, represented by the yellow and green lines, reflects the previous day's demand outturn. This information feeds into the predicted demand calculation, helping to refine future predictions and adjustments. The minute-by-minute profile exhibits large changes in output during key times of the day when underlying demand shifts rapidly. This variability underscores the importance of accurate metering and prediction to maintain system stability.

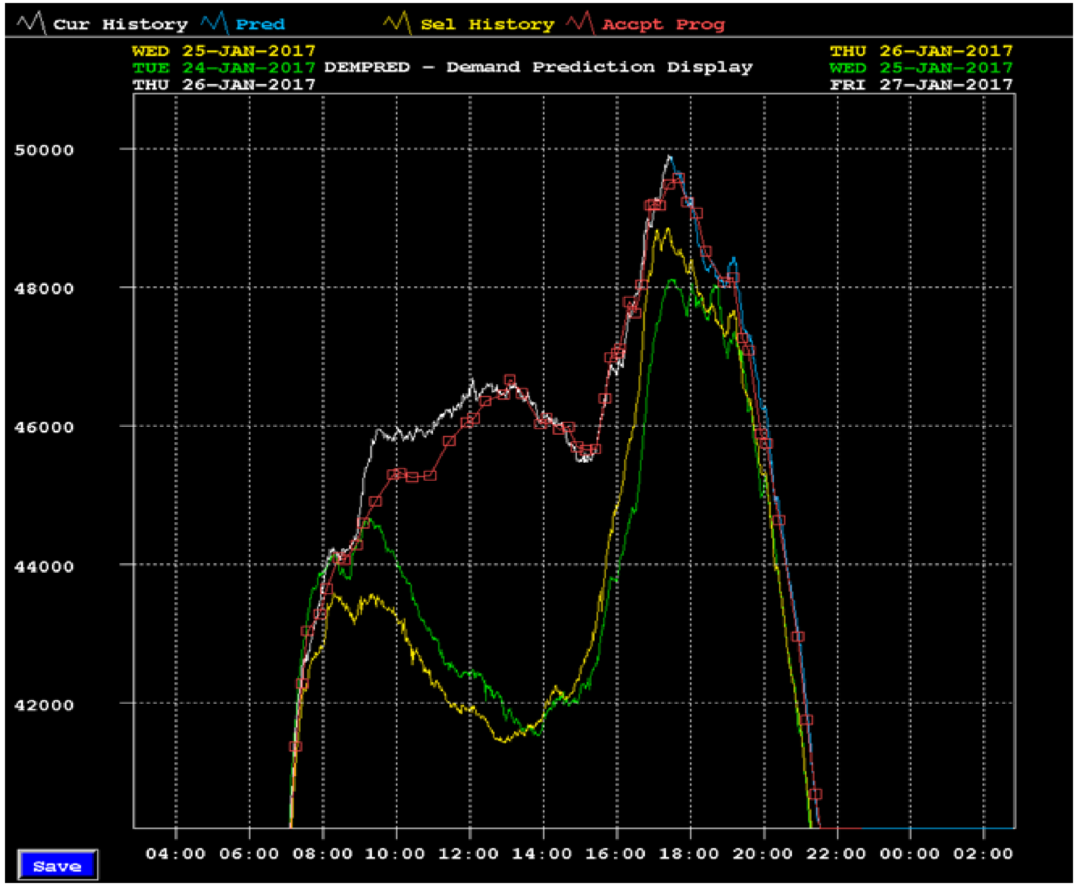


Figure 1.2 – Screenshot of the Demand Prediction Display used in the control room

NESO manages grid frequency control through a variety of specialised services, all of which require the same OM

The operational metering requirements for accuracy, frequency, and latency are similar across most frequency control services.

The Security and Quality of Supply Standards (SQSS) describes the requirements for controlling frequency and ensuring grid stability.

NESO services are each designed to address different aspects of maintaining grid stability. These services are designed to respond frequency deviations and energy imbalances over different time-scales. Part of these services are dispatch though the balancing mechanism platform.

Response is provided by which units have frequency measurement equipment on site and are expected to respond when frequency goes below a certain level. These actions are to maintain the frequency within the statutory and operational limits.

Units providing reserve will receive a signal from the ENCC to alter output and act to replace or take energy from the system that has been lost or gained unexpectedly and caused a frequency deviation.

The diagram on the right shows the different response and reserve products and their role in meeting the SQSS.

Participants in these services must meet specific technical requirements, such as response times, ramp times, and sustain times to qualify for participation. In general higher specifications metering is required for performance monitoring of frequency response services, due to the speed with which units need to respond. Whilst the response, ramp, and sustain times for each service may differ considerably, the operational metering requirements for accuracy, frequency, latency are similar across most of the products.

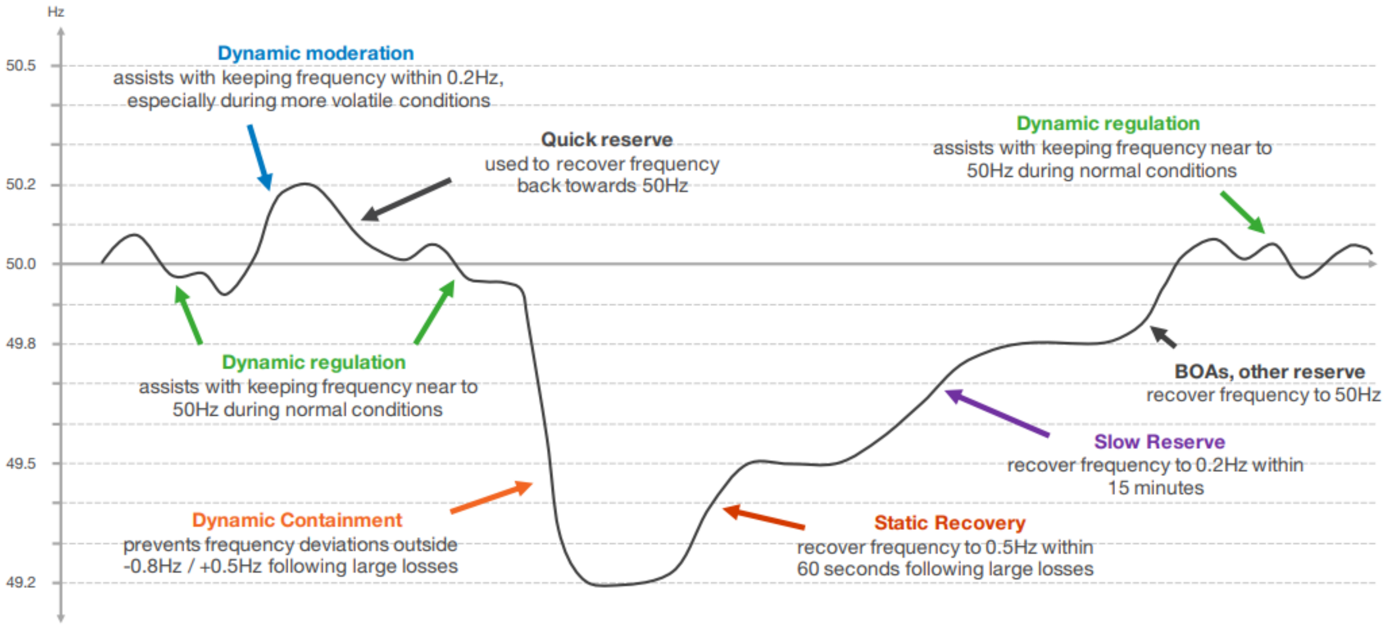


Figure 1.3 – Frequency control process representation

Operability Strategy Report: https://www.nationalgrideso.com/document/273801/download

Smaller assets in the GB can now participate in the Balancing Mechanism (BM) through several routes

Recent changes to the BM enable the aggregation of smaller-scale assets across GSP groups, facilitating greater market participation and flexibility, with four routes to enter the Balancing Mechanism.

Recent changes to the BM now allow assets to be aggregated across a GSP group, enabling smaller-scale assets to participate that previously couldn't meet the requirements. This aims to increase flexibility for the ENCC and provide the right price signals to encourage flexibility providers.

There are four ways to enter the Balancing Mechanism:

1. Generator – Directly connected (transmission connected) primary BMUs and embedded primary (distribution connected) BMUs, usually power stations or generating sites like wind farms. Each BMU is individually controlled and metered.

2. Supplier– Energy suppliers must register fourteen base BMUs for all MPANs they supply within different GSP groups across GB. These BMUs can't participate in the BM. Suppliers can register 'Additional BMUs' by moving selected MPANs they supply into a new BMU that can actively take part in the BM and is settled separately from the base BMUs.

3. Virtual Lead Party (VLP) – This route is for independent aggregators who are not the energy supplier but can offer flexibility, typically from behind-the-meter assets. MPANs move into a 'Secondary BMU' to be part of an aggregator's portfolio. Recent changes have improved settlement processes for VLPs through asset-level metering and baselining.

4. An Asset Meter Virtual Lead Party (AMVLP) can now register a 'Secondary BMU,' allowing settlements at the asset meter level instead of the boundary point meter.

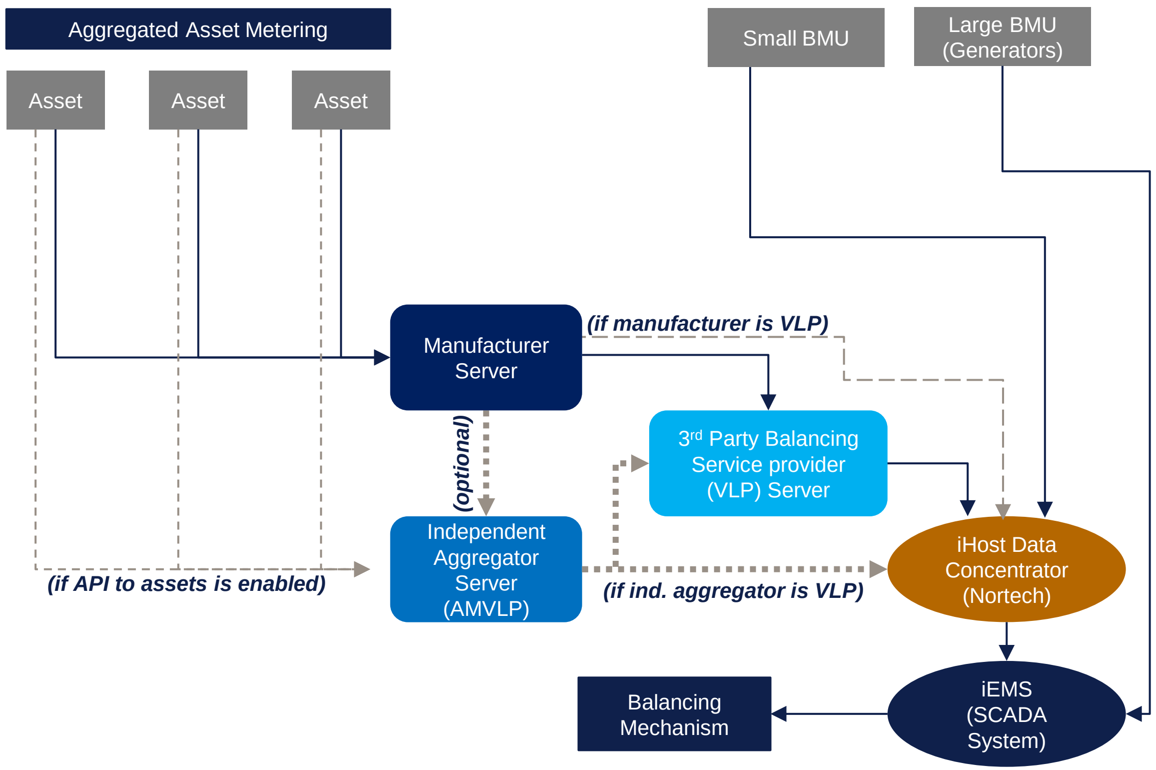


Figure 1.4 – Operational technology pathways for participation in the balancing mechanism

Currently operational metering requirements are the same for all assets that participate in the Balancing Mechanism

Operational metering requirements refer to the accuracy of the meter, the meter refresh frequency and the operational metering latency.

This section provides an overview of the operational metering requirements that asset meters should meet in order to participate in the Balancing Mechanism (BM) and balancing services.

As a condition of participation in NESO markets, NESO requires service providers to submit operational metering to the NESO close to real time. The current operational metering requirements have evolved for large traditional power stations and as discussed in previous sections they can present a barrier to smaller provider. As ESO's operational metering standards are currently written, each asset within an aggregated unit is obliged to provide data at the same frequency and latency as a discrete, standalone unit capable of meeting the minimum participation threshold.

The service requirements which are relevant for this study are defined within the table on the right.

The operational metering requirements which are in scope of this study are:

1. Operational meter accuracy
2. Operational meter refresh frequency
3. Operational meter latency

Service Requirements	Requirement Description
Operational Metering Required	A live feed to NESO control room to measure providers live service delivery
Asset metering permitted (vs boundary point metering system)	What type of metering is permitted? Some services only allow boundary meter data whilst others allow metering behind the boundary i.e. asset metering
Operational Meter Accuracy Required	The accuracy rating required of physical meters providing operational metering
Operational Meter Refresh Frequency	The frequency that the physical meter captures real-time data snapshots
Operational Metering Latency	Operational metering data must reach the NESO Control Room within this time
Aggregation /Virtual Lead Party (VLP) Route Available	The option of having more than a single asset within a unit

Table 1.1 – Service requirements relevant to this study

In the next page, the operational metering requirements for the in-scope NESO balancing presented.

According to the Grid Code, in addition to active power, other signals are required to be submitted

These are not relevant or technically feasible for CERs

Current Requirements:

According to grid code requirements ECC6.4.4 and ECC6.5.6, a minimum set of signals is necessary to comply with SQSS. The connected generator must provide measurement outputs for voltage, current, frequency, active power, and reactive power, along with plant status indications and alarms (e.g., circuit breaker status).

Additionally, depending on the type of generation, extra signals are needed. For solar PV (Photovoltaic) systems, these include global radiation and ambient temperature. For wind generation, wind speed and wind direction signals are required. Aggregated assets, including subunits with a capacity less than 1 MW, should send the specified signals below:

- ActivePower
- ReactivePower
- State of Charge(Import/Export)
- Energy Available (Import/Export)

Appendix F5 – Schedule 2 *(Use this version of schedule 2 for all Small and Medium)*
Site Specific Technical Conditions – Operational Metering requirements (ECC.6.4.4, ECC.6.5.6)

Signals (Generators ≥ 1MW)	Range	Scale (Unit)	Accuracy	Resolution	Refresh Rate
Active Power	-100 MW to +100MW	MW	1% of meter reading	1kW	1 per second
Reactive Power	-100 MVAr to +100MVAr	MVAr	1% of meter reading	1MVAr	1 per second
EU Code User System Entry Point Voltage	0 – 100%	kV	1% of meter reading	1kV	1 per second
Controlling Breaker	Open/Closed	0/1	Not applicable.	Not applicable.	On Change.
Tap Position	1 – 64	Value	Not applicable.	Not applicable.	On Change.
Additional requirements for wind farms only					
Wind Speed	0 – 50m/s	m/s	5%	1m/s	1 per minute
Power Available	0 – 100%	MW	1% of meter reading	1kW	1 per second
Wind Direction (0° denotes FROM due North)	0 – 360°	5°	±15°	5°	1 per minute
Additional requirements for Solar PV only					
Power Available	0 – 100%	MW	1% of meter reading	1kW	1 per second
Global Radiation	0 – 2000W/M²	W/m²	1% of meter reading	1W/m²	1 per minute
Ambient Temperature	-100 – +100°C	°C	1% of meter reading	1°C	1 per minute
Additional requirements for Tidal only					
Tidal Flow	0 – 5m/s	m/s	1%	0.1m/s	1 per minute
Tide Direction (0° denotes TO due North)	0 – 360°	°	±15°	5°	1 per minute

Aggregated Signals (including sub units <1MW)	Range	Scale (Unit)	Accuracy	Resolution	Refresh Rate
Active Power	-1000MW to +1000MW	MW	1% of meter reading	1MW	1 per second
Reactive Power	-1000MVar to +1000MVar	MVar	1% of meter reading	1MVar	1 per second
Power Available	0 – 100MW	MW	1% of meter reading	1MW	1 per second
State of Charge (Energy) (Export)	0 – 100%	%	1% of meter reading	1%	1 per second
State of Charge (Energy) (Import)	0 – 100%	%	1% of meter reading	1%	1 per second
Energy Available (Export)	0 – 1000MWh	MWh	1% of meter reading	1MWh	1 per second
Energy Available (Import)	0 – 1000MWh	MWh	1% of meter reading	1MWh	1 per second

Table 1.3 – Site Specific Technical Conditions – Operational Metering Requirements

BM dispatched services require the same operational metering where as Non-BM services have different requirements

The table below summarises a subset of service requirements, including the operational metering requirements, which assets should meet in order to participate in each respective service. It is worth noting that DFS participants and LCM participants are not required to provide a live feed to NESO control room and therefore accuracy requirements are lower and aligned with the accuracy requirements for Settlement as defined by the Code of Practice 11 (CoP 11) – see next section for details. For all the other services, operational metering requirements are the same, we have included in the table below services that might be an interest for CERs aggregators in addition to services which are not due to cease in the future.

The current interpretation of these NESO requirements is that that each sub-unit within an aggregated Balancing Mechanism Unit (BMU) or secondary BMU should provide data of the same granularity.

Service Requirements	Requirement Description	Dynamic Containment	Dynamic Moderation	Dynamic Regulation	Quick Reserve	Slow Reserve	Balancing Reserve	LCM	DFS
Operational Metering Required	A live feed to NESO control room to measure providers live service delivery	YES	YES	YES	YES	YES	YES	NO	NO
Asset metering permitted (vs boundary point metering system)	What type of metering is permitted? Some services only allow boundary meter data whilst others allow metering behind the boundary i.e. asset metering	Asset metering permitted	Asset metering permitted	Asset metering permitted	Asset metering permitted	Asset metering permitted	-	Boundary metering only	Asset level metering permitted (but with ad hoc boundary meter checks)
Operational Meter Accuracy Required	The accuracy rating required of physical meters providing operational metering	**+/-1%**	**+/-1%**	**+/-1%**	**+/-1%**	**+/-1%**	**+/-1%**	**N/A**	**+2.5% / -3.5% (COP11 DERIVED)**
Operational Meter Refresh Frequency	The frequency that the physical meter captures real-time data snapshots	**1Hz**	**1Hz**	**1 Hz**	**1Hz**	**1Hz**	**1 Hz**	**N/A**	**N/A**
Operational Metering Latency	Operational metering data must reach the NESO Control Room within this time	**5s**	**5s**	**5s**	**5s**	**5s**	**5s**	**N/A**	**N/A**
Operational Metering Signal Type	The type of electrical data collected for operational metering	Active power and SoE	Active power and SoE	Active power and SoE	Active Power	Active Power	Active Power	N/A	N/A
Performance Meter Refresh Frequency	The frequency that the physical meter captures real-time data snapshots (e.g. 20Hz= 20 snapshots per second)	20Hz	20Hz	2Hz or 20Hz	N/A - Phase 1 1Hz (TBC) - Phase 2	1Hz (TBC)	1Hz	Half Hourly	Half Hourly
Aggregation /Virtual Lead Party (VLP) Route Available	The option of having more than a single asset within a unit	YES	YES	YES	YES	YES	YES	YES	YES

Table 1.2 – Current service requirements

1.2 Consumer Energy Resources

Consumer Energy Resources (CERs)

CERs are small distributed assets which can be controlled to increase or decrease demand or generation, they are connected at 415V and below. Typical examples include residential or small business EV chargers, heat pumps, batteries and rooftop solar

Consumer Energy Resources (CERs) refer to distributed energy assets that are owned or operated by consumers. Generally, these resources are situated behind the meter at homes or small to medium businesses and are not directly visible to the system operator.

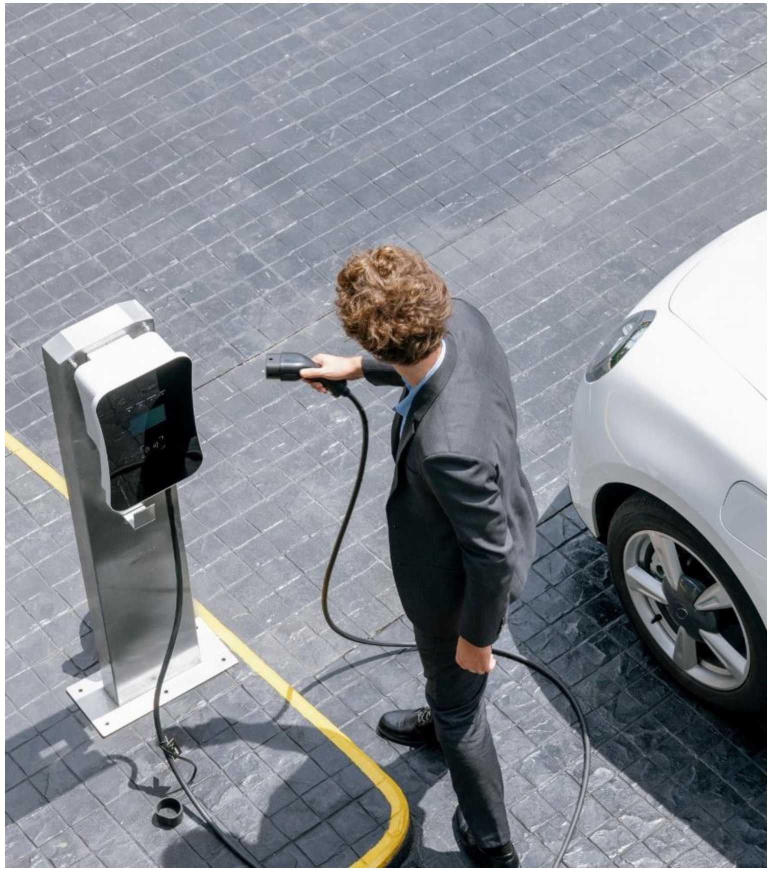
Typical examples include:

- Rooftop solar PV
- Electric vehicle charging units and V2G
- Home battery storage
- Heat pumps

For the purposes of this project, we have considered assets connected at 415V and below as CERs in line with NESO's current definition used in the Balancing Mechanism aggregated metering derogation:

- Asset size <1MW
- Connection point - 415 V and below (no specific connection agreement in place for the asset)
- Connection process - G98 or G99 Type - Category A
- Primary purpose of the asset is to provide a consumer with a service/resource e.g. Heating a home or transportation

Based on the findings of this project, for assets larger than 100kW it should generally be economically viable to install a meter that complies with the existing operational metering requirements. This is based upon feedback from industry that assets over 1MW have a positive business case to install dedicated metering, whilst for assets between 100kW and 1MW the business case is currently marginal it will become positive in the next few years given the falling costs of metering technology.

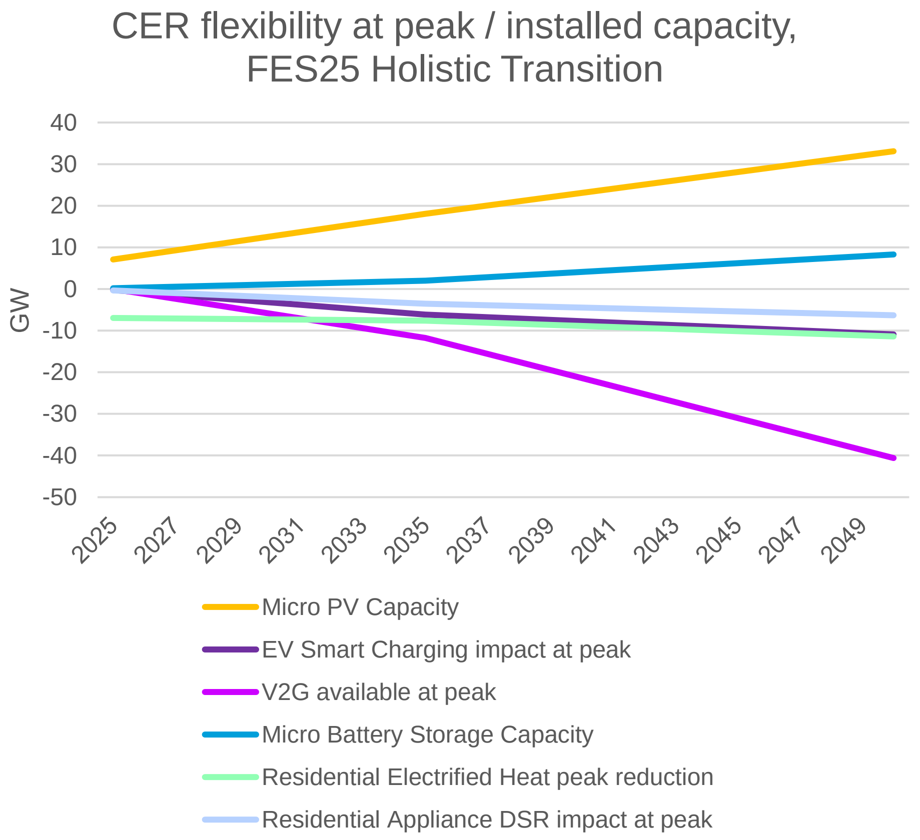


Highlighted CERs could provide around 31GW of flexible capacity by 2035 and 77GW by 2050

Highlighted CERs are expected by aggregators to be predominant asset types in portfolios

Technology Type		Micro PV **Capacity**	EV Smart Charging impact at peak	V2G available at peak	Micro Battery Storage **Capacity**	Residential Electrified Heat peak reduction	Residential Appliance DSR impact at peak
Unit power (range)		1-12kW residential (avg. 3.5kW) 10-100kW commercial	7kW	7-1000kW	10-30kW	4-16kW	2kW (avg. delivered)
Typical Connection Point		415V and below	415V and below	415V and below	415V and below	415V and below	230V
Capacity (GW)	**2024**	7.1	-0.25	0	0.19	-6.95	-0.34
	2035	18.1	-6.17	-11.79	2	-7.61	-3.5
	2050	33.1	-10.9	-40.6	8.3	-11.39	-6.3

Table 1.4 – Aggregated Consumer Energy Resources Projected Growth, Source: FES25 Databook Sheets ES1 and FLX1



Sources:
NESO FES 25
https://www.sunsave.energy/blog/demand-flexibility-service
https://www.glowgreenltd.com/solar-advice/commercial-solar-panels
https://www.greenmatch.co.uk/solar-energy/solar-panels
https://energysavingtrust.org.uk/advice/solar-panels/

EV chargers and home batteries are of greatest interest to aggregators

Assets with larger capacity have more revenue potential

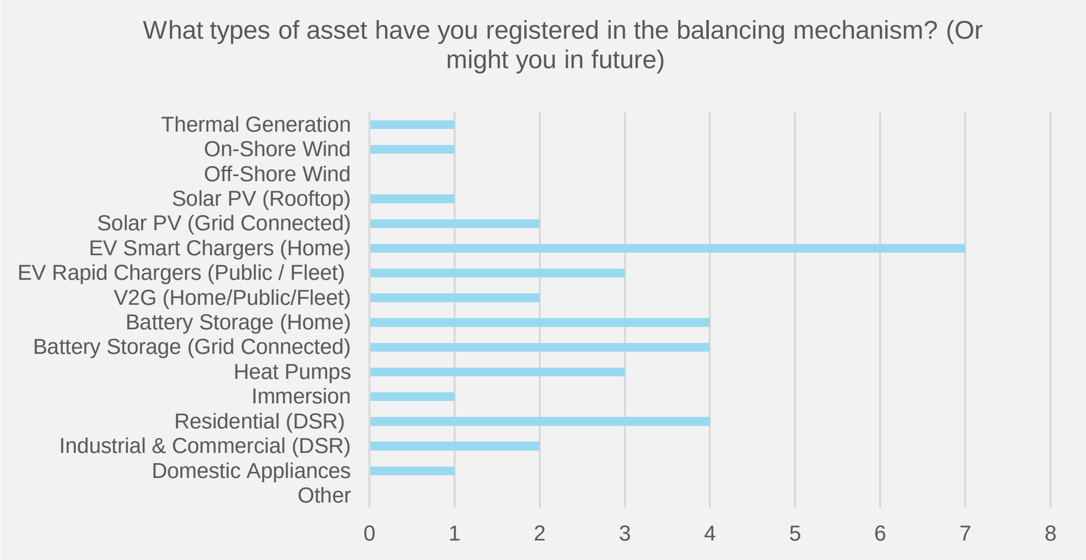


Figure 1.8 – Aggregator responses: What types of asset have you registered in the BM?

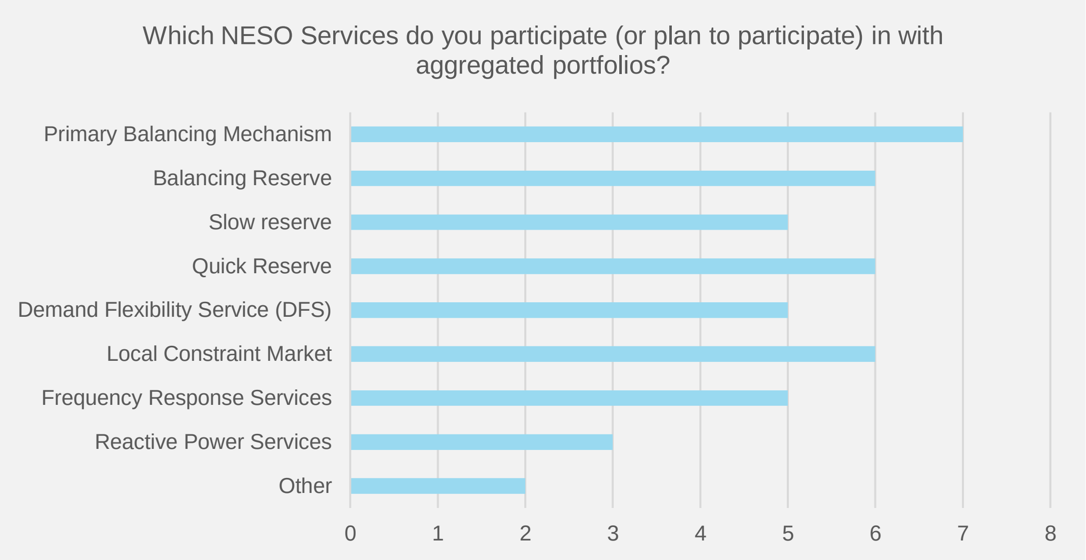


Figure 1.9 – Aggregator responses: Which NESO Services do you participate in?

Amongst the aggregators contacted as part of this review Home EV chargers were the primary asset of interest with all respondents stating interest in aggregation of EV chargers in NESO services. Home batteries and residential DSR were of interest to just over half of respondents, with just under half interested in aggregated heat pumps. One questionnaire respondent stated an interest in aggregating residential PV and smart white goods; one interviewee noted that Solar PV would be more valuable if used to charge EVs or home batteries; interviewees all reported that the business case for aggregated white goods was not positive due to low power demand per asset.

Aggregators expressed interest in participation in a range of NESO services. Amongst respondents selecting frequency response services the majority were already deploying grid-scale battery storage in these services. Interviews confirmed that although they have shown interest in frequency response services, they understand and confirm the need for strict requirements. One provider was interested in using home batteries in frequency response services. Obligatory Reactive Power Service (ORPS) uses transmission connected assets to manage voltage on the transmission network and lower voltage. CERs are useful to provide voltage services to the distribution network since voltage control is more location dependent, DER assets would need to be connected to the higher part of the distribution network (e.g. 66KV and 132KV) to be able to have an impact on the voltage on the transmission level.

The Holistic Transition FES Scenario used in our analysis has the highest CER installed capacity and system impact

The charts below show the number of hours per year in NESO Future Energy Scenarios output data with large step changes from CERs (MW/h) and can be used to compare the number of occurrences of extreme events between different FES 24 scenarios.

- Peak of extra demand/less generation drops from 37.3 GW/h in Holistic Transition (HT) to 29 GW/h in Electric Engagement (EE), 16 GW/h in Hydrogen Evolution (HE) and 6.6 GW/h in Counterfactual (CF).
- Peak demand reduction / generation drops from 17.3 GW/h in HT to 13.5 GW/h in EE, 10 GW/h in HE and 5.5 GW/h in CF
- Without the 200 most extreme hours the ramp up or down remains below 15.6, 12.4, 8.8 and 4.4 GW/h for HT, EE, HE and CF respectively.

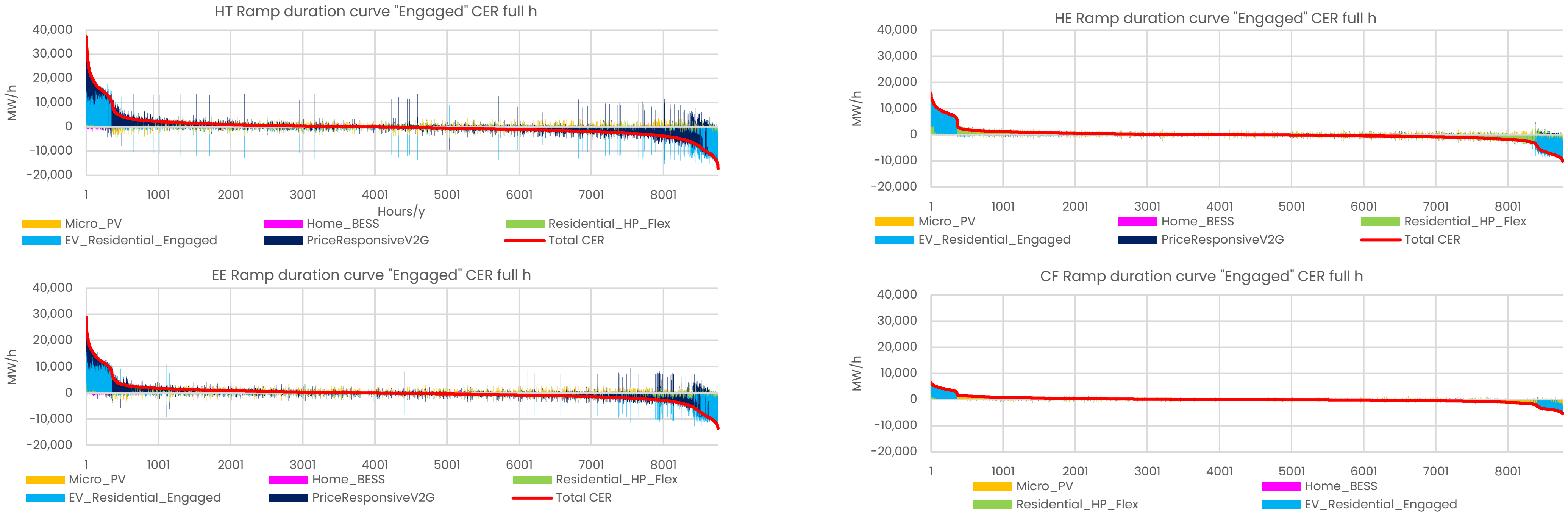


Figure 1.10 – Ramp duration curves for each FES 24 scenario

2. Why change is needed

Section Contents

Why change is needed

Implementation of the existing requirements for CERs is not practical, change is needed to provide appropriate requirements for this asset class and to facilitate visibility and control of CERs in the control room.

In the previous section we outlined the importance of Operational Metering and the significant role that CERs are expected to play in the future system.

In this section we set out the reasons why the current operational metering requirements cannot be applied to individual CER assets, the importance to NESO of CER participation in NESO markets, and why new metering requirements are therefore needed at the aggregated portfolio level which balance the needs of aggregators and NESO for mutual benefit.

Integrating CERs in the BM delivers broad system benefits across operational and market dimensions

CERs in the BM will increase reserve capacity, reduce costs, improve visibility for control operations, boost market liquidity, and provide a flexible resources against large system swings. For more information on the counterfactual analysis refer to appendix K.

Quantitative Assessment

Reserve Capacity

The integration CERs into the BM substantially increases the system's available reserve, strengthening grid flexibility and resilience.

Financial Impact

Integrating CERs into the market has the potential to deliver system-wide savings, particularly given that CER pricing is expected to be lower than that of large-scale batteries and other conventional generators e.g. CCGT enabling more cost-effective of balancing services

Qualitative Assessment

Visibility

Visibility of CERs in the BM improves situational awareness for the ENCC, enabling more informed and timely decision-making. This reduces the risk of misattributing frequency deviations and supports more accurate forecasting and dispatch.

Market liquidity

Integrating CERs in the BM will allow greater market liquidity. Market liquidity enhances the efficiency and responsiveness of the energy system by enabling more dynamic price formation, increasing competition among participants, and improving the visibility and valuation of flexible assets such as CERs.

Availability of resources

The availability of CERs within the BM provides a critical resources against large system swings by increasing the volume and diversity of responsive assets. With sufficient visibility and integration, CERs can act as a distributed, fast-acting reserve that complements traditional assets, reducing reliance on centralised interventions and improving overall system resilience

2.1 Impact of requirements on aggregators

CERs face three key barriers to participation in NESO services

Operational Metering accuracy, update frequency, and 1MW minimum portfolio are key barriers

Key Barriers Identified

Many assets do not currently meet the +/-1% meter accuracy requirement

- Most aggregators reported challenges meeting +/-1% accuracy, CER assets typically have embedded meters with accuracies from +/-1% to +/-2.5%
- Retrofitting legacy assets to achieve higher accuracy is cost-prohibitive
- There are multiple GB and EU regulatory and settlement standards which add complexity for manufacturers

1-second update frequency requirement poses significant challenges

- Cost of data transmission, particularly when using cellular networks
- Computing resources and data storage needed to processing and store 1-second data
- Legacy assets are often not capable of 1-second communication frequency

1MW portfolio requirement is restricting growth

- Achieving 1MW consistently in each GSP group is challenging, especially for newer technologies with lower market penetration, new entrants, or those focusing on specific technologies or regions.
- For EV chargers which have utilisation rates of around 5%, a large number of assets is required to consistently meet the 1MW threshold

Figure 2.1 – Typical domestic air source heat pump

Accuracy: many CER assets do not meet the ±1% requirement

6/6 aggregators reported that their asset base could not meet the 1% accuracy requirement, in part or in full

The main reasons provided for not being able to meet accuracy requirements were:

Limitations of existing meters in domestic and small-scale assets which were not designed to be capable of meeting the 1% accuracy requirement.

> *"No manufacturer is offering 1% at present; most are aware of and either working to or already able to meet the standards of CoP11."* Another that *"EV assets were not built with 1% accurate meters".*

Variable quality of asset metering capability across the asset base, with most assets not meeting the required standards.

> *"Asset metering is of variable quality but virtually non is MID compliant let alone 1% accurate"*

Cost of installation of high accuracy metering being too expensive for domestic or small-scale assets

> *"A domestic asset meter cannot bear the cost of a full smart meter".*

Using existing settlement meters to provide operational metering, which under current regulations are not required to meet 1% accuracy

> *"Settlement meters are +/-2.5% accurate so still not accurate enough".*

Subsequent interviews with manufacturers has revealed that a small number of newer models of CER assets can meet the 1% accuracy requirement, but these assets make up a small percentage of the total asset base. One EV charge point manufacturer reported a 1% accuracy capability across the majority of their install base, another manufacturer reported that only their latest charge points are capable of 1% accuracy. The expectations is that newer models of EV assets would be able to meet the 1% accuracy.

The main standards mentioned as driving future requirements are COP11 and MIR.

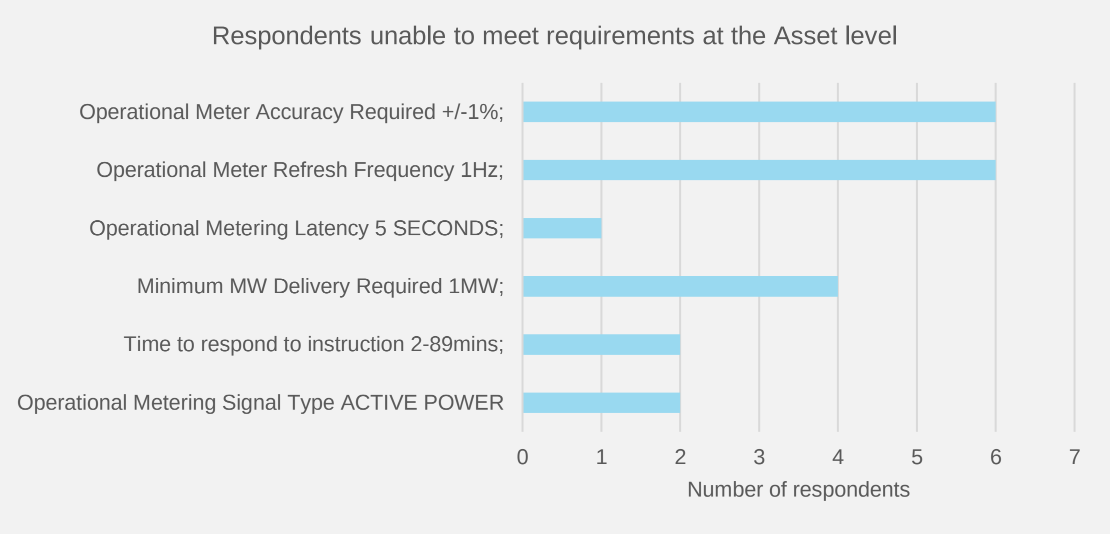


Figure 2.2 – Aggregator responses: Ability to meet requirements at asset level

All but one respondents reported that the 5s latency requirement was not a concern. Where concerns were expressed, they were closely linked to the cost of dedicated communication systems and on the ability of aggregator systems to process information quickly, rather than communication latency, the latency delays are mainly due to the data exchange between assets and manufacturer platforms, aggregators platforms and finally NESO platforms.

"To get below 5s latency can't use standard IoT systems, need dedicated systems which add a lot of cost and would exclude small sites."

"Latency -- not well defined how this should be measured. Hopefully it won't become a rigid requirement. Should be processing asset data as you receive the data, rather than holding them on the system for a few seconds."

1s update frequency: communication and cloud costs are the biggest barrier

Aggregators reported that there is no business case to support 1s data transmission from CER assets for participation in balancing services

There is uncertainty over the cost of data transmission given that no aggregators currently submit 1s meter readings. None of the respondents were able to provide exact data costs, or the size of meter data packets. Based on a literature review and interview responses, the expected data packet size for single asset is between 500bytes and 40,000bytes, which would result in monthly data costs of approximately £10 - £400 per month per asset.

One respondent reported that the cost of 10s read frequency is *"not insignificant but not unreasonable"*

Data transmission costs over Wi-Fi is negligible in comparison, however reliability is a key consideration. Whilst both 4G and Wi-Fi can have reliability and signal issues, for Wi-Fi, there are added concerns over reliance on home Wi-Fi equipment (password changes, replacement of router) and that the end-user must set up equipment via equipment software with unfriendly UI and requiring some technical expertise. For 4G concerns are over signal availability and long-term support (provisioning of SIMs onto networks, changing spectrum bands, different bands in different countries requiring different hardware).

In addition to data communication costs, 1s meter read frequency for 10,000's-100,000's of assets would incur significant cloud computing costs for data ingress, compute costs (validation of TCP data packets and summing 100,000's of readings per second), and data storage costs especially if there was to be a requirement to maintain asset data for audit.

One respondent notes that cloud platforms not optimised for high-frequency data:

> *"Most MQTT brokers are designed for IoT devices providing relatively infrequent data (1/min to 1/day). Cloud platform providers are not set up to receive a few million messages per second. High overhead on messages for a small amount of data."*

Game Over for Network Confusion: TCP vs UDP Explained

Figure 2.3 – Aggregator responses: Do you currently experience challenges?

Figure 2.4 – Mobile gaming

Video and game streaming is now commonplace over 4G networks and requires significantly greater data volumes than operational metering, so why isn't it feasible to transmit meter data economically?

Video streaming uses a different communication protocol (UDP) than that used to transmit operational meter data (TCP). UDP is a protocol used in applications where speed is critical and occasional data loss is acceptable, such as live streaming and online gaming. TCP is generally the preferred protocol transmitting secure, reliable alphanumeric data due to its reliability, ordered delivery, and compatibility with security protocols like SSL/TLS.

TCP has significantly higher cost due to the computational and network bandwidth overheads incurred by its added security and reliability.

Sources:
https://www.keysim.co.uk/resources/prices/
https://www.researchgate.net/publication/308837190_Smart_meter_packet_transmission_via_the_control_signal_of_LTE_networks

4G comms and cloud costs increase with read frequency

It is plausible that comms and data costs can exceed flexibility value for aggregators of domestic EV smart chargers

Aggregator estimate of 4G comms. and cloud costs provided in the survey

Metric	1 sec	5 sec	15 sec	30 sec
Message Configuration				
Message Rate (sec)	1	5	15	30
Message size (kb)	0.6	0.6	0.6	0.6
Usage Metrics				
Messages per Day per device	86,400	17,280	5,760	2,880
Daily usage per device (GB)	0.049	0.010	0.003	0.002
Monthly usage per device (GB)	1.48	0.30	0.10	0.05
Monthly usage per 1000 devices (GB)	1,483	297	99	49
Mobile Data Cost				
M2M Sim Cost (ex VAT)	£2.89	£2.89	£2.89	£2.89
M2M Data Cost (ex VAT)	£12.00	£4.98	£2.60	£2.60
Total Per Month per Device	**£14.89**	**£7.87**	**£5.49**	**£5.49**
Total Per Month (1000 Devices)	**£14,892**	**£7,867**	**£5,492**	**£5,492**
Cloud Processing Costs				
Azure IoT Hub (1000 Devices)	£1,820.367	£1,820.367	£182.037	£182.037
Azure Function In (1000 Devices)	£62.72	£10.82	£1.00	£1.00
Azure Function Out (1000 Devices)	£62.72	£10.82	£1.00	£1.00
Cloud Cost per Month (1000 Devices)	**£1,945.81**	**£1,842.01**	**£184.04**	**£184.04**

Table 2.1 – Aggregator estimate of 4G communication and cloud costs, provided in the survey

The costs shown in the table left assume 4G communication; some aggregators use Wi-Fi to communicate with their assets, in which case the communication costs are negligible, only the cloud processing costs would be relevant. Although Wi-Fi is cheaper, most meters are accessed using 4g due to reliability (e.g. user could turn it off, forget to pay the bill, coverage) and security concerns (e.g. middle through router access).

Aggregator flex value per asset per month was estimated by DNV at £4.26 based on the assumptions below, therefore it is certainly plausible that comms and data costs could significantly erode the flex value of assets – especially is communication is over more expensive 4G networks.

Flex value per asset per month based on bid win rate of 30%	Aggregator revenue share per asset per month (50% share vs. VLP / asset owner)
£8.52	**£4.26**

Assumptions:

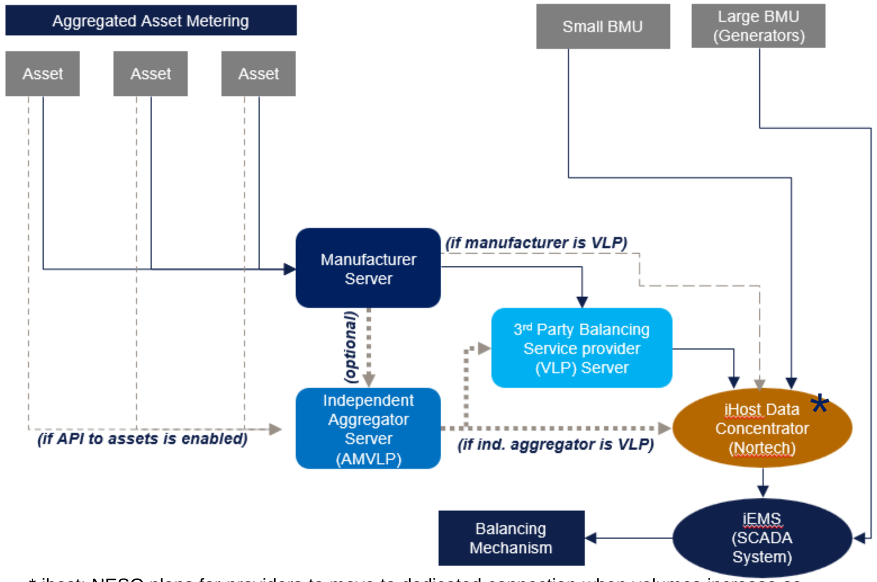
- Bid/Offer price for BM (£/MWh) 100 [Balancing Mechanism: how deep is the market for battery energy storage? - Research | Modo Energy]
- BM bid win rate 30% Assumption
- Flex value captured by aggregator (vs asset owner &
- VLP) 50% Assumption
- EV smart charger utilisation rate 5% Interviews and average EV milage

The ability of all aggregated portfolios to achieve a 5 second latency requirement is not clearly established

There is currently no mechanism to validate latency

- The 5s latency may be a problem for some participants due to potential for multiple third-party intermediaries in the metering chain, each of which introduces a processing delay (see diagram left).
- All but one respondents reported that they believed 5s latency requirement achievable but respondents noted that it was difficult to validate latency especially when receiving data from intermediaries. The following explanations were provided for the challenges to consistently meet 5 second latency:
    - Cost of changing from standard IoT systems to dedicated low-latency communication systems
    - Additional latency due to data exchange and processing where there are multiple steps in the chain of metering and aggregation (there could be more than one aggregation step)
    - Communication infrastructure or protocol limitations
    - Asset hardware constraints
    - Comms network congestion
- In the short term the impact of latency is hard to quantify because neither NESO nor industry have a way to validate the current latency performance. DNV are confident that latency is greater than for non-aggregated assets, however the performance will vary depending on the provider and network conditions.

Figure 2.5 – Operational technology example for participation in the balancing mechanism



* ihost: NESO plans for providers to move to dedicated connection when volumes increase so bypassing iHost

- Feedback received on latency requirements:

"To get below 5s latency can't use standard IoT systems, need dedicated systems which add a lot of cost and would exclude small sites."

"Latency -- not well defined how this should be measured. Hopefully it won't become a rigid requirement. Should be processing asset data as you receive the data, rather than holding them on the system for a few seconds."

With assets aggregated by a third party, then passed to us for aggregation with additional assets and sent on to NESO, it can be difficult to validate a sub 5 second latency. We are confident that within our own systems we can achieve this but when active as a route to market provider, this could be difficult. We are confident that 10 seconds latency would capture all out current connections."

Aggregator access to EV charger data

Accessing EV charger data though OEMs platforms may be subject to tighter restrictions for aggregators, necessitating negotiated commercial agreements to ensure compliance with operational metering (OM) requirements.

The methods used by aggregators to access EV charger data is important to contextualise when assessing potential operational metering options. Since 2022, all new private EV chargers sold in the UK must have a minimum level of smart functionality. This means they are designed to connect to the internet and can be remotely controlled.

Aggregators tend to access EV charger data via two main pathways:

1. Directly using Smart Energy Platforms or through partnership with a smart energy management platforms operator:

- Aggregators (e.g. Kaluza, Octopus, Flextricity) have built their own energy management platforms and have access to domestic EV chargers via:
  - Smart meter data
  - Cloud-connected EV charge points

2. Access through OEMs API

- OEM partnerships with car manufacturers or charger brands

Cloud-based Charging Station Management Systems (CSMS) are typically built using:

- Serverless technologies (e.g., AWS IoT Core, Lambda)
- Open Charge Point Protocol (OCPP) for charger-to-cloud interoperability
- MQTT/WebSocket for real-time bidirectional communication

Aggregators owning their own cloud-based control systems for EV chargers gain full control over data, dispatch, and platform design, enabling faster response and deeper market integration. Aggregators would be able to support higher read frequency and real-time control but must absorb all data processing costs.

In contrast, relying on OEMs can limit access, flexibility, and scalability due to vendor restrictions and API limitations. Aggregators would be required to negotiate data requirements with OEMs under a commercial agreement. This may limit data frequency and flexibility, requiring negotiated commercial agreements to meet operational metering standards.

Technically, both routes are feasible, but the direct route offers greater autonomy while the OEM route may be commercially lighter but less scalable.

Regulations: electric vehicle smart charge points - GOV.UK

Asset capacity vs. metering cost is a major factor in determining the business case for asset onboarding

Assets above 1MW can generally meet operational metering requirements
Below 1MW, and especially below 100kW, assets face significant barriers

Assets above 1MW (e.g. grid scale batteries and I&C flex) generally do not face major barriers in meeting current operational metering requirements, **except if downtime to upgrade metering is needed**

> *"Majority of these assets can meet requirements but not guaranteed that can easily and economically access that metering"*
>
> *"A 1MW battery is capable of being a merchant asset in many services, it can justify £20 / month data costs given £40-50k income per year of that asset."*
>
> *"To get below 5s latency can't use standard IoT systems, need dedicated systems which add a lot of cost and would exclude small sites."*

Assets of capacity 100kW to 1MW face more significant barriers as the cost of metering relative to asset revenue increases

> *"We don't go below 1MW due to metering costs"*
>
> *"As assets get smaller complexity of onboarding increases, assets need to be aggregated, less able to absorb data and comms and metering costs."*
>
> *"we aggregate assets above 250kW, the cost of metering is one of factors why assets below this are not viable"*

CER assets below 100kW face significant technical and economic barriers to meeting current operational metering standards. Respondents reported that the **revenue from flexibility, once divided across the value chain, was not sufficient to support expensive metering and communications**.

"Bill associated with [EV] charging can be slightly offset by accessing balancing markets, but this can quickly be overtaken by data and comms costs."

The asset revenue decreases in line with capacity and utilisation rate, which is why **no aggregator reported interest in aggregating domestic smart appliances such as washing machines and fridges.**

Figure 2.5 – Industrial refrigeration plant in a food distribution facility

The image above shows an industrial refrigeration plant in a food distribution facility. This is an example of assets in the range of 100kW-1MW which currently struggle to justify high frequency metering costs, once assets reach 1MW this is no longer a concern

Credit: Carlos Amat Photography

1MW minimum portfolio is a significant barrier

The combination of low market penetration and lack of HH settlement make it difficult to reliably reach 1MW

Although out of scope of this review, based on the interviews, there are a few key challenges for providers to meet the 1MW portfolio limit for participating in the Balancing Mechanism:

Low utilisation of EV chargers makes it difficult to consistently meet 1MW:

> *"The requirement to meet 1MW minimum per BMU is currently challenging: EV charging has around 5% utilisation, which means we need 3500 chargers in every GSP group to meet this requirement, which we can't in many GSP groups today, and we're the largest EV charging provider."*

The delay in implementing market-wide half-hourly settlement pushes back when more assets will be eligible to participate:

> *Only 5% of our customer base is settled half hourly so can't participate based on Elexon requirement. As a result, we don't meet the 1MW minimum bid at GSP level."*

The companies interviewed were some of the largest aggregators in the GB, the points below provide some context on the size of the portfolios:

Manufacturer of EV chargers, home batteries, and solar inverters:

> *“our total capacity is 20MW"*

Manufacturer of EV chargers:

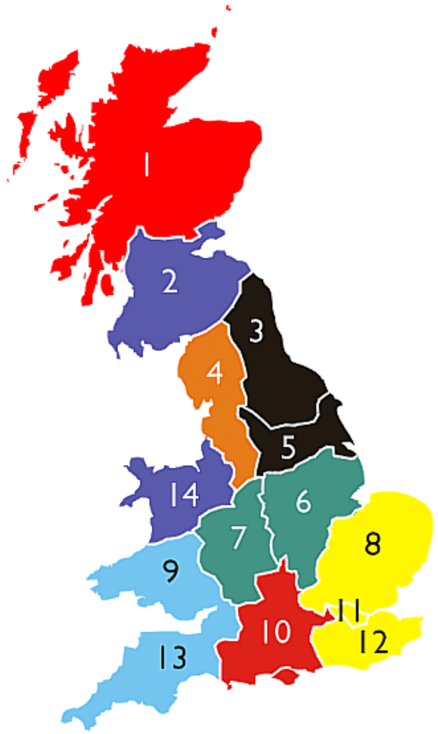
> *“We have 150,000 active users."*

Supplier of residential DSR:

> *“we have 1GW (150000 customers) with 0.3 GW of peak demand”*

While 1MW is found to be currently a significant barrier to prospective and current market participants, it is outside the scope of the OM review.

The Flexibility Markets Strategy considers wider barriers beyond the current scope of this work, such as the required transformation to the GB’s flexibility markets digital infrastructure including building and utilising the Simple Markets platform, Enduring Auction Capabilities quick and slow reserve, and building the control room infrastructure for DER and CER Visibility.



Aggregated BMUs must currently be registered within one of the 14 GSP-groups (see map), however NESO interviews highlighted a need to register at GSP which would make the 1MW barrier approximately 10x more difficult to overcome given there are more than 130 GSPs.

https://www.nationalgrideso.com/research-and-publications/markets-roadmap/flexibility-markets-strategy-call-input#Routes-to-Market-Review-for-Demand-Side-Flexibility

2.2 Impact of no visibility in CR

ENCC Overview of Operational Metering – Origins

The Balancing Mechanism initially comprised two main groups, allowing for precise real-time monitoring and control of power generation, ensuring system frequency stability within 0.4% of 50Hz by the ENCC through high-accuracy metering and rapid response to fluctuations.

Initially, the Balancing Mechanism contained two main groups: large-scale generating units, which had metering provided, and demand, which did not have metering provided. The generating units were capable of a high level of metering, with a one-second refresh rate and 1% accuracy. This precision allowed for real-time monitoring and control of the power generated.

The frequency on the system is maintained within +/- 0.2% of 50Hz by the ENCC. To achieve this, the sum of the Group C metering was assumed to be the 'demand' on the system. Fluctuations in demand were observed through the frequency feed, which updates in sub-second intervals, and the instructions taken by the ENCC could be seen and acted upon quickly.

‘True demand' is, represented by Group A, whereas generation output is represented by Group C, and our instructed level for Group C. If the frequency deviates from 50Hz, NESO can determine whether this is due to changes in either Group A or Group C, or if ESO’s instruction is not responding as expected. This ability to pinpoint the source of frequency changes is crucial for maintaining the stability and reliability of the power system.

Group A

No BM Metering

Demand-side assets consuming electricity as and when

Group C

BM Metering

Generating unit assets with high accuracy metering and read frequency to the ENCC

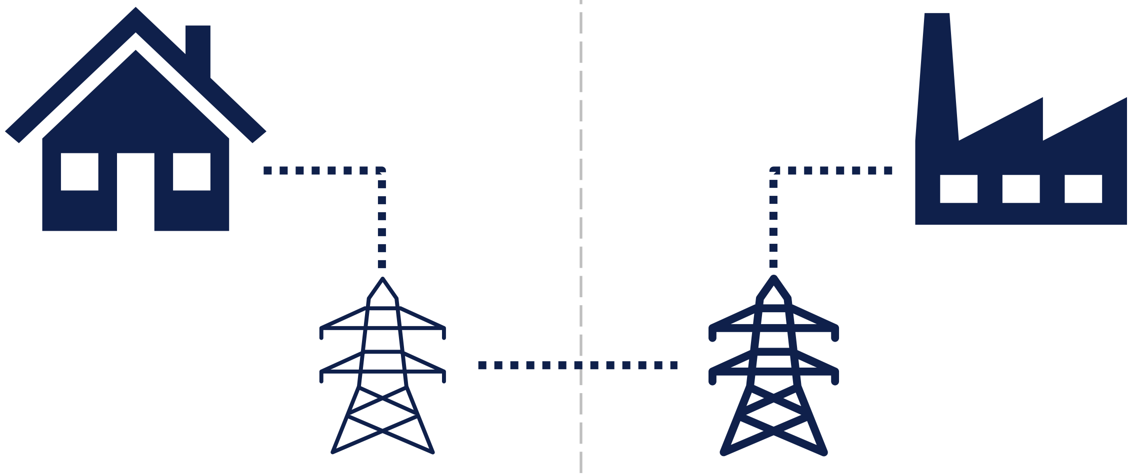


Figure 2.6 – Operational Metering BM Origin

ENCC Overview of Operational Metering – Current challenges

The introduction of embedded assets and flexible demand-side assets has complicated the understanding of system frequency imbalances, making precise metering in Group C essential for maintaining stability and managing fluctuations.

The introduction of embedded assets means that Group C metering no longer accurately represents Group A, or 'true demand'. This shift, along with the increased presence of flexible demand-side assets, has added complexity to understanding the causes of imbalances or increased volatility in system frequency.

When frequency changes away from 50Hz, it is now challenging to determine if this is due to changes in either Group A or Group B. However, due to the high capability of metering in Group C, NESO can still deduce if the change is due to assets within this group or if assets are not responding to instructions as expected.

Variations in Groups A and B have introduced more volatility into system frequency. Therefore, maintaining high levels of metering in Group C is vital, as it remains the only reliable way to monitor and manage these fluctuations. This precise metering allows NESO to respond quickly and effectively to maintain system stability amidst the increased complexity.

Group A

No BM Metering

Demand-side assets consuming electricity as and when

Group B

No BM Metering

Embedded assets such as Solar, Wind and Batteries

Group C

BM Metering

Generating unit assets with high accuracy metering and read frequency to the ENCC

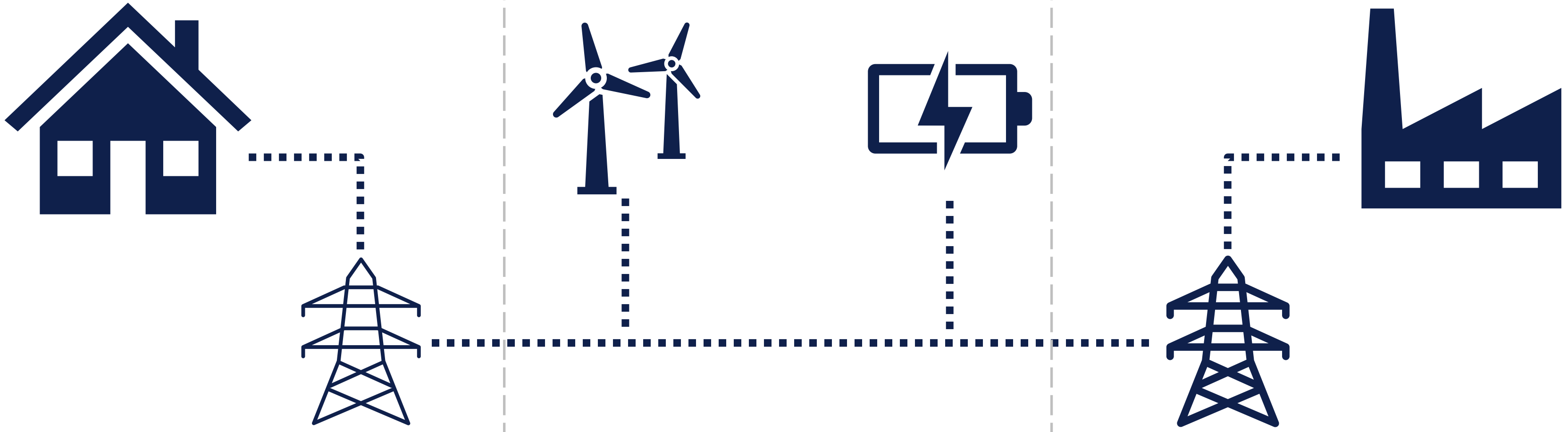


Figure 2.7 – Operational Metering BM Current*

**Some assets in Group A and B do participate in the BM and they provide operational metering. The picture illustrates the state of play for the majority of assets that sit in each group.*

BM access for aggregated portfolios improves SQSS

Aggregated CERs will still exist irrespective of BM access, visibility helps locational visibility and coordination however BM access should be encouraged as it expected that a significant amount of energy in the future will be provided by Distributed Energy Resources (DERs) and CERs

As the size and importance of aggregated portfolios increases, relaxed metering standards which allow slightly reduced accuracy, or a lag between real and metered power delivery, could impact situational awareness in control room, forecasting accuracy, and post-fault analysis. However, the clear message from interviews across the NESO is that having no access to metering, either due to faults or it not being required, has a significantly greater impact.

Aggregated portfolios of CER and big number of DERs currently rely on non-NESO markets for revenue, primarily DSO flex and wholesale markets. There are significant risks to NESO from not having visibility of tens of GW of aggregated assets participating in non-ESO markets, and utilising strategies such as NIV chasing (see box to right) which could create significant challenges in NESO control.

The current OM requirements present a significant barrier to aggregated CER portfolios registering in the BM. Given the expected rapid growth of CERs in the coming years, BM access for aggregated portfolios will become an increasingly acute issue for the NESO to ensure the flexibility they can provide it utilised to maintain a stable grid. Ability for these assets to submit compliant OM data it a prerequisite to this, and will also support situational awareness, forecasting, and post event analysis for CER assets.

BM access reduces the ability of assets to participate in NIV chasing strategies which would impact system balancing by creating rapid changes in generation/demand as many GW of flexible assets adjust their output through to real-time, even within the settlement period.

DER visibility is currently the focus of a separate strategic study led by the DER visibility team (which falls outside the scope of this study). By optimising OM, NESO can enable aggregated portfolio of CER in the BM, thereby enhancing visibility for the ENCC. However, to achieve higher visibility, there is a need for new business processes to enhance coordination between NESO and DSOs in their data exchange.

NIV Chasing

Net Imbalance Volume (NIV) is the net volume of actions taken to balance the system and determines the System Length (long or short). NIV chasing is where a BSC Party will deliberately incur an Energy Imbalance Volume in order to receive or pay the Imbalance Price rather than the market price for that energy.
If the Party is a Generator, they can incur a deliberate imbalance volume by over generating or under generating in relation to the volume of energy they sold before the Settlement Period.

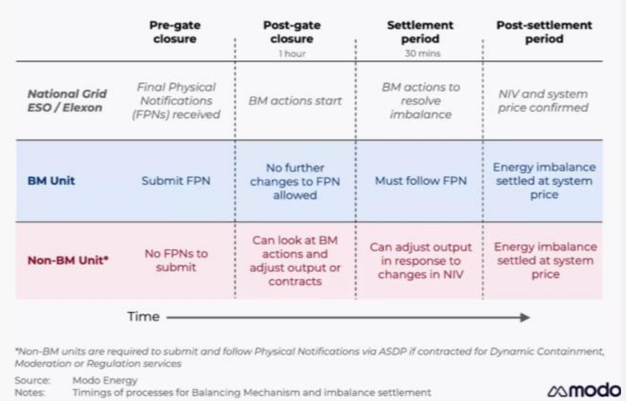


Figure 2.8 –Timings of processes for BM and imbalance settlement

Non-Physical Traders can incur an Imbalance Volume by buying energy from another trading party and not selling all of that energy on, or by selling energy to another a trading party and not buying enough energy to cover what they sold.

Non-Balancing Mechanism-registered systems have much more flexibility to NIV chase due to less stringent notification and compliance requirements compared to BM-registered units, or units participating in frequency response services. NIV chasing is an attractive strategy for aggregated CERs, especially if these assets face barriers to BM registration due to OM requirements. Assets which are BM registered or participate in frequency response services are less able to participate in NIV chasing because the requirement to submit and follow a PN significantly increases the risk of this strategy.

Sources:
https://www.elexon.co.uk/operational/balancing-and-settlement/elexon-insights-what-is-driving-increases-in-electricity-imbalance-volumes-july-2019/
https://modoenergy.com/research/niv-chasing-explainer

There is an existing need for better visibility of both DER and aggregated CER

Forecasting and real-time balancing are the primary areas of need for increased visibility

Demand Predictor / Forecasting

The Forecasting team has identified several challenges related to Consumer Energy Resources (CERs) that require improved operational metering (OM) data. Currently, aggregated BMU operational metering data is not utilised in forecasting or the demand predictor. This gap is particularly notable in the lack of visibility into potential and actual electric vehicle (EV) charging load at any given time. Aggregation currently takes place at GSP-Group (14 regions), however GSP-level data (130+ regions) is required for accurate forecasting. Aggregating as GSP would present a significant barrier to aggregators given the 1MW minimum BMU size, so a solution which provides split metering, or a location metadata, may need to be considered. As new technologies like batteries and aggregated CERs reach scale, the team acknowledges the need to incorporate these into their forecasting models, necessitating access to reliable OM data from these sources.

Network Modelling

The Analysis and Modelling team faces significant challenges in accurately representing CERs in their network models, which are used in critical systems across the NESO. At present, most small generators connected to the distribution network are not modelled in the iEMS system, and there is a lack of full metered visibility of the DNO network. This is relevant in GSPs where visibility into the distribution network is needed to understand interactions between distribution and transmission. For aggregated units, the team does not have access to accurate and complete location and portfolio composition data. To create comprehensive and accurate network models that include CERs the Analysis and Modelling team suggested that sourcing data from an intermediate system such as a Distributed Energy Resource Management (DERMS) system would be the best solution. It should be noted that providing asset level information for offline modelling does not require Operational Metering data specifically and could be more feasibly and economically achieved by uploading data from assets, or a sub-set of assets, on a daily/weekly basis.

Control Room Transmission Security

The Transmission team has highlighted that the lack of visibility into smaller assets poses a greater challenge than relaxed metering requirements. This is particularly evident in the case of unexpected loads from battery charging, which can create securable events. Improved OM data from CERs would enhance the team's ability to manage transmission security effectively. The Transmission team has identified that aggregated MVAR capability from DER at the GSP Group level would be valuable to NESO for Voltage Management, with this information ideally submitted via DNOs however CERs might have a lower impact due to the localised impact of reactive power.

DER Visibility

The DER Visibility team is actively working to gain comprehensive visibility of all Distributed Energy Resource (DER) assets, including CERs. The team has specifically noted the need for data beyond the GSP level, extending down to residential to 11kV to produce operational insight into DER and CER assets enabling improved whole system operation and reduced consumer costs.

Systems upgrades will enable increased visibility of DER & CER and make them easier to dispatch

Upgrades and replacements of core systems may increase the importance of accurate OM data from small BMUs as they become more integrated into frequency control processes

NCMS (iEMS replacement)

NCMS will replace the current iEMS SCADA system. It will provide modernised infrastructure and develop new online and offline modelling capabilities, including whole electricity system simulation and modelling aided by machine learning and probabilistic analysis allowing NESO to predict transmission problems in a more volatile operating environment. It will make the impact of distribution network capability more visible, so that NESO can make better decisions. Upgrades are needed given the increased data coming into the control centre so that engineers are able to understand and analyse data to make optimal decisions. The NCMS will continue to send data (e.g. OM) to Open Balancing Platform (replacement for BM), CCDR (replacement for Historian, Energy Forecasting System, OLTA. All integrations will go via the Data Integration Layer (Grid Data Fabric)

Open Balancing Platform

The Open Balancing Platform (OBP) is designed to modernise and optimise the balancing of the national electricity network by providing the following capabilities:

- Bulk Dispatch Capability: The OBP introduces a Bulk Dispatch Optimiser tool that allows NESO control room engineers to send hundreds of instructions simultaneously to smaller Balancing Mechanism Units (BMUs) and battery storage sites. This significantly reduces the time and manual effort required to issue dispatch instructions, thereby optimising network balancing and reducing operational costs.
- Enhanced Precision and Optimisation: The platform provides control room engineers with pre-selected and optimised lists of units to meet network requirements. This optimisation reduces the number of manual instructions and enhances the efficiency of dispatch operations, enabling technologies like battery storage to play a more active role in balancing the network.
- The OBP is set to incorporate a wider range of technologies and transfer existing response and reserve services from the Ancillary Services Dispatch Platform to the new system over the next few years. By 2027, the OBP aims to replace both the existing Balancing Mechanism and the Ancillary Services Dispatch Platform, streamlining the entire balancing process.

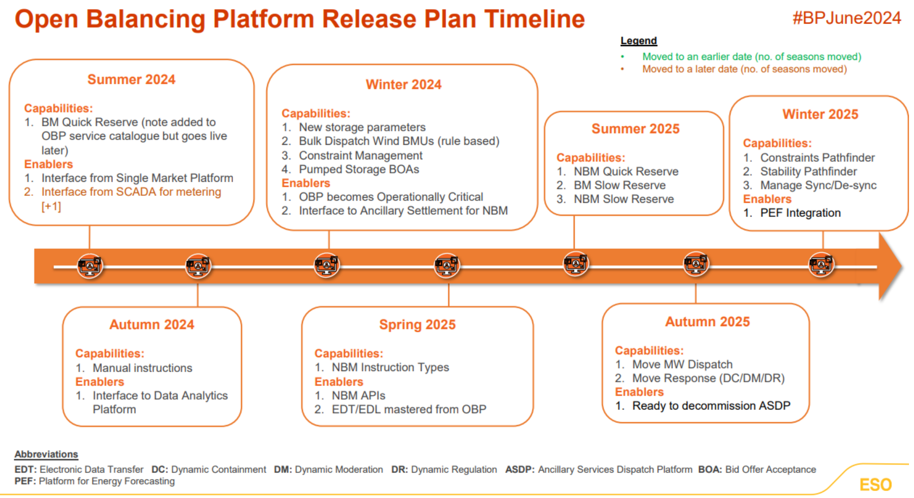


Figure 2.9 – Open balancing platform release plan timeline

Source: https://www.nationalgrideso.com/document/320711/download

2.3 Impact of aggregated metering on Control Room

Operational Metering is a key input to multiple real-time NESO systems and processes critical to SQSS

Function	System	Relevant Teams	Role of Operational Metering	Impact of poor-quality metering	Impact of inaccurate metering / lagging metering
	iEMS SCADA	Control Room Analysis and Modelling Transmission Security	• Provides real-time visibility of system state • Feeds data to other control room systems	• Reduced situational awareness for engineers • Less meaningful simulation results • May require manual overrides	• Reduced situational awareness • Potential for incorrect operational decisions e.g. under/over-correction of frequency
	PNA (includes State Estimator, Fault Level Analysis, Contingency Analysis)	Analysis and Modelling Control Room	• Provides inputs for network analysis (including state estimation, fault level, and contingency analysis)	• PNA algorithm attempts to correct for poor quality data • Less accurate state estimation*	• Limited impact given refresh rate of systems is 1 to 4 minutes • Potential for incorrect operational decisions
	Network Model (part of the PNA)	Analysis and Modelling Control Room	• OM data generates topology and real-time representation of network in iEMS • Supports network reduction for efficient modelling • Doesn't model all assets connected to distribution and aggregated assets.	• Difficulty in accurately representing network state	• Inaccurate network representation • Potential for incorrect operational decisions
	BM SORT	Control Room	• Input data for balancing mechanism systems, supports dispatch decisions • Monitor BMUs changing output according to BOAs • Monitor BMUs providing response following a change in frequency • Used to develop systems operating plans (36hrs-4hours ahead)	• Reduced confidence in asset performance • Potential for unnecessary dispatch actions	• Incorrect assessment of available balancing capacity • Suboptimal dispatch decisions • Potential system imbalances • Increased system operation costs
	Demand Predictor	Control Room Forecasting	• Provides real-time demand assessment • Supports short-term demand forecasting (0-4hrs ahead)	• Meter over-ride resulting in reduced situational awareness, inaccuracy of short-term forecasts, and increased workload	• Incorrect demand predictions and dispatch advice • Potential for unnecessary balancing actions • Increased system operation costs

Table 2.2 – Roles of Operational Metering for various systems and processes

* The state estimator determines the best estimate of the current state of the system, based on the available measurements from various measuring systems. e.g. SCADA

Real Time Balancing/ Analysis **Forecasting** **Post Fault Analysis**

More details on interview responses are provided in the Appendix

Historic data from Operational Metering is used in offline systems and processes to support SQSS

Function	System	Relevant Teams	Role of Operational Metering	Impact of poor-quality metering	Impact of inaccurate metering / lagging metering
	Data Historian	Technical Operations Policy Team Operational Metering team Frequency Risk and Modelling Energy Forecasting Team	• Data Historian OM data used for post-event analysis, metering quality assurance. • Data Historian input to Frequency Risk and Control Analysis, Platform for Energy Forecasting and Constraint Forecasting Tool	• Gaps in historical data • Challenges in post-event analysis	• Less accurate forecasts • Affect ability to understand asset behaviour • Less accurate post-fault analysis
	Constraint Forecasting Tool	Control Room Network Planning	• Input data for Constraint Forecasting model	• Less accurate constraint forecasts • Potential for unnecessary constraint management actions	• Incorrect assessment of future network constraints • Suboptimal network planning decisions
	Platform for Energy Forecasting	Energy Forecasting Team	• Used for forecast model training (provides inputs for demand, wind, and solar) • Used to create wind farm profiles • Not used for close to real time forecast	• Increased manual effort in data cleaning for model training • Reduced forecast accuracy	• No real-time impact • Reduced accuracy in Data Historian would impact forecasts if not corrected ex-post
	Frequency Risk and Control (FRCR) analysis	Frequency Risk and Modelling Team	• Combined with BMU PN's and error against closure to calculate reserve requirements	• Increased reserve requirement	• No impact of lag when ramping, only from accuracy of final value • Analysis only applies to generators >700MW

Table 2.3 – Roles of Operational Metering for various systems and processes (cont.)

Real Time Balancing/ Analysis **Forecasting** **Post Fault Analysis**

More details on interview responses are provided in the Appendix

Operational metering errors impacts the demand forecast, requiring reserve and response hence operational costs

The ENCC constantly manages numerous data inaccuracies. Introducing additional metering error adds uncertainty, leading to wrong decisions and increasing operational costs.

The NESO demand predictor uses operational metering data to produce a 0-4 hour demand forecast. Currently aggregated portfolios are not included in demand predictor but they are expected to be in future. Assets submitting data used in demand predictor today are predominantly large generators. Forecasts are used to estimate the generation of unmetered assets and demand curves from similar days estimate demand. As more consumers adopt CERs there is potential for the large groups of customer behaviour to synchronise, for example due to EV charging or home BESS behaviour aligning with market conditions or supplier tariffs. Therefore, it becomes more important to have real-time visibility of these assets rather than relying on forecasts.

Incorrect metering data in the demand forecasting engine control loop can lead to wrong decisions by control engineers. Since the ENCC relies on metering to assess unit, zonal, or national demand, any error in this data impacts dispatch instructions. These errors propagate through the system, affecting short-term demand forecasts and causing imbalances that manifest as frequency deviations.

The meter error in demand forecast can lead to the following risks:

1. Dispatch Errors: Inaccurate starting values lead to incorrect dispatches, with errors up to the size of the metering discrepancy.
2. Forecast Inaccuracy: Lagging data distorts short-term demand predictions until the next fixed forecast point.
3. System Imbalance: These inaccuracies affect zonal targets and dispatch programs, leading to real-time frequency drift.

Metering Error Effects:

1. Negative error (actual > metered): under-dispatch → low frequency.
2. Positive error (actual < metered): over-dispatch → high frequency.

To mitigate the risks, the ENCC uses Reserve and Response:

Response Measures: Pre-fault frequency response products are used to correct these imbalances.

Reserve Use: Fast-acting reserves (e.g., Quick and Balancing Reserve) are needed to correct short-term imbalances caused by metering errors.

Potential risk of large errors per CER type in a HT scenario

EV and V2G likely present the largest risk due to their very large installed capacity and fast ramp speeds

CER type	Max load on grid in 2035*	Potential risk for large error	Risk situation
EV “engaged” and V2G	28 GW (17.3 GW EV; 16 GW V2G)	High	High risk is because of the large potential capacity in the BM and fast ramping speeds. Relatively short MR interval is possible as mitigation, however the potential of quick ramping of large part of maximum capacity in a short time results in high risk of large magnitude errors. The maximum EV and V2G capacity is typically available during the evening, night, and early morning hours. According to the FES model, significantly fewer EVs are connected to home chargers during the day; however, considerable volumes of both office and home charging are still expected to benefit from low-cost solar PV energy.
Home BESS	1.75 GW	Moderate	Home BESS also has the potential to ramp to full load in a short time (the potential ramping speed per asset is quick), however the potential capacity in the market is expected to be significantly less than EV and V2G. V2G and Home BESS could ramp at the same time as they start to discharge.
Residential HP	5.5 GW	Moderate	Heat pump ramping speeds are likely low, and the probability of a high BM participation of heat pumps is lower than for EV, V2G and BESS since heat pumps are inherently more complex to control, having multiple components and control systems. Heat pumps are also potentially less flexible due to customer preference. It is questionable if Heat Pumps are currently capable of measuring with 10s MR interval or lower, or whether they are suitable for Report on Change metering.
Micro PV	15.9 GW	Moderate	Maximum solar PV generation occurs only on a few exceptionally sunny days, and ramping generally follows solar irradiance, making it relatively slow. Rapid ramping is only possible when micro-PV systems are curtailed. However, there is little incentive to curtail the portion of generation that meets behind-the-meter demand, which limits the amount of curtailable PV capacity. If wholesale prices turn negative and customers are charged for exporting solar energy, they are incentivised to align generation more closely with local demand, potentially resulting in high ramp rates, such as when responding to loads like water heaters. When PV is combined with home battery energy storage systems (BESS), curtailment becomes even less likely, and system behaviour is more likely to follow price signals.

Table 2.4 – Potential risk for various CER types

*FES 24 holistic transition

The number of risk profile exceedances differs significantly between scenarios and on EV & V2G randomisation

Even with an optimistic 10s meter read interval, no scenario is 100% within the NESO risk tolerance
Lower risk profile exceedances is correlated with FES 24 scenarios that feature less electrification

- Due to the decreased load and step-changes within EE, HE and CF, the risk profile exceedances per year are lower when compared to HT.
- Responsive V2G has a significant impact on non-randomised error. The HE scenario experiences far fewer non-randomised EV & V2G errors compared to HT and EE. This is due to the reduced presence of responsive V2G in the HE scenario.
- Randomised numbers are higher because they exceed the 30s duration tolerance more often than the non-randomised scenario. The 1s and 5s duration are exceeded less often and with high significantly lower magnitude.

	CER hourly swing [GW]			EV & V2G randomised		EV & V2G non-randomised	
FES Scenario	Highest	3rd highest (99.97 percentile)	Meter Read Interval	Exceedances of all NESO risk tolerance durations per year (all CERs)	% of minutes per year*	Exceedances of all NESO risk tolerance durations per year (all CERs)	% of minutes per year*
Holistic Transition	**37.3**	**33.8**	10	**7960**	1.6%	**4680**	0.9%
Electric Engagement	**29**	**25.6**	10	**7050**	1.4%	**3930**	0.8%
Hydrogen Evolution	**15.9**	**14.7**	10	**6030**	1.2%	**1370**	0.3%
Counterfactual	**6.6**	**6.3**	10	**200**	0.04%	**730**	0.1%

Table 2.5 – Risk profile exceedances for FES scenarios and randomised vs non-randomised EV & V2G

* Results are reported as % of minutes per year rather than % of minutes modelled, because interviews with industry found that aggregators are likely to dispatch assets at the settlement boundary to maximise revenue, therefore portfolios will in most cases only ramp during the settlement boundary period which we modelled. If all the minutes in the year were modelled with the same underlying assumptions the results would be expected to match the above.

Future risk envelope would need to be scaled up by a factor of 10 to 40 which could have a serious impact on system reliability

A higher penetration of CERs would breach NESO's current risk envelope. Expanding this envelope to accommodate such behaviour introduces considerable risk and is unlikely to be a sustainable long-term solution.

With a 10-second meter read interval; the following exceedances of current risk tolerance were observed across various durations: HT: 4,680 minutes/year, EE: 3,930 minutes/year, HE: 1,370 minutes/year and CF: 730 minutes/year

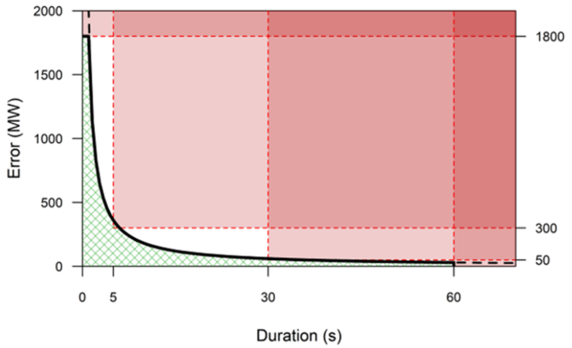
If such metering errors were permitted within the Balancing Mechanism (BM), NESO would need to increase considerable the current risks envelope potentially compromising system reliability. For example, to allow just 50 minutes of error per year (HT, blue line) under the HT scenario (HT representing the highest CER penetration), the risk envelope would need to expand significantly:

- Approximately 10 times larger for 1-second and 2-second durations,
- Approximately 40 times larger for 30-second durations

Table 2.6 – NESO's current risk tolerance

Risk tolerance	Error (MW)	Duration (s)
Largest infeed risk	1800	1
Imbalance not allowed to cause operational limit excursion	300	5
Half acceptable zonal error	50	30

Figure 2.10 – NESO's current risk tolerance



This suggests that future risks envelope would need to be scaled up by a factor of 10 to 40, depending on the duration, to maintain system reliability under such metering conditions. The above example is a simplified approach, and the NESO FRM team has developed a more detailed methodology to appropriately dimension reserve and response requirements.

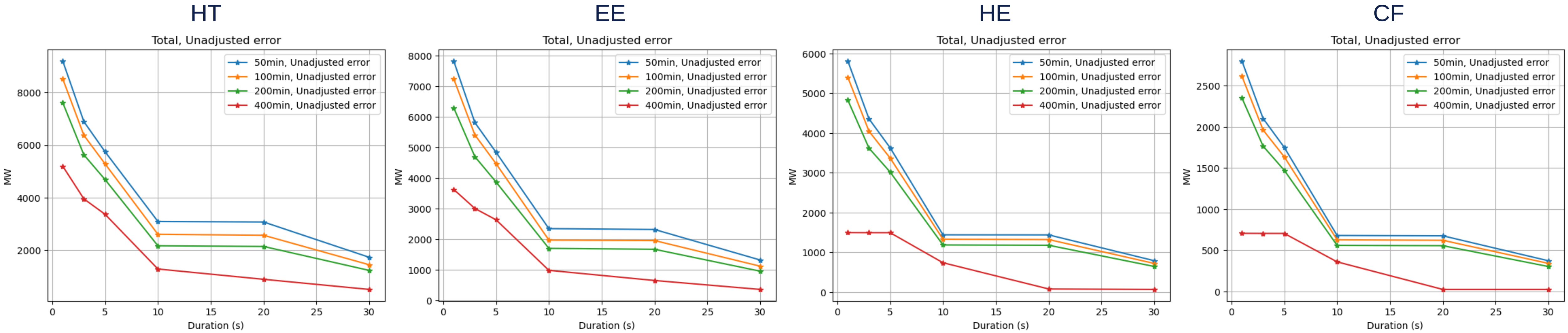


Figure 2.11 – Number of minutes in a year that the associated unadjusted error and duration is exceeded, for each FES 24 scenario

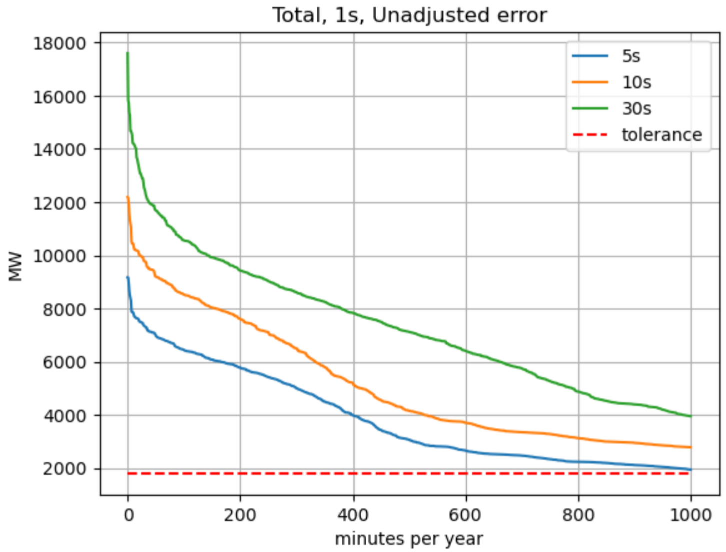
In Holistic Transition, even with 5s meter read interval the risk tolerance is exceeded for all NESO risk tolerance durations

Comparing 5s, 10s and 30s meter read intervals, none are able to stay within the NESO risk tolerance during large CER swings.

The charts below show the effect of changing meter read interval of CERs on risk profile exceedances when all EVs and V2G do not have a randomised delay applied (worst case scenario based on these assets being dispatched based on unusual market conditions). Without randomised delay for EV and V2G, the number of risk profile exceedances changes when the meter read interval is changed. We also computed errors for 3, 10 and 20 sec duration however errors the overall risk error was increased by 100 min, indicating that using 5, 10, and 30-second durations provides a reasonably accurate and balanced representation of the model.

Figure 2.12 – Minutes / year with >1800MW error for 1s duration

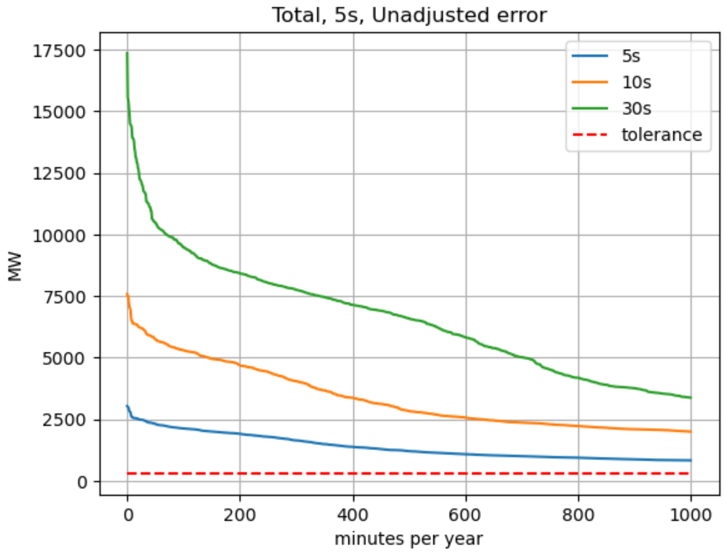
(shown for 5s, 10s, 30s MR interval)



MR 5s: 1080 minutes per year exceed risk tolerance
MR 10s: 1660 minutes per year exceed risk tolerance
MR 30s: 2220 minutes per year exceed risk tolerance

Figure 2.13 – Minutes / year with >300MW error for 5s duration

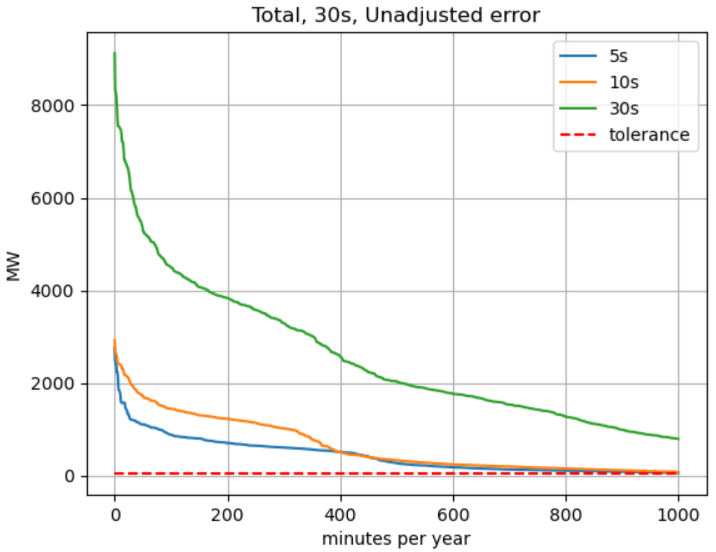
(shown for 5s, 10s, 30s MR interval)



MR 5s: 2260 minutes per year exceed risk tolerance
MR 10s: 3980 minutes per year exceed risk tolerance
MR 30s: 6030 minutes per year exceed risk tolerance

Figure 2.14 – Minutes / year with >50MW error for 30s duration

(shown for 5s, 10s, 30s MR interval)



MR 5s: 1060 minutes per year exceed risk tolerance
MR 10s: 1550 minutes per year exceed risk tolerance
MR 30s: 21000 minutes per year exceed risk tolerance

EV & V2G behaviour has a large influence on the impact from CERs, large swings in the wholesale market are possible

EV Smart Charging Regulations mandate 10-minute randomisation for EV and V2G assets on a day ahead schedule, for all scenarios we modelled both all randomised and all non-randomised to show the range of possible outcomes

Ramp assumptions for EV and V2G:

- **With** randomised delay: 10 minutes
- **Without** randomised delay:
  - 30s ramp up – vehicles typically step up charging rate in stages over ~30 seconds
  - 3s ramp down – vehicles typically stop charging in 2-3 seconds

Max EV and V2G maximum load for any hour during the year = 28GW

There are 100 hour-step-changes where more than 18 GW of the 28 GW total EV engaged and V2G capacity is ramping up (or down) in the FES data. While these fluctuations are less frequent, they present significant risks and will require careful management

Without randomised delay, or other measures to limit ramp rates, ramp rates as shown in the figure on the right could potentially occur at settlement period boundaries when EV and V2G have wholesale incentives to ramp all at the same time. Such ramping events will be incentivised by price differences between consecutive settlement periods, the ability to get the most revenue out of these price differences incentivise portfolios to ramp as fast as possible at the settlement period boundary.

This incentive likely result in one large ramping up event per day in the late evening, and one large ramping down event when prices increase again in the early morning. The magnitude of these two ramping events will change from day to day.

If the portfolios are scheduled day-ahead then randomisation will be in effect. However, if unexpected price changes occur and portfolios are dispatched to take advantage of the change in price, then they will not be randomised.

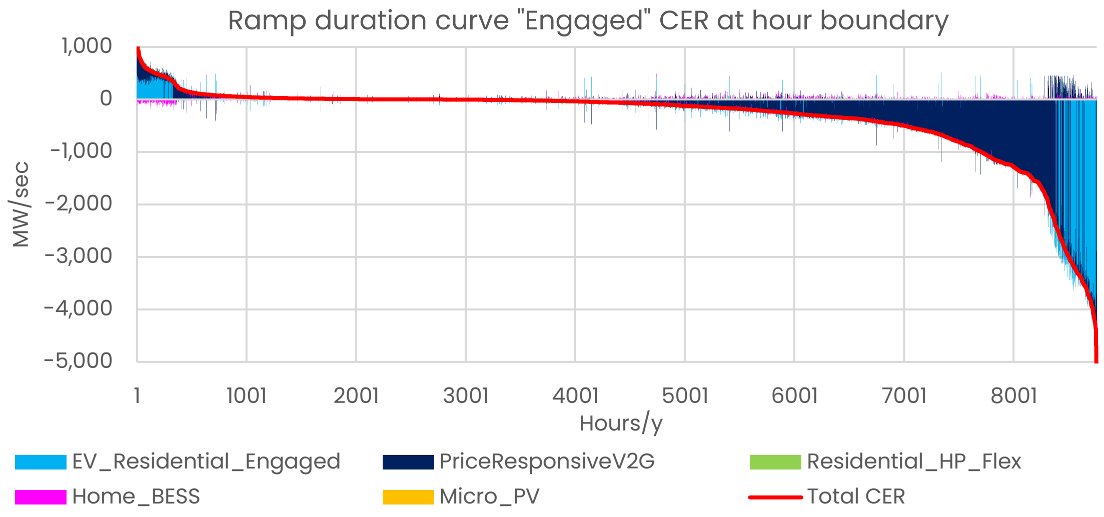


Figure 2.15 – CER ramp rates at the hour boundary without EV & V2G randomised delay

Scenario 1: 12 GW V2G / Home BESS / EV smart charging wholesale and BM adjusted scenario

NESO provided a plausible future system scenario utilising FES 24 data and operational experience based on the current system to simulate behaviour of assets in the Balancing Mechanism.

Scenario design

- The scenario considers various factors such as changes in demand, renewable generation shifts, interconnector flow variations, and market prices to ensure it encompasses a significant movement (whether instructed by ENCC, self-dispatched, or a combination of both) of metered CERs within a two-hour period.
- The morning demand pick-up period is particularly critical for system operation and balancing, characterised by a substantial increase in demand coinciding with a decrease in wind generation and a rise in interconnector exports. Consequently, it is highly likely that V2G price-responsive CERs could be charging until 06:00, before exporting to the grid between approximately 06:00 and 08:00, prior to PV generation coming online.
- The following potential scenario has been constructed using V2G price-responsive CER assets that may participate in the future, however this could be other CER as well as long as they can provide similar ramp rates and meter read and accuracy.

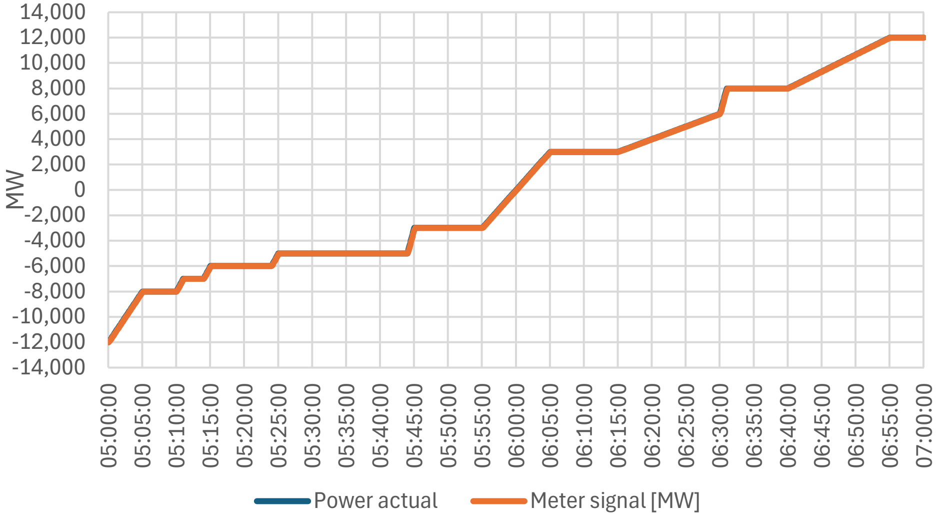


Figure 2.16 – Future System Scenario 1: Actual power vs Meter signal

The scenario was used to calculate the meter error as viewed from the control room.

- A 10 second CER portfolio meter read interval was assumed.
- 2% individual meter inaccuracy (inaccuracy at the moment of measuring)

Scenario outcome

The resulting OM error can be viewed on the chart below, the maximum error observed was 168MW, lasting for 60 seconds. Periods of lower magnitude error (20-70MW) persisting for longer time periods (up to 15 minutes) can also be observed during more gradual CER ramping. When applying Adjusted Aggregate Metering meter signal correction, this range narrows to ±70 MW which only persists for 10 seconds (same as MR interval). Detailed modelling and results of different MeterRead is available on [NESO SharePoint.]

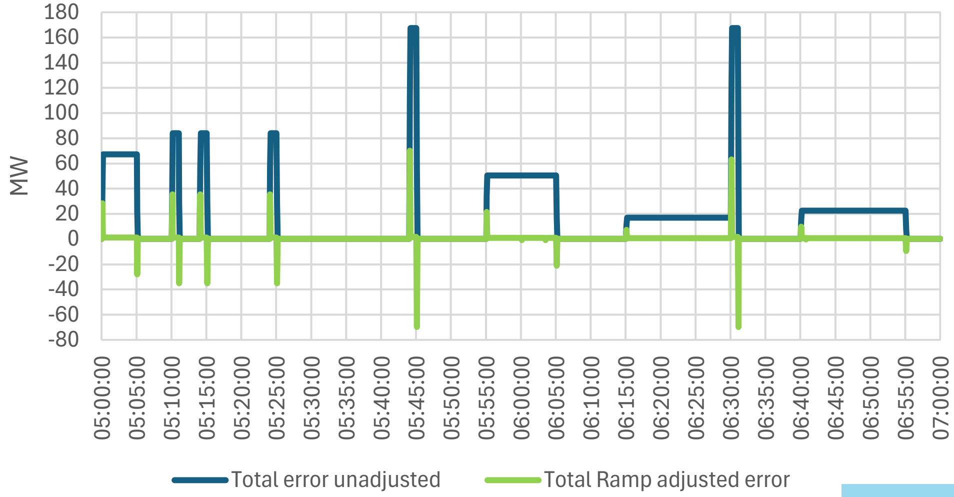


Figure 2.17 – Future System Scenario 1 Error

Scenario 2: modelling high number of energy balancing instructions

23/02/2025 was selected to model a day marked by rising wind output and forecasting errors

This scenario analyses how metering errors might accumulate during periods of high balancing market (BM) activity, reflecting the continuous nature of dispatch instructions rather than isolated spikes.

Although these corrected errors are smaller in magnitude, they remain a concern due to their continuous, fluctuating nature, which makes them difficult to predict. Unlike large spikes, these persistent deviations introduce an added complexity into demand forecasting. As a result, control engineers may be led to make operational decisions based on inaccurate or misleading projections. Detailed modelling and results of different MeterRead is available on NESO's SharePoint.

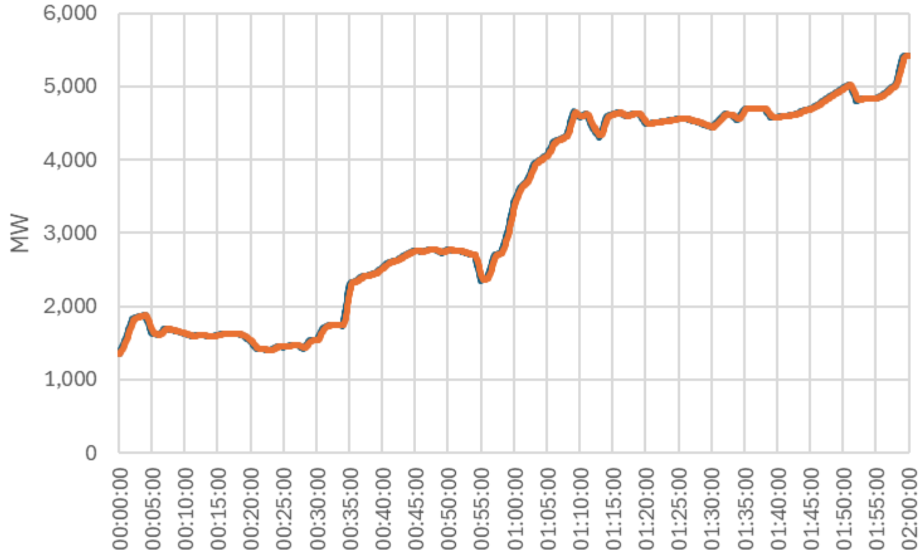
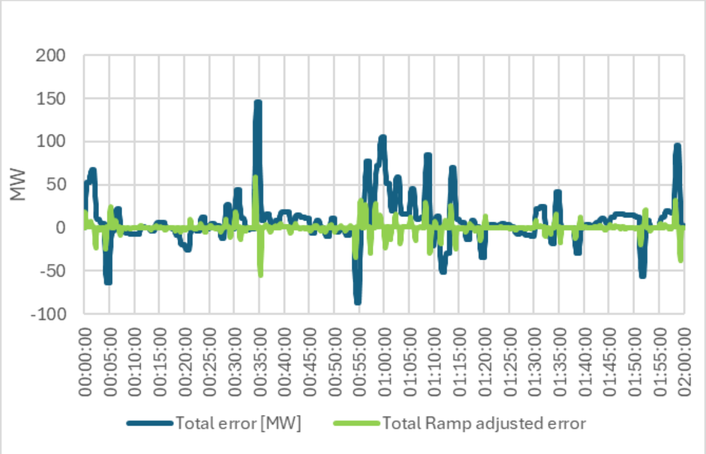


Figure 2.18 – Future System Scenario 2: Actual power vs Meter signal

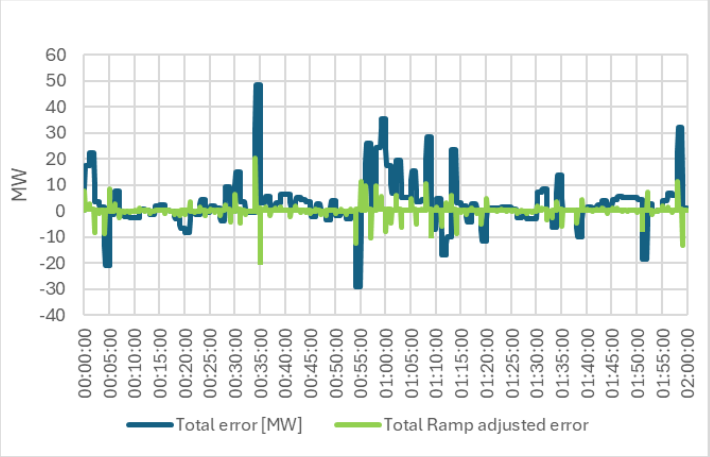
The figures show how different metering solutions might influence error profiles if customer energy resources (CERs) were to take on a larger role in system balancing.



Assuming a 30-second (MR), the error lag (blue line) ranges from -100 MW to +150 MW.

When applying Adjusted Aggregate Metering meter signal(green line) correction, this range narrows to approximately ±50 MW for a 30s meter read.

Figure 2.19 – Future System Scenario 2 Error for 30s MR



With a 10-second MR, the error is significantly reduced to around ±20 MW under the same metering adjustment

Figure 2.20 – Future System Scenario 2 Error for 10s MR

3. Operational Metering Options

Section Contents

Operational Metering Options

In the previous section we demonstrated that the current approach is unsustainable and new metering requirements are needed at the aggregated portfolio level.

In this section we consider the range of solutions available, acknowledging that the chosen approach must maintain SQSS while enabling CER participation.

Three main options are considered ranging from minor adjustments to current standards through to more complex solutions such as report-on-change and synthetic metering.

3.1 Solution Options

We assessed three high-level options for new CER Operational Metering requirements

#	Option	Description	Variant
1	Keep (close) to Current Requirements	Maintain current latency requirements, however measure Meter Accuracy on portfolio level, provide an option for assets capable of report-on-change to do so thus minimising data costs for aggregators.	a- Meter Accuracy= 1%, MR=1 sec (portfolio-NESO), Latency =5 sec (Counterfactual)
			b- Aggregated Meter Accuracy= 1%, Report On Change on asset level, Latency =5 sec
2	Use delayed CER OMD as real-time data	Allow CER portfolios to submit meter data with an induced delay from meter read interval of assets being >1s. Treat this delay as an error between the true state of the portfolio and the meter reading received by NESO. This error distorts demand forecasts, potentially leading control engineers to act on inaccurate information. Set limits on meter read interval* performance and increasing reserve and response levels to mitigate the impact on NESO system. **This option introduces an error into NESO systems relying on OM data, even when CER BMUs follow their PN/BOA.**	a- Allow error by mitigating its impact, set a 30s maximum meter read interval
			b- Allow error by mitigating its impact, set a 10s maximum meter read interval
			c- Allow error by mitigating its impact, set a 5s maximum meter read interval
			d- Ramp rate control (suitable to all range of MR). Aggregators must comply with an accuracy requirement by limiting the ramp rate of their portfolio according to its meter read interval, thus preventing high magnitude errors
3	Consider CER OMD, invest in systems to mitigate risk	Allow CER portfolios to submit meter data with an induced delay from meter read interval of assets being >1s. Treat this as delayed data and attempt to mitigate the impacts by upgrading NESO and aggregator systems to quantify the delay and limit its impact on operational decision making. **This option introduces an error into NESO systems relying on OM data only when CERs do not follow their PN / BOA, or the forecasted behaviour is inaccurate.** The error persists until the timestamped OM feed is received (likely 15-30 seconds). This error can be further reduced through different advanced forecasting methods (e.g. historical behaviour)	a- Aggregators timestamp OM data, NESO create real-time estimation and update with delayed OM feed
			b- Aggregators send synthetic data that best reflect the current real-time situation

Table 0.1 – Overview of Operational Metering Options

*The 60-second MeterRead interval was not modelled, as the 30-second results already significantly exceeded NESO's risk tolerance thresholds. Moreover, all aggregators indicated they were comfortable meeting the 30-second requirement, as confirmed by the WP1 survey.

3.1.1 Option 1 – Keep Close to Current Requirements

Introduction to Option 1 – keep close to current requirements

Reduction in data costs may make it possible for CERs to comply with current requirements in future (5+ years)
Report on Change (RoC) metering would be a very good immediate solution for compatible asset types

Option 1a is to maintain the current requirements. As shown in Section 1, the NESO risk profile is often exceeded even with a meter read interval of 5 seconds. Mandating meter read intervals below 10s places increasing burden on CER aggregators as the regulation gets closer to the current 1s requirement, mainly due to increased data communication costs and investment needed in IT/cloud systems to support high volumes of data ingress and processing. Given that data costs have been shown to decrease over time (see chart right), it is possible that the barrier to entry presented by the current regulations will decrease over time. **Note that even if current requirements are maintained, aggregated CERs will always have at least a 0.5 second meter read interval lag, because the aggregated 1s data will be made up of asset meter updates received over the previous second.**

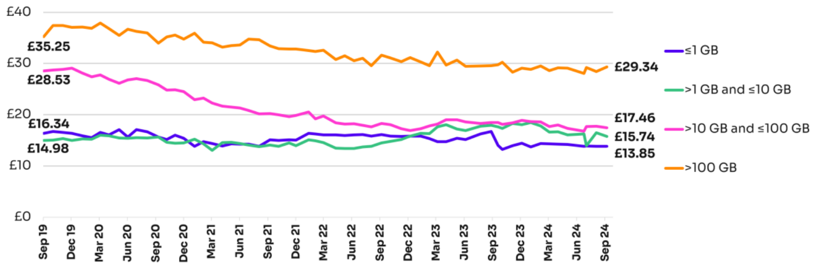
Option 1b is to implement Report on Change (RoC) metering as a means to maintain regulations close to the current 1s requirement. RoC metering systems monitor for changes in the monitored value that exceed predefined thresholds, only then sending updates. The core benefits of this approach include dramatically reduced data transmission volumes, decreased network congestion, and improved overall system efficiency—all while maintaining effective monitoring of critical parameters.

Assumptions for implementation of RoC:

- Report on Change would be activated by a threshold power value to be set at the asset level, where if the power output changes by more than the threshold (likely between 2-4%), then the assets begin sending metering.
- The meter read interval when reporting should be 1s to ensure that NESO receive data quality similar to traditional operations metering feeds.
- A heartbeat signal should be sent from the asset to the aggregator, and a summary sent to NESO, to confirm that communication with the portfolio is maintained

Falling mobile data costs (Ofcom 2024)[1]

Figure 16: Average pay-monthly SIM-only promoted mobile prices in real terms: September 2019 to September 2024 (£/month)



[1] https://www.ofcom.org.uk/siteassets/resources/documents/research-and-data/multi-sector/pricing/2024/pricing-trends-for-communications-services-in-the-uk-2024.pdf?v=387092#:~:text=The%20average%20monthly%20promoted%20prices,and%2010%20GB%20of%20data.

Option 1b: Report on Change – faces technical, financial, and regulatory potential barriers to implementation

Regulatory barriers are likely the main challenge to implementation of RoC metering because if mandated RoC potentially excludes certain technology types from participating in the BM

Several implementation challenges for Report on Change metering have been identified: technical, and financial, and regulatory.

Technical:

- Not all assets are suitable for report on change: RoC metering is best suited to asset types which have low underlying variability in power output.
- No CER communication protocols currently support RoC metering. Updating communication protocols to support RoC would require engagement with international standardisation bodies and would take time to implement.
- Not all asset meters may be capable of measuring and transmitting data with an interval of 1s. All modern EV charge point equipment is capable of this, but for other technology types this may not be the case.

CERs most suited to RoC metering:

1. EV smart charging
2. V2G
3. Home BESS
4. Heat Pumps
5. Solar PV

Figure 3.1 – Ranking of CERs by suitability to RoC metering

Financial

- Investment in aggregator systems needed to support RoC and potentially increased data costs for highly variable CERs mean that aggregators would need to develop a business case for implementation of RoC systems capabilities, and also on a portfolio-by-portfolio basis to upgrade asset firmware, or hardware if necessary.

Regulatory

- Because RoC is better suited to some CER asset types than others, it is unlikely that RoC could be mandated as a requirement since it would potentially exclude some asset types from the market, which runs contrary to NESO and Ofgem principles on maintaining fair and open markets. If not mandated, there would be no incentive for aggregators to invest in RoC capability.
- An appropriate update threshold for initiating RoC metering must be set:
  - Too low a threshold leads to excessive data transmission
  - Too high a threshold introduces unacceptable uncertainty

Because EV and V2G have the largest system impact, and the lowest underlying variability, there is a risk that setting a single recommended threshold value to accommodate all CER types results in unnecessary reduction in EV & V2G report on change meter quality.

EV and V2G – Report on Change impact on risk envelope

With a 2% power threshold, EV and V2G could exceed the 30s tolerance for up to 500 minutes per year

Two methods can be used to initiate report on change, however only the first option below is likely to be feasible:

1. Report on change is triggered by change in power output, a threshold of **~2% of asset capacity** is used in our analysis.

   The 30sec/50 MW risk tolerance could be exceeded for up to 500 minutes (up to 300MW) per year (FES HT with non-randomised EV / V2G) because even though the meters are updated every second, the data in the aggregated signal could be anyway between 0 and 1 seconds old which introduces a small meter lag. For the ramping assets this lag results in an error between 0 and 2%. As they all change their power in one direction there will be no error with opposite sign to compensate.

2. Report on change is triggered by the signal from the aggregator instructing the EV to ramp up/down.

   The second option is not feasible for two main reasons:

a) The asset could change power output without being instructed by the aggregator

- E.g. if manually overridden by the owner

b) Even when instructed aggregators do not have full control over asset behaviour

- The aggregator could instruct the asset (e.g. an EV charger), but it may not respond immediately (e.g. if the vehicle does not accept the power), which introduces the challenge of deciding when the charger is allowed to stop sending 1s meter updates though the vehicle may begin charging at any time. A similar situation could arise for heat pumps, which have their own internal control systems which constrain their ability to respond to a dispatch instruction.

- This is because, during ramping events, the error per EV and V2G assets could be shifted to be centred more around the Threshold/2 (1% i.e between zero and 2% threshold).
  - During ramp down assets will not have negative errors to compensate for positive error.
- When 5 GW of EV and V2G are all ramping for 30 seconds or longer in a row, than this could result in a system error larger than 50 MW, for more than 30 seconds in a row.
- During normal operation (without a large incentive or signal to ramp), the error would be less than 0.5 MW for the potential 28 GW of EV engaged and V2G in the UK system.
- Additionally, meter accuracy error would be less than 0.3 MW.

When the whole population ramps at the same time the error density shifts to the right, in the scenario analysed this results in ~1% error

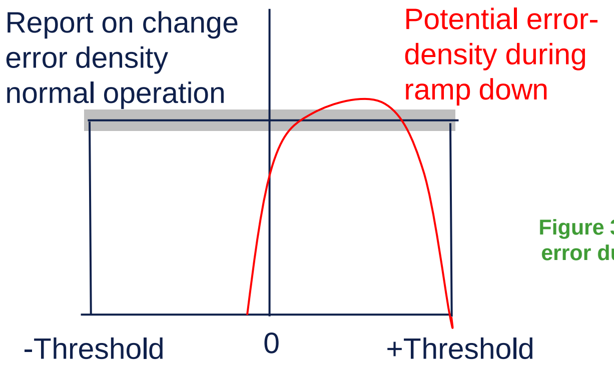


Figure 3.2 – Shifting of asset error during ramping events

Event-driven reporting for EVs - An exemption for inactive assets could reduce data costs

Exempting EV chargers which are not plugged into a vehicle from sending meter updates could reduce data costs by between ~65% to ~82% and should be considered despite concerns over technology agnostic regulations.

Whilst implementing report-on-change based on power thresholds would likely require significant development, it may be possible to reduce communication and cloud costs by allowing an exemption for EV chargers which are **not plugged into a vehicle** from providing updates. This is distinct from report-on-change as previously discussed during this project, which would require EV chargers to send meter updates more frequently **when the vehicle is charging**.

User behaviour varies widely, but average plug-in periods are usually around 12 hours, twice a week. One respondent indicated that their chargers are connected 27% of the time on average across their portfolio. The predicted costs for chargers connected 27% of the time are displayed to the right. However, it should be noted that additional costs would be incurred corresponding to a lower frequency ‘heartbeat’ communication, allowing confirmation that an unconnected uncommunicative charger is operating correctly, rather than non-operational.

Another possible solution would be to implement event-driven reporting such that chargers are only required to report at increased frequency when a vehicle is charging or discharging, with aggregators utilising the heartbeat communication to track the number of available resources within their current portfolio. This would further reduce costs compared to the original report-on-change light. One respondent indicated that their chargers spend 9% of their time charging on average, for which the cost is also calculated in the table to the right.

Depending upon the chosen heartbeat frequency, implementing event-driven reporting could result in savings of ~65% when reporting plugged in vehicles and ~82% when reporting only charging vehicles assuming aggregators are sending a heartbeat every 5min.

This exemption would be specific to EV chargers, since no other CER technology has an equivalent disconnected state where there is no possibility of change in power, therefore given that the requirement is not technology agnostic, consideration needs to be given to whether this can be implemented ahead of the development of a more generally applicable report on change solution. Despite that the solution not being technology agnostic, it does not make sense to require EV chargers which are not plugged in to send meter updates, it causes unnecessary costs and carbon emissions, creates barriers to entry for the most mature CER asset class, and the resulting cost is likely to passed to consumers.

Mobile Data and Cloud costs for 1000 devices without and with an exemption for inactive assets

- **1000 assets = 7 MW EV portfolio, chargers connected 27% of the time on average, chargers connected and charging 9% of the time on average.**

	Metric	1 sec	5 sec	15 sec	30 sec
No exemption for inactive assets	Mobile Data Cost, Total per Month	£14,892	£7,867	£5,492	£5,492
	Cloud Cost, Total per Month	£1,945.81	£1,842.01	£184.04	£184.04
	Total Cost per Month	**£16,838**	**£9,709**	**£5,676**	**£5,676**
Exemption for inactive assets (plugged-in)	Mobile Data Cost, Total per Month	£4,020.84	£2,124.09	£1,482.84	£1,482.84
	Cloud Cost, Total per Month	£525.37	£497.34	£49.69	£49.69
	Total Cost per Month	**£4,546.21**	**£2,621.43**	**£1,532.53**	**£1,532.53**
Exemption for inactive assets (Plugged-in & charging)	Mobile Data Cost, Total per Month	£1,340.28	£708.03	£494.28	£494.28
	Cloud Cost, Total per Month	£175.12	£165.78	£16.56	£16.56
	Total Cost per Month	**£1,515.40**	**£873.81**	**£510.84**	**£510.84**

Table 3.2 – Estimated mobile data and cloud costs

Event-driven reporting is mostly feasible for existing EV chargers and could be implemented quickly

Respondents indicate that the majority of chargers would be capable of implementing event-driven reporting with an over-the-air firmware update.

EV charger capability: Modern EV chargers support both event-driven and interval-based telemetry, with many capable of detecting when a vehicle is plugged in and adjusting reporting behaviour accordingly. This is typically managed via OCPP configurations, allowing telemetry intervals to be set based on connection status. Most modern chargers now support this as standard functionality.

Implementation: Implementing “event-driven reporting ” or “report on change” (RoC) for EV chargers is generally low-cost when using OCPP-compliant devices, as it typically involves simple configuration changes. For chargers using proprietary protocols, the cost may be higher due to the need for custom integration or architecture update. Most OEMs support over-the-air (OTA) firmware updates, making it feasible to enable such features remotely without technician visits, unless hardware changes are required.

Data Costs: The main costs associated with EV charger data handling are communications and data storage. Communication costs are primarily relevant for chargers using 4G mobile networks, where regular data transmission can lead to higher monthly or annual expenses. Among these, the ongoing data transfer costs—rather than upfront setup—are the dominant factor. Wi-Fi costs tend to be considerable negligent compared to 4g mobile costs. Data storage costs can become significant depending on how long the data is retained, especially when large volumes are ingested into cloud systems. While architectures vary across manufacturers, cloud ingestion and storage are typically the most substantial cost drivers.

Data meter access: Aggregators may interact with EV chargers either directly or indirectly, depending on the setup. When connected via OCPP, the aggregator can communicate directly with the charger to gather data. However, in many cases, data is first routed through the OEM’s cloud platform or a third-party server and then passed on to the aggregator. In such scenarios, the aggregator may incur data access costs depending on the OEM’s infrastructure and commercial arrangements..

Considerations for OM requirements:

Assessing EV Charger Capabilities and Compliance: NESO may wish to carry out an analysis of the national EV charging status quo to determine what proportion of chargers are capable of implementing the proposed methodologies, and consequently, what percentage may be excluded. To support this, it is recommended that a Proof of Concept (PoC) be conducted to test charger capabilities and establish a framework for compliance monitoring. It is anticipated that the majority of new charger installations will support report-on-change light functionality, resulting in a growing share of compatible chargers over time.

Incentives: Given report-on-change light enables lower MR intervals to be financially viable especially for aggregator with event-driven chargers, it should a big incentive for the aggregators with existing capabilities to implement.
In addition, NESO may consider introducing mechanisms to encourage such implementation. This could involve implement financial controls that reflect the cost savings associated with reduced risk from lower latency or actively engaging with the wider industry to raise awareness on such requirements.

RoC and Event Driven Reporting have the lowest impact on control room

Assuming 1s metering when reporting, the metering quality provided by RoC would be similar the current requirements

Risk Envelope

- Lowest impact on CR because data OM quality is maximised:
  - Assuming 1s meter read interval, maximum lag in aggregated signal is 0.5s
  - Assuming chargers at higher MeterRead (e.g. 1s) are on reporting when plugged in/charging for event driven reporting
  - Chosen threshold value introduces some additional uncertainty into meter read signal for RoC reporting

Market liquidity / visibility

- Not all assets will be available to report on change or event driven charging which will have impact on CER visibility and ENCC access to balancing resources. This is of particular concern for Heat Pumps and potentially Solar PV (although rooftop solar PV is not expected to be BM registered in the foreseeable future).

Financial Impact

- Small to no requirement for additional Reserve and Response
- Small to no investment in NESO IT Systems, implementation costs are likely to be borne primarily by aggregators

3.1.2 Option 2 – Use delayed CER OMD as real-time data, mitigate by setting new requirements at the asset level

Introduction to Option 2 - Use delayed CER OMD as real-time data, mitigate by setting new requirements at the asset level

This option introduces an error into NESO systems relying on operational metering data, even when CER BMUs follow their PN/BOA. Impacts could be reduced by setting a maximum allowed meter read interval, or by setting an accuracy requirement

Use delayed CER OMD as real-time data

Under this option the current view of Operational Metering (OM) data as reflecting real-time data is maintained, the OM feed from the CERs is considered to to reflect the real-time situation and the delay induced by the meter read interval of the CER assets is considered to be an error which appears during ramping periods. This error is input into NESO systems and affects decision making, irrespective of whether the CER BMU is following it's PN/BOA.

To mitigate the impact of this error two alternative appraches could be considered: define an acceptable meter read inteval which reduced the delay in the signal, or set an accuracy requirement which considers both the induced delay in the signal and the ramp rate of the assets (which combine to produce the actual impact seen in the control room). These two options and their variations are described below in options 2 a-c, and 2d respectively.

Option 2: mandate either a maximum meter read interval of:

2 a: 30s; **2b:** 10s; **2c:** 5s

2d: Set an accuracy requirement: NESO would mandate an accuracy requirement as a % of the portfolio nameplate capacity, which aggregators could comply with by limiting ramp rate according to MR capability

Option 2a/b/c: relaxing the 1s MR interval is needed otherwise CERs not be visible to NESO (or participate in BM)

Despite the need to relax the 1s MR interval, even the 5s MR interval is not compliant with the NESO risk profile in 2035. Increasing the meter read interval increases both the number and magnitude of risk profile exceedances

Table: Summary of modelling results for Holistic Transition scenario including all CERs (EV, V2G, Heat Pumps, Solar, Home BESS) at three meter read intervals (5s, 10s, 30s). 60s was not modelled since the 30s results already significantly exceed NESO risk tolerances.

Meter Read Interval	Risk Profile		(with EV and V2G randomised)			(EV and V2G non-randomised)		
Meter read Interval	Risk profile error duration	Risk profile error threshold	Minutes per year where threshold is exceeded	Highest Error	Highest error excluding 100 most extreme minutes	Minutes per year where threshold is exceeded	Highest Error	Highest error excluding 100 most extreme minutes
5 seconds	1s	1800 MW	0	500 MW	250 MW	1080	9170 MW	6430 MW
	5s	300 MW	0	400 MW	200 MW	2260	3030 MW	2130 MW
	30s	50 MW	3400	115 MW	115 MW	1060	2760 MW	890 MW
	(1s, 5s, 30s, combined)	-	3400		-	2770		-
10 seconds	1s	1800 MW	0	697 MW	350 MW	1660	12190 MW	8520 MW
	5s	300 MW	100	603 MW	300 MW	3980	7580 MW	5290 MW
	30s	50 MW	7500	149 MW	149 MW	1550	74 MW	1440 MW
	(1s, 5s, 30s, combined)	-	7960		-	4680		-
30 seconds	1s	1800 MW	0	1700 MW	900 MW	2220	14330 MW	10560 MW
	5s	300 MW	6000	1680 MW	840 MW	6030	13180 MW	9470 MW
	30s	50 MW	30000	690 MW	690 MW	21000	5080 MW	4500 MW
	(1s, 5s, 30s, combined)	-	30000		-	22300		-

Table 3.3 – Risk exceedances and highest error for various meter read intervals

The exceedances per year are split into the three risk profile time durations we have looked at previously (1800MW for 1s, 300MW for 5s, 50MW for 30s).

Minutes are not double counted in the combined category.

I.e. If the same minute that experiences a 30s duration error also experiences a greater magnitude 5s error this minute is counted only once in the combined row.

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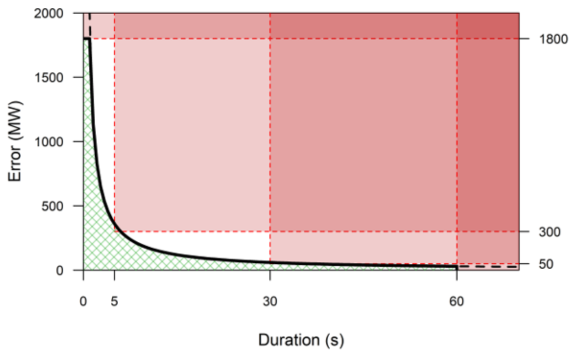
Option 2d: setting an accuracy requirement for MR interval is a balance between NESO Risk Tolerance and limiting CER capability

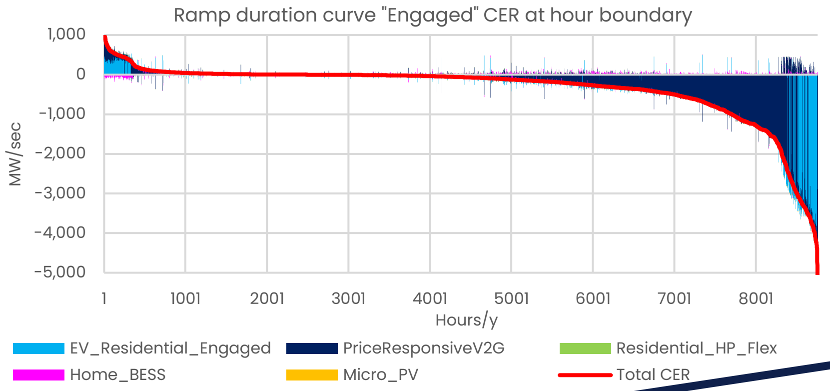
The MR accuracy requirement is determined by three broad factors, changing any of the factors shifts the balance of the other two

Factors

1. NESO Risk Tolerance (acceptable error from all CER)



2. Overall capacity and largest expected swings of CERs sending metering (cannot be influenced)



3. CER ramp rate and meter read interval capability (which combine with 2. to result in error of x magnitude and y duration)

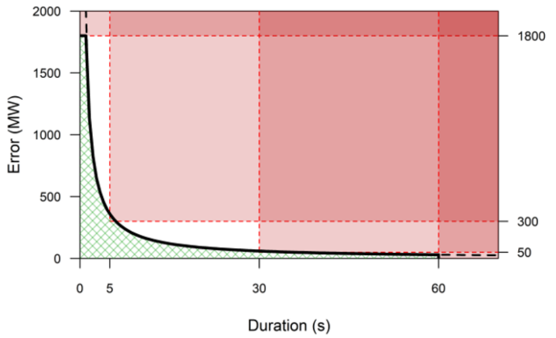
CER MR Accuracy Requirement

Figure 3.3 – The three main factors determining CER MR Accuracy Requirement

2d: The MR accuracy requirement is determined by the risk tolerance and the largest expected CER swing

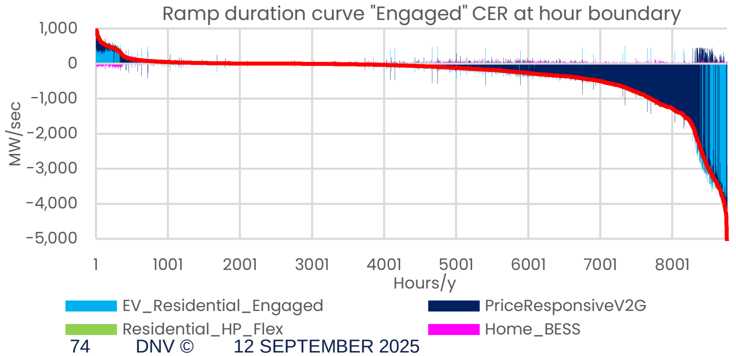
Based on worst case scenario modelling outcomes for 2035, the MR accuracy requirement needed to remain within NESO risk profile is determined. CER performance (ramp rate and meter read interval) is constrained by the MR accuracy requirement

1. NESO Risk Tolerance (acceptable error from all CER)



Determines

2. Overall capacity and largest expected swings of CERs sending metering and part of the BM (cannot be influenced)



Determines

CER MR Accuracy Requirement

Constrains

3. CER ramp rate and meter read interval capability
(which combine with 2. to result in error of x magnitude and y duration)

- The impact on control room from CER metering is directly related to the meter read interval, the ramp rate, and the size of the CER swing.
- The size of the CER swing is limited by the maximum capacity of CER on the system, whilst the meter read interval and ramp rate of the CER are within the control of aggregators.
- The maximum CER swing will increase in future as more CERs enter the system and become controllable.

Figure 3.4 – Determination of constrained factors because of the CER MR Accuracy Requirement

2d: The MR accuracy requirement at the system level determines a maximum error allowed per portfolio

The MR accuracy requirement at the system level translates to the same requirement at the portfolio capacity, the MR accuracy requirement is defined as a percentage of nameplate capacity

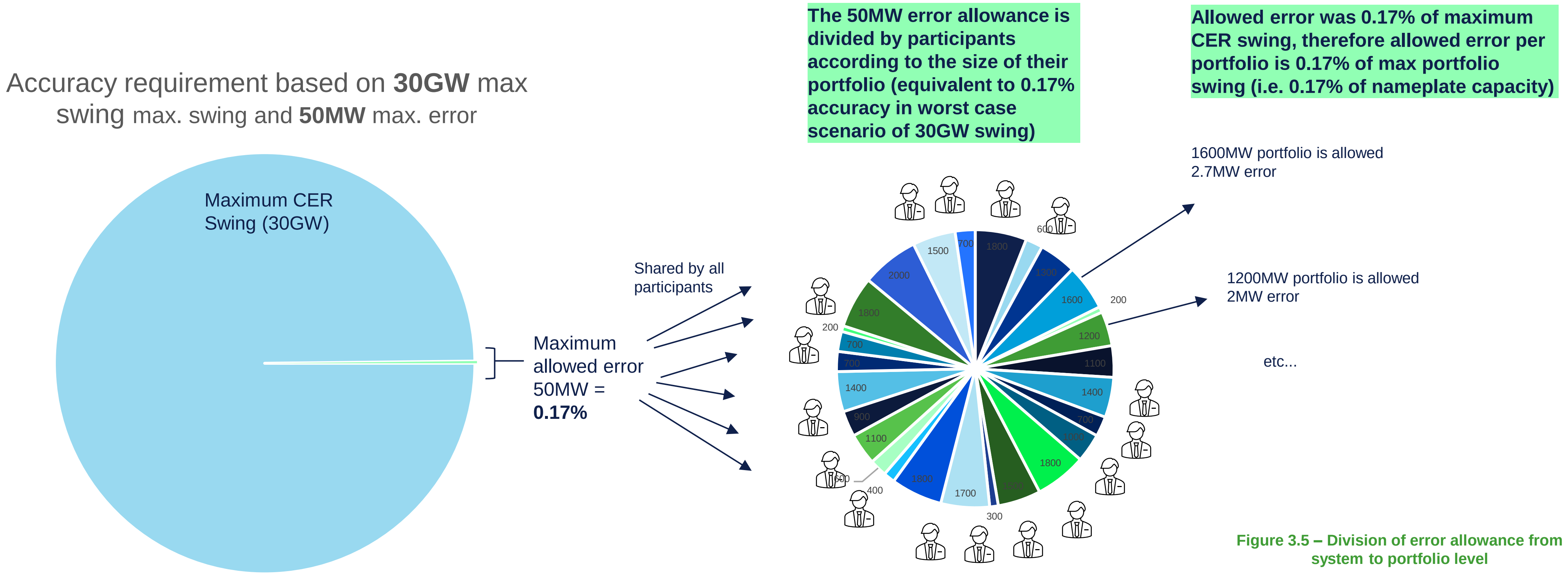


Figure 3.5 – Division of error allowance from system to portfolio level

$$Accuracy\ requirement\ [as\ \%\ of\ portfolio\ capacity] = \frac{Total\ Acceptable\ System\ Error}{Maximum\ CER\ Swing}$$

Aggregators must stay within their maximum allowed error and have flexibility in how to comply

Aggregators know their maximum allowed error, and determine the maximum ramp rate based on the meter read capability

Aggregators can choose either of the following strategies to stay within their maximum allowed error:

- Use assets with faster meter reading capabilities and ramp up power more quickly
- Use assets with slower meter reading capabilities but ramp up power more gradually

The simplest way to comply is to adjust the ramp rate depending on the meter read capability of the assets:

$$Ramp\ Rate\ \left[\frac{MW}{sec}\right] \leq \frac{2 * Allowed\ Portfolio\ Error\ (MW)}{MR\ (s)},$$

This formula is derived from the timelag of aggregated meter signals with a meter read interval >1s. The meter signal has a timelag of $\left(\frac{MR}{2}\right)$ seconds behind the actual power of the portfolio. The faster the portfolio changes in power the larger the discrepancy between actual power and metered power.

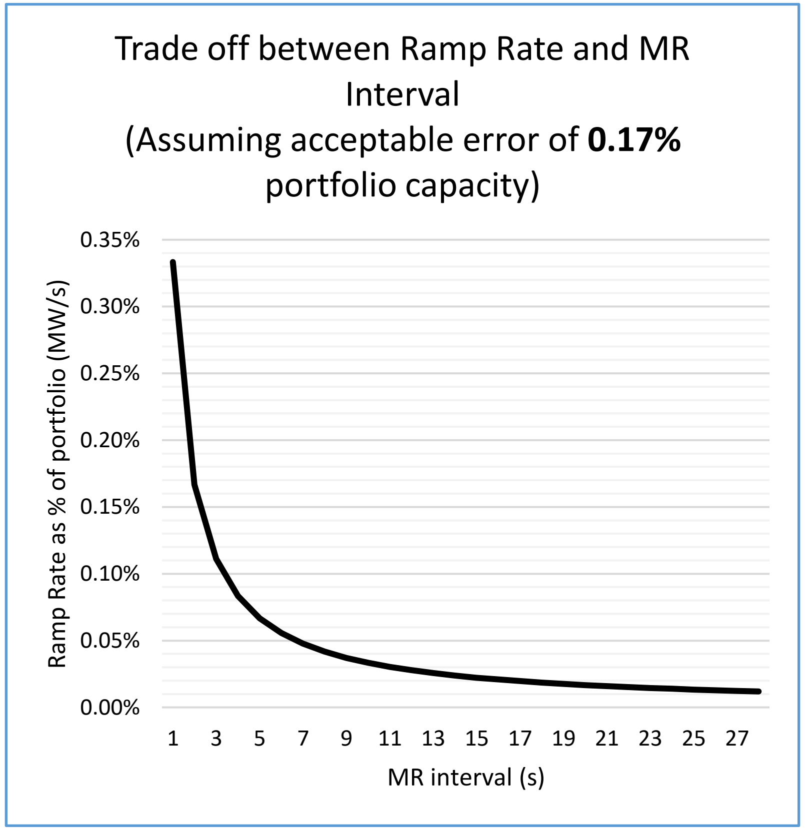


Figure 3.6 – Trade off between ramp rate and MR interval

As the meter read interval increases (x-axis), the maximum allowable ramp rate (y-axis) must decrease to maintain acceptable metering accuracy

The NESO risk tolerance is too restrictive for an accuracy requirement to be practical in 2035

Aggregators know their maximum allowed error, and determine the maximum ramp rate based on the meter read capability

- The NESO risk profile has a maximum error of 50MW for 30s duration. Although the risk profile allows higher error for shorter durations, in practice market participants need to be provided with a clear accuracy requirement so the lowest acceptable error for any duration must be used. Also, since complying with the accuracy requirement involves limiting the portfolio ramp rate, spreading the error over a longer ramp time, the 50MW for 30s limit becomes the most likely risk profile to be breached.

- To stay within the NESO risk profile based on 2035 population of CERs from Holistic Transition, even with a 5s meter read interval, the 50MW maximum error would result in portfolios taking nearly 30 minutes to ramp up and down. This situations is unlikely to be acceptable to aggregators since it is highly restrictive in their ability to ramp portfolios, it is more restrictive than the current 10-minute randomisation for EVs scheduled in the wholesale market and would penalise consumers who offer flexibility since their assets could take up to 30 minutes to activate.

- Furthermore, such a restriction significantly reduces ENCC's ability to balance the system by deploying fast responding portfolios.

Example 1: System with **15GW** max CER swing and **50MW** max. system MR error (= 0.33% accuracy requirement)

BMU= 100 MW, 10 second meter read interval

Portfolio error limit = 100*0.33% = 0.33MW

$Ramp\ Rate \left[\frac{MW}{sec}\right] \leq \frac{2*0.33\ MW}{10\ sec}$ = the portfolio must ramp at ≤ 0.066MW per second

If the whole portfolio is ramped up, it takes 1515 seconds (25.3 minutes).

Example 2: System with **30GW** max CER swing and **50MW** max. system MR error (= 0.17% accuracy requirement)

BMU= 500 MW, 5 second meter read interval

Portfolio error limit = 500*0.17% = 0.85MW

$Ramp\ Rate \left[\frac{MW}{sec}\right] \leq \frac{2*0.85\ MW}{5\ sec}$ = the portfolio must ramp at ≤ 0.34MW per second

If the whole portfolio is ramped up, it takes 1471 seconds (24.5 minutes).

Derivation of equations

The accuracy requirement for a given Risk Profile (total acceptable system error) is found by:

$$Accuracy\ requirement\ [as\ \%\ of\ portfolio\ capacity] = \frac{Total\ Acceptable\ System\ Error}{Maximum\ CER\ Swing}$$

The allowed portfolio error for a given accuracy requirement is found by:

$$Allowed\ Portfolio\ Error\ [MW] = Accuracy\ requirement\ [as\ \%\ of\ portfolio\ capacity] \times Portfolio\ Capacity[MW]$$

The latency "timelag" caused by meter read interval is found by:

$$\text{timelag} = \frac{MR\ interval}{2}$$

The ramp rate to comply with the accuracy requirement is found by:

$$Ramp\ Rate\ \left[\frac{MW}{sec}\right] \leq \frac{2*Allowed\ Portfolio\ Error\ (MW)}{MR\ (s)}$$

Use delayed CER OMD as real-time data has the highest impact on control room

Use delayed CER OMD as real-time data always results in the error propagating into NESO systems, even when CERs are following BOA / PN. Setting a MR interval higher error impact on ENCC but offers improved liquidity in the BM and better quality resources for system balancing

2a / 2b / 2c. Setting a maximum MR Interval

Risk Envelope

- NESO risk tolerance will be breached often in a 2035 Holistic Transition type scenario, even with a 5s meter read interval. CR might take wrong decisions due to delays in CER OM data.
- Use delayed CER OMD as real-time data always results in the error propagating into NESO systems, even when CERs are following BOA / PN.

Market liquidity / visibility

- setting a 30s maximum MR interval will present minimal barriers to aggregators, improving visibility in the BM and access to resources

Financial Impact

- Incorrect CR actions due to CER meter errors will be mitigated by increased reserve and response, resulting in additional balancing costs to consumers. Likely very high cost given large magnitude of errors which could be expected in future.

2d. Setting an accuracy requirement & limiting ramp rates

Risk Envelope

- An accuracy requirement could be set to maintain errors within the tolerance, but this would not be practical for the reasons below.
- Treating as an error always results in the error propagating into NESO systems, even when CERs are following BOA / PN.

Market liquidity / visibility

- An accuracy requirement and ramp limits which complies with NESO’s risk tolerance would be highly restrictive on aggregators if it is set based on expected 2035 risks with high CER penetration. This would supress market liquidity and visibility of CERs.
- Ramp rate limits reduce ENCC access to fast responding assets to balance the system

Financial Impact

- There would be an increased reserve and response requirement, though much lower in comparison to setting a maximum MR interval.
- Reduced access to fast responding balancing resources could increase cost of system balancing

3.1.3 Option 3 - Consider delay in CER OMD, invest in systems to mitigate risk

Introduction to Option 3 - Consider delay in CER OMD, invest in systems to mitigate risk

This option relies mainly on upgrading NESO/Aggregators systems to mitigate the impact of lag in CER meter feeds

Consider delay in CER OMD: Under this option the current view of OM data as reflecting real-time data is overturned – at least for CERs. The value of the OM feed from the CERs is to provide insights and control to the lowest voltage levels is considered to outweigh the cost of accepting a meter feed which has a delay of up to 30 seconds.

3a

Requirement on aggregator to:

1. Add a timestamp to the outgoing meter packets, and provide the average meter read interval of the portfolio to NESO.

Investment in NESO systems:

1. Create a synthetic meter feed (forecast) based on BOA, PN, and historical meter data, use this data where required for real-time decision making.

2. Once the true meter signal is received, use the timestamp and average MR interval of the portfolio to check how closely the portfolio followed the synthetic meter feed. Adding new requirements to enable data in downstream systems (e.g. demand predictor) to be updated with the corrected values to ensure that any discrepancies do not propagate.

3b

Requirement on aggregator to:

1. Construct the synthetic meter profile and send this to NESO

2. Timestamp and send the (delayed) operational metering feed alongside the synthetic feed, which enables NESO to verify the accuracy of the synthetic feed

Investment in NESO systems:

1. Once the true meter signal is received, use the timestamp and average MR interval of the portfolio to check that how closely the portfolio followed the synthetic meter feed. Adding new requirements to enable data in downstream systems (e.g. demand predictor) to be updated with the corrected values to ensure that any discrepancies do not propagate.

Option 2 and Option 3 take different approaches to the challenge of meter lag in aggregated portfolios

For both Option 2 and Option 3, there is a delay of approximately 15 seconds in the meter feed received from the FSP. Information about non-compliance (under/over-delivery) will reach NESO late in all cases. The difference in alternatives is the way NESO reacts to this delay.

Situation	**Option 2** **NESO uses delayed CER OMD as if it is real-time data.** OMD is considered to reflect the real-time situation, introducing an error in the data during ramping periods.	**Option 3** **NESO takes account of the inherent delay from meter read interval and latency, and attempts to mitigate it.** OMD is time-stamped, NESO / Aggregator estimates the real-time OMD based on available data (OMD, PN and BOA)
BMU following BOA / PN	Option 2 always performs worse than Option 3 because OMD **always** shows under-delivery, error is **always** propagated to demand predictor and other systems.	Option 3 performs better than Option 2 in most cases, because the estimated meter feed is used in demand predictor and other systems no error is propagated, **provided the forecast is accurate.**
BMU not following BOA / PN	In this scenario for the first 15 seconds Option 2's delayed meter feed probably results in more accurate data than Option 3's estimated meter feed. However, whilst the Option 2 meter feed is more accurate in this case (it correctly shows under/over-delivery) it still has a 15 second delay which propagates into NESO systems.	In this scenario Option 3's estimated meter feed (depending on how it is constructed) will likely show that the BMU is performing to its BOA/PN when in fact it is not. The discrepancy can be identified after 15 seconds, at which point NESO can decide whether to fall back to the Option 2's standard meter feed with its 15 second delay.

Table 3.4 – Option 2 vs Option 3

Option 3a: suggested method 1 for synthetic profile/value:

Use BOA or PN as OMD in the first 15/30 seconds and correct when delayed OMD is available (i.e. after MR interval/2 seconds)

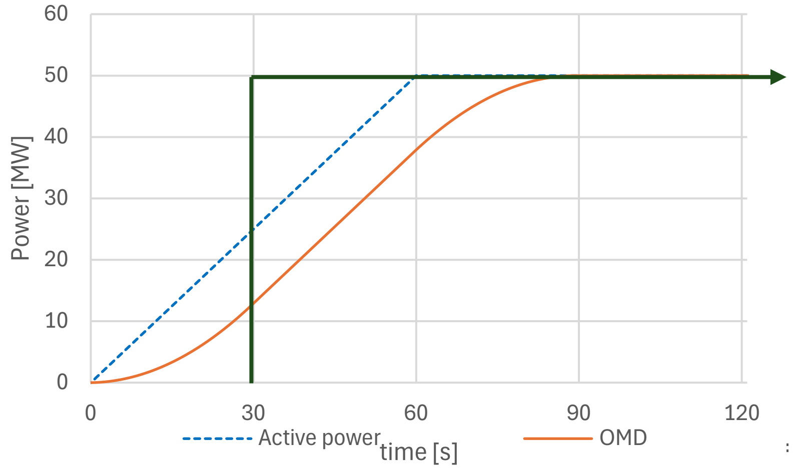
The method below could be used to construct the synthetic meter feed for real-time systems

Assumptions	Meter read interval is 30 seconds (every second 3% of meters is read) FSP sends aggregated meter data, NESO creates estimate based on OMD and PN or BOA. Ramping period starts at T_0 Aggregators submit PN/BOA which factors in average time for portfolio to ramp up/down
Input	OMD (received at time T), including timestamp (T-15) (with a 30 second interval, the aggregation of all meter data at time T represents the physical situation at T-15).
Required Output	OMD estimate at time T (real-time): OMD_{est}.
Method	If T – T0 < 15: $OMD_{est}(T) = PN(T)$ Else: $OMD_{est}(T) = PN(T) * OMD(T-15) / PN(T-15)$
Alternative method to estimation	Based on the delay that is communicated by the Aggregator (through timestamping), NESO shifts the BOA/PN by the same delay by comparing OMD(T-15) with BOA(T-15) (or PN(T-15)). The calculated difference is considered the difference in real-time (thus propagated to the ST forecast).

Example 1 – FSP delivers according to BOA / PN

If the delay in the meter feed is treated as an error NESO systems will always be impacted

Treat as an error



30 seconds after ramping started, OMD shows an error/deviation of 15MW.

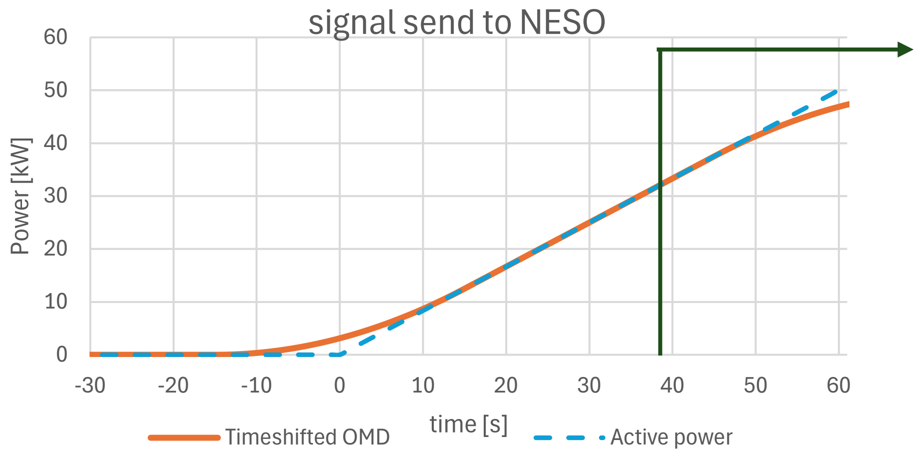
This error is propagated to the demand predictor. Assuming the demand prediction was balanced, this will trigger an additional 15MW balancing power to be activated, which is unnecessary.

Additional fast reserves are needed to absorb the 15MW imbalance that is caused.

Only 30 seconds after the ramping ends, OMD is accurate again.

This problem occurs for all FSPs (that follow their BOA), for the full ramping period.

Do not treat as an error



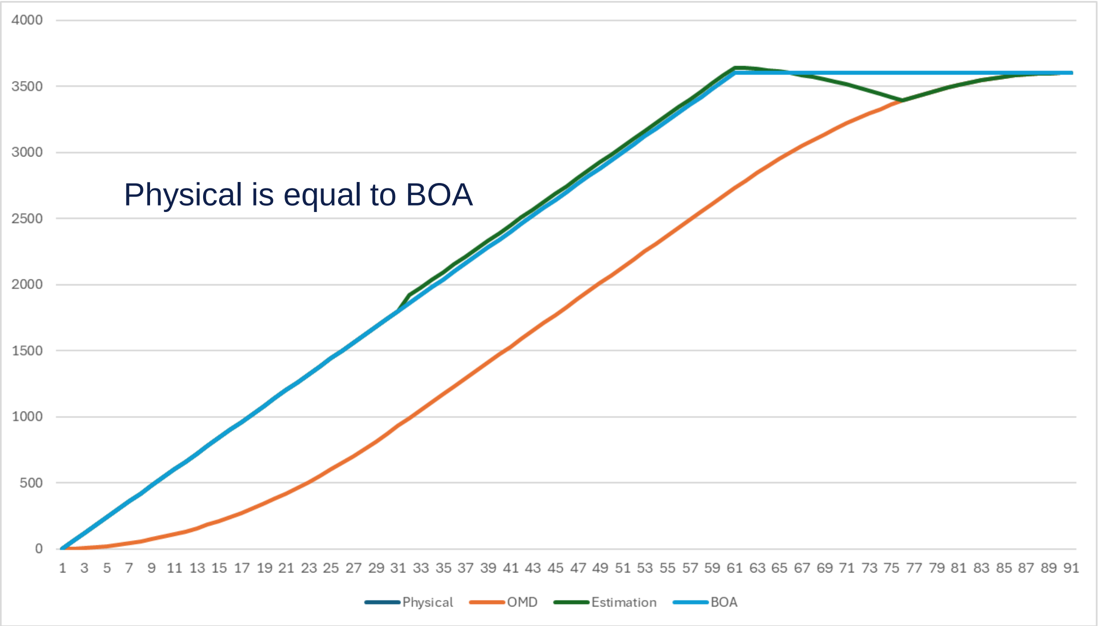
Throughout the ramping period, incl. 30 seconds after ramping started, the synthetic OMD is accurate.

Little error is propagated to the demand predictor. No additional (unnecessary) balancing power is activated.

Figure 3.7 – Impact of treating meter feed delay as error

Example 1- Performance of estimated OMD vs. delayed OMD when aggregator follows BOA

Based on ramping period of 60 seconds



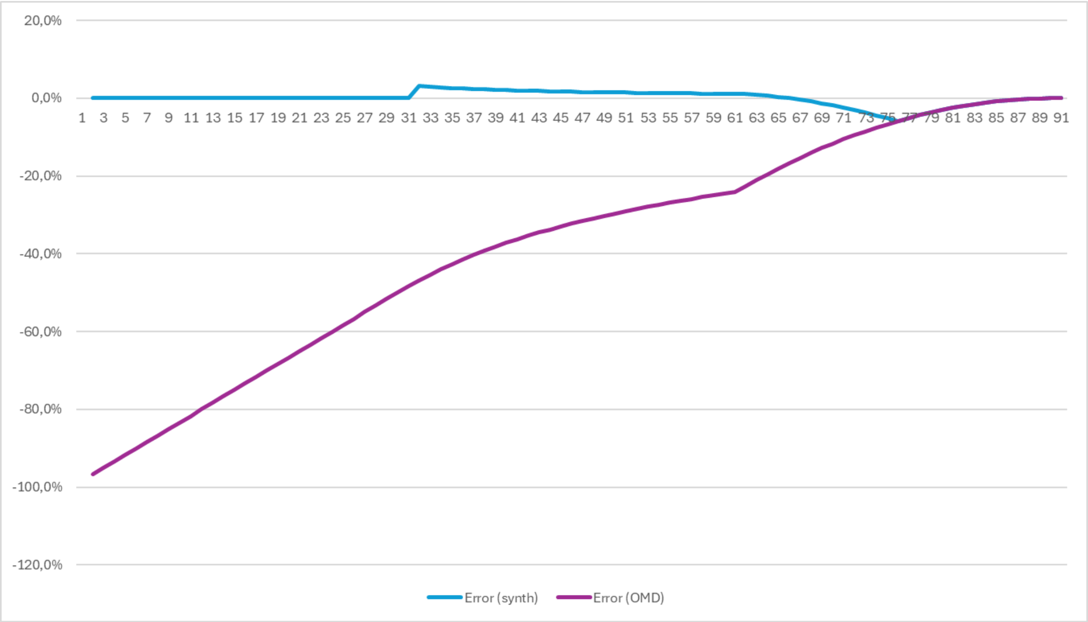


Figure 3.8 –Performance of estimated OMD vs delayed OMD when aggregator follows BOA

Estimation strongly outperforms the delayed OMD

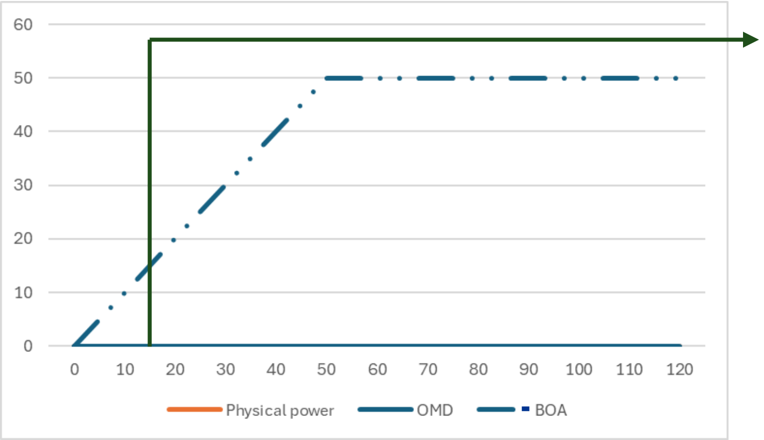
- Largest error in estimation occurs after ramping has just started or ended (further enhancement is conceivable using more advanced estimation method)
- Error in delayed OMD is very large, throughout the ramping period.

Example 2 – FSP does not deliver according to BOA / PN or the synthetic meter feed is inaccurate

In case the FSP does not deliver according to the BOA / PN, or the synthetic meter feed is inaccurate, the normal OMD performs best

FSP fails to deliver

Treat as an error

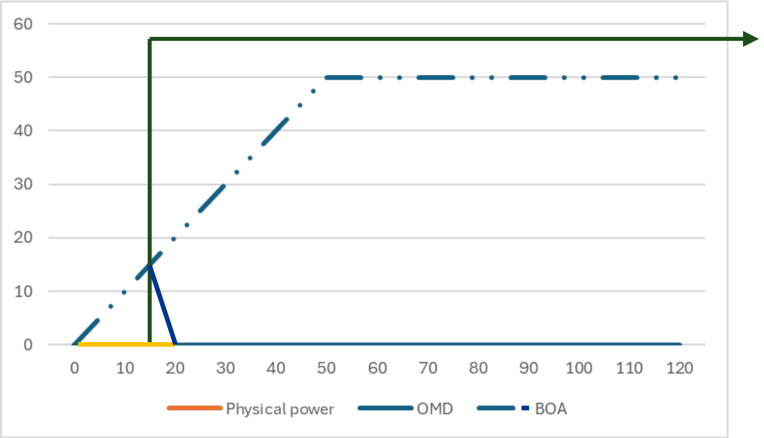


15 seconds after ramping started, OMD still shows 0. In this case OMD is equal to the physical state. When the portfolio is only partly responding, an error is introduced, relative to the part that has been activated.

This (smaller) error is propagated to the demand predictor. Assuming the demand predictor forecast was balanced, this may trigger additional balancing power to be activated, which is unnecessary.

In this (extreme) case of a portfolio not responding at all, the OMD is equal to the physical power. In general, it will show a smaller error than synthetic data, during the first 15 seconds.

Do not treat as an error



During the first 15 seconds an error is introduced. The synthetic OMD will be largely based on the BOA / PN, which is not met. This error will be propagated to the demand predictor, and additional (unnecessary) balancing power may be activated, if this is instantaneously decided.

However, within 15 seconds, it becomes clear that the portfolio is not following the BOA / PN. The synthetic OMD can be updated with real data, this will reduce the error that was introduced.

This problem occurs only for the FSP not meeting their BOA / PN, and only for the first 15 seconds.

This period could even be shorter when the FSP creates the synthetic profile.

Figure 3.9 – Impact of FSP failing to deliver

Example 2 – Performance of estimated OMD vs. delayed OMD when aggregator delivers only ¼ of BOA

Performance of the suggested method for calculating the synthetic profile

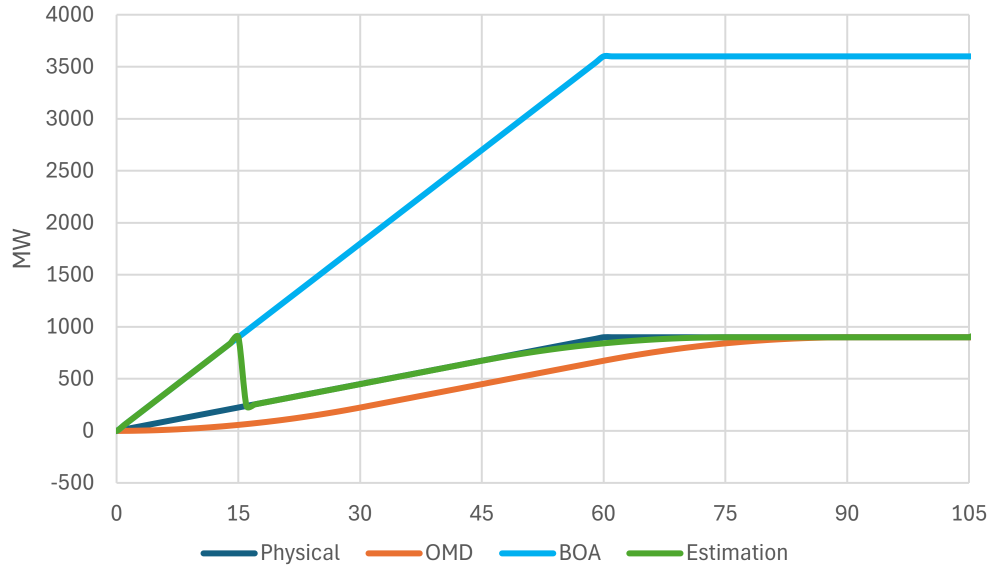


Figure 3.10 – Performance comparison of synthetic profile

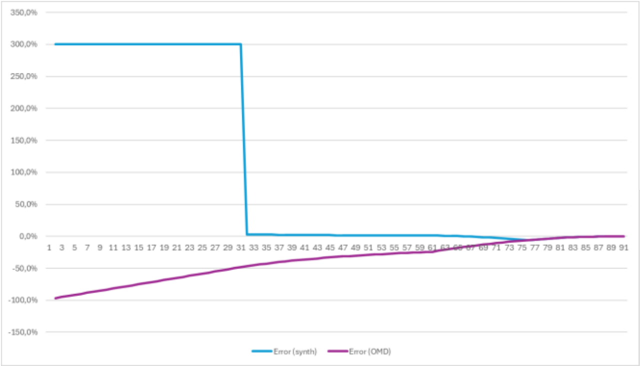
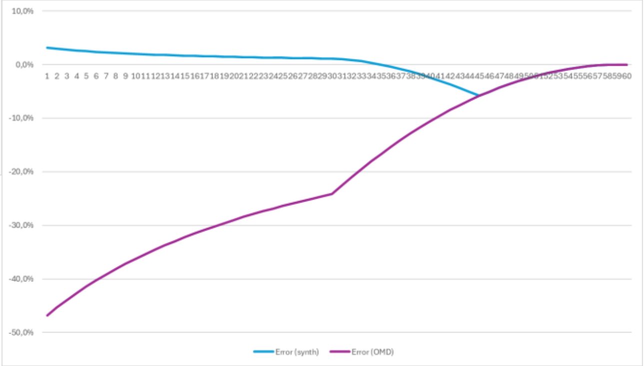


Figure 3.11 – Full period

Figure 3.12 – Period excluding first 15 seconds



Delayed OMD outperforms the estimation the first 15 seconds

- Further enhancement for estimation is conceivable using more advanced estimation method for the first 15 seconds

Estimation strongly outperforms the delayed OMD after the first 15 seconds, throughout the remainder of the ramping period.

- Error in OMD is very large, throughout the ramping period.

Considerations

While the overall average performance across the ramp may improve, several important considerations remain:

- BOA Non-Compliance Risk: If a unit fails to follow its PN/BOA, this methodology can perform worse than using delayed OMD especially during the initial 15-30 sec. MeterRead. An incentive mechanism should be established to encourage the submission of accurate static data e.g.PN, ramp rates
- Demand Predictor Sensitivity: The control loop in the demand predictor operates continuously, ingesting OMD data to inform forecasts and control room decisions. Errors at any point can propagate through the system, introducing additional risk into the balancing process. This would require additional reserve and response.
- Algorithmic Estimation Challenges: Using an algorithm to estimate metered reads can introduce further complexity. Estimation method should be carefully chosen supported by an incentive mechanism should be established to encourage the quality meter data

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Option 3b: suggested method 2 for synthetic profile/value: Adjusted aggregate metering (ramp adjusted correction)

The aggregate meter signal is adjusted to correct for error resulting from meter read lag (more detail in WP3 report)

Solution Option	Metering Basis	Description
Adjusted aggregate metering (ramp error correction)	Real measurements plus extrapolation of the latest (aggregated) measured ramp rate	A weighted average smoothened ramp factor is added to the aggregate meter signal, this compensates for error from readinterval, especially during ramping. This adjustment is based on the change in aggreged portfolio power in the previous x seconds (2.5-15 seconds was analysed during our study, depending on readinterval). The above approach is one method to adjust the aggregate meter error, it is possible that other methods exist which might have better performance.

Table 3.5 – Summary of Option 3b

<u>Adjusted aggregate metering example</u>

Meter read interval = 5 seconds

Portfolio size = 10 assets

= asset meter updated this second

Aggregate meter reading = current sum + (smoothened ramp x timelag)

Smoothened ramp = ramp x (weights (1, 1/2) / sum of weights)

timelag = (meter interval - 1) / 2 = (5-1)/2 = 2 seconds

Adjustment calcuation for t=0

ramp	x	weights		sum (t=0, t=1)		smoothened ramp
t=0	2 x	(1) / (3/2)	=	0.66	+	
t= -1	2 x	(1/2) / (3/2)	=	1.33	=	2

sm'd. ramp	x	timelag	=	adjustment
2	x	2	=	4

	current sum	+	adjustment	=	current sum
Aggregated meter reading =	48	+	4	=	52

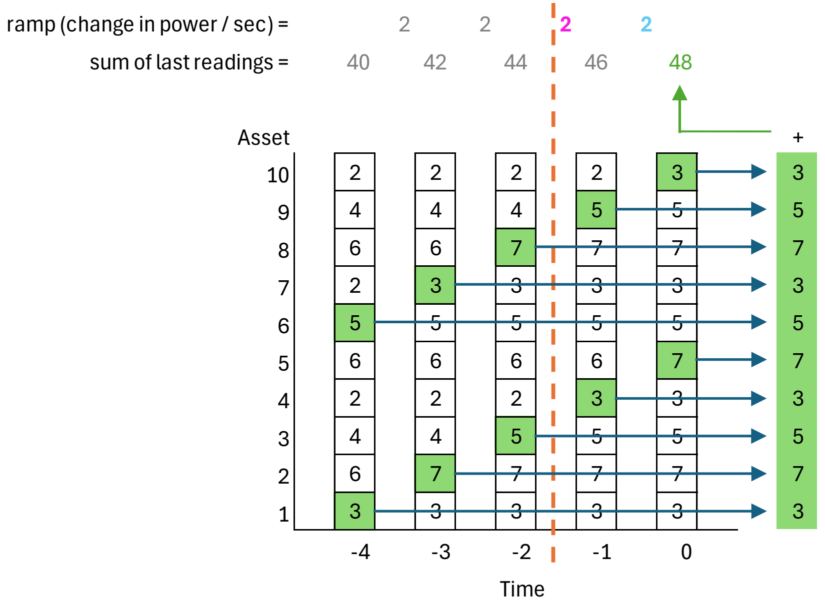


Figure 3.13 – Example of aggregate meter read adjustment

Synthetic meter profile methods performance

Best use cases, benefits and drawbacks

Use BOA or PN as OMD in the first 15/30 seconds and correct when delayed OMD is available (i.e. after MR interval/2 seconds).

Works best with:

- Large share CER, does follow BOA or PN
- Accurate BOA / PN prediction

Benefits

- Historic OMD are updated when accurate measurement is available (MR interval/2 second after realtime)
- In years when CER are still small, NESO can validate that aggregators send good enough PN's to work with this methodology, without a large impact.

Drawbacks

- If a large share of the metered CER don't follow their BOA, the methodology can be worse than the delayed OMD in the first half of the MR interval
- If communication is failing the estimated power (i.e. BOA/PN) is long not updated.
- Need to make sure that updating of the OMD is done in all systems that take historic (MR interval/2 seconds ago) into account.

Adjusted aggregated metering (ramp adjusted correction)

Works best with:

- Long portfolio ramptime relative to meter readinterval
- Gradual ramp-up/down

Benefits

- Small number of nonresponsive assets hardly increases the error as less activation will be reflected in the aggregated ramp up/down.
- Asset ramptime doesn't really matter, portfolio ramptime is the important parameter.
- Very small error during relatively stable portfolio operation (i.e. low changes in ramping up and down, so also during stable ramping up or down)

Drawbacks

- Requires good knowledge of portfolio average readinterval
- Quick changes in portfolio ramping up/down causes relatively large errors (ramp of ramp). Needs a full readinterval to fully catch up with ramp changes.

Risks for both synthetic adjustment methods

- Having algorithmic estimations in the real-time data can complicate the process and therefore more difficulty in interpreting the meter signal by the control room.
- Requires good knowledge of portfolio average readinterval by the aggregator, which he uses to assess the valid timestamp of OMD
- Potential to high sense of security as most error will be very low, while error do occur during start and end of ramping

DNV

“Consider CER OMD, invest in systems to mitigate risk”: the impact on control room depends on PN/BOA accuracy and synthetic profile accuracy

The impact is determined by how accurately the FSP follows their PN / BOA, and the ability of the synthetic profile to predict the beginning of the ramp within the minute granularity of the PN

3a (NESO construct synthetic meter profile)

Risk Envelope

CR have real-time estimate of CER behaviour, with any errors rectified within ~15-30 seconds. Wrong decision made only if synthetic profile is inaccurate, or CER does not follow BOA/PN.

Market liquidity / visibility

3a presents minimal barriers to aggregators beside timestamping outgoing data, therefore it is likely to maximise market liquidity and visibility of CERs.

Financial Impact

Financial impact (reserve and response) is determined by the accuracy with which CERs follow their BOA / PN, and the forecast accuracy of the synthetic meter profile (which in 3a is with NESO’s control). The financial impact should be lower than for Option 2 because situational awareness is only affected when CERs do not behave as expected, rather than being affected all the time.

3a likely requires the largest investment in NESO systems compared to all other options, since the capability to develop synthetic meter feeds, as well as to support two meter feeds per BMU, and switch between them depending on data quality, needs to be developed for operational metering and downstream systems.

3b (aggregator constructs synthetic meter profile)

Risk Envelope

CR have real-time estimate of CER behaviour, with any errors rectified within ~15-30 seconds. Wrong decision made only if synthetic profile is inaccurate, or CER does not follow BOA/PN.

3b is less transparent and as a result might impact NESO’s situational awareness, leading to incorrect decisions

Market liquidity / visibility

3b places more responsibility on aggregators, requiring them to invest in capability to construct the synthetic meter feed, however this is unlikely to be a significant barrier compared to the current requirements.

Financial Impact

Financial impact (reserve and response) is determined by the accuracy with which CERs follow their BOA / PN, and the forecast accuracy of the synthetic meter profile (which in 3b is not within NESO’s control). The financial impact should be lower than for Option 2 because situational awareness is only affected when CERs do not behave as expected, rather than being affected all the time.

3b is likely similar to 3a in the investment needed in NESO systems. Although developing the synthetic meter feed is the responsibility of the aggregators, investment may be needed in validation of aggregator synthetic metering.

DNV

3.2 Alternative methods to manage impact or gain visibility

The Grid Code and updated processes provide a mechanism to gain visibility outside of Operational Metering Requirements

Implementation of visibility requirements in the Grid Code could be considered for assets not wanting to participate in the BM

The Grid Code already contains requirements for meter data submission for non-BM registered assets e.g. License Exemptible Embedded Medium Power Stations (LEEMPS) are required to submit meter data to DNOs every 1-minute. Similarly, the Grid Code stipulates ramp limits for interconnectors and Type C and D Generators. Similar requirements could be introduced for aggregated CER portfolios to either increase visibility or reduce the impact of ramping.

- The Grid Code could be modified to include requirements for CERs which do not participate in the BM or other NESO markets to submit meter data as a solution to gain visibility for these assets. However, since there will be no commercial incentive to provide meter data (e.g. though BM revenue) it is unclear which party (aggregators, consumers, manufacturers, suppliers etc.) should be held responsible for ensuring that meter data is submitted and who would ultimately pay for the cost of data submission.

- Grid code limits on CER ramp rates are likely to be needed at some point in future to manage the risk of large CER swings affecting frequency stability, however NESO should consider ways to reduce the impact such restrictions may have on the ENCC’s ability to balance the system for instance by providing an exemption for portfolios responding to NESO or DNO instructions.

In addition, to improve operational forecasting accuracy and grid management, DNOs could submit granular and frequent forecasting data to NESO by transitioning from GSP group-level demand forecasting to hourly forecast on group supply point. Hourly forecasts could be submitted on Day-Ahead and Intraday updates:

- DNOs submit hourly annual and seasonal demand forecasts at the GSP (Grid Supply Point) group level, mainly through Week 24 process. This shift could enable better visibility of local demand patterns, support targeted flexibility deployment, and enhance coordination with the NESO for congestion management and balancing in line with DESNZ’s and NIC’s strategic recommendation on the need for a fit-for-purpose distribution network that can handle rising demand from electrification and decarbonisation.

4. Impact Assessment

Section Contents

Impact Assessment

In the previous section we identified possible metering options and their technical characteristics. We need to consider how these options affect system operation, cost, and scalability under different CER penetration scenarios.

In this section we use modelling and stakeholder insights to answer the question: “What are the operational and economic impacts of each option?”

To help answer this we use models of CER behaviour developed for the purposes of this project, combined with FES 24 outputs for 2035, in addition to scenario analysis, and industry interviews to inform feasibility. Options are assessed against a set of guiding principles and evaluation criteria.

4.1 Solution guiding principles and constraints

Guiding principles and evaluation criteria

The following guiding principles have been used to evaluate the options across 4 areas

Guiding Principles

1. System Reliability: ensure that all solutions contribute to the stability and resilience of the energy system.
2. Operational Feasibility: prioritise approaches that are technically and practically implementable within existing infrastructure and regulatory frameworks.
3. Scalability and Flexibility: design mechanisms that can scale with future growth and adapt to evolving technologies and market conditions.
4. Transparency and Accountability: maintain clear, auditable processes and data flows to support trust and regulatory compliance.
5. Cost-effective Consumer Cost: minimise the financial burden on consumers by promoting cost-effective solutions and ensuring that any additional costs are justified by tangible system or societal benefits.

Evaluation Areas:

1. Control Room Impacts: assess effects on visibility, situational awareness, demand forecasting accuracy, and access to controllable resources.
2. Aggregator Impacts: consider technology agnostic solution, evaluate clarity and duration of requirements, capital and operational expenditure (CAPEX/OPEX), and market accessibility.
3. Implementation Complexity and Timeline: technology and systems readiness, as well as the need for legislative or protocol changes.
4. Cost to Consumer: Analyse the direct and indirect financial implications for end users, including tariff structures and potential incentives.

DNV Independent Scoring:

The following slide shows DNV evaluation of options using the following scoring criteria:

1. 🔴 Red – High impact on aggregator access to BM , high risk of implementation delays and costly solution.
2. 🟡 Amber – Moderate risk requiring attention; may affect aggregator access to BM and lead to additional costs.
3. 🟢 Green – Low risk with smooth implementation expected and minimal cost impact.

Table 4.1 – DNV RAG evaluation of options

	Option	Solution	Control room impact	Aggregator impact	Implementation complexity and timeline	Cost to consumer
1	Keep (close) to Current Requirements	a- Meter Accuracy= 1%, MR=1 sec (portfolio-NESO), Latency =5 sec	No impact	Processing the data in the cloud is cost-prohibitive, and not all assets can transmit 1-sec MR	Requires changes to communication protocols. Not all CER technologies are able to meet the 1 sec MR, requires cheaper data storage& processing	Higher data quality results in lowest impact on CR however the restricted access not allow CERs to participate which impact market liquidity/earning potential
		b- As above + Report On Change/Event Driven on asset level	Lowest impact on CR because data OM quality is maximised. Not all assets will be available to report on change which will have impact on visibility and access to resources	Most new chargers have event driven capabilities however further investment in systems needed in case of some chargers or to implement RoC that business case must be proven. suitable for EV/V2G, and potentially Home BESS portfolios, but not for other CER types.	Most new chargers have event driven capabilities. Requires changes to communication protocols. Not all CER technologies suitable for RoC. Requires upgrades to asset firmware and aggregator IT systems	Higher data quality results in lowest impact on CR and response and reserve costs however the restricted access not allow CERs to participate which impact market liquidity/earning potential
2	Use delayed CER OMD as real-time data, mitigate by setting new requirements at the asset level	a- Allow error by mitigating its impact (MR=30sec)	Although it will allow visibility in the BM and access to resources, CR might take wrong decisions due to delays in CER OM data which will be mitigated by increased reserve and response	No impact	No impact	The impact would be lower at the start but as more CERs enter the BM, it would require increased response and reserve to mitigate error impacting situational awareness that might lead to wrong decision
		b&c- Allow error by mitigating its impact (MR= 5, 10sec)	Although it will allow limited visibility in the BM and access to resources, CR might take wrong decisions due to delays in CER OM data which will be mitigated by increased reserve and response	Relatively higher cost to the aggregator compared to 2a	Requires changes to communication protocols. Not all CER technologies are able to meet the 5-10 sec MR,	Still require reserve and response to mitigate risks, the restricted access to some CERs to participate will impact market liquidity/earning potential
		d- Ramp rate control (suitable to all range of MR)	Requires an accuracy requirement limit which can be implemented by controlling assets ramp, the might error persist for longer duration. CR ability to balance system impacted by CER ramp limit. Imbalance risk grows if BM lacks fast-ramping assets to offset wholesale volatility	Accuracy limit reduces ability to (quickly) act on all markets, but allows own cost benefit analysis for investment in metering capability	Aggregators can easily limit their ramp rate slower staggering assets.	It would require relatively less amount of additional response and reserve to mitigate error impacting situational awareness that might lead to wrong decision
3	Consider delay in CER OMD, invest in systems to mitigate risk	a- Aggregators timestamp OM data, NESO create real-time estimation and update with delayed OM feed	CR have real-time estimate of CER behaviour, with any errors rectified within ~15 seconds. Wrong decision made only if estimate is inaccurate, or CER does not follow BOA. Requires additional work to ensure performance of PN/BOA	Small investment in systems needed to add timestamp to outgoing data	Requires investment in NESO OM (SCADA) and demand predictor (BM) systems (ongoing upgrade), as well as industry coordination to implement timestamps. Implementation timeline likely 2-5 years. Visibility of wholesale market assets is essential for effective deployment	Likely very low additional need for response (as not all aggregators will fail to comply with their obligations at the same time). Reserve not needed because metering corrects <30s.
		b- Aggregators send synthetic data that best reflect the current real-time situation	Process less transparent and might impact NESO's situational awareness that might lead to wrong decision	Investment in systems needed	No impact	Likely very low additional need for reserve and response (as not all aggregators will fail to comply with their obligations the same time)

4.2 Impact on Cost to Consumers

Operational metering errors impacts the demand forecast, requiring reserve and response hence operational costs

The ENCC constantly manages numerous data inaccuracies. Introducing additional metering error adds uncertainty, leading to wrong decisions and increasing operational costs.

The NESO demand predictor uses operational metering data to produce a 0-4 hour demand forecast. Currently aggregated portfolios are not included in demand predictor but they are expected to be in future. Assets submitting data used in demand predictor today are predominantly large generators. Forecasts are used to estimate the generation of unmetered assets and demand curves from similar days estimate demand. As more consumers adopt CERs there is potential for the large groups of customer behaviour to synchronise, for example due to EV charging or home BESS behaviour aligning with market conditions or supplier tariffs. Therefore, it becomes more important to have real-time visibility of these assets rather than relying on forecasts.

Incorrect metering data in the demand forecasting engine control loop can lead to wrong decisions by control engineers. Since the ENCC relies on metering to assess unit, zonal, or national demand, any error in this data impacts dispatch instructions. These errors propagate through the system, affecting short-term demand forecasts and causing imbalances that manifest as frequency deviations.

The meter error in demand forecast can lead to the following risks:

1. Dispatch Errors: Inaccurate starting values lead to incorrect dispatches, with errors up to the size of the metering discrepancy.
2. Forecast Inaccuracy: Lagging data distorts short-term demand predictions until the next fixed forecast point.
3. System Imbalance: These inaccuracies affect zonal targets and dispatch programs, leading to real-time frequency drift.

Metering Error Effects:

1. Negative error (actual > metered): under-dispatch → low frequency.
2. Positive error (actual < metered): over-dispatch → high frequency.

To mitigate the risks, the ENCC uses Reserve and Response:

Response Measures: Pre-fault frequency response products are used to correct these imbalances.

Reserve Use: Fast-acting reserves (e.g., Quick and Balancing Reserve) are needed to correct short-term imbalances caused by metering errors.

Future risk envelope would need to be scaled up by a factor of 10 to 40 which could have a serious impact on system reliability

A higher penetration of CERs would breach NESO's current risk envelope. Expanding this envelope to accommodate such behaviour introduces considerable risk and is unlikely to be a sustainable long-term solution.

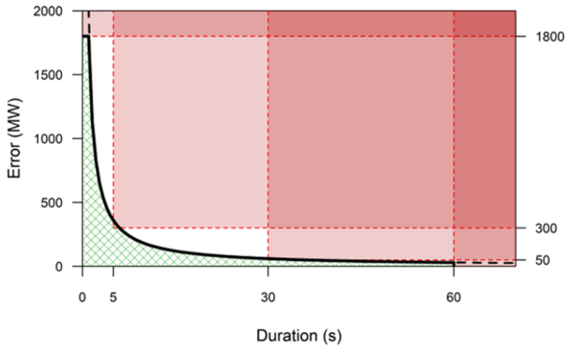
With a 10-second meter read interval; the following exceedances of current risk tolerance were observed across various durations: HT: 4,680 minutes/year, EE: 3,930 minutes/year, HE: 1,370 minutes/year and CF: 730 minutes/year

If such metering errors were permitted within the Balancing Mechanism (BM), NESO would need to increase considerable the current risks envelope potentially compromising system reliability. For example, to allow just 50 minutes of error per year (HT, blue line) under the HT scenario (HT representing the highest CER penetration), the risk envelope would need to expand significantly:

- Approximately 10 times larger for 1-second and 2-second durations,
- Approximately 40 times larger for 30-second durations

Risk tolerance	Error (MW)	Duration (s)
Largest infeed risk	1800	1
Imbalance not allowed to cause operational limit excursion	300	5
Half acceptable zonal error	50	30

Figure 4.1 – NESO's current risk tolerance



This suggests that future risks envelope would need to be scaled up by a factor of 10 to 40, depending on the duration, to maintain system reliability under such metering conditions. The above example is a simplified approach, and the NESO FRM team has developed a more detailed methodology to appropriately dimension reserve and response requirements.

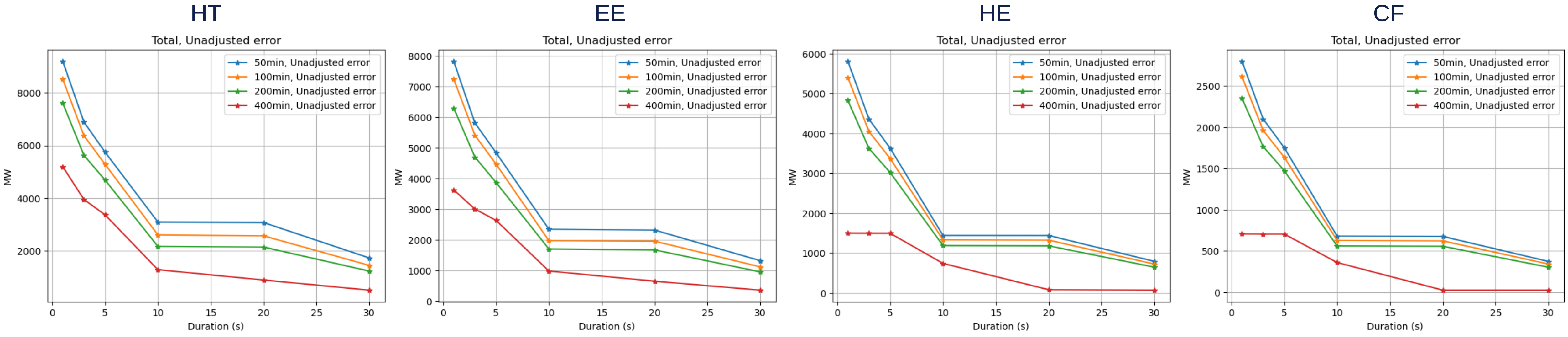


Figure 4.2 – Number of minutes in a year that the associated unadjusted error and duration is exceeded, for each FES 24 scenario

Carrying additional reserve and response lead to higher operational costs- example: increased Response holding

Higher penetration of CERs would significantly increase the need for reserve and response, driving up overall operational costs, an approach that is unlikely to be sustainable in the long term.

- Taking the errors modelled from the FES 2035 dataset (HT pathway), it is possible to estimate how this would impact NESO service procurement.
- Assuming minutely average errors will be fed through the control loop, therefore having the potential for inefficient dispatch and creating forecasting errors leading to frequency deviations.
- Taking the example of covering this through pre-fault frequency response holdings*. Currently NESO procure around 700-800MW (both directions) of pre-fault frequency response between DM & DR products.
- As has been shown, the time of day influences the size and direction of errors expected. The response requirement would vary to mirror this. In Option 2, the pre-fault requirement could increase to up to 10 times the current requirement to accommodate 30 second measurements.
- Option 3a/b (ramp adjusted), can help reduce the additional response requirement, however this is heavily reliant on accuracy of methodologies and ability of units to follow intended delivery.

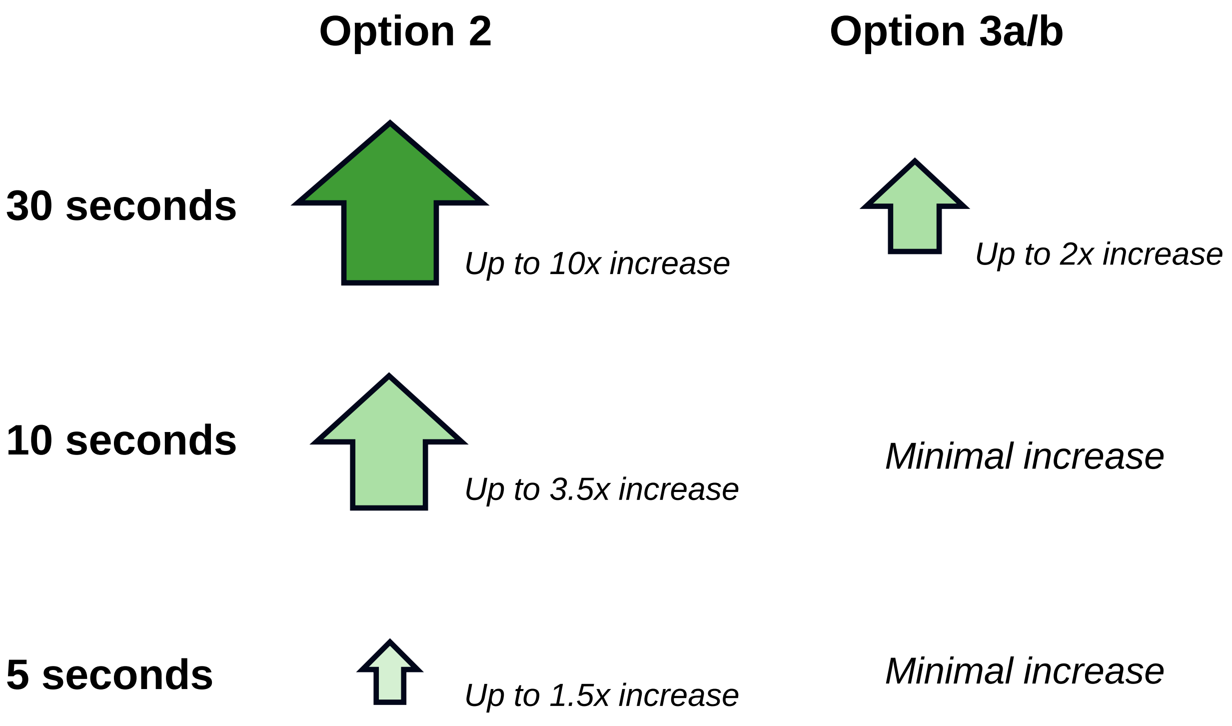


Figure 4.3 – Response requirement comparison between option 2 and 3a/b at various MR intervals

*The reality would be that NESO would be continually reviewing how these errors propagate into impacts on system balancing, allowing them to formulate more accurate requirements across response and reserve products to mitigate the impacts.

Integrating CERs in the BM delivers broad system benefits across operational and market dimensions.

CERs in the BM will increase reserve capacity, reduce costs, improve visibility for control operations, boost market liquidity, and provide a flexible resources against large system swings

Qualitative Assessment

Reserve Capacity

The integration CERs into the BM substantially increases the system's available reserve, strengthening grid flexibility and resilience.

Financial Impact

Integrating CERs into the market has the potential to deliver system-wide savings, particularly given that CER pricing is expected to be lower than that of large-scale batteries and other conventional generators e.g. CCGT enabling more cost-effective of balancing services

Qualitative Assessment

Visibility

Visibility of CERs in the BM improves situational awareness for the ENCC, enabling more informed and timely decision-making. This reduces the risk of misattributing frequency deviations and supports more accurate forecasting and dispatch.

Market liquidity

Integrating CERs in the BM will allow greater market liquidity. Market liquidity enhances the efficiency and responsiveness of the energy system by enabling more dynamic price formation, increasing competition among participants, and improving the visibility and valuation of flexible assets such as CERs.

Availability of resources

The availability of CERs within the BM provides a critical resources against large system swings by increasing the volume and diversity of responsive assets. With sufficient visibility and integration, CERs can act as a distributed, fast-acting reserve that complements traditional assets, reducing reliance on centralised interventions and improving overall system resilience

4.3 Industry evaluation of options

DNV distributed a survey to gather industry views on the proposed options for new OM Requirements

The survey was sent to all NESO external stakeholders including Power Responsive members, responses to the questionnaire are detailed in Section 2 of this report

Stakeholder Engagement

Stakeholder engagement was carried with the following groups, through a survey, emails, and drop-in sessions to discuss the options:

- Aggregators
- Suppliers
- Manufacturers
- Trade associations and lobby groups

10

The questionnaire was distributed to all NESO external stakeholders including Power Responsive Members and there were 10 responses, plus one written response from Energy UK.

The survey collected information on the technical and commercial feasibility of proposed options for new Operational Metering Requirements, in addition to information on forecasting accuracy for Physical Notification data, reliability of portfolio response to dispatch instructions, and preferred regulatory mechanisms for implementation including existing standards like COP 11 and EV Smart Charging Regulations.

Figure 4.4 – Stakeholder responses

Respondents' evaluation of the technical and commercial feasibility, and preferred options shows that Options 2 and 3 are most favoured

Option	Technical Score*	Commercial Score*	Total score	Summary of responses
1a – stay close to current requirements	3.3	2.2	5.5	Maintaining close to current requirements was widely rejected by respondents primarily due to the view that the most consumer devices cannot support the requirements without expensive hardware replacement or extensive modifications, while IT systems would struggle to manage real-time data at this frequency across large portfolios. The technical difficulty and high cost are reported by industry to undermine the economic case for consumers to adopt compliant devices, and aggregators to register and scale portfolios.
1b – report-on-change	3.3	3.3	6.6	Report-on-change (RoC) was recognised by some respondents as promising to reduce data transmission costs but reported as likely to introduce additional hardware and integration cost and complexity, with highly variable applicability across different hardware types: *"It is impossible to know to what extent devices are excluded by making this choice"*. Because RoC is not part of industry standard protocols like OCPP it would exclude providers which are not vertically integrated and rely on third party devices. One company relying on manufacturer partnerships reported that RoC is supported by some partners, however other partners do not support this option because to implement it they would need to rearchitect their metering system.
2a – 30s MR limit	6.7	7.8	14.5	The 30-second MR interval was described as achievable by most providers with manageable increases in data costs and integration effort. However, one respondent noted that 30-second MR interval is not widely available across all charger manufacturers, with 60 seconds being the standard metering interval. There are concerns about creating regulatory barriers that could disadvantage providers that integrate with third-party hardware. Four respondents identified this option as their preferred approach.
2b – 10s MR limit	6.7	5.6	12.3	Views on the viability of 10-second MR interval were mixed. Vertically integrated companies were more likely to support it, but it's considered at the limit of commercially feasibility since data communication, ingress, and processing costs could limit participation to only the most cost-effective assets and use cases. Respondents noted that most charge point manufacturers do not support 10s MR intervals, and many assets might require upgrades to hardware and/or firmware. Three respondents selected 2b as their *second* preference.
2c – 5s MR limit	3.3	1.1	4.4	The 5-second meter interval was considered commercially prohibitive for most consumer flexibility providers due to high implementation costs and would likely exclude consumer-led flexibility from the Balancing Mechanism entirely. Respondents considered 5s MR technically very challenging (similar challenge to 1s MR) for most current consumer assets without complete hardware replacement and major IT infrastructure upgrades.
2d – ramp limits based on MR interval	5.6	4.4	10.0	Ramp limits were viewed as commercially unviable rather than technically challenging, with several respondents highlighting the risk that artificially limiting ramp rates would devalue CER portfolios in the BM and other markets, making them less attractive to control room therefore limiting revenue opportunities: "*Slowing down portfolio response based on metering capability would reduce the value and effectiveness of consumer flexibility in the BM. If assets are forced to respond more slowly, they contribute less to system needs, making the proposition less attractive for both aggregators and end customers. Reduced response capability may lead to lower revenues or exclusion from certain services, undermining the business case for participation. It risks penalising portfolios with technically capable assets simply because of data visibility limitations, rather than any operational risk."*
3a – NESO constructs synthetic profile	6.7	6.7	13.4	NESO constructing the synthetic profile based on a timestamp is widely viewed as feasible, with minimal commercial barriers, requiring only low-cost investment and reduced barriers compared to other options since timestamps are often already captured in existing data streams. Respondents noted ambiguity around implementation details, particularly whether underlying assets would need individual timestamping or if a central timestamp for aggregated data would suffice, and whether assets would need to be forced onto a fixed time grid. Some respondents suggested that aggregators are better positioned estimate portfolio behaviour than NESO.
3b – aggregator constructs synthetic profile	7.8	7.8	15.6	Aggregators submitting a synthetic profile to NESO is viewed as significantly reducing barriers compared to options 1 and 2, with three respondents identifying this as their preferred option. Perceived advantages include aggregators already possessing the necessary data and expertise in data science and understanding of portfolio behaviour to create synthetic profiles. The approach is considered technically achievable, respondents noted that this option puts the responsibility on Flexibility Service Providers to demonstrate that their synthetic data accurately matches actual performance, which many see as preferable to data-intensive alternatives, though it requires investment in developing and validating estimation methodologies for different asset categories.

Table 4.2 – Respondents' evaluation of options

***Technical and commercial** scores based on number of times each option was selected as technically / commercially feasible (normalised to maximum score of 10).

DNV

Respondents' perspectives on the extent to which each option aligns with the five guiding principles for option selection described in WP3, inferred from the implementation survey responses

Option	Reliability	Feasibility	Scalable for Future Growth	Transparent & Accountable	Cost-effective (for Industry)
1a – keep close to current requirements	**Low:** All but one of the respondents did not think this option was technically feasible, therefore it cannot be considered reliable.	**Low:** Multiple respondents report current requirements exclude consumer assets and create technical barriers for CERs. Only feasible for traditional generation assets.	**Low:** Creates significant barriers to entry that prevent market growth. Octopus: *"completely exclude consumer flex assets"* needed for 12GW target.	**High:** Clear 1-second standard with established procedures	**Low:** Very high costs for hardware, data transmission and storage. Multiple respondents cite this as main barrier to participation. Enel X: *"risk eroding or fully offsetting the net benefit of participating"; high upfront costs*
1b – report-on-change	**Medium:** Report-on-change may introduce variability in data quality.	**Medium:** Mixed feasibility - some hardware partners support it while others would need architectural changes. Pod Point: *"not supported by industry standard protocol, OCPP"*	**Medium:** Better than 1a but still excludes some asset types. Allows more participation while maintaining some barriers. Flexitricity: *"impossible to know to what extent devices are excluded."*	**Medium:** Uncertainty about what constitutes a "change" and how to handle ramp periods reduces transparency.	**Medium:** Lower costs than 1a by reducing data transmission, but adds new implementation costs. Octopus: *Report-on-change may reduce data transmission costs slightly, but these savings are marginal compared to the upfront hardware and integration costs.*
2a – 30s MR	**High:** Proven technical possible, though legacy assets and some current manufacturers may not be capable. *Flexitricity: "2a is trivial to achieve"*	**High:** Most respondents can implement with existing systems. Aligns with capabilities of modern CER hardware and communication infrastructure. Octopus: *"strikes workable balance"*	**High:** Enables mass participation from consumer assets while maintaining system visibility. Removes key barriers to market entry. Octopus: *"enables broad participation from consumer energy resources (CERs)."*	**High:** Clear, simple 30-second standard that all parties can understand and implement consistently.	**High:** Minimal to no additional costs for most assets. Easee*: "30s: N/A" - no additional cost*. Octopus: *"broadly manageable for most"*
2b – 10s MR	**High:** Technically reliable but some older assets cannot achieve this standard, creating consistency issues across portfolios.	**Medium:** Requires hardware and software upgrades for many assets. Flexitricity: *"achievable by most assets though older EV chargepoints may not succeed"*	**Medium:** Excludes some asset types, particularly older EVs and potentially heat pumps as well. Creates moderate barriers that limit growth potential.	**High:** Clear 10-second standard maintains transparency	**Low:** Significant increase in data costs and infrastructure requirements. May exclude lower-value assets from participation. Octopus: *"significantly higher data costs...may exclude some asset types"*
2c – 5s MR	**High:** Technically possible but pushes limits of consumer hardware, risking data quality issues at scale.	**Low:** Requires major infrastructure overhaul. Axle: *"5s...is feasible for effectively none";*	**Low:** Would exclude majority of consumer assets, severely limiting market growth and participation.	**High:** Clear 5-second standard	**Low:** Prohibitive costs for hardware upgrades and data transmission. Makes participation uneconomical for most assets.
2d – ramp limits based on MR capability	**Medium:** Portfolio approach introduces complexity. Ccet: *"open to manipulation or errors"* affecting reliability.	**Low:** Slowing down portfolio response is technically feasible but would reduce asset value, limit revenue, and make EV chargers less attractive for dispatch, with the main concern being commercial impact rather than technical capability.	**Low:** Multiple respondents note it would reduce market attractiveness, limit EV fleet potential, and potentially exclude assets from services. Octopus notes it could lead to *"exclusion from certain services, undermining the business case for participation"*	**Medium:** Limited feedback on transparency. Ccet raises concerns about *"manipulation or errors."* Most respondents haven't considered this option enough to assess accountability.	**Medium:** Mixed - reduces costs for some assets but requires expensive system upgrades for implementation. Reduces asset value through slower dispatch, lost revenue from reduced trading opportunities and system service participation.
3a – NESO construct synthetic meter feed	**Medium:** Octopus: *"asynchronous timestamps...can introduce significant discrepancies"*	**High:** Simple to implement - timestamps already part of most data systems. ev.energy: *"least work option for FSPs."*	**High:** Removes technical barriers enabling wide participation. Accommodates all asset types and capabilities. Enel X: *"barriers...are greatly reduced"*	**Medium:** Some uncertainty about how NESO would process asynchronous data, but methodology can be standardized. Flexitricity: *"requires greater clarity" on implementation*	**High:** Minimal implementation costs. Uses existing data without requiring infrastructure changes. ev.energy: *"We have all this data to hand";* Axle: *"lLow-cost investment"*
3b – aggregators construct synthetic meter feed	**Medium:** Estimation introduces uncertainty but Pod Point notes *"ramp rates quite predictable in aggregate"* for EVs.	**Medium:** Achievable with data science capabilities most aggregators possess. Flexitricity: *"We would incur a cost...but it is achievable"*	**High:** Enables maximum flexibility and participation by working with any asset capability level. Pod Point: *"delivers accuracy NESO needs, at minimum extra cost"*	**Medium:** Estimation methodology needs clear standards, but Ccet: *"Massive estimation error"* concern ev.energy suggests *"proving process"* for validation.	**High:** Very cost-effective - uses existing data with analytical overlay. Pod Point: "minimum extra cost and effort."

Table 4.3 – Respondents' perspectives on options

PN accuracy is expected to be at least within 10%

All respondents able to provide an answer expected a PN accuracy of within 10%, in one case based on real BM data

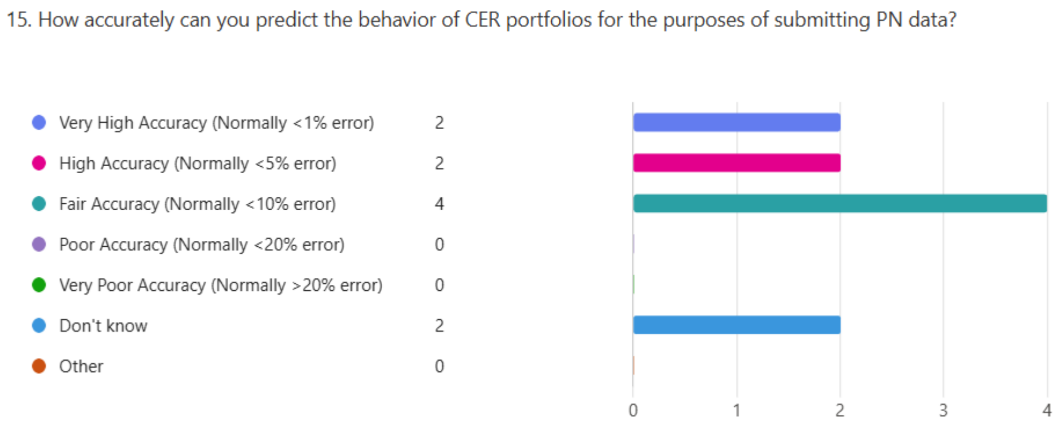


Figure 4.5 – Stakeholder responses: CER behaviour prediction

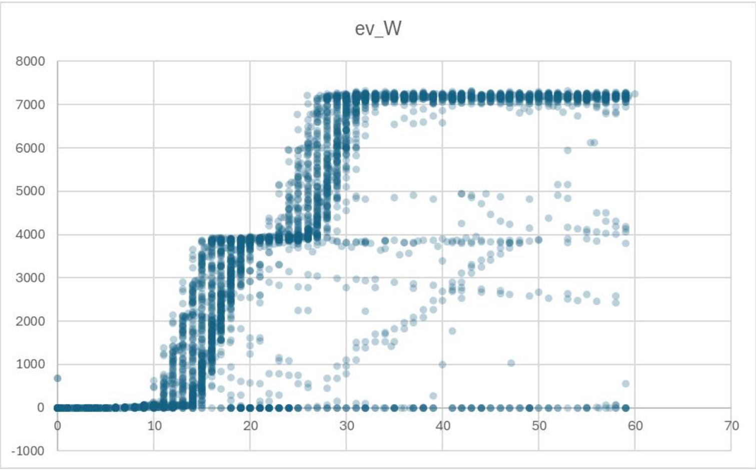
Explanation of answers to Q15:

- *“Dependent on size of portfolio / BMU - larger portfolios have smaller errors”*
- *“This assessment is based on internal exercises reviewing our own portfolio and analysing consumption profiles within specific programmes. It does not rely on data currently used for submitting PNs”*
- *“Our CER portfolio is made up of several different technologies, e.g. I&C flexible demand, EV chargepoints, batteries, CHPs and heat pumps. We will be able to achieve higher accuracy for some technologies that operate on regular patterns, whilst other assets are more difficult to predict as their operations are influenced by a number of factors e.g. ambient temperatures, processing demands etc. We will be forecasting the demand of each individual asset in our CER portfolio; our data science team will be alerted if our accuracy threshold is not met for a given asset. The asset demand forecasts are then aggregated to create the PN to submit to NESO; the process of aggregation results in reduced error.”*
- *“Answer based on NESO’s own analysis of our BM performance to date”*
- *“I considered saying <1% error - I think we might be able to achieve that, but I can't prove it today. I will supply 1s power data for 10 chargers, which includes 2000 charging sessions.”* **– See graph right**

Most challenging aspect of PN accuracy:

- *“Max output and therefore ramp starts”*
- *“It is dependent on the portfolio type, for BESS assets, for I&C BESS we do not see any major challenges, however, for assets such as curtailment there is a real challenge to be highly accurate from PN start and end to run/down rate”*
- *“The PN start and end MW is the most challenging; the most important output of the ML models is an accurate reflection of how many of each asset class is available and consuming. Dynamic parameters are reasonably stable within each asset category.”*
- *“Perhaps I'm over confident, but I don't think being accurate in the aggregate will be challenging.”*
- *“FSPs need to start building these capabilities before they know what would be most challenging. With a large enough sample size and a suitable period of testing, an FSP should have confidence in estimating each metric. EV chargers for example, we see that dispatches track a similar ramp rate.”*

Figure 4.6 – EV portfolio ramp data



“Raw data to support my contention that EV ramp ups are modellable in the aggregate. To visualise: this chart is for one charger and its power in Watts on the Y axis, and time since energy was offered in the X. A reminder: the protocol between an EV and and EVSE is that we offer energy, and the EV decides when and how much to take. You can see that we do nothing for 10s, then ramp up in steps getting to full power by 30s.”

Respondents appear willing to engage with NESO on improving PN accuracy, ideally through Power Responsive

Respondents emphasise that NESO should build upon the existing commercial framework. NESO can draw parallels to the recent initiatives undertaken for wind assets and work towards improving PN accuracy through tracking and issuing guidance across asset types.

Respondents note that many Flexibility Service Providers entering the market may lack understanding of function and importance of PN's. NESO could engage with new market entrants, perhaps through the BMU registration process and/or Power Responsive programme, to familiarise them with Physical Notification requirements and their application to aggregated assets. Performance could be reviewed through Power Responsive which could be a forum within which to drive improvement on key parameters.

> *"If NESO were to facilitate a workshop, why would any FSP who has this capability help their competitors. However, many FSPs are coming into this space fresh and may not understand what a PN means. Describing the data points and how they relate to aggregated assets may be helpful."*

> *"Learn by doing. Ensure that CERs participate in the BM by making operational metering standards tractable; otherwise, no learning can take place. As the sector grows, Power Responsive should review category performance with providers so that providers can focus their efforts on improving the parameters that matter most."*

One respondent suggests that NESO can support PN accuracy by ensuring that forecasting by aggregators to support PN (and potentially OM) submission align with settlement rules since in their view this would drive improved performance.

> *"Current financial incentives and penalties inherent in cashout/ imbalance arrangements provide a strong commercial motivation for aggregators to forecast and submit accurate PNs for aggregated CERs. Clear, predictable settlement rules aligned with accurate forecasting will naturally drive improved performance."*

Two respondents proposes that NESO could implement a risk-based audit or accreditation approach, requesting high-resolution data from statistically relevant subsets of assets for verification purposes rather than mandating continuous granular reporting.

> *"NESO can support accurate PN provision for aggregated CERs by adopting a forecast-based model, where accredited aggregators submit PNs using validated portfolio-level forecasts rather than real-time 1-second data from each individual asset".*

> "It [NESO] *could potentially ""audit"" the CERs occasionally - request high resolution data for a statistically relevant subset for validation."*

Recent NESO Guidance (Aug 2024): A Model for Proactive PN Accuracy Oversight

NESO has published guidance focused on improving PN accuracy, particularly for wind BMUs. It sets clear thresholds for what constitutes "Good Industry Practice": Net Error: ±2.6% of available capacity per month, Absolute Error: <9% of available capacity per month.

A six-month monitoring process ran between November 2024 and May 2025, including education, tracking, and potential escalation to Ofgem. This framework is designed to reduce balancing costs and operational risk, and it sets a precedent for future guidance across other asset types, including aggregated CERs.

Power Responsive is a stakeholder-led programme, facilitated by NESO, to stimulate increased participation in the different forms of flexible technology such as Demand Side Response (DSR) and storage.

It brings together industry and energy users, to work together in a co-ordinated way. A key priority is to grow participation in DSR, making it easier for industrial and commercial businesses to get involved and to realise the financial and carbon-cutting benefits.

The role of Power Responsive is to:

- raise awareness of DSR and engage effectively with businesses
- shape the growth of the market in a joined-up way and ensure demand has equal opportunity with the supply side when it comes to balancing the system

https://www.neso.energy/industry-information/balancing-services/power-responsive

BOA accuracy is expected to be better than PN accuracy

All respondents able to provide an answer expected a BOA accuracy of within 10%, with generally higher accuracy expected compared to PN accuracy

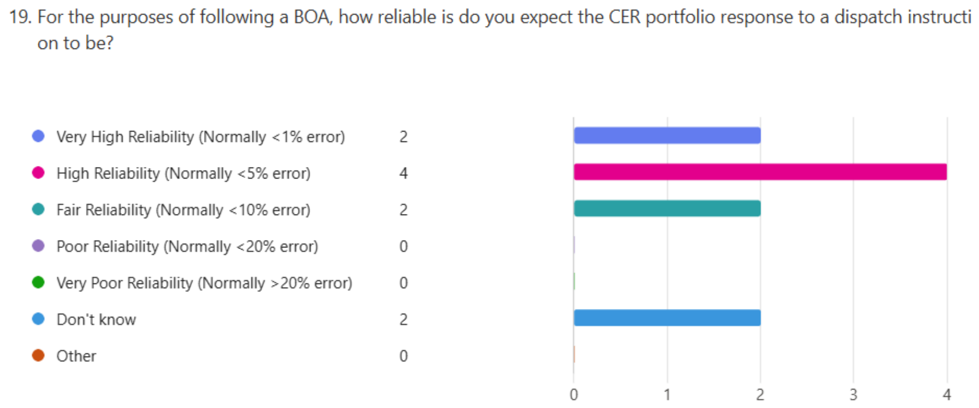


Figure 4.7 – Stakeholder responses: Reliability of CER response

Explanation of answers to Q19:

- *“Dependent on size of portfolio / BMU - larger portfolios have smaller errors. “*
- *“We control the assets via scada. “*
- *“It depends on dispatch levels an asset can reach they may not be able to turn down every MW but may drop in steps”*
- *“We maintain a high level of reliability in our response to dispatch signals, largely because we only utilise assets with a strong track record of accurate performance. However, this selective approach limits the full potential of flexibility in certain programmes, as it excludes assets that could contribute value but lack proven predictability.”*
- *“We echo our response to Q16 here, but would add that we have live operational feedback from every asset and are able to tune delivery at the moment of dispatch by activating more assets as required.”*
- *“Again, I don't want to over-promise. We are at those levels of reliability for other grid flex activities, and it's possible we could get to 1%.”*
- *"NESO’s own analysis of our BM performance to date "*
- *“As with predicting behaviour, we don't know until we start. And as soon as we have a metric to measure, then we can invest in improvements.”*

Beside new regulation there are few incentives to improve meter capabilities

Aggregators have limited incentives to invest in improved meter capabilities beyond new regulatory requirements, with the main drivers being CoP11 compliance and occasional benefits in other markets, though many consider the revenue uplift insufficient to justify upgrade costs.

Q21: Assuming there is no specific requirement to improve asset meter accuracy, or MR interval and send updates more regularly than they do presently, to access the Balancing Mechanism (e.g. Options 2a or 3a), what other incentives do aggregators have to invest in improved asset meter read capabilities?

- *Other markets also require specific meter reading capabilities.*
- *We have been asking to provide more granular data to NESO for a long time but NESO systems haven't been able to accept it. More granular data more accurately represents our performance, currently NESO always underestimate our actual delivery with the less granular data. Sometimes perhaps the question should be are there alternatives to increased accuracy that would bring greater benefits to customers such as an indication from units of whether they have reached full delivery (so the NESO control room knows if the need to dispatch more units etc).*
- *None under CfDs. Small amount of incentives in the regulator market*
- *For many CERs and smaller Behind-the-Meter assets, the revenue uplift from improved granularity is unlikely to outweigh the cost of upgrading metering, communications, and IT systems. Aggregators are unlikely to make proactive investments in this area at scale*
- *There is a large incentive to meet Elexon's CoP11 requirements, because BSC-compliant asset metering substantially reduces settlement risks for BTM assets. If CoP11 asset metering is not used, settlement is against boundary flows, which are contaminated by noise from other energy-using assets at the premises. We expect this requirement to in fact dominate metering choices if and when a tractable revision to these operational metering requirements is confirmed.*
- *We need to pass CoP11 to use Asset Metering under P375 and P483. Asset metering has a number of advantages to the aggregator, not just avoiding the need for HHS, but also improved reliability and less risk of imbalance causes by other household loads.*
- *N/A*
- *Repeating that not all charge points can report at 30 second intervals.*

Industry prefer legislation and updating existing requirements to drive continuous improvement

Industry favour using a combination of legislation and existing standards like CoP11 to drive improvement in metering due to concern about fragmented country-specific requirements creating compliance burdens and market barriers.

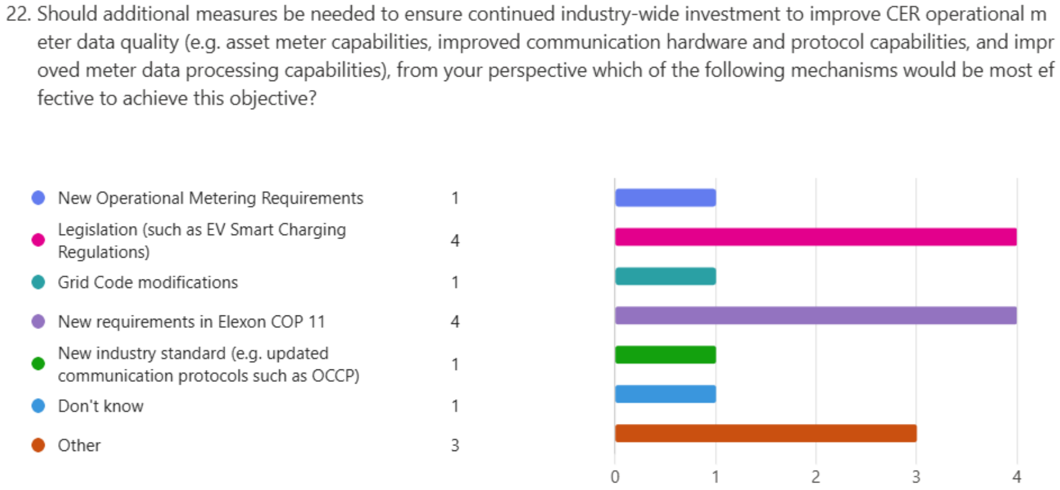


Figure 4.8 – Stakeholder responses: Change mechanism effectiveness

- *Use existing global standards as much as possible. OEMs understand different continents having different standards, but the challenge comes when every country has their own standards. ;*
- *Experience in seeing different countries come out with their own standards which are so similar/trying to fix the same problems, but require different testing, certification in each country.*
- *Legislation will mandate hardware to meet these requirements; the other methods risk creating a 'stranded asset base' of customers who unwittingly buy devices that don't meet necessary requirements.*
- *The most effective mechanism to implement new Operational Metering Requirements would be a combination of Grid Code modifications and updates to Elexon CoP11, ensuring alignment with existing industry compliance frameworks. Support via new industry standards (e.g. communication protocols like OCPP) could help but should avoid introducing rigid, one size fits all obligations that could limit flexibility participation.*
- *CoP11 is a thoroughly-worked standard which is also compliant with Capacity Market requirements. It is not sensible to pepper the industry with multiple overlapping metering requirements beyond absolute necessity.*
- *I don't have strong view on how you do this, but CoP11 just seems the natural choice to me.*
- *"We believe that meter data requirements in the Balancing Mechanism should reflect existing technology capabilities and avoid forcing premature or unnecessary change. At present, there is little alignment across industry standards, for example, NESO is proposing 1% accuracy, Elexon's COP 11 requires 2.5%, and the EV Smart Charging Regulations only mandate 10%. This inconsistency creates confusion and adds cost and complexity for asset providers and aggregators. From our perspective, the most effective mechanism would be to work toward alignment across existing framework. We are comfortable working towards using COP 11 (2.5% accuracy) as a realistic and enduring baseline. We could support COP 11 as a consistent requirement across markets. However, we believe 1% (as in Option 1a) is unnecessarily strict and completely commercially unviable for most consumer assets. Other aspects of Option 1a are similarly disproportionate and risk locking out valuable flexibility. We also urge NESO to focus on reliability at the portfolio level - in many cases, aggregated portfolios can deliver accurate and timely response even if individual asset telemetry is less precise. Improved performance at the system level does not require unrealistic expectations at the device level. In summary, we support measured improvements to data quality, but only where they are aligned across industry codes and regulations, and grounded in what is technically and commercially achievable today"*
- *There are dozens of charger brands and likely to be more in the years to come. EV drivers will not buy a charge point because it is CoP11 certified. The market has not proven yet that a charge point that is CoP11 certified (we don't believe any have been publicly announced) is more competitive than non certified. Legislation is the strongest mechanism to ensure that all charge points sold in GB can be used to help balance the grid.*

4.4 NESO evaluation of options

NESO impact assessment against principles

Option	Reliable	Feasible within Current Systems	Scalable for Future Growth	Transparent & Accountable	Cost-effective for consumers
1a	Maintaining the current requirements would be the most reliable option for NESO considering data quality	Limited change needed	This solution is not scalable for future growth since it limits the ability of aggregators to enter NESO markets	Requires a validation process on asset registration, and perhaps random spot checks, that devices are sending correct meter update frequency. This should be relatively straightforward to implement based on ex-post data submission.	Barriers to entry for CERs in NESO markets result in increased balancing costs
1b	Risk is minimal given aggregation across many different sites; direct notification of significant power changes provides good system reliability	Limited system impacts expected; aligns with current deadband times/zones across iHost with minimal development required	Solution can accommodate future CER growth without technical scalability barriers	Requires additional compliance procedures to verify that report on change activation threshold and changes in meter read interval are implemented correctly.	Some additional costs for system readiness and compliance processes, but relatively low compared to alternatives
2a	Highest impact on control room forecasting and modelling, highest impact on system reliability	Option 2 a/b/c is feasible within current systems however action may be needed to mitigate the impacts of reduced data quality resulting from Option 2	Option 2 a/b/c does not have any technical scalability barriers; however, it is not expected to be scalable in the long-term due reduced data quality resulting in unacceptable reserve and response costs.	Requires a validation process on asset registration, and perhaps random spot checks, that devices are sending correct meter update frequency. This should be relatively straightforward to implement based on ex-post data submission.	Up to 10x increase in reserve and response costs.
2b	Impact on control room forecasting, modelling, and system reliability in-between 2a and 2c	Option 2 a/b/c is feasible within current systems however action may be needed to mitigate the impacts of reduced data quality resulting from Option 2	Option 2 a/b/c does not have any technical scalability barriers; however, it is not expected to be scalable in the long-term due reduced data quality resulting in unacceptable reserve and response costs.	Requires a validation process on asset registration, and perhaps random spot checks, that devices are sending correct meter update frequency. This should be relatively straightforward to implement based on ex-post data submission.	Up to 3.5x increase in reserve and response costs.
2c	2c preferred for better error detection situation awareness.	Option 2 a/b/c is feasible within current systems however action may be needed to mitigate the impacts of reduced data quality resulting from Option 2	Option 2 a/b/c does not have any technical scalability barriers; however, it is not expected to be scalable in the long-term due reduced data quality resulting in unacceptable reserve and response costs.	Requires a validation process on asset registration, and perhaps random spot checks, that devices are sending correct meter update frequency. This should be relatively straightforward to implement based on ex-post data submission.	Up to 1.5x increase in reserve and response costs.
2d	Lack of ability to enforce ramp rates in real-time creates reliability concerns; limitations on actual unit output hard to enforce	New functionality required for balancing systems to limit participant submissions; additional registration and compliance processes needed	Increased skip rates due to units not being dispatched because of ramp rate limitations; may limit market participation	Requires additional compliance procedures to ensure that aggregators stay within ramp limits. This should be relatively straightforward to implement based on PN submissions and ex-post data validation.	Additional costs for system development and compliance processes; potential efficiency losses from dispatch limitations
3a	Requires close monitoring of PN accuracy to be used as real-time monitoring; creates additional risk in time-critical processes; relies on currently submitted data feeds being of adequate accuracy, which is unproven	Only should be implemented if proven more accurate than options 1 or 2. Requires significant development for accurate real-time estimation of output; needs much closer monitoring of PNs/CCLs; requires 1-2 years proof-of-concept plus 2-3 years development; new capability needed to monitor accuracy of provided feeds	Scalability limited by only NESOs capacity to predict the behaviour of a large number of BMUs.	Additional compliance procedures required to audit accuracy of currently submitted data parameters (PNs/CCLs)	Substantial costs including proof-of-concept/innovation (1-2 years), system development (2-3 years), ongoing monitoring resources, plus expected mitigating actions for large step changes. However, these costs are likely to be significantly lower than response and reserve costs incurred under Option 2.
3b	Understanding data quality much more difficult than other options as unpicking actual metered data becomes very challenging; creates additional risk with algorithms being applied to data in time-critical processes; resilience concerns with new process layers	Only should be implemented if proven more accurate than options 1 or 2. Requires detailed collaboration/trialling/innovation to determine best approaches; significant system development needed; requires 1-2 years proof-of-concept plus 2-3 years development; new monitoring capability needed for synthetic feeds	Good scalability since each aggregator can submit their own prediction and NESO only need to validate performance, which could be partially automated.	Additional and more in-depth compliance processes would be required to audit accuracy of synthetic metering feeds submitted	Similar substantial costs to 3a including proof-of-concept, innovation, system development, ongoing monitoring resources, plus mitigating actions; additional complexity of managing synthetic feeds may increase costs further. However, these costs are likely to be significantly lower than response and reserve costs incurred under Option 2.

Table 4.4 – NESO impact assessment

NESO impact assessment guidance

NESO assessed the impact of all options on its systems & processes, people, timeline & cost, risk &mitigation

Assessment Category	Criteria	Description
1. Assess System and Process Impacts	System Readiness	• *Evaluate compatibility with legacy systems and integration complexity, communication protocol readiness.*
	Process Alignment	• *Identify business processes that will be disrupted or need redesign.*
	Stakeholder Interfaces	• *Map interactions between NESO, aggregators, and end users under each proposed option, considering visibility, access, and control room impacts.*
2. Evaluate People and Compliance Factors	People Readiness	• *Assess training needs for control room operators, aggregators, and asset owners. Include change management for transitioning to new metering standards. Strategic partnerships?*
	Compliance	• *Evaluate how each option supports regulatory compliance and market participation. New regulatory and policies required? Standards and certification requirements?*
3. Timeline and Cost Planning	Time Allocation	• *Evaluate timeline to implement options.*
	Market Demand and Timing	• *At what time should we transition between options?*
	Cost Considerations	• *Compare implementation complexity, budget allocation and approval, cost to consumers across options.*
4. Risk Identification and Mitigation	Risks	• *Evaluate risks related to each option and evaluate risks based on criticality.*
	Risk Mitigation	• *Actions to mitigate risks based on urgency.*

Table 4.5 – NESO impact assessment criteria

General barriers to onboarding CER metering

Assessment Category	Criteria & Description	Input/Findings
1. Assess System and Process Impacts	System Readiness	• **Communication standards:** ○ Communication via leased line should be encouraged where possible. ○ Units may only connect to iHost as outlined in the Communication Standards document. This states that any aggregated asset over 300 MW must connect to iHost and a secondary, independent VPN with failover capability. ○ In the medium term, it needs to be carefully assessed, and the rules revised accordingly if the current NESO Communication Standards is insufficient for aggregated CERs in the BM. • **Registration:** Scalability is a concern for the short term if the capacity is to be beyond 750MW in the next 3-4 years.
	Process Alignment	• **Aggregator Impact Matrix (AIM):** the process in NESO for AIM needs to be established in the medium term (by 2028) so the control room can get the required visibility of aggregated CERs to mitigate the operability challenges related to breaching constraints.
	Stakeholder Interfaces	• NCMS currently connects to aggregator systems either directly via leased line, or via iHost through API. Connection via iHost may change in the future based on decision made around whether resiliency of iHost is adequate. This will become increasingly important as aggregated CERs scale. • The interface between OLTA (or its successor) and SMP needs to be more established. • For all other systems, the existing interface will remain the same.
2. Evaluate People and Compliance Factors	People Readiness	• Training is needed for all control room engineers on aggregated CER units, covering their capabilities, dispatch and scheduling assumptions, and metering requirements. • Training is needed for BM registration team around metering solutions that are acceptable and how they manage initial requests to enter the BM.
	Compliance	• The BM operational metering policy needs to be updated to reflect the new standards. • Bilateral Connection Agreements (BCAs) need to updated and operational metering requirements need to be ringfenced for the BM so that it doesn't affect ancillary service requirements. • Market monitoring for compliance will be required to ensure that CERs comply with the new standards. • Compliance with communication requirements based on the Control Point Threshold will be necessary.
3. Timeline and Cost Planning	Time Allocation	• The key actions needed ahead of go-live for all options are: • Establish whether any limits are needed on the capacity of CER BMUs registered or scheduled/instructed through the BM in order to manage operational issues posed by aggregated CER BMUs exacerbating existing system constraints. • Update BCAs to ringfence the operational metering requirements. • Determine how CER data (particularly demand-side flexibility) should be treated in the control loop and short-term forecasting. • Introduce a compliance process into the registration workflow.

Table 4.6 – NESO identified barriers to CER metering

General barriers to onboarding CER metering

Assessment Category	Criteria & Description	Input/Findings
3. Timeline and Cost Planning		
	Market Demand and Timing	• Increasing resiliency of iHost • Connection to NCMS
	Cost Considerations	1. **Resilience of iHost** due to increased volume of aggregated CERs in the BM. 2. **Group-level monitoring** in the control room is hindered by reduced CER metering accuracy and the introduction of a delay, which impairs real-time situational awareness 3. **Constraint costs** – as there is only GSP group level visibility of CERs in the BM. 4. **Skip rates** - Current scheduling and dispatch processes and systems don't consider certain CER characteristics resulting in error and increased skip rates. 5. **Registration processes** may be insufficiently scalable or responsive to accommodate the increasing volume and changes to CER units, leading to delays in market entry and mismanagement of unit changes 6. **Primacy:** Since CERs are connected to the distribution network, DNOs may override NESO instructions in order to manage distribution constraints.
4. Risk Identification and Mitigation	**Risks**	1. **Resilience of iHost:** Connection via leased line will be encouraged. In the medium-term, it needs to be carefully assessed, and the rules revised accordingly if the current NESO Communication Standards is insufficient for aggregated CERs in the BM. 2. **Group-level monitoring:** There is a decision required from OBP and ENCC on how CER data (particularly demand-side flexibility) should be treated in the control loop and short-term forecasting. In the medium-term, automated background monitoring in OBP to flag real-time deviations from PNs will be put in place. 3. **Constraint costs:** Limits must be set on the capacity of aggregated CER BMUs scheduled or accepted within a single GSP group. This does not apply to demand turn down. In the medium term, making use of the AIM and transitioning the BM to accept sub 1 MW units will help ENCC get better visibility of aggregated CER assets. 4. **Skip rates:** Limits must be set on the capacity of aggregated CER BMUs scheduled or accepted within a single GSP group. This does not apply to demand turn down. 5. **Registration processes:** Better understanding of Elexon registration processes and closer alignment of NESO and Elexon processes are required (especially considering the volume of assets that could be changing every week in a given unit). Improved forecasting of the units wanting to participate in the BM will enable the registration team to do better workforce planning and prevent delays in registration. 6. **Primacy:** To prevent breaches, clear primacy rules for CER control must be established.

	Risk Mitigation	• **Communication standards:**
		  ○ Communication via leased line should be encouraged where possible.
		  ○ Units may only connect to iHost as outlined in the Communication Standards document. This states that any aggregated asset over 300 MW must connect to iHost and a secondary, independent VPN with failover capability.
		  ○ In the medium term, it needs to be carefully assessed, and the rules revised accordingly if the current NESO Communication Standards is insufficient for aggregated CERs in the BM.
		• **Registration:** Scalability is a concern for the short term if the capacity is to be beyond 750MW in the next 3-4 years

Table 4.7 – NESO identified barriers to CER metering (cont.)

Option 1B: Report on change

Table 4.8 – NESO impact assessment of Option 1b

Assessment Category	Criteria & Description	Input/Findings
1. Assess System and Process Impacts	**System Readiness**	Limited system impacts expected • Ensure approach aligns with current deadband times/zones across iHost * • Ensure metering systems can receive infrequent data updates and have relevant processes set up across to ensure downstream systems have the data they require * *note that meter systems will still receive 1s updates from the aggregator, only the connection from the asset to the aggregator will be report-on-change • Potential development required to highlight which units are operating on report on change
	Process Alignment	Limited process impacts expected
	Stakeholder Interfaces	Limited system impacts expected
2. Evaluate People and Compliance Factors	**People Readiness**	• Initial work with providers to agree best practises and create thorough guidance (in particular comms drop out/resilience) • Limited training required for internal colleagues
	Compliance	Additional compliance checks required to ensure unit is operating correctly in report on change mode, assessing any latency in real-time reporting of data and granularity of data when changing outputs
3. Timeline and Cost Planning	**Time Allocation**	Likely 6-12 months to have relevant systems, compliance measures and training put in place
	Market Demand and Timing	NESO would likely be ready to transition to this solution before the industry is ready, this is a preferred option to option 2/3, so the sooner the better.
	Cost Considerations	Some additional costs checking system readiness, resourcing for new compliance processes
4. Risk Identification and Mitigation	**Risks**	Solely reliant on report on change functionality at an individual asset which is unlikely to owned by provider, meaning any issues with the functionality are unlikely to be able to be fixed in a quick time-frame
	Risk Mitigation	Risk is likely to be minimal given aggregation of many different sites

Option 2a,b,c: CER OMD as real-time data

Table 4.8 – NESO impact assessment of Option 2a,b,c

Assessment Category	Criteria & Description	Input/Findings
1. Assess System and Process Impacts	System Readiness	• **Balancing systems:** BM will still be used for some functionality until July 2026 • OBP: For effective dispatch, there is a need for CER assets to be split into different zones. A decision is required from the control room whether CER assets should be allocated to one separate zone or split into North/South zone. Bulk dispatch capabilities are currently available within the small BMU and the battery zones and will need to be made available for CERs. • **WAAPI** is the only way to send dispatch instructions to BMUs over the internet and currently WAAPI capacity is a limiting factor.
	Process Alignment	• **Control room processes** e.g. group level monitoring and demand predictor for real-time balancing and dispatching, unexpected regulation action, scheduling for aggregated batteries/EVs will face the most disruption due to the delay in CER metering and inaccurate CER metering affecting situational awareness. It needs to be determined whether CER data should flow into demand predictor. • **Forecasting processes** e.g. short-term forecasting, demand forecasts for all asset types, scheduling via SPICE, calculation energy consumption for a settlement period will face some disruption due to delay in CER metering and inaccurate CER metering. • **Registration:** processes need to become more scalable. Compliance needs to be embedded in the existing registration workflow.
	Stakeholder Interfaces	• As mentioned in the *'General barriers to onboarding CER metering'* section.
2. Evaluate People and Compliance Factors	People Readiness	• Training is needed for all control room engineers on aggregated CER units, covering their capabilities, dispatch and scheduling assumptions, and metering requirements.
	Compliance	• As mentioned in the *'General barriers to onboarding CER metering'* section.
3. Timeline and Cost Planning	Time Allocation	• As mentioned in the *'General barriers to onboarding CER metering'* section.
	Market Demand and Timing	• The timing of the enduring solution will be driven by the market demand to enter the BM under the relaxed operational metering standards. Significant volumes of aggregated CER BMUs could result in demand swings which, when combined with the lag in metering data, result in control room risk tolerances being breached. To mitigate this we propose to introduce a limit on the volume of aggregated CER BMUs registered and/or scheduled/instructed in the BM. The enduring solution will need to be implemented before this limit is reached.
	Cost Considerations	- As mentioned in the *'General barriers to onboarding CER metering'* section.
4. Risk Identification and Mitigation	Risks	• **Data quality –** 2a/b/c is preferred as more data enables better error detection and understanding. Additionally, reduced latency would improve situation awareness. • All other risks as mentioned in the *'General barriers to onboarding CER metering'* section.
	Risk Mitigation	• **Data quality:** The difference between the metered data and the PN indicates the error. However, it's unclear whether discrepancies will be due to inaccurate metering or an incorrect PN. Post-event analysis using actual meter readings can help identify the source. Further trials using REVEAL are needed. To date, only one aggregated CER unit has been tested where the PN accuracy was acceptable. • All other risks as mentioned in the *'General barriers to onboarding CER metering'* section.

Option 2d: ramp rate control

Assessment Category	Criteria & Description	Input/Findings
1. Assess System and Process Impacts	**System Readiness**	• **Balancing systems:** New functionality required to limit what participants can submit as ramp rates, linked to what they have provided as part of registration data. Also limits required on PN ramping data • **Registration:** Like required to need more information and process this in a better format for downstream uses of the data about what metering capability is being utilised.
	Process Alignment	• Ensuring registration data is transferred for compliance and also real-time monitoring of unit's data parameters and activity
	Stakeholder Interfaces	• Visibility required of units that have limited ramp rates due to metering approach
2. Evaluate People and Compliance Factors	**People Readiness**	• Detailed guidance will need to be provided to industry participants, linking meter read interval and number of assets in a unit to allowed ramping rates
	Compliance	• Additional compliance to monitor ramp rate data parameters, ensuring they align with data provided at registration • Additional compliance to monitor unit output in relation to submitted parameters (PN's & Ramp rates) to ensure providers are adhering to requirements
3. Timeline and Cost Planning	**Time Allocation**	• Requires additional time on top of Options 2a/b/c (approximately less than a year additional)
	Market Demand and Timing	• Option 2d is a way of reducing impacts of options 2a and b. If options 1 or 3 don't offer viable alternatives to options 2a/b/c (if this has already been implemented), it is expected that Option 2d will be a likely solution to transition to once step changes become large enough.
	Cost Considerations	- Additional cost of system development - Additional resource for systems and compliance processes
4. Risk Identification and Mitigation	**Risks**	• **Lack of ability to enforce ramp rates in real-time** – Limitations on actual output of units hard to enforce in real-time, meaning impacts of metering solutions could still be experienced • **Increased Skip rates** due units not being dispatched because of ramp rates which are tied to metering approaches
	Risk Mitigation	• Penalties and/or performance monitoring type approaches could be adopted in relation to ramp speeds • Improve documentation and awareness of dispatching processes and why units might not be applicable for certain instructions

Table 4.7 – NESO impact assessment of Option 2d

Option 3a,b: CER OMD as real-time data

Table 4.9 – NESO impact assessment of Option 3a,b

Assessment Category	Criteria & Description	Input/Findings
1. Assess System and Process Impacts	**System Readiness**	Solutions need to be identified and detailed to be able to do a detailed impact assessment on systems. The same impacts from options 2a and b will stand across Communication protocols, Balancing systems, Registration **Balancing systems:** Further development will be required to update key data channels (e.g. short-term demand forecasting) to include a different feeds to the typical operational metering feed. 3a will require new significant development to be able to create accurate real-time estimation of output, this will either be in the form of much closer monitoring of PN's/CCL's if using these (see below), or a new approach to creating a more accurate feed if not. • **Monitoring Capability:** For both 3a and b, New capability will need to be created to monitor accuracy of provided metering feeds. • **Proof-of-concept capability:** System requirement to proof and validate what the best solutions would be to these options.
	Process Alignment	The same impacts from options 2a and b will stand across Control Room, Processes (e.g. short-term forecasting) and modelling. Given the accuracy, reliability and detailed approach are yet to be determined for solutions 3a and b, it is expected that the impact will be worse across these areas unless strong evidence and justification can be provided that the solution will be more accurate. • **Proof of concept** – An initial phase will be required to trial, innovate and ultimately dictate the detailed solution for options 3a and b. • **Monitoring processes** – New processes required to monitor accuracy and compliance of data across both approaches • **Post-event analysis** – Many offline analyses of system events would need to reconsider how they use metering data from these assets.
	Stakeholder Interfaces	The same impacts from options 2a and b will stand. Further validation will need to done around • 3a – Close work to ensure currently submitted data feeds (e.g. PN's) are of an adequate accuracy to be used as real-time monitoring. Or detailed collaboration/trialling/innovation around the best approaches for forecasting expected outputs to be used for real-time metering. • 3b – Detailed collaboration/trialling/innovation to work out the best approaches for providers to be able to provide metering feeds.
2. Evaluate People and Compliance Factors	**People Readiness**	• This option will require closer monitoring on an enduring basis likely, including ongoing resource, process and system support. So, it is expected to be a larger impact than Option 2a/b would be
	Compliance	• The same impacts from options 2a and b will stand. • Additional compliance would be required to audit accuracy of either currently submitted data parameters that will be utilised to create real-time metering (3a), or for synthetic metering feeds submitted (3b)

Option 3a,b: CER OMD as real-time data

Table 4.10 – NESO impact assessment of Option 3a,b (cont.)

Assessment Category	Criteria & Description	Input/Findings
3. Timeline and Cost Planning	**Time Allocation**	Same time limits apply in relation to iHost (as shown for options 2a and b). Additional timelines: • **Innovation/proof of concept** – An initial phase will need to be completed to validate the most reliable and accurate approach that can be adopted for either option. This needs to include (but not limited to) analysis of created metering feeds (e.g. accuracy and reliability), process/system implication of different approaches and compliance processes to support enduring approach. – approximately 1-2 years • **Development of new system/process capability** – Monitoring capability, Balancing systems changes improved post event analysis processes – Approximately 2-3 years • **Development of new compliance processes**
	Market Demand and Timing	• Option 3a/b should only be transitioned to if it is deemed a more accurate, reliable and resilient approach to real-time metering that options 1 or 2, this will need to proven through the proof-of-concept phase highlighted above. • If option 2 is implemented, there is a point where the size of step changes from CER's can have material impact on balancing processes, leading to additional mitigating actions to be taken (likely through additional response and reserve). It is expected that steps changes in the 100's of MW would require some mitigating process, as these grow to GW step changes, significant mitigating actions would be required and this option is unlikely to remain viable from a cost perspective.
	Cost Considerations	- Increasing resiliency of iHost, connection to NCMS, process and system for internet despatch and an API environment to be able to implement this solution efficiently will need to be fleshed out as a next stage. - System updates (including ones mentioned for Option 2a/b) - Resourcing requirements for proof-of-concept/innovation/compliance/system development/process development and analysis - Mitigating actions – Although this solution should only be implemented if it can be proven to be a better approach than options 1 / 2, it is still expected mitigating actions will need to be taken
4. Risk Identification and Mitigation	**Risks**	• **All risks detailed for option 2a/b stand, additional concerns** • **Data quality –** Understanding data quality much more difficult in option 3b than 2a/b, as unpicking what the actual metered data is will be difficult • **Resilience** – Option is reliant on metering feeds and algorithms being applied to data to create feeds, creating an additional risk with a new process happening in an already time-critical process
	Risk Mitigation	• **All risks detailed for option 2a/b stand** • Performance monitoring like approaches could be adopted to help ensure data quality

Systems requiring upgrade:

- **iHost** - Resilience improvements
- **NCMS** - may need changes based on resiliency decisions
- **Balancing Systems** – from July 2026 OBP will handle dispatch
- **Registration System** - Scalability concerns for handling beyond 750MW in next 3-4 years
- **Communication Protocol** - Connection requirements need alignment with Control Point Threshold (e.g., ≤100MW)
- **OLTA/OLTA Interface** - Requires replacement
- **SMP** - Needs updates
- **Communication Infrastructure** - Need to expand beyond internal/MPLS, OPTEL or leased lines to communicate with CERs
- **AIM** – AIM and supporting business processes need changes/overhaul
- **Control Room Operations** - Processes need updates at both group level monitoring and demand predictor levels
- **Forecasting Systems** - Short-term forecasting processes face disruption
- **Demand Forecast Systems** - Need updates
- **SPICE** - Scheduling system will face disruption
- **Energy Consumption Calculation Systems** - For settlement periods

5. Recommended Solutions

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Recommended Solutions

In the previous section we explored multiple options and assessed their feasibility. Our key finding was that maintaining close to current regulations is not feasible, but that no single option exists which meets all solution requirements and would be simultaneously optimum for NESO, aggregators, and consumers. Selection of final recommendations will therefore involve balancing priorities and feasibility on the behalf of different stakeholders.

In this section we outline the preferred solution(s) and supporting measures.

5.1 A combined phased approach

DNV recommends that a combination of options are implemented in a phased approach

PHASE 1: The best short-term solution is 2a combined with event-driven reporting for specific assets, which achieves feasibility, and maintain transparency however not scalable. Option 1b remains viable for specific asset types but has limited scalability.

Phase 1 – options which can be implemented within 12 months

- **Implement Option 2a: Set a maximum asset MR interval of 30s –** reasonable as a short-term solution since it enables mass participation from consumer assets – most of which can achieve 30s (those that cannot can still access the derogation). Cannot be an enduring solution because it becomes very expensive (up to 10x increase in reserve and response costs(i.e. capacity required)) in medium-long term as the impacts of systematic error in control room increase. At this point 2a must either be supplemented with 3 a/b, or replaced with a lower MR interval (e.g. 2b, 2c)
- **Incentivise higher OMD quality:** NESO can incentivise higher-quality OMD by applying performance metrics that reward accuracy with increased market access to ancillary services. By increasing accuracy, NESO reserve costs can be reduced. Aggregators using event-driven reporting can lower data costs while meeting accuracy thresholds, enabling broader market participation and operational efficiency

Guiding Principles

Ensure solutions are reliable, feasible within current systems, scalable for future growth, transparent and accountable, and cost-effective for consumers.

Important Considerations:

1. Incentivises higher PN or forecasting accuracy: by assessing the performance of PNs. Improved accuracy reduce the need for corrective actions and contribute to greater overall system efficiency and reliability.

2. Incentivise higher meter quality: by linking performance to metering standards, the framework should motivate stakeholders to invest in higher-quality meters.

DNV recommends that a combination of options are implemented in a phased approach

PHASE 2: Option 3a/b should be considered as a final solution pending further development, as it requires a proof-of-concept and significant system changes. Option 1b remains viable for specific asset types but has limited scalability.

Phase 2 – options to be developed and implemented later, *to supplement Option 2a*

- **Incentivise 1b - Report on Change metering:** Optimal for national balancing activities but only works for specific asset types (e.g. EV, V2G) so cannot be a broad requirement on industry since it is against principles of technology agnostic regulations. Requires changes to comms protocols and incentivises for aggregator investment in metering upgrades to enable this especially because it increases data submission volumes compared to 2a*.
- **Evaluate Options 3a and 3b and implement the best performing approach:** 3a and 3b mitigate errors using an additional adjusted metering feed (developed by NESO (3a) or by aggregators (3b)) which anticipates the behaviour of CER portfolios within the coming 30 seconds. Likely best medium-long term solution because it is technology agnostic, presents no restrictions on market entry, CER performance, or CR resources, and limits impact on situational awareness to instances where BMUs behave unexpectedly. Feasibility and benefits of 3 should be explored in an innovation project.
    - **3a – NESO constructs synthetic meter feed:** requires significant investment to update NESO systems, and to a lesser extent aggregator systems. Requires estimation methodology to be developed and PNs to be accurate. Does not lead to larger reserve and response costs as CER population increases. Does not incentivise aggregator investment in metering. Scalability potentially limited by NESOs resource and system capacity to predict the behaviour of a large number of CER BMUs.
    - **3b – aggregator constructs synthetic meter feed in addition to real-time feed:** investment required by NESO is significantly reduced however is still needed for NESO to verify quality of metering submitted by aggregators in real-time. Likely more resource-intensive than 3a overall, since all market participants must implement their own solution. Aggregator responsibility for synthetic profile may have lower confidence by the ENCC compared to 3a, however aggregator has a better understanding of its portfolio and therefore is more able to construct an accurate meter feed, this option is likely more scalable than 3a and with proper validation the performance of synthetic feeds could be managed.

Guiding Principles

Ensure solutions are reliable, feasible within current systems, scalable for future growth, transparent and accountable, and cost-effective for consumers.

Important Considerations:

1. Incentivises higher PN or forecasting accuracy: by assessing the performance of PNs. Improved accuracy reduce the need for corrective actions and contribute to greater overall system efficiency and reliability.
2. Incentivise higher meter quality: by linking performance to metering standards, the framework should motivate stakeholders to invest in higher-quality meters.

DNV's Recommendation

Following the feedback received from NESO's external stakeholders and NESO and informed by DNV's independent evaluation of the available options, it is recommended that new **operational metering requirements for CERs be implemented through a phased approach**, with requirements for other asset types remaining unchanged.

New requirements are needed for CERs since these assets have the highest barrier to entry to the balancing mechanism due to their high cost of metering relative to potential flexibility revenue per asset, in addition to the lack of clarity in the current requirements whether performance should be measured at the asset level or the portfolio level. Industry feedback indicated that assets >1MW had no barriers to entry, and assets between 100kW and 1MW had marginal barriers which were expected to be resolved with new lower cost metering technology.

Specifically, **the rollout should begin with Option 2a**, establishing a foundational level of compliance. **Over time, Option 2a should be supplemented with Options 3a/3b**, to enhance system robustness and reduce overall costs (pending further development to confirm their ability to deliver the anticipated benefits and effectively mitigate associated risks).

Concurrently, **efforts should be made to promote improvements in the quality of operational metering data**, as outlined in Option 1b (e.g. RoC or event-driven), to support long-term performance and reliability.

The new requirements should apply to aggregated portfolios of assets connected at voltage levels of 415V and below.

CER Operational Metering Requirements

Option 2a:

- Meter Accuracy (KW)
  - Asset Level: No extra requirement, as per applicable British Regulation*.
  - Portfolio Level: 1% (calculated based on accuracy of underlying assets considering effect of the law of large numbers) AND Min Asset Number in Portfolio = 30. (If the number of assets in the portfolio is above 100 the portfolio can be assumed to meet the minimum accuracy requirements given that COP11 and EV Smart Charing regulations already require accuracy +/- 10%)
- Meter Read Frequency & Latency (seconds):
  - Asset Level[1]: every 30 seconds
  - Portfolio Level: every 1 second
  - Latency[2] : 5 seconds (end to end latency from the asset to NESO's platform)
- [1] For assets unable to meet the specified MR interval requirements, alternative route if offered though the existing BM derogation pathway.
- [2] For aggregators not able to meet the 5-second latency requirement, compensation will be applied via the MR interval, using the formula: MR interval = 30-2*ΔLatency, where ΔLatency= Latency Actual – Latency Requirements. This formula accounts for the fact that 1s of communication latency has 2x the impact of 1s of additional MR interval.
- * Refer to recommendation 7.5

Guidance on MR interval

- For assets unable to meet the specified MR interval requirements, it is recommended that they continue to utilise the existing BM derogation pathway[1]. Currently, 3% of the 300MW capacity is operating under this derogation. NESO will maintain active oversight of the derogation pot to ensure sufficient headroom remains for accommodating non-compliant assets within the BM framework.

- 1. BM OM derogation

Σ Aggregated Signals (Including sub-assets < 1 MW)	Range	Scale (unit)	Accuracy	Resolution	Refresh Rate
Active Power	- 50 MW to 50 MW	MW	Sub-asset measuring within 2.5% of meter reading	1 kW	1 per second at aggregate level. Up to 1 per 60 seconds at sub-asset
Circuit Breaker Simulated Indications	Open/Closed	0/1	Not Applicable	Not Applicable	On Change

Figure 5.1 – Existing Balancing Mechanism derogation requirements

Guidance on latency

- **DNV recommends that NESO work with industry to develop a methodology to measure the latency of aggregated assets by comparing timestamps for asset data communication and data receipt by NESO systems (either ex-post using granular asset data, or by averaging asset timestamps in in the portfolio meter signal).**

- Once the mechanism is available to test latency, assets that cannot meet the required latency thresholds can still participate in the Balancing Mechanism (BM) by compensating using a frequent MR interval, using the formula: MR interval = 30-2*ΔLatency, where ΔLatency= $\text{Latency}_{\text{Actual}} - \text{Latency}_{\text{Requirements}}$. For example, an overall 10 sec latency would require MR interval of 20 sec, whereas an overall latency of 15 sec, would require a MR interval of 10 sec. For overall latency greater than 20sec latency MR interval should be 1sec.

- In the long term, NESO may need to reassess its latency requirements considering the latency testing outcomes, ensuring alignment with the capabilities of the CERs portfolios. Once the 3a/3b solution is implemented, it is expected to incorporate considerations for communication latency.

Other recommendations related to Operational Metering Requirements

Table 5.1 – Other recommendations related to Operational Metering Requirements

#	Recommendation	Details	Responsible
1	**Operational Metering**		
1.1	DNV recommends that NESO makes plans to transition from GSP Group-level (14 regions) to GSP-level (130+ regions) aggregation for CER operational metering data to improve forecasting accuracy and constraint management, whilst acknowledging this may require multiple data feeds and operational parameter disaggregation to maintain the current 1MW minimum portfolio threshold.	The current GSP Group aggregation provides insufficient granularity for accurate demand forecasting and network constraint management, as evidenced by the Forecasting team's requirement for GSP-level data to properly model distributed energy resources. Moving to GSP-level aggregation would create a ten-fold increase in the difficulty of meeting the 1MW minimum bid size, alternatively aggregation could remain at GSP-group but operational meter feeds for BMUs aggregated at GSP-group could be split by GSP to maintain system visibility without creating insurmountable barriers for smaller aggregators.	NESO
1.2	DNV recommends that NESO should investigate the need for implementation of line loss correction factors when using CER meter readings for system balancing, as CERs connected at the lowest voltage level may experience significant losses between their metering point and the transmission system that NESO directly manages.	Power losses occur through distribution transformers and networks between the asset-level meters and the transmission connection points, meaning that raw CER meter readings will systematically underestimate the actual impact of demand/generation on system frequency and voltage control without appropriate loss adjustment factors applied to the aggregated portfolio data. Since it is probably not feasible to perform load flow calculations to assess / compare the impact of individual bids, simulations should be run to assess exemplary situations, comparing the contribution of bids from LV assets vs MV and HV assets to affect system frequency.	NESO
1.3	DNV recommends that NESO develop clear operational metering testing validation and compliance monitoring to test CERs connecting to the BM.	This is in line with the current testing conducted for large generator to validate accuracy and test meter read interval, and latency.	NESO

6. Implementation

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Implementation

In the previous section we identified the recommended solution and its benefits. Our key finding was that a ≤30s meter read should be applied to CER assets, whilst efforts to develop report-on-change for capable assets, and to upgrade NESO and aggregator systems to mitigate impacts progress.

In this section we examine how to implement these changes, which is important because execution risk could undermine the benefits of reform. This section sets out the implementation steps for each option, the required implementation timeline, and governance considerations.

6.1 Implementation steps for the recommended solutions

The timeline to improve Option 2a by implementing Option 3a/b depends on multiple factors

The four main factors impacting the timeline to improve 2a by implementing 3a/b are the NESO risk profile, the rate of CER adoption, the utilisation rate of CERs, and the proportion of CERs entering the BM.

Using the risk profile provided by NESO we can estimate the approximate timeline for the required implementation of Option 3a/b using the growth rate of CERs. Since EV's are expected to be the main asset type entering the BM in the next 5 years we have used only EV's in this analysis. DNV estimated the EV population of UK# roads each year to 2030 based on the Zero Emission Vehicle mandate being achieved. The results of the analysis are shown on the following slide.

Table 6.1 – Estimated UK BEV fleet up to 2030

YEAR	UK BEV car sales/year	Retired	UK BEV cars (cumulative)	Total chargers	Total MW
2024			1,300,000	1,000,000	7,000
2025	472,000	-92500	1,679,500	1,291,923	9,043
2026	569,000	-92500	2,156,000	1,658,462	11,609
2027	710,000	-92500	2,773,500	2,133,462	14,934
2028	900,000	-92500	3,581,000	2,754,615	19,282
2029	1,200,000	-92500	4,688,500	3,606,538	25,246
2030	1,600,000	-92500	6,196,000	4,766,154	33,363

Assumptions:
- Charger capacity is 7kw
- Zero Emission Vehicle mandate for 2030 is achieved (80% of car sales to be zero emission by 2030)
- All pre-2016 BEVs sold are retired between 2025-2030
- Current ratio of approximately 1,000,000 home charge points to 1,300,000 BEVs is maintained.*
- Theoretical maximum metered swing is all chargers in the BM moving in same direction simultaneously

Caveats:
Includes Northern Ireland sales, but on the other hand omits BEV Light Commercial Vehicles and Plug in Hybrid Vehicles

* Zapmap Home and Community Charging Stats
* Zapmap EV Driver Survey PDF

The size of EV swing required to breach NESO's risk profile duration was calculated using the model DNV developed for analysis of CER metering behaviour during this project. The assumptions are based on solution 2a being in place. Given there is minimal V2G connected at present, if it occurred this swing would consist of EV Smart Charging load reduction.

Size of EV swing required to breach each risk of NESO's risk profile durations:

NESO risk profile		Required CER swing to exceed risk tolerance*
Error duration	Permitted Error	
1s	1800 MW	3600 MW
5s	300 MW	750 MW
30s	50 MW	420 MW

Table 6.2 – NESO's risk profile

***Based on DNV modelling of CER behaviour under the following assumptions:**
- 30 second MR interval
- CER portfolios ramp to full response in 10 seconds (e.g. EV smart charging load reduction)
- 5s latency excluded

NESO's risk profile is exceeded once CER swings of 420MW begin to occur, likely by 2028 at the latest based only on EVs

NESO must begin evaluating the feasibility of Options 3a/3b immediately and be ready to implement other mitigations in control room (e.g. response and reserve).

The table below and chart right show in which year CER swings of the size required to breach the NESO risk profile can be expected based on estimated EV adoption and varying assumptions on EV utilisation rate provided by PodPoint, Octopus, and NESO. The rate of uptake of EVs into the BM is also a crucial unknown factor, indicative values were selected based on discussions with NESO.

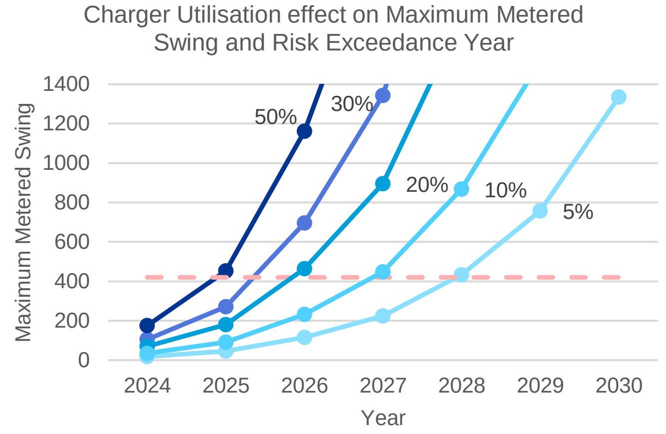
The results of the analysis show that by 2028 at the latest (based on the lowest utilisation rate) there could be risk profile exceedances based on a worst-case scenario of all utilised EVs swinging at the same time. If the utilisation rate or BM adoption is higher then this could be expected to occur sooner. However, the likelihood of all utilised EV's behaving in this way also need to be considered. DNV concludes that a transition to 3a/b is likely to be needed within the next 5 years, and that work to develop 3a/b should begin without delay.

Expected year of risk profile breaches based on estimated EV adoption, and varying assumptions on charge point utilisation and BM participation

		5% average utilisation (PodPoint)			30% average utilisation (Octopus)			50% utilisation at peak (FES 24)		
YEAR	Home charger installed capacity (MW)	MW utilised (average)	Of which in BM	Maximum metered swing (MW)	MW utilised (peak)	Of which in BM	Maximum metered swing (MW)	MW utilised (peak)	Of which in BM	Maximum metered swing (MW)
2024	7,000	350	5%	18	2,100	5%	105	3,500	5%	175
2025	9,043	452	10%	45	2,713	10%	271	4,522	10%	452
2026	11,609	580	20%	116	3,483	20%	697	5,805	20%	1,161
2027	14,934	747	30%	224	4,480	30%	1,344	7,467	30%	2,240
2028	19,282	964	45%	434	5,785	45%	2,603	9,641	45%	4,339
2029	25,246	1,262	60%	757	7,574	60%	4,544	12,623	60%	7,574
2030	33,363	1,668	80%	1,335	10,009	80%	8,007	16,682	80%	13,345

Table 6.3 – Predicted maximum metered swing based on estimated EV adoption and utilisation rates

Figure 5.2 – Risk exceedance timeline for various charger utilisation rates



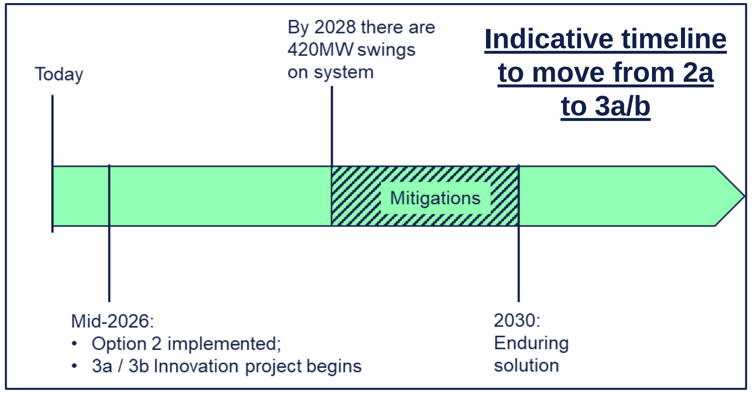


Figure 5.3 – Indicative timeline to move from Option 2a to Option 3a/b

Common Implementation Steps for all options

Implementation Steps:

- Revise contractual agreements
- Update BM operational metering policy to reflect new standards
- Establish whether any limits are needed on the capacity of CER BMUs registered or scheduled/instructed through the BM in order to manage operational issues posed by aggregated CER BMUs exacerbating existing transmission constraints.
- Determine how CER data (particularly demand-side flexibility) should be treated in the control loop and short-term forecasting.
- Introduce a compliance process into the registration workflow.
- Develop market monitoring for compliance and implement procedures to validate meter read and latency performance of assets during registration and operation
- Create thorough guidance with providers on best practices (especially for comms drop out/resilience)
- Provide training for internal stakeholders

Option 1b - Report-on-Change

Additional Implementation Steps:

- Develop report on change rules and methodology suitable for all asset types (reporting based on change in power could apply to all assets, for EV Chargers it could be based only on whether the vehicle is plugged in or not)
- Develop capability to highlight which units are operating on report-on-change mode
- Develop compliance checks required to ensure unit is operating correctly in report on change mode, assessing any latency in real-time reporting of data and granularity of data when changing outputs

Option 3a - NESO constructs corrective synthetic meter feed

Implementation Steps:

Pre-requisite: 2a in place

Innovation project – Feasibility and proof of concept

- Engage with industry to understand asset and communication protocol timestamp capabilities and suitability for NESOs requirements.
- Evaluate suitable estimation methodology (e.g. using the CER meter feed and PN/CCL*) for respective CER technologies and test performance on offline data
- Assess impact of fall-back to traditional meter feed on NESO systems and identify any upgrades needed
- Create an MVP monitoring capability for chosen estimation methodology

Innovation project – Proof of Concept

- Upgrade NESO systems to capture and process timestamps
- Test performance of CER synthetic metering on real-time data feeds
- Develop prototype automated monitoring of synthetic meter feed performance and intervention strategy for fall-back to traditional meter feed
- Agree final timestamp specifications with industry

Execution and BAU deployment

- Upgrade of NESO systems to support solution deployment
- Develop new data channels in balancing systems for synthetic feeds
- Establish compliance procedures to audit accuracy of submitted data parameters
- Create post-event analysis processes
- Ongoing monitoring resources and procedures

Option 3b - Aggregators submit a corrective synthetic meter feed to supplement their traditional metering

Implementation Steps:

Pre-requisite: 2a in place

Innovation project – Feasibility and proof of concept

- Engage with industry to understand synthetic metering approaches and capabilities.
- Validate industry proposed estimation methodologies for respective CER technologies and test performance on offline data
- Assess impact of fall-back to traditional meter feed on NESO systems and identify any upgrades needed
- Create MVP monitoring capability for synthetic metering

Innovation project – Proof of Concept

- Upgrade NESO systems to synthetic meter feeds and process timestamps
- Test performance of CER synthetic metering on real-time data feeds
- Develop prototype automated monitoring of synthetic meter feed performance and intervention strategy for fall-back to traditional meter feed
- Agree final synthetic metering standards and specifications with industry

Execution and BAU deployment

- Upgrade of NESO systems to support solution deployment
- Develop new data channels in balancing systems for synthetic feeds
- Establish compliance procedures to audit accuracy of submitted data parameters
- Create post-event analysis processes
- Ongoing monitoring resources and procedures

* **Physical Notification (PN):** For each BM Unit, data that describes the BM Participant's best estimate of the expected input or output of Active Power at the Grid Entry Point or Grid Supply Point.
* **Capped Committed Level (CCL):** the maximum expected output of a Balancing Mechanism unit, as determined by its Physical Notification (PN) and any Bid/Offer Acceptances (BOAs), capped by the Maximum Export Limit (MEL)

Guidance on Meter Validation

Random validation audits are required to ensure compliance with the implemented strategies.

As part of the implementation process, an element of validation and compliance monitoring is required. The data properties identified for monitoring are meter read interval, and latency.

Accuracy of the aggregated portfolio data relies on a minimum number of assets within the pool, as shown in the figure on the right. Given the portfolio threshold of 1 MW, all the technologies considered would require a portfolio size significantly higher than the minimum number of assets required to meet the accuracy requirements to enter the BM, therefore monitoring for accuracy is not required. Existing regulations and standards such as EV Smart Charging Regulations and COP11 already include minimum accuracy requirements of at least +/- 10%.

To monitor the meter read interval and latency, DNV proposes a pre-test and a random audit process. This would include timestamped data from the assets, allowing the meter read interval and latency to be assessed. At a random interval, several randomly selected aggregators would be required to submit their historical data from the most recent period of a duration to be determined.

Ensuring aggregators continue to comply between audit periods will be critical, which necessitates a level of randomness and uncertainty in the audit process. The audit interval and number of portfolios to sample should randomly selected from a range. This range for each parameter should be set such that aggregators cannot assume a subsequent audit will not occur imminently, even if a previous audit has recently taken place. Similarly, the period of data required should be of a long enough duration to discourage any non-compliance.

Table 6.4 – Measurement accuracy impact – Number of assets needed to meet 1% accuracy

MEASUREMENT ACCURACY IMPACT – NUMBER OF ASSETS NEEDED TO MEET 1% ACCURACY

				1MW Portfolio		30MW Portfolio	
Technology	**Size (kW)**	**Accuracy**	**Number of Assets to meet 1% accuracy**	**Number of assets**	**Maximum inaccuracy (MW) (1MW portfolio)**	**Number of assets**	**Maximum inaccuracy (MW) (30MW portfolio)**
EV	7	2%	4	143	0.17%	4286	0.03%
EV	7	10%	100	143	0.84%	4286	0.15%
Home BESS	14	2%	4	72	0.24%	2143	0.04%
Home BESS	14	3.5%	13	72	0.41%	2143	0.08%
Heat Pump	3	3.5%	13	334	0.19%	10000	0.04%
Heat Pump	3	10%	100	334	0.55%	10000	0.10%
Solar PV	5	2%	4	200	0.14%	6000	0.03%
Solar PV	5	10%	100	200	0.71%	6000	0.13%

Each individual CER meter has some measurement error, but by applying the Law of Large Numbers (LLN), aggregating readings from many meters reduces the overall error, scaling with 1/√n. This means that increasing the number of CERs improves the accuracy of the total measurement, even if individual meters are imprecise.

In practice, a sample size of 30 or more is often considered a reasonable number, but this is more a rule of thumb from the Central Limit Theorem than a strict requirement of LLN.

However, LLN only mitigates random errors, not systematic ones, so regulations like the Electric Vehicles (Smart Charge Points) 2021 require that inaccuracies not be systematic, a standard DNV recommends extending to Energy Smart Appliances.

Common Requirements Across Options 2 & 3:

NESO have identified the following common requirements for system upgrades to support the increased participation of CERs in NESO markets, these upgrades are required irrespective of whether Option 2 or Option 3 is implemented

- Address iHost resilience concerns for increased CER volumes
- Consider transition from internet to MPLS/OPTEL/leased line communications as capacity grows
- Establish interface between OLTA/OLTA's replacement and SMP

Strategic implementation journey: delivering change through key phases, milestones & industry engagement

NESO working closely with the PR stakeholders to harness the value of CERs

1. DNV Recommendations *(By Sept 25)*

Review and incorporate change to OM requirements based on DNV's recommendations

Align OM recommendations with contractual revisions and stakeholder feedback

2. Updated OM Requirements (*Sept 25 – Jan 26)*

Revise contractual agreements.

Design market monitoring framework for compliance.

Update operational metering requirements

Scope and secure approval for Feasibility Option 3.

Engage with industry to ensure alignment on updated requirements and policy changes.

Engage with industry to support implementation of 1b (ongoing)

3. Feasibility Option 3 (*Feb 26 – Aug 26)*

Launch and manage feasibility project.

Assess and select suitable estimation methodologies.

Scope and obtain approval for 3.

Engage with industry to test feasibility assumptions and gather input on estimation approaches.

4. PoC Option 3 *(Aug 26 – Aug 27)*

Build PoC monitoring capabilities.

Validate performance using ex-post data.

Scope and gain approval for Execute Option 3.

Engage with industry to review PoC results and refine execution plans.

5. Execute Suitable Option (*Aug 27 – Aug 29)*

Develop and deploy IT systems.

Integrate systems across platforms.

Define and implement fall-back strategy.

Plan and execute BAU transition strategy.

Lead change management activities.

Engage with industry to coordinate rollout and support adoption.

6. Transition to BAU (*By Jan 29)*

Complete transition to Business-As-Usual operations.

Engage with industry to monitor performance and ensure long-term compliance.

6.2 Complimentary reforms and recommendations

Other reforms and recommendations

Additional actions are recommended to integrate the recommendations appropriately during the implementation stage.

Further to the metering requirements recommended in Section 5.1, DNV advises that several additional actions are taken to align the industry and integrate the recommendations appropriately. These steps will help to ensure the continued safe and reliable operation of the system throughout the implementation stage.

The following slides detail the other reforms and recommendations, split into the following categories:

1. **Legislation**
2. **Standardisation**
3. **System planning**
4. **BM operational rules**
5. **Forecasting (Operational Timescale)**
6. **Grid code**
7. **Market and settlement rules**
8. **Operational Metering**

Other reforms and recommendations

#	Recommendation	Details	Responsible
1. Legislation			
1.1	NESO to consult with Department for Business and Trade (DBT) to consider capability to provide meter readings with 1s granularity in Energy Smart Appliances Device Regulations	DNV recommends that NESO further engage with DBT to raise awareness of their needs, such as: • to develop report-on-change capability in future • to ensure that Energy Smart Appliances have the capability to measure and communicate electrical power data every one second even if this is not enabled by default. This would ensure that in future ESAs will be able to provide 1s report-on-change, and 1s ex-post data for validation of operational metering.	NESO, Department for Business and Trade
1.2	NESO to consult with Department for Business and Trade to include a requirement in future legislation that for CER systems which include an inverter (EVs and Home BESS), that the meter is installed on the AC side of the inverter, or that an adjustment is made to account for inverter losses in line with settlement metering requirements.	Inverter losses can range between 5-25%[1] DNV recommends that NESO request that Energy Smart Appliances Device Regulations (expected to be unified with EV Smart Charging Regulations) avoid the impact of inverter losses on CER metering by requiring meters to be installed on the AC side of inverters.	NESO, Department for Business and Trade
2. Standardisation			
2.1	To accelerate the development and adoption of advanced communication protocols such as “report-on-change” mechanisms, NESO should take an active role in standardization bodies like BSI, IEC (International Electrotechnical Commission) and CENELEC (European Committee for Electrotechnical Standardization)	To support the development of advanced communication protocols like “report-on-change,” NESO should take an active role in standardisation bodies by nominating technical representatives to working groups focused on data exchange, flexibility, and interoperability. NESO should advocate for real-time, event-driven protocols to support improvement of meter data quality, collaborate with DNOs, aggregators, and technology providers to pilot and validate emerging standards, and ensure these efforts are aligned with regulatory goals.	NESO

Table 6.5 – Other recommendations

[1] https://assets.publishing.service.gov.uk/media/6808a2630324470d6a394eb2/SSES-consultation-response.pdf

[2] https://etech.iec.ch/issue/2024-03/the-case-for-direct-current#:~:text=Every%20conversion%20results%20in%20some%20energy%20loss%2C,on%20the%20quality%20of%20the%20electrical%20infrastructure.

Other reforms and recommendations

#	Recommendation	Details	Responsible
3. System planning			
3.1	FES team to engage with industry to update modelling assumptions for CERs penetration, availability, and proportion of CERs exposed to market signals	Understanding the expected behaviour and availability of CERs is key to understanding their system benefits and impacts. The FES team should engage with industry to refine the assumptions and methodology used in FES modelling. Some assumptions, such as number of vehicles plugged in at peak, have a significant influence on the expected operational challenges of the future electricity system.	NESO
3.2	Dimensioning reserve and response should be more regular activities to account for increased uncertainty created on the system by growth of CER flexibility in the BM and other energy markets	As the influence of CERs on the system increases and the impact of CER metering on control room grows, NESO should dimension reserve and response regularly accounting for the yearly CERs increase to ensure that SQSS is maintained.	NESO
4. BM operational rules			
4.1	DNV recommends that NESO continue to engage with potential new entrants to the BM through Power Responsive to inform them of the purpose and importance of PN accuracy, BOA precision and other operational data parameters	PN accuracy is already a key concern for NESO, however the capability of aggregators to submit high accuracy PNs and follow BOA accurately would be critically important for CERs in order to forecast their behaviour (whether carried our by aggregators or NESO). NESO should engage with industry to ensure providers understand how and when to provide required operational data and the relevant accuracy requirements	NESO
4.2	DNV recommends that once updates to NESO systems allow, the minimum 1 MW unit and bid size should be reviewed to enable increased adoption of CERs in the BM	The current 1MW minimum unit and bid size in the BM is challenging for aggregators to meet because with a limited number of assets available any time within a single GSP group it is often difficult to reach the minimum 1MW unit size. Also, bids must increase in increments of 1MW which reduces the ability of small portfolios to fully participate in the market if their availability is just short of full MW.	NESO

Table 6.6 – Other recommendations (cont.)

Other reforms and recommendations

#	Recommendation	Details	Responsible
4. BM operational rules			
4.3	DNV recommends that once CERs reach sufficient scale, NESO should mandate that CER portfolios should be of a single technology type (e.g. EV's, Heat Pumps, Home BESS, Solar PV). This requirement should not apply to aggregated industrial and commercial assets which are significantly more heterogeneous and difficult to aggregate into similar technologies at the required scale.	CER portfolios should ideally be of a single technology type to accurately characterise, predict, and validate their behaviour. Since CER penetration is currently low mixed technology BMUs are currently used to reach the minimum 1MW BM bid size. However, once the 1MW minimum bid size is reduced, or aggregators begin to have sufficient scale to reach that minimum in most GSP groups with a single technology, there should be a requirement for CER BMUs to be of a single technology type. NESO should explore whether it is better to implement this change industry-wide at the same time or case-by-case based on the size of an aggregators portfolio (e.g. by requiring that bids above a certain size are from a single technology portfolio).	NESO
4.4	DNV recommends that NESO enforce compliance with the 1% portfolio accuracy and required meter read intervals by requesting ex-post data from aggregators for analysis. Aggregation and portfolio meter data quality management should be the responsibility of aggregators and their supply chain, only the performance of the methodologies should be of consequence.	Ex-post data submission should be used to evaluate compliance with the Operational Metering Requirements for CER portfolios, either on a regular basis, at random, or a combination of both. The following should be the responsibilities of aggregators, the performance of which will be evaluated in accordance with the requirements: • Aggregation process to combine all asset data received each second into an aggregated signal • How to treat loss of communications • How to treat data that is deemed inaccurate • How to treat non-responding units	NESO

Table 6.7 – Other recommendations (cont.)

Other reforms and recommendations

Table 6.8 – Other recommendations (cont.)

#	Recommendation	Details	Responsible
5. Forecasting (Operational Timescale)			
5.1	DNV recommends that NESO prepare to fully integrate embedded demand and generation into forecasting processes.	NESO does not currently include BMUs connected through iHost (which includes all aggregated units) in forecast models. As NESO considers the replacement of iHost, preparations should be made for the integration of BMUs which currently connect to iHost into existing forecasting processes.	NESO
6. Grid Code			
6.1	DNV recommends that NESO keeps under review whether CER portfolios should be subject to ramp rate limits to prevent frequency deviations (implemented either through the Grid Code or legislation), and whether in which cases exemptions to these requirements are appropriate.	DNV’s analysis found that should the expected number of CERs under the Holistic Transition scenario materialise, the largest swings in CER portfolios at settlement boundaries could pose significant challenges to control room ability to keep frequency within operational limits, therefore Grid Code requirements or legislation to limit portfolio ramp rates may need to be considered in future. Exemptions which exist in EV Smart Charging legislation (and proposed for other CERs in the Energy Smart Appliances legislation) mean that aggregator dispatch of fast ramping CER portfolios based on intra-day price signals would not be restricted by 10-minute randomisation and could have significant system impacts.	NESO

Other reforms and recommendations

#	Recommendation	Details	Responsible
7. Market and settlement rules			
7.1	DNV recommends that NESO actively supports and collaborates with Elexon in developing standardised flexibility products, data flows, and registration processes that enable seamless value stacking across local and national electricity markets.	Value stacking is crucial for maximising the economic potential of CERs. The Open Networks Challenge Group is working to create the market infrastructure needed for frictionless value stacking by standardising service definitions, aligning timeframes, and establishing consistent data flows. The parallel transition to half-hourly settlement from October 2025 to July 2027 will unlock the real-time pricing signals necessary for consumers and aggregators to monetize flexibility services. NESO's support would help ensure these initiatives align with system operations and create a coherent framework that benefits both system stability and market participants.	NESO, Elexon, ENA
7.2	NESO should continue to work with ENA and Elexon on the harmonisation of baseline methodologies and procedures, which is relevant across all processes	ENA and Elexon are working to establish baselining rules to enable accurate validation, settlement, and visibility of CER portfolio flexibility. NESO should engage with this work and look for opportunities to harmonise baselining methodologies ensuring alignment across planning, forecasting, and operational decision-making processes	NESO, ENA, Elexon
7.3	DNV recommends that NESO align with Elexon to ensure that NESO's data requirements for CERs are included in Flexibility Market Asset Registration (FMAR) design.	FMAR will provide a single platform for asset registration, reducing the current complexity where flexibility providers must register the same assets multiple times in different DSO and NESO markets. NESO should engage with FMAR to ensure that data requirements expected to be of importance to NESO (such as locational data) are included in FMAR design.	NESO, Elexon
7.4	DNV recommends that NESO review the metering requirements for individual products and sets proportionate metering requirements for each.	At present the metering requirements for most NESO products align with the Balancing Mechanism. There may be an opportunity to relax metering requirements for some NESO products which do not require high resolution metering (such as is the case for the slow reserve), whilst maintaining a high-quality standard for the BM. This would provide less capable and legacy assets with alternative routes to market than the BM whilst reserving BM access for the most capable assets	NESO

Table 6.9 – Other recommendations (cont.)

Other reforms and recommendations

Table 6.10 – Other recommendations (cont.)

#	Recommendation	Details	Responsible
7. Market and settlement rules			
7.5	NESO should work with industry and regulators to harmonise metering requirements across existing regulatory frameworks e.g. COP11 and MIR, to reduce manufacturer compliance costs and certification burdens.	The current fragmented regulatory landscape requires manufacturers to meet multiple, often conflicting metering standards creating significant cost barriers through lengthy certification processes and the need to redesign equipment to meet GB-specific requirements that differ from European standards. NESO should actively work with partners to align requirements, both now and in the future, so that simplified requirements which balance the needs of all parties are maintained. For example, the proposed requirement for Energy Smart Appliances to have MIR Class B compliant meters goes beyond the capabilities identified as necessary for Operational Metering identified in this report.	NESO, DBT, Ofgem, Elexon
7.6	To provide NESO with visibility on rebound volumes[1], DNV recommends that independent aggregators should either be incentivised and/or obliged to control the rebound by including their (flexibility) dispatch volumes in their physical notifications (rather than the absolute volumes of the CERs they control, to avoid double-counting with suppliers including the CER volumes in their PNs).	In the current wholesale arrangements for independent aggregation, there is neither a need nor incentive for independent aggregators to control the rebound effect. Consequently, rebound volumes (having the same order of magnitude as CER dispatch volumes) will not become visible to NESO, since they are not dispatched by independent aggregators (hence not included in their PNs), and not known/visible to Suppliers (who are therefore not able to include these volumes in their PNs).	NESO

[1] A further explanation about the rebound effect, and rebound volumes, can be found in smartEn's position paper about the rebound effect.

WHEN TRUST MATTERS

Operational Metering Requirements

WP5: Final Report

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Appendix A: BM Services

Balancing services includes reserve, response, voltage services procured to ensure the security and quality of electricity supply

Response Services

NESO licence obligation to control system frequency at 50Hz plus or minus 1%. We make sure there is sufficient generation and demand held in readiness to manage all credible circumstances that might result in frequency variations. There are two categories of frequency response:

- Dynamic frequency response is a continuously provided service used to manage the normal second by second changes on the system
- Non-dynamic response is usually a discrete service triggered at a defined frequency deviation.

The definition of each service is shown on the next slides.

Traditionally, Firm Frequency Response (FFR) is ESO's traditional frequency response suite used for balancing grid frequency in real time. Static FFR will continue to be actively procured until replaced with a future enduring static product. Dynamic FFR is being phased out over the period FY23/24 as new dynamic response services Dynamic Containment, Dynamic Moderation and Dynamic Regulation (DC, DM, DR) offset this requirement. Together they work to control system frequency and keep it within NESO licence obligations of 50Hz plus or minus 1%.

Dynamic frequency response is a continuously provided service used to manage the normal second-by-second changes on the system and needs to provide:

- Primary response - Response provided within 10 seconds of an event, which can be sustained for a further 20 seconds.
- Secondary response - Response provided within 30 seconds of an event, which can be sustained for a further 30 minutes.
- High frequency response - Response provided within 10 seconds of an event, which can be sustained indefinitely

Reserve Services

System conditions are changing, and faster-acting services procured closer to real-time are required to meet three distinct criteria:

1. To restore frequency to within statutory limits within 60 seconds.
2. To recover frequency to within operational limits within 15 minutes.
3. To respond to transient supply demand imbalances that take pre-fault frequency close to operational limits.

Reserve is needed for frequency management when there is an imbalance between supply of energy and demand for energy.

A suite of new Reserve products are being designed to replace the existing suite of positive and negative Reserve products. The existing Short Term Operating Reserve (STOR), Fast Reserve (FR) and Optional Downward Flexibility Management (ODFM) services will not be included in the report due to prior or planned phase-out.

Reactive Power Services

Reactive power services are used to ensure voltage levels on the system remain within a given range, above or below nominal voltage levels. NESO instructs generators or other asset owners to either absorb reactive power (decreasing voltage) or generate reactive power (increasing voltage).

The flows of reactive power on the system will affect voltage levels. Unlike system frequency, which is consistent across the network however with regional variations, voltages experienced at points across the system form a 'voltage profile', which is uniquely related to the prevailing real and reactive power supply and demand. NESO must manage voltage levels on a local level to meet the varying needs of the system. Without the appropriate injections or absorptions of reactive power at the right locations, the voltage profile of the transmission system will exceed statutory planning and operational limits.

The definition of each service is shown on the next slides.

Response, reserve, flexibility and voltage services have different roles in meeting the SQSS, hence different service requirements

Service	Type	Role	Aggregation locality	Procurement	Min requirement	Activation time/speed	Sustain time (min)	Metering Requirements
Balancing Mechanism (Regulating Reserve)	Reserve	correct energy imbalances (differences between generation and demand)	GSP Group	60min ahead of real time	1 MW	Defined by dynamics parameters	15min max for energy limited assets	Active power measurements required at 1Hz at an accuracy of +/- 1%.
Quick reserve*	Reserve	aimed for reacting to pre-fault disturbances to restore the imbalance quickly and return the frequency close to 50 Hz.	GSP Group	Daily – 14:30	1 MW	1 minute	1-30 minutes	TBD
Slow reserve*	Reserve	designed to operate post-fault, provides NESO access to firm, bi-directional energy to displace large losses on the system and recover frequency to ± 0.2Hz within 15 minutes	GSP Group	Daily – 14:30	1 MW	15 min	(30-120)	TBD
FFR (static)	Response	a non-dynamic frequency response service which is triggered at a defined frequency deviation.	Nationwide	Daily Auction	1 MW	30sec	30	Real time active power/frequency measurement required, performance data upon request1
Mandatory Frequency Response (MFR)	Response	automatic change in active power output in response to a frequency change, it helps NESO to keep frequency within statutory and operational limits, depends on BMU size and location, as per the connection agreement	Nationwide	via BM (payment monthly)	Depends on connections			Real-time active power measurement at a rate of 1Hz. (Dx only) Performance monitoring requires active power/frequency measurement at a rate of 20Hz on an hourly basis

*Quick and slow reserve requirements currently under consultation so subject to change

DNV

Response, reserve, flexibility and voltage services have different roles in meeting the SQSS, hence different service requirements

Service	Type	Role	Aggregation locality	Procurement	Min requirement	Activation time/speed	Sustain time (min)	Metering Requirements
Dynamic Containment (DC)	Response	post-fault service, prevents frequency deviation outside -0.8Hz/ +0.5Hz following large losses	GSP Group	Day-ahead tenders	1 MW	0.5s	15	As above
Dynamic Moderation (DM)	Response	provides fast acting pre-fault delivery for particularly volatile periods, assists with keeping the frequency within +/- 0.2Hz	GSP Group	Day-ahead tenders	1 MW	0.5s	30	As above
Dynamic Regulation (DR)	Response	staple slower pre-fault service, assists keeping the frequency near 50Hz	GSP Group	Day-ahead tenders	1 MW	2s	60	As above however performance monitoring only required at a rate of 2Hz or 20Hz.
Demand Flexibility Service (DFS)	Flexibility	access additional megawatts (MW) during times of high national demand, particularly on peak winter days when the system could have been placed under stress	GSP Group	Day ahead – 16:30	1 MW	7.5 hours minimum	Min 30	Active Power - Half hourly boundary point or asset metering
Obligatory reactive power service (ORPS)	Voltage	Obligatory provision of reactive power to help manage system voltages close to the generator point of connection.	GSP Group	BM	supplying rated power output (MW) at any point btw the 0.85 PF lagging and 0.95 PF leading at the BMU terminals	2 min		Active power measurements required at 1Hz at an accuracy of +/- 1%.
Enhanced reactive power service (ERPS)	Voltage	suitable for generators who can provide reactive power but aren’t required to provide ORPS	GSP Group	BM		2 min		As above
Balancing Reserve	Reserve	Allow the NESO to procure Regulating Reserve on a firm basis on a Day Ahead.	GSP Group	Day-ahead	1 MW	2 min	10 min	Accuracy +/- 1%, refresh frequency 1Hz, latency 5s
Stability Markets	Stability	Maintain minimum inertia and fault levels on the network	GSP Group	Y-4, Y-1, D-1	1 MW	2 min		As above

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Appendix B: BMU Requirements

BMUs vs non-BMU requirements

The Requirements for Generators sets harmonised European standards for generator performance, categorising them into four types (A-D) based on voltage and capacity, with specific technical criteria to ensure grid stability and efficiency.

Requirements for Generators (RfG)

RfG is one of the main drivers for creating harmonised solutions and products necessary for an efficient pan-European market in generator technology. The purpose of the code is to bring forward a set of coherent requirements in order to meet these challenges of the future. The requirements under RfG are similar to the existing GB Grid Code for larger generators. For generators below 10MW there are differences; and the requirements go all the way down to 800W.

The technical requirements in RfG are arranged in four types A-D based on the connection voltage and MW capacity. The maximum levels allowed are as follows:

Type	Connection Voltage	Capacity	Description
A	<110kV	0.8kW – 1MW	Provides a basic level necessary to ensure capability of generation over operational ranges. It has limited automated response and minimal system operator control.
B	<110kV	1MW - 10MW	Type B provides for a wider range of automated dynamic response, with greater resilience to more specific operational events
C	<110kV	10MW - 50MW	Provide for a refined, stable and highly controllable (real-time) dynamic response, aiming to provide principle ancillary services to ensure security of supply.
D*	>110kV	50MW +	Requirements specific to higher voltage connected generation with an impact on entire system control and operation. They ensure the stable operation of the interconnected network, allowing the use of ancillary services from generation Europe-wide.

**Any Generator connecting at 110kV or higher is classified as Type D regardless of capacity*

Technical Requirements	Type A	Type B	Type C	Type D
Operation across a range of frequencies	●	●	●	●
Limits on active power output over frequency range	●	●	●	●
Rate of change of frequency settings applied (likely to be at least 1Hz/sec)	●	●	●	●
Logic interface (input port) to cease active power output within 5 secs	●	●	●	●
Ability to automatically reduce power on instruction		●	●	●
Control schemes, protection and metering		●	●	●
Fault Ride Through requirements		●	●	●
Ability to reconnect		●	●	●
Reactive capability		●	●	●
Reactive current injection			●	●
Active power controllability			●	●
Frequency response			●	●
Monitoring			●	●
Automatic disconnection			●	●
Optional Black start			●	●
Stable operation anywhere in operating range			●	●
Pole slipping protection			●	●
Quick resynchronisation capability			●	●
Instrumentation and monitoring requirements			●	●
Ramp rate limits			●	●
Simulation models			●	●
Wider Voltage ranges / longer minimum operating times				●
Synchronisation on instruction				●
Enhanced Fault Ride through				●

Table 7.3 – Description of generator types

BMUs vs non-BMU requirements

License Exemptible Embedded Medium Power Stations (LEEMPS) must provide metering data as per their DNO Bilateral Connection Agreement, using broadband and the IEC 60870-5-104 protocol. No equivalent exists for large demand.

License Exemptible Embedded Medium Power Station

The data acquisition system for the License Exemptible Embedded Medium Power Station (LEEMPS) will facilitate operational metering as required in the relevant DNO's Bilateral Connection Agreement. Communications between the User's system and NGET's data concentrator will use a broadband internet connection, with signals transmitted via the IEC 60870-5-104 protocol.

Before commissioning, the DNO will provide the user with a detailed Inter-operational Specification, including the necessary IP addresses. This specification will outline the specific configuration for the communication between the User's system and DNO's data concentrator using the IEC 60870-5-104 protocol.

The signals provided by the User will comply with the specifications in the table below and will be transmitted using the IEC 60870-5-104 protocol via the internet to the NCC. The user can select the method of connecting to the internet, whether through a dedicated connection or GPRS.

Signal Type	Range	Accuracy	Resolution	Refresh Rate
Active Power	0-150MW	1% of reading (down to 5MW)	0.1 MW	1 per min
Reactive Power	-100 MVAr to +100MVAr	1% of reading (down to 5MVAr)	0.1 MVAr	1 per min
User System Entry Point Voltage	132kV = 60 – 160kV 66kV = 40 – 80kV 33kV = 20 – 40kV 11kV = 5 – 20kV	1% of full scale	0.1 kV	1 per min
Wind Speed	0-35 m/s	+/- 2m/s	1 m/s	1 per min
Wind Direction	0-360 deg	+/- 15 deg	5 deg	1 per min

Table 7.4 – Operational metering requirements for LEEMPS

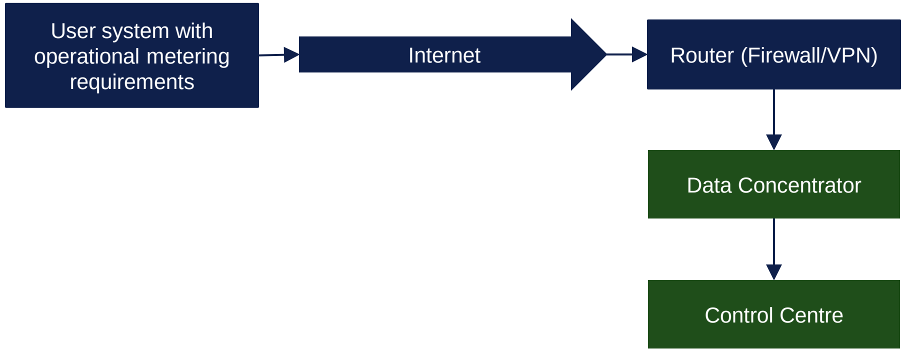


Figure 7.1 – LLEMPS Operational Metering System

Large generators requires Dynamic System Monitoring (DSM)

Large generators are required to provide high frequency DSM as specified in the grid code

Dynamic System Monitoring (DSM) is a system implemented by the NreplaceESO to continuously monitor and analyse the dynamic behaviour of the GB's electricity transmission network. This monitoring is essential for ensuring the stability and reliability of the power grid, particularly as it integrates more renewable energy sources.

The requirement to install DSM technology is specified in the Grid Code and applies to the following generator types:

- Type C (10MW - 50MW)
- Type D (50MW+ or connected at 110kV+).

The primary purpose of DSM is:

- Grid Stability and Reliability: To maintain the stability and reliability of the power grid by providing real-time data on system dynamics.
- Event Detection: To capture transient events (e.g., faults) and slower disturbances (e.g., voltage depressions) that can affect grid performance.
- Model Validation: To validate power system models used in planning and operation by providing accurate and high-resolution data.
- System Performance Reporting: To support post-fault investigations and system performance reporting by providing synchronised and accurately timed data.

DSM systems record voltage, active power, reactive power, and frequency, and are designed to provide:

- Continuous Data Collection: Collect and store data continuously at a high sampling rate (at least 256 samples per cycle, with some specifications increasing this to 512 samples per cycle).
- High-Resolution Time Tagging: Tag all sampled and derived data with a time accuracy of 1 microsecond or better, synchronised to UTC, TAI, or GPS time.
- Event Flagging and Notifications: Detect deviations from set thresholds and trigger event flags, with customizable notifications for specific events such as rate of change, level deviations, and oscillatory conditions.
- Data Storage: Store data in non-volatile memory for a minimum of 28 days before overwriting, ensuring data availability for analysis and reporting.

Sources:
Grid Code https://www.nationalgrideso.com/document/105026/download;
DSM:https://www.nationalgrid.com/sites/default/files/documents/39188-20.%20RES_TS_3.24.70_i1.pdf ;
Generator types: https://www.nationalgrid.com/sites/default/files/documents/RfG%20Factsheet%20June%202018.pdf

Appendix C: GB Metering Requirements

BM operational metering requirements are different from other type of metering requirements

The existence of many different metering requirements for settlement and TSO/DSO services is discouraging for market parties who wish to access multiple services. In addition, manufacturers look to government regulations when designing asset metering capabilities.

This section summarises metering requirements for various markets or metering requirements driven by regulation for certain technologies. More specifically, the following requirements are analysed:

- Metering requirements of Balancing Services assets for settlement purposes
- Metering requirements for DSO flexibility services;
- Measuring Instruments Regulation (MIR) 2016 requirements;
- Metering requirements for ESO's capacity market;
- Meter requirements for EV smart charger; and Smart Appliances

For each of the requirement groups we have answered the following questions:

- Which markets and services have these requirements;
- Which organisation is responsible for defining the requirements
- Type of meters allowed;
- Which technologies are affected; and
- What the requirements are.

At the end of the section, we provide conclusions with an overview of all the different requirements, and we compare them against the current operational metering requirements.

Multiple metering standards for Smart Charging Regulations, BM, DSO flex, CM
Respondents reported significant challenges due to the multiple metering standards required across various regulatory frameworks. The complexity and cost of compliance are high, with different standards for Smart Charging Regulations, Balancing Mechanism, Distribution System Operator flexibility, and Capacity Market. Many organizations expressed the need for harmonisation of these standards to reduce the burden and streamline operations.
"It's challenging to understand and comply with the menagerie of different metering standards across Smart Charging Regulations, DSO, CM, and BM. If all flex metering (operational and settlement) could align with COP11, it would massively simplify the challenge of delivering products to market and maximizing flex value." "EV assets were not designed to align with Operational Metering requirements, causing significant implementation challenges. Existing standards that EV assets comply with should be considered in regulatory requirements."

Settlement metering requirements are more relaxed compared to OM requirements for smaller assets

CoP11 has grouped accuracy requirements for asset meters into 5 different categories. The minimum accuracy requirements are 2% for all the categories under laboratory testing environments

Balancing Mechanism Settlement requirements

Responsibility: Elexon is responsible for settlement metering requirements. ELEXON is an independent third party who oversees the strategic operation and day-to-day management of the Balancing and Settlement Code (BSC). As part of its role, ELEXON also manages settlement services for the Balancing Mechanism (BM), including the balancing services.

Assets/ Technologies: This section focuses on the metering requirements for assets which comprise a secondary Balancing Mechanism unit and are defined under the Code of Practice (CoP) 11 [1]. This Code of Practice is only applicable to sub-meters for assets which provide balancing services (i.e., it is not applicable to whole energy trading or other type of services). All balancing services allow for sub-metering to be used for settlement purposes following a recent modification of the BSC which is called P375 Modification and has been applied since June 2022. This Code of Practice is not relevant to Metering Equipment comprised within a Boundary Point Metering System(s). For the Metering Equipment requirements for Boundary Point Metering Systems Code of Practice 1, 2, 3, 5 and 10 are applicable, as well as Code of Practice 4 for calibration, testing and commissioning requirements. The accuracy requirements for Boundary Point Metering are higher or same level as CoP11.

Type of meters: The type of meters that are allowed to be used as sub-meters under CoP11 are:

1. Category 1- Existing Balancing System Code Approved Half-Hourly Meters (used for Balancing Mechanism, and billing)
2. Category 2 - Operational Meters (for example, these that are used for operational data by the NESO); and
3. Category 3 - Meters embedded within a product (for example in EV charger point).

Metering requirements for settlement as per CoP11

Accuracy requirements for Asset Meters are grouped into 5 different categories. On the next page we present the accuracy requirements for the assets of smaller sizes, as these are the most interesting for the scope of the project. Elexon and other stakeholders have clarified that the accuracy requirement for embedded meters is 2%. The +2.5% / -3.5% accuracy reflects accuracy requirements on-site and with other equipment connected. So, the minimum accuracy requirements under laboratory testing environment are 2%.

We would like to note that as of November 2024 independent aggregators will be able to participate in the wholesale markets with portfolio of assets (modification P415). The current intention is that implementation of P415 will use existing , recently modified arrangements related to independent aggregators and asset participation in the balancing markets. However, this has not been confirmed and is subject to implementation details.

Sources:
https://bscdocs.elexon.co.uk/codes-of-practice/code-of-practice11-code-of-practice-for-the-metering-of-balancing-services-assets-for-settlement-purposes

CoP11 accuracy requirements for settlement asset meters vary per asset size

The accuracy requirements presented below reflect on-site accuracy and with other connected equipment

Current expressed as a percentage of Rated Measuring Current	Power Factor	Limits of Error
120% to 10% inclusive	1	+-0.5%
Below 10% to 5%	1	+-0.7%
Below 5% to 1%	1	+-1.5%
120% to 10% inclusive	0.5 lag and 0.8 lead	+-1.0%

Table 8.1 Asset Metering Type 1 - Metering of circuits with a rated capacity greater than 100MVA

Current expressed as a percentage of Rated Measuring Current	Power Factor	Limits of Error
120% to 10% inclusive	1	+-1.0%
Below 10% to 5%	1	+-1.5%
Below 5% to 1%	1	+-2.5%
120% to 10% inclusive	0.5 lag and 0.8 lead	+-1.0%

Table 8.1 Asset Metering Type 2 - Metering of circuits with a rated capacity not exceeding 100MVA

Current % of rated measuring current	Power Factor	Limits of error
120% to 10% inclusive	1	+-1.5%
Below 10% to 5%	1	+-2.0%
120% to 10% inclusive	0.5 lag and 0.8 lead	+-2.5%

Table 8.3 Asset Metering Type 3 - Metering of circuits with a rated capacity not exceeding 10MVA

Current % of rated measuring current	Limits of error at stated system power factor	Power Factor
120% to 10% inclusive	+-1.5%	1
Below 10% to 5%	+-2.5%	1
120% to 10% inclusive	+-2.5%	0.5 lag and 0.8 lead
100% to 5% inclusive	+2.5% to -3.5%	All

Table 8.4 Asset Metering Type 4 - Metering of energy transfers with a Maximum Demand of up to (and including) 1MW

Current % of rated measuring current	Power Factor	Limits of error
In to Imax inclusive	All	+2.5% to -3.5%

Table 8.5 Asset Metering Type 5 - Metering (embedded within equipment) for energy transfers with a Maximum Demand of up to (and including) 100kW

https://bscdocs.elexon.co.uk/codes-of-practice/code-of-practice11-code-of-practice-for-the-metering-of-balancing-services-assets-for-settlement-purposes

Metering accuracy standards

With respect to accuracy the CoP regulations refer to BS EN standards (BS: British Standard, EN: European Norm). These standards are essentially the same standards as the international IEC standards. The standards referred to in the CoP regulations are the following.

For Active Energy:

- BS EN/IEC 62053-22, “Electricity metering equipment – Particular requirements – Part 22: Static meters for AC active energy (classes 0.1S, 0.2S and 0.5S)”
- BS EN/IEC 62053-21, “Electricity metering equipment – Particular requirements – Part 21: Static meters for AC active energy (classes 0.5, 1 and 2)”

For Reactive Energy:

- BS EN/IEC 62053-23, “Electricity metering equipment – Particular requirements – Part 23: Static meters for reactive energy (2 and 3)”
- BS EN/IEC 62053-24, “Electricity metering equipment – Particular requirements – Part 24: Static meters for reactive energy (0.5S, 1S, 1.2 and 3)”

Further the CoP regulations also refer to EN 50470-3. This standard was specifically developed by the EU (CENELEC) for meters to comply with MID.

- EN 50470-3, “Electricity metering equipment – Part 3: Particular requirements – Static meters for AC active energy (classes indexes A, B and C)”

How to read the accuracy requirements?

0.x: This indicates the accuracy class, meaning the device has an error margin of ±0.x%.

S: This signifies that the device maintains its accuracy even at lower current levels, typically down to 1% of the rated current.

Metering accuracy standards: IEC vs MID accuracy

There is a difference between the accuracy classes described in the IEC standards as compared to MID (or EN 50470-3). This is stated in EN 50470-3: “The correspondence of accuracy classes between different standards and regulations is not direct. For instance, accuracy classes may be based on meter performance at reference conditions, whereas others may be based on combined error.”

The correspondence between IEC and MID is shown in the table below, copied from the EN 50470-3. So, an MID type B meter corresponds with an IEC meter with accuracy of ±1%.

In its normal operating range, an MID Type B meter will have a maximum permissible error (MPE) of ±2% (see slide 61). This MPE is not the same as the accuracy as defined in the IEC standards. When IEC 62053-21 talks about a class 1 meter with an accuracy of ±1%, this accuracy only includes one type of error namely the error due to variation of the current. In MID (and EN 50470-3) there are four factors that contribute to the MPE and the error due to variation of the current is only one of those factors (the others are temperature, voltage and frequency)

Table C.1 — Accuracy classes for active energy in different standards and regulations

Standard or regulation	Designations (lowest accuracy to highest accuracy)				
EN IEC 62053-21:2021/A11:2021 EN IEC 62053-22:2021/A11:2021	2	1	0,5 / 0,5 S	0,2 S	0,1 S
Directive 2014/32/EU	A	B	C		

Measurement Instrument Regulation define the regulations that any meters “used for trade” should adhere to

Many of the requirements are basic minimums that are expanded upon in the Codes of Practice, especially CoP 11 which is dedicated to asset meters including EV charge points.

Measurement Instrument Regulation (MIR) 2016[1]

Responsibility: MIR is the British measurement regulation, which is reflecting Measuring Instruments Directive (MID) 2014/32/EU.

Assets/Technologies: By this regulation anything which is using a meter reading as the basis for payment under 100KW, is constituted to cause a trade so everything under 100kW needs to comply with MIR. This includes submeters. Under MIR s.3, within the definition of “measuring instrument” active electrical energy meters are included with that term meaning meters:

“for use for trade other than an instrument which is used under an agreement providing for the supply of active electrical energy where—

(i) the maximum quantity supplied exceeds 100 kilowatts per hour; and

(ii) the instrument provides measurement on a half-hourly basis”

Type of meters: The measuring devices which are covered under the regulation include but are not limited to water meter, gas meters, active electrical energy meters, heat meters, and taxi meters.

Measuring requirements: MIR requirements follow the MID EU directive standards. The instrument specific requirements for active electrical energy meters are described in MID Annex V and include, amongst other, requirements regarding measurement accuracy of the meters. is also important to note that this MID Annex only applies to active electrical energy meters intended for residential, commercial and light industrial use. However, there is no clear definition of what residential, commercial and light industry actually entails. In any case, the MID was not written or designed considering use cases that use embedded meters.

Regarding the measurement accuracy, the MID describes the term maximum permissible error (MPE). Different influence quantities are taken into account to calculate the MPE. Active energy meters are divided in several classes (class A, class B, and class C) depending on their accuracy.

The figure below shows Table 2 from the MID Annex V

MPEs in percent at rated operating conditions and defined load current levels and operating temperature

	Operating temperatures			Operating temperatures			Operating temperatures			Operating temperatures		
	+ 5 °C … + 30 °C			− 10 °C … + 5 °C or + 30 °C … + 40 °C			− 25 °C … − 10 °C or + 40 °C … + 55 °C			− 40 °C … − 25 °C or + 55 °C … + 70 °C		
Meter class	A	B	C	A	B	C	A	B	C	A	B	C
Single phase meter; polyphase meter if operating with balanced loads												
$I_{min} \leq I < I_{tr}$	3,5	2	1	5	2,5	1,3	7	3,5	1,7	9	4	2
$I_{tr} \leq I \leq I_{max}$	3,5	2	0,7	4,5	2,5	1	7	3,5	1,3	9	4	1,5
Polyphase meter if operating with single phase load												
$I_{tr} \leq I \leq I_{max}$, see exception below	4	2,5	1	5	3	1,3	7	4	1,7	9	4,5	2
For electromechanical polyphase meters the current range for single-phase load is limited to $5I_{tr} \leq I \leq I_{max}$												

Sources:
1 https://www.gov.uk/government/publications/measuring-instruments-regulations-2016/measuring-instruments-regulations-2016-great-britain

DNV

MIR compliancy is still a grey area for GB as according to the NESO, there are stranded residential assets because they do not comply with MIR

In particularly, according to an ADE-Power responsive study, less than 1% of all existing asset meters in the GB are MIR compliant.

As it has been indicated by previous studies the cost for asset meters to be MIR compliant (especially for residential assets) is disproportionate and discourage customers to instal MIR compliant meters for participating in balancing services. Whether MIR compliance is required to participate in balancing services is still to be explored. The interpretation of MID phrase that MIR is applicable to asset meters that are intended “for use of trade” – see previous page – could probably imply that also flexible assets that participate in balancing services and DSF services should be eligible as these services are considered a trade.

In addition, MID requires measuring instruments to indicate their result “by means of a display or hard copy”. This cannot be indicated via computer screen or phone app and must be an in-built display in the instrument itself. Unlike the MIR, the EV regulations do not stipulate the manner in which the measuring results must be communicated to the customer. Most smart EV charge points contain an embedded meter that does not have an external meter reading display. Therefore, if an EV charge point is to engage in smart functionality and be MIR compliant it must have a display for the customer to read the metering results in a “clear and unambiguous” manner. GB stakeholders are exploring if this requirement could be met by a not in-built display.

The industry is now exploring whether there can be a light touch on MIR compliancy for sub-meters. This means that instead of asking sub-meters to comply with the full set of MIR requirements, there can be a modification of the requirements or a less strict interpretation of the requirements so that the process is simplified.

This” light touch” still under investigation by NESO, Ofgem, Department of Business and Trade Office of Product Safety & Standards and Department of Energy Security & Net Zero.

Reflecting our engagement with stakeholders to date and previous work on the topic of MIR compliancy, we have identified the following barriers for small assets:

- Accuracy requirements: in these residential assets with embedded meters (only the metering electronics) the accuracy is unknown. This is based on previous projects DNV has been involved in and limited literature available, we estimate this to be between 1% and 10%, to be "on the safe side".

- The requirement for an “in-built” display;

- Extensive list of requirements which have not been discussed in detail with the stakeholders but are not relevant to the accuracy requirements.

Although MIR compliancy is not in scope of this study, we consider it relevant when discussing metering requirements barriers for participating in the Balancing Mechanism and Balancing services. In conclusion our current understanding of MIR compliancy is not relevant for embedded meters.

Metering data are used in DSO flexibility services to monitor performance, settlement and baselining

Flexible assets are allowed to include boundary metering or asset metering. No accuracy requirements are defined. Read frequency is minute by minute.

DSO Flexibility services

Responsibility: The DNO is responsible for monitoring performance and for settlement of the DSO flexibility services. As such the DSO defined the metering requirements & standards for DSO flexibility services. All metering requirements are defined in the Flexibility Services Standard Form Agreement (SFA) that has been developed by the Electricity Networks Association (ENA) in collaboration with all the DNOs.

Assets/ Technologies: Metering requirements are applicable to all assets that participate in the service.

Type of meters: This is not defined in the SFA.

Metering requirements:

- The Provider shall send **aggregated Flexible Unit meter data** in a format as specified by the Company at minutely or half-hourly granularity, every month for the previous month where the FU was providing services. The meter data shall include any additional time periods required to calculate the agreed baseline.

- The Provider shall also be able to provide minute by minute meter data **at each asset** which comprises a flexibility unit (FU) on request

- At the request of the DNO the FSP should make available to the company information about the metering equipment at the DER

- During the qualification process a proving test is required during which the FSP should demonstrate delivery from the metered data from each DER within the Flexible Unit.

- There is no requirement to provide live feed to the DNOs.

The metering requirements in Capacity Market (CM) can vary depending on the individual configuration of the Capacity Market Unit (CMU)

CM metering requirements for the majority of assets and type of meters align with BSC metering requirements. The main differences lie into the submission of data and volumes calculation.

Capacity Market

Responsibility: The metering requirements for Capacity Market have been designed by the Electricity Market Reform (EMR) Settlement Limited, which is Elexon's wholly owned subsidiary.

Assets/ Technologies: The metering requirements are applicable to all assets which participate in the CM i.e., generator units, interconnectors and demand side response (DSR) assets.

Type of meters: In the CM there are four types of Metering Configuration Solution**:** Balancing Mechanism Unit (BMU) (BSC Metering); Supplier Settlement (Non-BMU) (BSC Metering); Balancing Services; and Bespoke solutions which is required in case of splitting BMUs (i.e., asset meter), difference metering and additional metering (not used in BSC settlement).

Metering requirements: Metering requirements vary per metering configuration solution.

For those **assets that are BSC registered**, no further requirements are defined for participation market. Compliance with the associated Codes of Practice (COP) is sufficient for CM arrangements.

For those **assets that provide Balancing Services** to NESO but are not BSC registered , the asset can use a metering device that is capable of providing adequate metering signals for NGESO's requirements. For this type of installation, the Metering System has to meet the accuracy requirements specified in the relevant Balancing Services Agreement. The applicable contracts in CM are STOR, FFR, FCDM according to 2022 publication. We expect that the new frequency and reserve services will also be applicable but this needs to be confirmed in updated guidance. Where a Half Hourly Meter is not used in the Metering System for the provision of DSR the output must be collated and converted into energy (multiples of Wh) and Settlement Period (48 periods of 30-minute duration per day; clock change days 46 or 50 periods, as applicable) format.

Bespoke solution – Splitting BMUs: Under this configuration the spitted units are already metered by a metering system which is part of the BSC there are no additional metering requirements and the metering systems is BSC compliant. The only "bespoke" element of this solutions is that the metering test would be on data submission. A CSV File would have to be submitted as part of the commissioning evidence along with independent confirmation of the metered volumed contained within.

Bespoke solution - Difference metering: The purpose of difference metering is to get individual Metered Volumes for a particular generating unit that has no metering but is part of the BMU portfolio by deriving it from other metering sources. The only "bespoke" element of this solution is that To get the Metered Volume for an unmetered generating unit, the net Metered Volume from the other metered Generating Units will be subtracted from the net Metered Volume at the Boundary Point. The metering equipment at boundary point will still have to be BSC compliant which is sufficient for the Capacity Market arrangements.

The CM bespoke solution of additional metering provides alternative metering requirements for individual meters that will be installed at asset level

Even for the bespoke solution, the CM metering requirements align with COP standards or MIR standards which ensures consistency in the requirements. The only deviation is that there is not a COP11 equivalent; smaller assets will still have to meet the higher accuracy requirements which are defined under the existing metering types requirements.

Capacity Market

Bespoke solution – Additional metering : Where additional metering has to be installed behind the existing BSC metering at boundary point (i.e., asset meter) then this asset meter will have to meet the Bespoke Technical requirements of the Capacity Market.

The requirements are split into four Metering Types based on the rated capacity of the circuit or the maximum demand:

1. Metering Type 1 - for circuits rated greater than 100MVA;

2. Metering Type 2 - for circuits rated up to 100MVA and rated greater than 10VA;

3. Metering Type 3 - for circuits rated up to 10MVA; and

4. Metering Type 4 – for circuits with a maximum demand up to 1MW.

The accuracy requirements for individual metering equipment are shown on the table at the right. It is worth mentioned that CM metering types are equivalent to COP metering types as shows in the table. It is worth mentioning that there is not a COP11 equivalent yet.

Metering type	Minimum Accuracy Class
1 (equivalent to COP1)	0.2s
2 (equivalent to COP2)	0.5s
3 (equivalent to COP3)	1.0
4 (equivalent to COP5)	2

Where the Meter has been approved under the Measurements Instrument Directive (MID) the relevant standard is EN 50470-3 where Class C is equivalent to Class 0.5s, Class B is equivalent to Class 1.0 and Class A is equivalent to Class 2.0. It should be noted that there is no MID equivalent to a Class 0.2s Meter required under Metering Type 1.

In addition to the individual equipment requirements for accuracy, the Metering System in its entirety must be within the Overall Accuracy limits, shown at the next page. The combined error of the Meter, Current Transformer and Voltage Transformer must be within the allowed limits for Overall Accuracy

The CM bespoke solution of additional metering provides alternative metering requirements for individual meters that will be installed at asset level

The overall accuracy requirements of the metering system (not the individual equipment) are lower as it considers errors in other devices, not only the metering equipment.

Metering Type	Current expressed as a percentage of Rated Measuring Current	Power Factor	Limits of Error
1	120% to 10% inclusive	1	+-0.5%
	Below 10% to 5%	1	+-0.7%
	Below 5% to 1%	1	+-1.5%
	120% to 10% inclusive	0.5 lag and 0.8 lead	+-1.0%
2	120% to 10% inclusive	1	+-1.0%
	Below 10% to 5%	1	+-1.5%
	Below 5% to 1%	1	+-2.5%
	120% to 10% inclusive	0.5 lag and 0.8 lead	+-2.0%
3	120% to 10% inclusive	1	+-1.5%
	Below 10% to 5%	1	+-2.0%
	120% to 10% inclusive	0.5 lag and 0.8 lead	+-2.0%
4	120% to 10% inclusive	1	+-1.5%
	Below 10% to 5%	1	+-2.5%
	120% to 10% inclusive	0.5 lag and 0.8 lead	+-2.5%

Smart Charge Point regulations mandate the requirements that charge points sold in GB should follow

The requirements focus on the smart functionality that charge points should have, allowing EV charging when there is less demand on the grid or when there is more renewable energy available.

The Electric Vehicles (Smart Charge Points) Regulations 2021

Responsibility: This guidance has been produced by the Department for Business, Energy, and Industrial Strategy (BEIS) and the Office for Product Safety & Standards (OPSS) to assist those selling electric vehicle charge points in complying with these new statutory obligations.

Assets/ Technologies: The regulations cover:

- electric vehicle private charge points which are sold for use in a domestic or workplace environment in Great Britain
- smart cables (defined as an electrical cable which is a charge point and is able to send and receive information)

Exceptions: The regulations do not apply to:

- public charge points: A charge point which is intended (that is, designed and marketed) for use primarily by members of the general public. This includes charge points in the following locations:
  - Public roads; or
  - Public and privately-owned car parks, whether or not those car parks are available only to consumers of specific goods or services.
- non-smart charging cables: An electrical cable which can be used to charge an EV, but which is not able to send and receive information.
- rapid charge points: A charge point that allows for a transfer of electricity to an electric vehicle with a power of at least 50 kilowatts Rapid charge points should adhere to the European Standards EN62196-2 as per “The Alternative Fuels Infrastructure Regulations 2017”.

Metering requirements

The requirements cover a range of topics including smart functionality, electricity supplier interoperability, loss of communications network access, safety, requirements for the measuring system, off-peak charging, randomised delay, security and assurance. For the purpose of this review, we would like to highlight the following requirements which can be compared against OM requirements:

- The charge point should be able to send and receive information via a communications network.
- The charge point should be able to **measure or calculate every second** the electrical power it has imported or exported
- The measurement or calculations should be in watts or kilowatts; and
- The measurement or calculations **should be accurate to within 10%,** and any inaccuracies must not be systematic. An inaccuracy is systematic if, as a consequence of the charge point’s design or manufacture, it is consistent or predictable.

Sources:
https://www.legislation.gov.uk/uksi/2021/1467/regulation/9/made
https://assets.publishing.service.gov.uk/media/628ce214e90e071f653a494a/Guide-to-evscp-regulations-2021-V2.1.pdf

Energy Smart Appliances regulations are not matured, but the government acknowledges their importance

The uptake of smart appliances is expected to grow, driven by regulatory mandates which is planned to be in act in 2028.

First phase regulations for energy smart appliances – April 2024

The document focuses on the first phase of regulations for energy smart appliances (ESAs) aimed at supporting the GB's goals for reducing carbon emissions. This involves integrating smart functionality into domestic heat appliances to facilitate DSR, ensuring grid stability, and maintaining cybersecurity.

The following appliances fall under the scope of the first phase regulations: Hydronic Heat Pumps, Storage Heaters, Heat Batteries, Indirect Cylinders with Electric Heating Elements, Standalone Direct Electric Storage Water Heaters, Standalone Heat Pumps for Domestic Hot Water, Hybrid Heat Pumps, Domestic Electricity Battery Storage Systems.

Two primary options are discussed:

1. Do-Nothing Scenario: Maintain the current regulatory state, allowing consumers to purchase both smart and non-smart appliances without mandating smart functionality.
2. First Phase ESA Regulations: Implement regulations mandating smart functionality, cybersecurity measures, and grid stability requirements.

The regulations mandate that appliances must have robust cybersecurity measures, with regular reviews and security testing. Additionally, appliances are required to include randomised delay functionality to prevent synchronised operation that could destabilise the grid. They must also incorporate smart functionality, including remote communication and output modulation, while ensuring that consumers retain control over the extent of smart functionalities used.

The following benefits have been identified:

- Automating DSR through smart appliances can shift demand to off-peak times, reducing peak load and overall system costs.
- Potential reduction in consumer energy bills due to more efficient energy use.
- DSR can provide significant cost savings to the electricity system, estimated between £40-50 billion by 2050.
- Flexible use of heat pumps could shift up to 50 TWh of demand annually by 2050.

The following costs have been identified:

- Manufacturers will incur costs related to software development, testing, cybersecurity measures, and customer support.
- Estimated first-year costs are £56 million, with cumulative costs over ten years ranging from £175 million to £471 million (2023 prices).
- Additional smart hardware is estimated to cost £40 per unit initially, potentially decreasing over time due to technological advancements and economies of scale.

The implementation of the first phase ESA regulations aims to ensure the widespread adoption of smart appliances, enhancing DSR participation, and providing significant system and consumer benefits. While initial costs are substantial, the long-term benefits in terms of grid stability, cybersecurity, and energy cost savings justify the regulatory intervention. According to the Association for Decentralised Energy, **smart appliances mandate will not be in act before 2028.**

Metering Requirements in GB markets

While the GB aligns with various service mechanisms in metering requirements, there are significant differences in metering accuracy, refresh frequency, and latency standards.

- Only the balancing mechanism, and the services dispatched via the BM, require operational metering with a live feed to the NESO control room.
- Asset meter participation is allowed on all services.
- Balancing mechanism requires +/- 1% accuracy, stricter than settlement's +/- 2%. Capacity market and DSO flexibility services have variable or unspecified accuracy requirements.
- Balancing mechanism requires a 1 Hz, while settlement allows 30 minutes. Capacity market and DSO flexibility services have solution-dependent or flexible frequencies.
- Balancing mechanism mandates 5 seconds, whereas settlement, capacity market, and DSO flexibility services have unspecified or variable latency requirements.
- Uniformly requires both active power and SoE across all mechanisms.
- All mechanisms support aggregation or having multiple assets within a unit.

Operational metering requirements are stricter compared to those for other services, with the capacity market generally aligning with settlement metering requirements in most cases. Our recent survey highlighted the complexity and divergence of these requirements which make it challenging for market participants to navigate the different metering requirements needed for various services.

Service Requirements	Requirement Description	Balancing Mechanism (and Services dispatched via BM)	Settlement	Capacity Market	DSO Flexibility Services
Metering Required	A live feed to NESO control room to measure providers live service delivery	YES	NO	NO	NO
Asset metering permitted (vs boundary point metering system)	What type of metering is permitted? Some services only allow boundary meter data whilst others allow metering behind the boundary i.e. asset metering	Asset metering permitted	Asset metering permitted	Asset metering permitted	Asset metering permitted
Operational Meter Accuracy Required	The accuracy rating required of physical meters providing operational metering	**+/-1%**	**+/-2%**	**+/-0.5% - +/-2.5%**	**None**
Operational Meter Refresh Frequency	The frequency that the physical meter captures real-time data snapshots	**1Hz**	**30m**	Half-hourly or converted to 30-minute Settlement Period format.	**1m - 30m**
Operational Metering Latency	Operational metering data must reach the NESO Control Room within this time	**5s**	**N/A**	Dependant of type of solution	**N/A**
Operational Metering Signal Type	The type of electrical data collected for operational metering	Active power and SoE	Active power and SoE	Active power and SoE	Active power and SoE
Aggregation /Virtual Lead Party (VLP) Route Available	The option of having more than a single asset within a unit	YES	YES	YES	YES
Regulation	Applicable regulation/required compliancy	See CM	CoP11 (based on IEC/EN standards)	Equivalent to CoP 1,2,3 5 but not CoP11	N/A

Appendix D: International Metering Requirements

This section summarises global metering requirements for various ancillary services

Due to Great Britain's island nature and limited AC interconnection, GB balancing services require a greater variety of products compared to mainland Europe to ensure system stability and reliability. It would be beneficial for NESO to aim for harmonising requirements with European markets as this would facilitate participation from aggregators active in the European markets.

ENTSO-e balancing/ ancillary services*	Definition	Procurement method	Delivery duration	Availability duration	Time to full response	Bid size requirements	NESO Balancing Services
Frequency Containment Reserve (FCR)	FCR limits and stabilise frequency deviations and is automatically activated at +/- 200 mHz deviations from 50 Hz in the synchronous area.	Daily auction with 6x4 h symmetric products	30 min (15 min for limited energy sources i.e. batteries)	4 h	30 s	1 MW	Dynamic Containment
Automatic Frequency Restoration Reserve (aFRR)	The automatic activated FRR restores system imbalance within 15 min.	DA asymmetrical pay-as-bid capacity obligations and voluntary bids for non-contracted BSPs. Merit order energy bids.	15 min	24/7 (15 min period)	5-7.5 min	1-5 MW	MFR (secondary Response)
Manual Frequency Restoration Reserve (mFRR)	In case of incidents and substantial long-lasting power imbalances, TSO manually activates mFRR (incident reserve).	Annual and DA asymmetrical pay-as-bid capacity auction.	1 – 2 h	4 – 24 h	15 min	1MW	Slow/Quick Reserve Regulating Reserve
RR	RR is used to reconstitute the automatic frequency restoration reserves (aFRR) within 30 min.	Annual and DA asymmetrical auction.	1,5 h	15 min	30 min	1 MW	Slow/Quick Reserve Regulating Reserve

* Note that the requirements are uniform only for European-side markets (FCR Cooperation, PICASSO, MARI and TERRE). Not all countries included in the following benchmark participate to all of these markets. Differences are indicated as intervals.

Operational Metering Requirements for Aggregated Assets

Belgium has set lowered accuracy requirements for smaller consumers (<100 kVA) and allowed participation of asset metering in the mFRR market.

ENTSO-e balancing/ ancillary services	Operational metering required	Asset metering permitted (vs boundary meter)	Aggregation route available	Accuracy	Refresh frequency	Latency	Signal Type	Data collection, validation and storage
FCR	Yes	No	Yes, as a Virtual Delivery Point*	1% (10 mHz for frequency)	2 s	2 s (real-time)	Active power (100 kW precision)	Prequalification of delivery points via 1-day real-time communication test vs a synthetic frequency profile.
aFRR	Yes	No	Yes, as a Reserve Providing Group (RPG)	1%	4 s	2 s (real-time)	Active power	Prequalification of delivery points via 1-day real-time communication test. Test can be performed on Providing Group <100 MW.
mFRR/RR	Yes	Yes, required MID-compliance for Wh-meters < 5MW	Yes, as a Reserve Providing Group (RPG)	2% <100 kVA 1% <1 MVA 0.5% < 5 MVA up to 0.2S	15 min	15 min	Active energy (1 kWh precision)	As for aFRR. Submeter Technical Info Checklist and Commissioning Test must be accepted by Elia to verify minimum tech. requirements.

*** Virtual Delivery Points** are an aggregation of technical units. The aggregation contributes with less than 1.5 MW to the BSP's portfolio of delivery points supplying FCR. Elia requires individual power measurement of all delivery points, except for virtual delivery points. For these, the BSP can send to Elia aggregated measurements. Also, for frequency measurement, one frequency meter per each virtual delivery point suffices and BSP may decide where to install it. Nevertheless, Elia always has the right to request ex-post the individual delivery point data from the BSP for verification purposes. BSP is responsible for data monitoring when Elia does not have its own measurements.

FCR metering requirements: 20200518TC BSP FCREN
aFRR metering requirements: 20230928 TC BSP aFRREN and 20200331_aFRR_ Communication_requirement v1_EN
mFRR metering requirements: BSP Contract mFRR_EN and 20231201_General-technical-requirements-submetering_final

Operational Metering Requirements for Aggregated Assets

In France, lower accuracy and communication requirements are set for non-telemetered site to participate in mFRR, although submeters are not permitted outside of a wholesale market experiment.

ENTSO-e balancing/ ancillary services	Operational metering required	Asset metering permitted (vs boundary meter)	Aggregation allowed	Accuracy	Refresh frequency	Latency	Signal Type	Data collection, validation and storage
FCR	Yes	No*	Yes, as a Reserve Providing Group (RPG)	0.5%	< 10s	10 s	Active power (10 kW precision)	Prequalification test can be on RPG level, but technical specs required for single units. Units must be tested for qualification at least every 5 years. Additional in case of deviation from expected response + envelope. Unavailability is calculated with determined margins. RP's failure of telemetry for a maximum of 30 h/6 months. In case of RTE failure, ex-post measurements must be delivered.
aFRR	Yes	No*	Yes as a Reserve Providing Group (RPG)	0.5%	< 10s	10 s	Active power (1 MW precision)	
mFRR & RR	N/A	No*	Yes	Telemetered site: 1% Profiled site (not telemetered): 2%**	5 min	Ex-post	Active power	Regular and unannounced tests can be performed.

* On NEBEF mechanism (wholesale market), **RTE launched an experiment on the possibility of monitoring load reductions achieved from measurements obtained at a lower scale than that of the site**. The experiment has been running since 2021 and will be evaluated in 2025.
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 the reality of load reductions: no effects of "compensation within the same site".
** There are two types of sites: **telemetered or remote metering sites** (usually industrial sites) and **profiled sites** (usually light commercial and residential sites). The limit between light and heavy industry is not clearly defined in the regulation.

FCR and aFRR metering requirements: RTE Frequency Ancillary Services T&C, RTE Documentation Technique de référence – Chapter 4.7 and RTE projet-trame-type-afrr-agregat-n
mFRR metering requirements: mFRR and RR T&C
NEBEF dubmetering test: https://www.services-rte.com/en/learn-more-about-our-services/participate-in-the-submetering-experiment.html

Operational Metering Requirements for Aggregated Assets

The Netherlands allows asset meters in all ancillary services. Particularly, it support the participation of smaller consumers by setting ex-post or longer communication latency requirements in FCR and mFRR, without drastically reducing the measurement precision (refresh frequency) for FCR. No accuracy requirements are defined for aFRR and mFRR.

ENTSO-E balancing/ ancillary services	Operational metering required	Asset metering permitted (vs boundary meter)	Aggregation route available	Accuracy	Refresh frequency	Latency	Signal Type	Data collection, validation and storage
FCR	No	Yes	Yes, as a Reserve Providing Group (RPG) or special RPG*	1% (Class 0.5s) (10 mHz for frequency)	1-4 s	Ex-post	Active power (resolution 100 kW)	Each unit need to undergo a prequalification test** and repeat it after 5 years. Data must be sent before D+1 9:00, otherwise a "non-availability" penalty is applied. Measures must be stored for 6 months.
aFRR	Yes	Yes, only telemeter or smart meter.	Yes, as a Reserve Providing Group (RPG).	N/A***	1, 2 or 4 s (1 s in the future)	Real-time	Active energy and power	TenneT verifies delivery of service comparing real-time measures against reference signal + delta setpoint with -10%/+20% tolerance. Measures must be stored for 6 months.
mFRR/RR	Yes	Yes, required MID-compliance	Yes, no profiled connections.	N/A	5 min	5 min	Active energy and power	Verification similar to aFRR. Licenced MDC must measure data, exception for smaller connections.

* A BSP has the right to aggregate the measurement data of units whose power is lower than 1.5 MW via **(special) Reserve Providing Group (SRPG)** to a max of 30 MW.
** Unit of the same type, with a rated power of less than 1.5 MW and with the same control behaviour as already qualified units, **do not need to undergo an individual prequalification test and can be added to a SRPG after TenneT's approval**. BSP remains responsible of the overall behavior of the SRPG.
*** It is considered a risk of the BSP if the service delivery cannot be correctly monitored for verification.

FCR metering requirements: TenneT Handboek FCR voor BSPs
aFRR metering requirements: TenneT aFRR manual for BSPs en
mFRR metering requirements: TenneT Handboek mFRR noodvermogen product voor BSPs

Outside EU

In US, New Zealand and Australia, we observe lower and/or specific requirements for demand response in ancillary markets.

	Asset metering/ submeter permitted (vs boundary meter)	Participation in balancing/ ancillary services	Aggregation allowed	Accuracy	Refresh frequency	Latency	Signal Type	Data collection, validation and storage
US - PJM	Telemetry required at DER aggregation level [1]. Residential DER aggregation resources (CERs) with non-interval meters can use representative sample [1,2]. Mass market consumers (residential consumers and small I & Cs) can have aggregated meter data [1].	Ancillary services (regulation and reserves). Min: 100 kW [1,2,3] (Aggregation: at least 1 unit >99kW). [2]	Yes [1,2]	2% (ANSI c12.1 and c57.13 standards) [3] For V <600 V ad hoc verification can be conducted. [2]	Regulation: <4 s Reserves: <10 s [3] Load response (demand response): 1 min [2]	Real-time. Load response: ex-post [2]	Energy and power	A register needs to be kept for verification. [3] Ex-post data must be delivered within 2 days to the ISO. Data from each submeter delivered ex-post. [2] Random, unannounced audits are performed. [2]
Australia - AEMO	Submeters allowed upon AEMO's approval. Measurement data at aggregated level. [4]	Frequency Control Ancillary Service (FCAS). [4]	Yes [4]	2% [4]	100 ms - 4 s Depending on market product. [4]	1 s - 5 min Depending on market product. [4]	Energy and power	Access to 12 months historic data must be provided. [4]
New Zealand - Transpower	Submetering allowed for Dispatch Notified Load (DNL, small-scale aggregated resources) [8]	Instantaneous reserve IR (fast and sustained). Min: n/a Max: 100 MW [6]	Yes	0.5% (2% is allowed for <500A) [6]	0.1 s DNL: 30 min [8]	Ex-post [8]	Power [5]	Data recorded must be stored for 15 business days, [6]

[1] PJM Order No. 2222 Compliance Transmittal
[2] PJM manual 11
[3] PJM Manual 01
[4] Market Ancillary Services Specification - v8.2 effective 3 Jun 2024 (aemo.com.au)
[5] Standard Terms Part A - Foundation (transpower.co.nz)
[6] Electricity Industry Participation Code 2010 | Electricity Authority (ea.govt.nz) - Part 10
[7] Electricity Industry Participation Code 2010 | Electricity Authority (ea.govt.nz) - Part 1
[8] Electricity Industry Participation Code 2010 | Electricity Authority (ea.govt.nz) - Part 15

Balancing market differences in and outside GB

While the GB aligns with other regions in several operational metering requirements for fast ancillary services, notable differences exist, primarily in metering accuracy, refresh frequency, and latency requirements when it comes to slower services

- The GB allows asset metering, similar to the Netherlands, the US, Australia, and New Zealand. France and Belgium*, however, does not permit asset metering, however all aggregators to use a boundary point metering system.

- The GB requires a +/- 1% accuracy, which is stricter than Belgium Australia and New Zealand (+/- 2%) when studying CERs. Asset meters are not yet permitted in France though Boundary Meters can provide services to the mFRR and RR market through the boundary meter with boundary meter accuracy of 2% for light commercial and residential sites. **Thus, the GB sits in the strictest range, demanding higher accuracy than the countries under study.**

- The GB's refresh frequency requirement of 1 Hz is more stringent than most other regions, which allow for a broader range. Belgium's refresh rate varies from 2 seconds to 15 minutes, France from 10 seconds to 5 minutes, the Netherlands from 1 second to 5 minutes, and Australia from 4 seconds to 10 seconds. New Zealand permits 6 seconds to 1 minute. **The GB's consistent requirement indicates a greater emphasis on real-time data, contrasting with the more flexible approaches elsewhere.**

- The GB mandates a 5-second latency for operational metering data to reach the NESO Control Room, which is more stringent than the Netherlands' 10 seconds and falls within the broader range of 2 seconds (FCR and aFRR) to 15 minutes (mFRR/RR) in Belgium and France. **This shows the GB's preference for quicker data transmission, highlighting its focus on timely data updates compared to regions with more lenient standards.**

- All regions, including the GB, allow for aggregation or having more than a single asset within a unit. This uniform acceptance indicates a broad move towards flexible and inclusive metering solutions industry-wide.

In conclusion, it is recommended to align operational metering requirements with those of other markets to avoid the need for manufacturers to develop GB-specific capabilities, which can be quite costly

			EU			Outside EU		
Service Requirements	Requirement Description	GB	Belgium	France	Netherlands	US	Australia	New Zealand
Operational Metering Required	A live feed to NESO control room to measure providers live service delivery	YES	NO, with exception of mFRR	NO	YES	YES	YES	YES
Asset metering permitted (vs boundary point metering system)	What type of metering is permitted? Some services only allow boundary meter data whilst others allow metering behind the boundary i.e. asset metering	Asset metering permitted	Asset metering permitted	No	Asset metering permitted	Asset metering permitted	No	Asset metering permitted
Operational Meter Accuracy Required	The accuracy rating required of physical meters providing operational metering	+/-1%	+/-2%	+/- 0.5% / 2%	+/-1% for FCR N/A for aFRR, mFRR and RR	+/-2%	+/-2%	+/- 0.5%/2%
Operational Meter Refresh Frequency	The frequency that the physical meter captures real-time data snapshots	1Hz	2s – 15m	10s – 5m	1s – 5m	4s – 10s	100 ms - 4 s	6s – 1m
Operational Metering Latency	Operational metering data must reach the NESO Control Room within this time	5s	2s – 15m	10s	-	-	1 s - 5 min	-
Operational Metering Signal Type	The type of electrical data collected for operational metering	Active power and SoE	Active power and SoE	Active power and SoE	Active power and SoE	Active power and SoE	-	Active power and SoE
Aggregation /Virtual Lead Party (VLP) Route Available	The option of having more than a single asset within a unit	YES	YES	YES	YES	YES	YES	YES

Appendix E: NESO Communication Requirements

NESO offers three routes for providing operational metering to the balancing systems

To enable the connection of small BMU's (≤100MW) to the NESO's BM Systems and facilitate participation in the GB Balancing Mechanism, a wide range of communication protocols are offered. Small providers usually prefer connection via iHost.

This section provides an overview of the operational metering communication protocols that aggregators are expected to use to exchange operational metring data with NESO systems in order to participate in the Balancing Mechanism (BM) and balancing services.

National Grid NESO recognises the need for a variety of solutions dependent on the size of Market participant. A new Data Concentrator, which is hosted by a third party, has been implemented as a new route to balancing systems. The new environment (iHost™) provides limitless capacity, which is configurable and scalable, quicker to connect and offers a reduced end-consumer cost of making new connections compared to the traditional route of connecting using an RTU. In future, a range of connection protocols will also be offered to the Market Participant.

NESO currently offers three routes for providing operational metering to the balancing systems. The below options offer varying levels of resilience, delivery (connection) time, cost and are based on the size of the Market Participant.

1. Connect to an existing GB Transmission Owner's Real-time Telemetry Unit (RTU).
2. Install a new RTU and provide dedicated telecommunication signals to that location.
3. Connect to the SCADA Data Concentrator host (iHosT).

Standard	Description	Source
GI74 (serial protocol)	Proprietary protocol used to connect RTUs to the iEMS	
IEC 60870-5 101 protocol (serial protocol)	For GB existing RTUs and prospective new RTUs providing dedicated telecommunication signals to the iEMS	
IEC 60870-5 104 protocol (TCP/IP)	For operational metering assets <1MW, for BM wider access, Freq Services and others connected to iHOST	https://www.nationalgrideso.com/document/150286/download
MQTT protocol (TCP/IP)		

Table 9.1 – Communication Standards

NESO can offer additional protocols on request. The new host platform is also capable of supporting additional protocols and each will be considered by NESO on a case-by-case basis.

The next page reports on the stakeholder's engagement feedback on communication protocols.

Compliance with the communication requirements is a condition of approval of requests for connections

Connecting registered Balancing Mechanism Units to the Balancing Mechanism is achieved using the internet-based Wider Access API, or dedicated communication links from Trading Points and Control Points.

Communication standards requirements

The submission of Bid Offer Acceptances (BOAs) to Control Points is an activity undertaken by Market Participants. There are two ways in which Market Participants can provide these services. For larger units, Market Participants normally elect to provide and own dedicated Electronic Despatch & Logging (EDL) and Electronic Data Transfer (EDT) communication circuits to Control Points whereas, for smaller units, the Wider Access API may be a more appropriate communications mechanism.

Communication services between NESO and participants have been solely using fixed-line Multi-Protocol Label Switching (MPLS) connections, for EDL/EDT services. These services can be potentially cost-prohibitive, especially for Market Participants wishing to enter the Balancing Mechanism for the first time.

NESO has made available the Wider Access Application Protocol Interface (WA API) and the Operational Metering hub (iHOST) to Market Participants. Market Participants are free to use such technologies, until such time that their portfolio of BM Units exceeds certain thresholds. Above these limits, the participants will be required to move over to fixed-line MPLS and RTU technology, where power-resilience is guaranteed through redundancy.

The Market Participant can use an existing EDL Managed Service Provider to submit commercial data. NESO will review such arrangements on a case by case basis and track the underlying risks, e.g. multiple EDL Managed Service Providers inadvertently using the same Data Centre.

The health of the communications route through to the Control Point must be indicated back to the Market Participant to ensure their Control Room knows whether electronic instructions will get to the Control Point in question.

Table 9.2 – Communications requirements based on Control Point Threshold

Control Point Threshold per Site (MW)	BM Unit Thresholds (MW)		API	EDL/EDT (Fixed Lines)	Operational Metering		Telephony	24/7 (Staffed Operations)
	Aggregated	Primary or Sub-assets			Hub	RTU		
≤10	NA	NA	√	O	√	O	System	O
≤50	NA	NA	√	O	√	O	System	O
<100 **	NA	NA	√	O	√	O	Control	M
<300	NA	<100	√	O	√	O	Control	M
<300	NA	>100	X	O	√	O	Control	M
<600	<300	<100	√	O	2nd independent VPN*	O	Control	M
<600	NA	>100	X	M	2nd independent VPN*	O	Control	M
<600	>300	NA	X	M	2nd independent VPN*	O	Control	M
<1000	<300	<100	√	O	2nd independent VPN*	O	Control	M
<1000	NA	>100	X	M	X	M	Control	M
<1000	>300	NA	X	M	X	M	Control	M
≥1000 to 3600	NA	NA		M	X	M	Control	M
>3600	Fixed-line (MPLS) Connection required 3600MW is the Maximum industry limit for use of the API							

* a second independent and unique VPN (or a second resilient link in the case of MQTT (Message Queuing Telemetry Transport) protocol is required in order to avoid a single point of failure.

√ - Compliant to use
O = Optional
M - Mandatory

https://www.nationalgrideso.com/document/303756/download

Compliance with the communication requirements is a condition of approval of requests for connections

Communication failure in the aggregated meter feed for Medium portfolios (>100MW), could result in loss of visibility of a significant amount of generation/demand, with the loss of Large Portfolios (>1GW) creating operational challenges for frequency and short-term forecasting

Security and availability requirements

The resilience, support and redundancy requirements for the onward communication system to the Control Point is the responsibility of the Market Participant. Market Participant must comply with the following requirements to ensure that systemic risks are mitigated:

1. Data in transit should be protected

2. Communication should be either of the following: use a dedicated circuit replicating the current EDL leased line or using an IpSec VPN with cryptographic algorithm internet-based connection. Security event and alarm monitoring should be in place and NESO made aware of significant breaches

3. The Market Participant shall ensure that independent penetration tests and vulnerability assessments are carried out on the hosted environment at least annually, based upon HMG National Cyber Security Centre Cyber (HMG NCSC).

The Market participant with an internet-based API has a responsibility to diagnose and resolve faults and problems on the communication services. The Market Participant is responsible for selecting and managing suitable connectivity to the Internet however it is recommended that it is a permanent link with appropriate SLA and uses fixed IP addresses. It is the Market Participant's responsibility to ensure the SLA with their provider supports their intended hours of operation and recovery in the event of a problem.

Total MW capacity at risk / affected	No. of BM Units at risk	Fix Time within	Average Availability	Minimum Redundancy
0 – <100MW	n/a	12 hrs, 24/7	< 12 hrs downtime pa	Not specified
100 – <300MW	n/a		< 12 hrs downtime pa	Dual redundancy on communication links
300MW – <1 GW	n/a		< 4 hrs downtime pa	
1 GW – <3.6 GW	<=20			
1 GW – <3.6 GW	>20		< 4 hrs downtime pa, or < 1 hr downtime pa	Dual redundancy on comms links. Preferred dual redundancy throughout system (no single event will remove service)
3.6 GW or more	n/a		< 1 hr downtime pa	Dual redundancy throughout system (no single event will remove service)

Table 9.3 – Fix times, availability and redundancy requirements

Aggregators are generally satisfied with the communication protocols and standards offered by the NESO

Providers are satisfied with MQTT protocol for submitting metering, but improvements could be made to the on-boarding process

We asked aggregators and flexibility providers whether they are satisfied with the current process for submitting Operational Metering Data to the NESO, and what could be improved:

- *Yes, we create a stream and feed it to NESO via a supplier, seems to work.*
- *The current preferred method of using IEC104 protocol to send data is harder to implement with modern development methods vs using the MQTT protocol, which you do support but details are sparse.*
- *Not currently participating. But proposed comms protocol MQTT is fine.*
- *Once set up and up and running the process is fine. The steps needed for sign off are quite tedious and inefficient.*

One respondent was dissatisfied with the lack of standardisation between protocols for control, operational metering and settlement metering:

> *"Can there be a harmonisation for control, operational metering, and settlement protocols? There are incentives for market players to silo these off. Not aware of any standard which meets all these requirements currently.“*

We asked respondents which protocols they might consider in future:

> *"Open ADR, with national variations could be an option in future.”*

The current requirements for increased redundancy of communications for portfolios above 300MW serves to keep aggregated portfolios <300MW. One of the interviews with an existing VLP revealed an upper size limit of 300MW for their portfolios, beyond which they would establish a new portfolio with a separate connection to NESO systems.

Communication systems and protocols utilised to communicate with internal systems and the NESO
Direct API with no specific protocol applied
Communication between the charger hardware and the cloud is over Internet Protocol, on which we use either proprietary PCPP protocol, or OCPP protocol
AMQP, API, manual data dumps
MQTT for operational metering. Dedicated integrations for BM, ASDP and performance monitoring

Appendix F: Relevant (Meter) Communication Standards

Communication Standards and Protocols in EU balancing services

A wide variety of communication standards are protocols, such as protocols for substation automation, DER and demand response, data models and messaging protocols are used to support the EU balancing services.

In the context of operational metering, a wide variety of communication standards and protocols are employed to support EU balancing services. These include protocols for substation automation, such as IEC 61850 and IEC 60870-5-104, which ensure efficient and reliable communication within substations. Standards like OpenADR, IEEE 1547, and IEEE 2030 (though not as relevant in the EU market) are crucial for the integration and management of distributed energy resources and demand response. Data models and interfaces, such as the Common Information Model and proprietary RESTful APIs, facilitate seamless information exchange. Additionally, messaging protocols like MQTT and AMQP are utilized for IoT and machine-to-machine communication, enhancing the interoperability and functionality of smart grid applications.

Standards for Substation Automation and Communication

- IEC 61850
- IEC 60870-5-104 (and DNP3, less relevant for the EU market)

Standards for Distributed Energy Resources and Demand Response

- OpenADR
- IEEE 1547 (Not relevant in the EU market)
- IEEE 2030 (Not relevant in the EU market)
- OCPP

Data Models and Information Exchange

- Common Information Model

Messaging Protocols for IoT and M2M Communication

- MQTT & AMQP
- ZigBee Smart Energy Profile
- Matter

Communication Standards and Protocols in EU balancing services

IEC 61850 and IEC 60870-5-104 are essential for operational metering in electricity as they enable reliable, standardised communication and control within and between substations however they are currently used for larger assets.

IEC 61850

- IEC 61850 is an international standard that defines communication protocols for substation automation and other power utility automation applications. It provides interoperability between different equipment, such as protection, control, and measurement devices, and enables seamless communication within substations.
- It can be used as an addition to the IEC 60870-5-104 protocol. Like IEC 60870-5-104, IEC 61850 can be used to send measurement data as well as control signals to assets. IEC 61850 offers more advanced features, including high-speed communication and a comprehensive data model, making it suitable for complex automation tasks.
- Today, IEC 61850 is mostly used to manage larger assets (> 1 MW), such as large-scale power generation facilities and substations.
- Several European countries, including Germany, Italy, and the Netherlands, are working on defining an interface based on IEC 61850 to manage smaller assets (< 1 MW). This effort aims to extend the benefits of IEC 61850, such as interoperability and advanced communication capabilities, to smaller distributed energy resources, enhancing grid management and integration of renewable energy sources.

IEC 60870-5-104

- IEC 60870-5-104 (in short IEC-104) is an international standard released in 2000 and its application layer is based on IEC 60870-5-101, facilitating communication between control stations and substations via a standard TCP/IP network using the TCP protocol for secure, connection-oriented data transmission.
- IEC 60870–5 is a protocol standard for telecontrol, teleprotection, and other telecommunication functions for electric power systems.
- IEC 60870–5-101 (IEC101) is a standard for power system monitoring, control and other related communications to automate electric power systems.
- IEC 60870–5-104 (IEC104) is an extension of the IEC 101 protocol, including transport, network, link & physical layer extensions to enable a full network access.

Communication Standards and Protocols in EU balancing services

MQTT is more suitable for lightweight IoT communication in energy markets, while AMQP offers secure, robust messaging for complex enterprise applications, including smart grid and renewable energy integration.

MQTT

- MQTT (Message Queuing Telemetry Transport) is a lightweight, publish-subscribe messaging protocol that is designed for low-bandwidth, high-latency, and unreliable networks.
- MQTT uses a broker-based architecture, where clients connect to a central server (broker) and exchange messages on topics. The broker handles the delivery of messages to the subscribers of each topic.
- MQTT is widely used in the Internet of Things (IoT) and machine-to-machine (M2M) communication, especially for applications that require low power consumption, high scalability, and real-time data exchange.
- MQTT is also used in the energy market, where it enables the communication between smart meters, grid operators, energy suppliers, and consumers.
- MQTT can also support the integration of renewable energy sources, demand response, microgrids, and smart grids, by enabling the coordination and management of distributed and heterogeneous energy resources.
- MQTT can help to improve the efficiency, reliability, and security of the energy system, by facilitating the monitoring, control, and optimization of energy generation, transmission, distribution, and consumption.

AMQP

- AMQP stands for Advanced Message Queuing Protocol, an open standard for messaging middleware that enables interoperability among different applications, platforms, and vendors.
- AMQP provides a reliable and secure way of exchanging messages between producers and consumers, using queues, exchanges, bindings, and routing keys.
- AMQP is used in the energy market for various purposes, such as:
  - Smart grid communication: AMQP enables the communication between smart meters, grid operators, and energy suppliers, allowing for real-time monitoring, control, and optimization of the grid.
  - Demand response management: AMQP enables the coordination of energy demand and supply, by allowing consumers to adjust their consumption based on price signals, incentives, or events from the grid.
  - Energy trading and settlement: AMQP enables the exchange of market data, bids, offers, and transactions between energy traders, brokers, and market operators, ensuring transparency, efficiency, and compliance.
  - Renewable energy integration: AMQP enables the integration of renewable energy sources, such as wind and solar, into the grid, by allowing for the management of variability, uncertainty, and intermittency.

Communication Standards and Protocols in EU balancing services

For small, resource-constrained assets, MQTT is often a simpler and more efficient protocol for transporting measurement data compared to the more complex IEC 60870-5-104 or IEC 61850, while AMQP is preferred for its reliability and suitability in complex enterprise applications.

MQTT vs IEC 60870-5-104 & IEC 61850

- While individual assets may benefit from using the MQTT protocol for communicating measurement data due to its simplicity and efficiency in resource-constrained environments, this may not be efficient for NESO if 10000 (or more assets) will communicate directly with NESO on a very frequent basis as this will require a lot of message processing.
- MQTT is a protocol that is often used within the IoT and IIoT world. This protocol is much more “light weight” than the IEC 60870-5-104 protocol. There are no (consumer) IoT devices that use IEC 60870-5-104. MQTT is the more natural communication protocol to use for such devices.
- Similar arguments hold for MQTT vs IEC 61850. IEC 61850 is an even more complex protocol than IEC 60870-5-104
- MQTT is only a protocol to transport data between a publisher and subscriber. There is not a specific data model defined. This is a drawback when compared with the IEC-protocols. IEC 61850 does have standardized data models
- MQTT is also OASIS standard (Organisation for the Advancement of Structured Information Standards)
- <u>Conclusion:</u> For small assets (residential assets), IEC 60870-5-104 or IEC 61850 seems less feasible and MQTT is perhaps the better/easier protocol to transport measurement data

MQTT vs AMQP

- Aggregators may prefer MQTT to collect measurement data from 1000s of assets. They will need to aggregate the data and transfer this to NESO. MQTT could also be used here. But this is maybe not the best “use case” for MQTT.
- Aggregators often find the AMQP protocol more advantageous (as indicated by interview findings).
- AMQP (Advanced Message Queuing Protocol) is designed for reliable, secure, and interoperable communication, making it more suitable for complex enterprise applications and business messaging.
- AMQP is an OASIS standard (Organisation for the Advancement of Structured Information Standards) and an ISO standard (ISO/IEC 19464), ensuring broad industry support and interoperability and validating its robustness and suitability for enterprise-level applications. For example, ENTSO-E utilises AMQP in their Energy Communication Platform.

Communication Standards and Protocols in EU balancing services

OpenADR facilitates flexible, scalable, and secure communication for demand response and distributed energy resources, while IEEE 1547 and IEEE 2030 provide standards for safe grid interconnection and smart grid interoperability, promoting a resilient and sustainable power system.

OpenADR

- OpenADR (Open Automated Demand Response) is a standard for communication and control of demand response (DR) and distributed energy resources (DER) in the electricity grid.
- OpenADR is developed and maintained by the OpenADR Alliance, a non-profit organization that promotes the adoption and implementation of the standard. The OpenADR Alliance also provides certification, testing, and education for OpenADR products and services.
- OpenADR enables utilities, aggregators, and customers to exchange information and signals for DR and DER programs, such as price signals, load curtailment, and grid reliability.
- OpenADR is based on a client-server architecture, where a server (called a virtual top node or VTN) sends DR and DER signals to one or more clients (called virtual end nodes or VENs).
- OpenADR supports two types of DR and DER signals: event-based and service-based. Event-based signals are used for discrete DR and DER events, such as peak shaving, load shifting, or emergency response. Service-based signals are used for continuous DR and DER services, such as ancillary services, frequency regulation, or voltage control.
- OpenADR is designed to be flexible, scalable, secure, and interoperable with other standards and technologies, such as smart meters, smart appliances, distributed generation, energy storage, and microgrids.

IEEE 1547

- Standard for Interconnecting Distributed Resources with Electric Power Systems.
- Defines criteria and requirements for grid interconnection of renewable energy sources like solar and wind.
- Ensures safe and reliable operation of distributed energy resources (DERs) when connected to the grid.
- Includes guidelines for voltage regulation, frequency response, and islanding prevention.

IEEE 2030

- Guide for Smart Grid Interoperability of Energy Technology and Information Technology Operation.
- Provides a framework for integrating renewable energy, electric vehicles, and smart grid technologies.
- Addresses communication, information management, and control technologies needed for smart grid functionality.
- Facilitates the development of a more resilient, efficient, and sustainable power system infrastructure.

Communication Standards and Protocols in EU balancing services

CIM (Common Information Model) is an electric power transmission and distribution standard developed by the electric power industry. It aims to allow application software to exchange information about an electrical network. It has been officially adopted by the International Electrotechnical Commission (IEC).

CIM (Common Information Model)

- CIM is a standard series that defines how to model the components and interactions of power systems, such as generators, transformers, substations, lines, and loads.
- CIM enables interoperability and data exchange among different applications and systems that manage, monitor, and control power systems.
- CIM is widely adopted by the energy market operators and participants, such as transmission system operators (TSOs), distribution system operators (DSOs), market operators, and energy service providers.
- CIM facilitates the integration of renewable energy sources, distributed energy resources, smart grids, and demand response programs into the power system.
- CIM supports the development and implementation of market mechanisms, such as day-ahead and real-time markets, congestion management, ancillary services, and balancing.
- CIM enables the analysis and optimization of power system operation, planning, and reliability, such as power flow, state estimation, contingency analysis, and security assessment.
- CIM provides a common vocabulary and framework for data exchange and communication among different stakeholders and regulatory bodies in the energy sector.

CIM in GB

Ofgem has set out a regulatory approach that mandates the use of CIM for network data exchanges under standard network licences. This is part of the Long-Term Development Statement (LTDS) reforms.

According to OFGEM, a national governance body is expected to manage the GB CIM profiles and any bespoke extensions required. However, the absence of such a body is not seen as an impediment to the use of CIM for licence conditions and grid code modifications.

The transition to a more digitalised energy system, characterized by an increase in low-carbon and distributed energy resources, necessitates the standardization of data. CIM helps in avoiding duplication of efforts and minimizing barriers to entry for new participants and service providers.

Some CIM Standards

- IEC 61970 series: focusing on exchange of network models essential for system coordination
- IEC 61968 series: facilitate standardised data exchange between different systems.
- IEC 62325 series: facilitate standardised data exchange in deregulated energy markets.

Sources:
https://www.ofgem.gov.uk/publications/common-information-model-cim-regulatory-approach-and-long-term-development-statement
https://www.ofgem.gov.uk/sites/default/files/2022-01/The%20Common%20Information%20Model%20%28CIM%29%20regulatory%20approach%20and%20the%20Long%20Term%20Development%20Statement.pdf
https://www.ofgem.gov.uk/publications/next-steps-our-reforms-long-term-development-statement-ltds-and-key-enablers-dso-programme-work

Communication Standards and Protocols in EU balancing services

The Open Charge Point Protocol (OCPP) is an application protocol for communicating between electric vehicle charging stations and a central management system. The protocol was designed in 2009 on request of the ELaadNL foundation in the Netherlands

OCPP (Open Charge Point Protocol)

- OCPP is developed and maintained by the Open Charge Alliance (OCA), a global consortium of public and private stakeholders in the e-mobility sector.
- OCPP has several versions, ranging from 1.2 to 2.0.1, each with different features and capabilities. The latest version, 2.0.1, was released in 2018 and supports features such as firmware management, local authorization, reservation, and diagnostics.
- OCPP enables interoperability between different vendors and operators of charging infrastructure, allowing them to exchange information such as status, configuration, transactions, and smart charging.
- OCPP is an open and vendor-neutral protocol, meaning that it is free to use and implement, and does not favor any specific technology or solution.
- OCPP is based on a client-server architecture, where the charging station (also called charge point) acts as the client and the central system (also called central server or charge point operator) acts as the server.
- OCPP uses either SOAP or JSON as the message format, and either HTTP or WebSocket as the transport protocol. The choice of format and protocol depends on the version and configuration of OCPP.
- OCPP defines a set of messages and data types that can be exchanged between the charge point and the central system. These messages cover various use cases, such as boot notification, heartbeat, start transaction, stop transaction, meter values, status notification, remote start, remote stop, data transfer, and many more.
- OCPP is widely adopted and implemented by various stakeholders in the e-mobility industry, such as manufacturers, operators, service providers, regulators, and standardization bodies. OCPP is compatible with other standards and protocols, such as OCHP, OCPI, and ISO 15118.

Communication Standards and Protocols in EU balancing services

The Zigbee Smart Energy profile specification defines an Internet Protocol based communication protocol to monitor, control, inform and automate the delivery and use of energy and water.

Zigbee Smart Energy Profile

- Zigbee Smart Energy Profile (SEP) is a standard for interoperable communication between smart devices and energy management systems.
- SEP enables energy service providers to monitor and control smart devices such as meters, thermostats, appliances, and lighting.
- SEP allows consumers to monitor and manage their energy consumption and production, and utilities to optimize the grid efficiency and reliability.
- SEP supports demand response, load control, pricing, prepayment, metering, and diagnostics.
- SEP is based on the Zigbee PRO network layer, which provides mesh networking, security, and commissioning features.
- SEP defines application layer protocols and data models for different device types and services. SEP defines several device types, such as energy service portal, metering device, in-premise display, programmable communicating thermostat, smart appliance, smart plug, and electric vehicle supply equipment.
- SEP is compatible with other standards such as IEEE 802.15.4, IETF 6LoWPAN, and OpenADR.
- SEP has been adopted by several countries and regions, such as the US, Canada, Europe, Australia, and Japan.
- SEP is continuously evolving to meet the needs of the smart energy market, with the latest version being SEP 2.0.
- Zigbee smart energy profile (SEP) is a communication protocol for smart grid applications that enables interoperability and security among different devices and services.
- SEP supports various use cases such as demand response, metering, pricing, load control, distributed generation, electric vehicle charging, and home energy management.
- SEP specifies a set of application layer clusters, which are groups of attributes and commands related to a specific function, such as demand response and load control, simple metering, pricing, messaging, tunneling, key establishment, and diagnostics.
- SEP facilitates the integration of renewable energy sources and storage systems, such as solar panels, wind turbines, batteries, and microgrids, into the smart grid.
- SEP enables the participation of aggregators and third-party service providers, who can offer value-added services and incentives to consumers and utilities.

Communication Standards and Protocols in EU balancing services

Matter is a freely available connectivity standard for smart home and IoT (Internet of Things) devices. It aims to improve interoperability and compatibility between different manufacturers and security, and always allowing local control as an option.

Matter

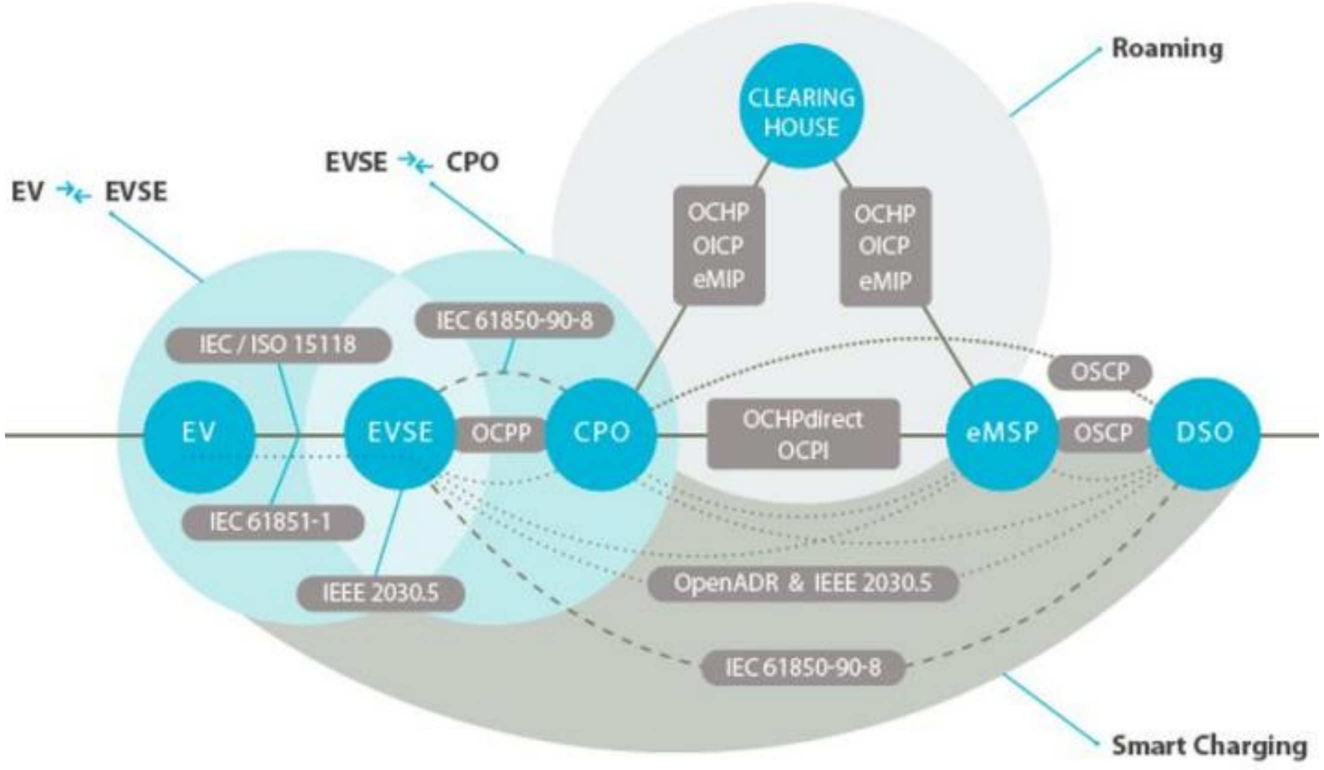
- Matter is developed by the Connectivity Standards Alliance (CSA), formerly known as the Zigbee Alliance, which includes over 200 companies such as Amazon, Apple, Google, Samsung, and Philips.
- Matter is based on the Internet Protocol (IP), which means that devices can communicate directly with each other and with cloud services, without the need for proprietary hubs or gateways.
- Matter supports multiple wireless technologies, such as Wi-Fi, Thread, and Bluetooth Low Energy (BLE), and can automatically choose the best one for each device and situation.
- Matter uses a common application layer that defines how devices work together, such as how a light switch controls a light bulb, or how a door lock notifies a security system.
- Matter will be compatible with existing smart home platforms such as Amazon Alexa, Apple HomeKit, Google Assistant, and Samsung SmartThings.
- Matter aims to create a more unified, secure, and interoperable smart home experience for consumers, developers, and manufacturers.

Matter and Energy Management

- Matter devices can communicate with smart meters and thermostats to optimize energy consumption and reduce costs for consumers and utilities.
- Matter devices can enable demand response programs that adjust the power usage of appliances and devices according to the grid conditions and price signals.
- Matter devices can support distributed energy resources such as solar panels, batteries, and electric vehicles, and facilitate peer-to-peer energy trading and grid services.
- Matter devices can provide data and insights on energy usage patterns, trends, and anomalies, and help consumers and utilities make informed decisions and improve efficiency.

Source: https://csa-iot.org/newsroom/matter-1-3-specification-released/

Different (standard) communication protocols are used to exchange data between EV stakeholders



EV Technology	EV standards
Smart Charging: all forms of smart charging ranging from being able to stop / restart charging during a charging session to schedule based charging	Open Smart Charging Protocol (OSCP) 1.0 OpenADR 2.0 Open Charge Point Interface (OCPI) 0.4 IEEE 2030.5 / Smart Energy Profile (SEP)
EVSE-CPO	OCPP 2.0 IEC 61850-90-8
Roaming: exchanging information (primarily authorization) to enable EV users to charge using 1 token at different charge points of different EMSPs and CPOs	Open Clearing House Protocol (OCHP) 1.4 Open Charge Point Interface (OCPI) 2.1 Open InterCharge Protocol (OICP) 2.1 eMobility Inter-Operation Protocol (eMIP) 0.7.4
EV-EVSE	IEC 61851-1 ISO / IEC 15118

CPO: Charge Point Operator: Operates and maintains charging points
MSP / eMSP: E-Mobility Service Provider: Handles all communication and billing towards EV users
EV: Electric Vehicles that have battery energy storage
EVSE: Electrical Vehicle Supply Equipment: Logical unit in a charge point that supplies electric energy via a connector for charging

Appendix G: Current and Future Asset Metering and Communication Capabilities

There is a high degree of variability in CER metering technology and communication capabilities

The most frequently cited factors influencing choice of metering technology were cost and regulations

Integrating large numbers of small, distributed assets into electricity markets and system operations presents new challenges around metering and communications. This section briefly examines the current and future capabilities of DER/CER assets in terms of:

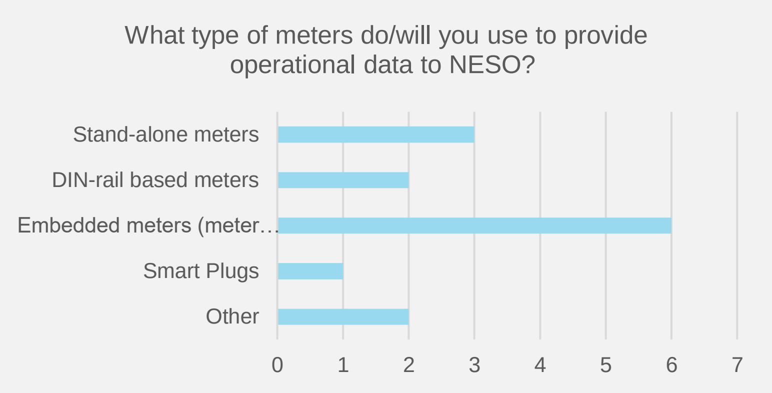
1. Metering types - including embedded meters in devices vs. external meters
2. Meter capabilities such as accuracy, and data sampling frequency
3. Communication protocols and systems; frequency of transmission, latency and cyber security

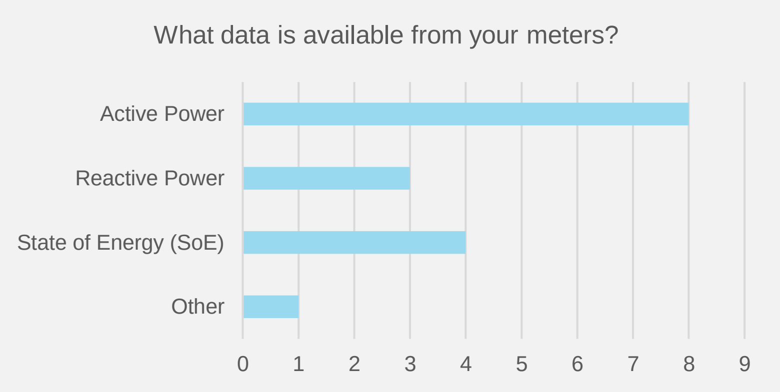
We consider both the technical capabilities of assets currently deployed, as well as expected improvements in future asset generations. The analysis mainly covers residential-scale assets like EV chargers and home batteries, as well as larger commercial & industrial assets up to around 1 MW in size. Metering used by large generators is included for comparison.

Understanding these capabilities is critical for determining what requirements can realistically be imposed on CER assets participating in flexibility markets and grid services, without creating undue barriers to entry. It also informs what system operators can expect to receive in terms of meter data quality from large portfolios of distributed assets.

Many flexibility providers have no control over the type of metering technology installed in all or part of the portfolios they manage, given that all or part of their portfolio is manufactured by third parties. There are multiple conflicting metering requirements in national and European legislation, as well as requirements set by settlement bodies and TSOs, therefore manufacturers may not have a strong incentive to align metering capabilities to the service requirements of a particular TSO.

Some manufacturers already provide flexibility services directly to DSOs and TSOs, whilst others indicated that they may do so in future. Yet during our interviews market access was mentioned less often as a driver of metering technology than cost and regulations.





Definition of “embedded meter” is not consistent

In this report embedded meters are defined according to the definition in COP11

An Embedded Metering Device under COP11 is defined as an *Asset Meter* that measures Active Power and/or Active Energy and is embedded within equipment used for other purposes. This means the primary function of the equipment is not to measure power or energy, but to serve another purpose, such as an electric vehicle (EV) charging unit or a small-scale domestic battery storage unit.

The key characteristics of an Embedded Metering Device are:
- It is not a dedicated meter
- Its primary purpose is not the measurement of Active Power and/or Active Energy
- It is embedded within equipment used for purposes other than metering

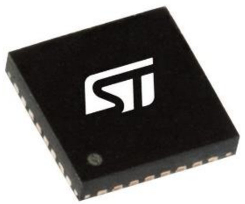
The definition provided under COP11 does not distinguish between different types of embedded meters, such as sensor on chip and din-rail meters housed within appliance enclosures. Both types of meters can be considered Embedded Metering Devices as long as they meet the criteria outlined above.

Specifically:
- Sensor on Chip: These are integrated circuits that can measure electrical parameters and are often embedded directly within the equipment's electronics.
- Din-Rail Meters: These are typically mounted on a DIN rail within an enclosure and can be part of the equipment's internal metering system.

In previous engagements with EU TSOs DNV have defined embedded meters as those using a sensor on chip embedded within the asset's electrical hardware, distinct from DIN-rail meters which can be installed inside or outside the asset enclosure but are always a separate component rather than directly integrated into the electronics. To avoid confusion the definition of embedded meter within this report is the one provided by COP11.

The COP11 definition focuses on the functional aspect of the meter being embedded within equipment used for other purposes rather than the specific form factor, capability, or installation method of the meter. Therefore, both sensor on chip and din-rail meters housed within appliance enclosures qualify as Embedded Metering Devices under COP11, yet the same DIN-rail meter would be considered a dedicated meter if housed outside the device enclosure.

DIN-rail meter


Sensor on chip

Manufacturer roadmaps for metering technology will provide higher capability at lower cost

Main drivers for improved metering are cost reductions, regulations, and enabling increased market access

Manufacturers incorporating more advanced metering

- Manufacturers are developing and incorporating higher capability metering with lower hardware costs, with new capabilities expected to come to market over the next 5 years.
- Improvements are expected in accuracy and read frequency.

Hardware cost reduction

- Increased integration of meter hardware in embedded assets resulting in economies of scale
- Commoditisation of more capable current and voltage sensors results in lower costs to install more capable metering

Data transmission costs are falling

- Data transmission costs will remain a significant barrier particularly for high read frequency data from embedded meters
- However, cost of data transmission has been falling over time, with 38% annualised increase in GBs translating to a 4% revenue increase for cellular providers - implying falling cost per GB for consumers
- If this trend continues communication costs may become less of a barrier in future

Source: https://techneconomyblog.com/2023/08/03/on-cellular-data-pricing-and-consumptive-growth-dynamics-the-elephants-in-the-data-pipe/

There are multiple drivers for more capable metering

- Compliance with government regulations and standards e.g. Smart Charging and Energy Smart Appliance regulations
- Market access: Reducing barriers for assets to access existing markets by lowering metering costs
- New markets and system needs: Development of technology to serve unmet system needs (e.g., LV network monitoring) with potential dual-use of this technology for operational metering
- Future-proofing: Anticipating stricter requirements in the future to avoid stranded assets

CER Asset Meter and Communications Capabilities

The table below summarises the meter technology and capabilities commonly found in different types of CER asset. Buildings (DSR) refers to demand side response provided for residential and small commercial buildings, in GB the NESO DSR scheme does not require operational metering but uses Smart meter data for baselining validation of service delivery.

	Residential Solar	EV Charger	Heat Pump / AC	Immersion heater	Micro Battery Storage	Buildings (DSR)	Domestic Appliances
Meter Types (Embedded, None, Both)	- Embedded meter - Standalone meters (in separate fuse box)	- Embedded meter - Also standalone meters may be used here	Sensor electronics	Sensor electronics	- Embedded meters - Standalone meters (in separate fuse box)	- Embedded meters - Standalone meters (in separate fuse box) - Typically, multiple meters aggregated via a gateway	Sensor electronics
Signals available	Real-time active power output Total active energy produced Daily active energy produced	Active Energy Imp/Exp Reactive Energy Imp/Exp Active Power	Active Energy Active Power	Real-time active power consumption Total active energy usage	Active Energy Imp/Exp: Energy drawn form or sent to the grid Active energy stored in the battery Acive energy used from battery Real-time power In/Out	Active energy consumption and generation Power demand Real-time power	Active Energy Active Power
Accuracy	± 2% (IEC 62053-21) or better	± 2% (IEC 62053-21) or better	Not well know ± 10%	Not well know ± 10%	± 2% (IEC 62053-21) or better	± 2% (IEC 62053-21) or better	Not well know ± 10%
Latency: communication meter/appliance to central system	The latency depends much on the used communication technology Communications over **4G/5G** and Internet is typically **lower that 1 s** The latency in **NB-IoT** networks is typically between **1.6 to 10 sec** The latency in **LTE-M** is typically in the range of **100 – 200 msec**						
Latency: comm between backend → aggregator → NESO	Also, the latency of the comm between backend system and aggregator, and processing at the aggregator must be included**.** This may also take several seconds (e.g. **1-10 sec depending on processing time**)						
Frequency	From meter perspective, 1 sec is possible. But is this feasible? → Communication cost, data processing in back-end systems	Normally, transaction based. Aligned with residential metering (15 min). In theory 1 sec is possible.	5 min; 10 or 15 min is OK 30 sec to 1 min: OK More frequent communication is feasible but limited by communication cost and data processing in back-end systems				
Timestamps and Time accuracy	Appliance can provide timestamps Time Accuracy: 1 sec	Appliance can provide timestamps Time Accuracy: 1 sec	Appliance can provide timestamps Time Accuracy: 1 to 10 sec	Appliance can provide timestamps Time Accuracy: 1 to 10 sec	Appliance can provide timestamps Time Accuracy: 1 sec	Meters and/or gateway can provide timestamps Time Accuracy: 1 sec	Appliance can provide timestamps Time Accuracy: 1 to 10 sec

CER Asset Meter and Communications Capabilities

	Residential Solar	EV Charger	Heat Pump / AC	Immersion heater	Battery Storage	Buildings (DSR)	Domestic Appliances
Communication Technologies	Device dependent, typically WIFi at end-user, Zigbee + Internet, 4G/5G cellular					LAN: field networks like MBUS, Modbus, etc WAN:	Typically, Wi-Fi at end-user + Internet
Communication Protocols	Local: Modbus, or pulses, Proprietary over Wi-Fi, Zigbee Smart Energy, Future: Matter	Local: Modbus WAN: OCPP	Proprietary protocol over home Wi-Fi, Zigbee Smart Energy Future: Matter	Proprietary solutions, Zigbee Smart Energy profile, Future: Matter	Modbus, M-BUS Zigbee Smart Energy profile Proprietary solutions Future: Matter	Local: modbus, M-BUS	Zigbee Smart Energy profile, Matter Zigbee2MQTT Proprietary Communication over open Internet **Matter is becoming an Industry standard of consumer IoT**.
Cyber Security	Typical scenario for Home LAN network: - device/appliance start own wifi AP - App communicates with this AP and user provides credentials for his home wifi AP - Device/appliance connects to home network WAN: Internet communication with Cloud via TLS	WAN: **TLS** can be used with OCPP	Typical scenario for Home LAN network: - device/appliance start own wifi AP - App communicates with this AP and user provides credentials for his home wifi AP - Device/appliance connects to home network WAN: Internet communication with Cloud via TLS	Typical scenario for Home LAN network: - device/appliance start own wifi AP - App communicates with this AP and user provides credentials for his home wifi AP - Device/appliance connects to home network WAN: Internet communication with Cloud via TLS	LAN: e.g. existing Wi-Fi security WAN: TCP/IP based communication that can be secured via TLS.	Communication in the local network: - Modbus protocol is mostly not secured. But the connection between the meter and the aggregating gateway is mostly wired. - The same holds true for M-Bus WAN communication: ?	Typical scenario for Home LAN network: - device/appliance start own wifi AP - App communicates with this AP and user provides credentials for his home wifi AP - Device/appliance connects to home network WAN: Internet communication with Cloud via TLS
Certification (Communication Protocols)	Meter accuracy verified according to IEC standards Certification also of communication technologies (Wi-Fi, Zigbee, 4G/5G, …)	OCPP certification Meter either according to MID or IEC standards	No certification or verification of meter (accuracy) Certification of communication technologies (Wi-Fi, Zigbee, 4G/5G, …)	No certification or verification of meter (accuracy) Certification of communication technologies (Wi-Fi, Zigbee, 4G/5G, …)	Meter accuracy verified according to IEC standards. Certification also of communication technologies (Wi-Fi, Zigbee, 4G/5G, …)	Meter accuracy verified according to IEC standards. Certification also of communication technologies (Wi-Fi, Zigbee, 4G/5G, …)	No certification or verification of meter (accuracy) Certification of communication technologies (Wi-Fi, Zigbee, 4G/5G, …)
Firmware Update	Typically, firmware update of the appliance software is possible. Typically, no remote update of meter firmware.						Typically, firmware update of the appliance software is possible.

(*) It must be noted that the meter itself cannot be used for load control; the meter will only measure energy/power. Another communication with the appliance is necessary for load control. Therefore, we believe that such a feedback loop can take some time, certainly when measurements from multiple meters are aggregated.

Asset Mapping: Out of scope for impact assessment

The table below outlines the typical capacity and meter capabilities of generators with capacity above 1MW. Based on the Terms of Reference of this study and feedback from industry gathered during this study assets with a capacity of above 1MW do not face significant barriers complying with Operational Metering Requirements. Therefore, these assets will not be directly considered for relaxed requirements or analysed as part of the Impact Assessment work package (unless any of the recommendations would apply to them).

	Centralised Generation			**Distributed Generation >1MW**					
	Gas	Nuclear	Pumped Hydro	Solar	Onshore Wind	Offshore Wind	Grid Battery Storage	CHP	Reciprocating Engine
Unit capacity range	100-1000 MW	1000-1600 MW	300-1700 MW	1-75 MW	1-300 MW	100-1500 MW	7MW-100MW+	1-50 MW	1-5MW
Metering point Point	Metering at the connection point to the grid. Separate metering per generating unit								
Metering cost	suitable for Meters used are industrial and expensive and requires CT and VT to reduce the voltage and current flowing through the meter. A metering installation which includes the meter + CTs and VTs can range from £ 500 to £1500** depending on features, installation requirements, and the supplier								
Meter Types	Typically, indirect metering using CTs and VTs instrument transformers								
Meter Examples (We only provide some examples. More meters exist.)	Schneider Electric Powerlogic ION series Siemens Sentron PAC series GE Multilin EPM Series Landis+Gyr E650, E660 Iskraemeco MT880								
Accuracy (*)	CT: 0.2s VT: 0.2 Wh: 0.2s Varh: 0.5								CT: 0.2 VT: 0.2 Wh: 0.5 Varh: 2
Frequency	Per 1s measurements are possible.								
Latency	Depending on communication infrastructure								
Communication	Meters are locally read out via modbus by an RTU. On RTU conversion to IEC60875-5-104 to send to SCADA. Conversion to IEC61850 is also possible.								

(*) According to IEC standards: IEC 62053-21, IEC 62053-22, IEC 62053-23, IEC 62053-24. The example accuracies are for Belgium. Other EU countries are similar.
(**) These meters are not applicable CERs as they are not fit for the power level and are too expensive.

Appendix H: Impact of Metering Requirements

H.1 Accuracy Impact

Accuracy Impact

Measurement error from sensor accuracy is reduced by aggregation according to the Law of Large Numbers

Each CER meter has some inherent sensor measurement error. In the context of consumer energy resources (CERs) and their meter readings, we can apply the Law of Large Numbers (LLN) to increase the accuracy of aggregated measurements.

Applying the LLN, as the number of assets in the portfolio (n) increases, aggregation results in sensor error is cancelled out, increasing the accuracy of the total measurement. The error in the aggregated measurement scales with 1/√n, so quadrupling the number of CERs halves the error. This principle allows for more accurate overall measurements even when individual meters have relatively high error rates.

While this principle is powerful, there are some real-world factors to consider:

- If an aggregated meter reading updates every second and samples all assets in a portfolio, the LLN is applied to the last measurement value for each meter, since each meter continues to be represented in the aggregated signal irrespective of whether it updated in the past 1s. However, if the aggregate meter signal is based on extrapolating a sub-set of meter readings to estimate the total portfolio power, the LLN is applied only to the meter readings used in the extrapolation. (Errors resulting from variation in asset power between meter readings is treated separately and will be discussed later).
- The Law assumes that errors are random and independent. If there's a systematic error affecting all devices (like all meters reading slightly high due to a manufacturing issue), this won't be eliminated by aggregation. The Electric Vehicles (Smart Charge Points) Regulations 2021 2..9.4.b states that charge points must be configured so that any inaccuracies are not systematic. **DNV recommends that an equivalent requirement should be included in the proposed Energy Smart Appliances regulations.**

MEASUREMENT ACCURACY IMPACT – NUMBER OF ASSETS NEEDED TO MEET 1% ACCURACY

				1MW Portfolio		30MW Portfolio	
Technology	Size (kW)	Accuracy	Number of Assets to meet 1% accuracy	Number of assets	Maximum innaccuracy (MW) (1MW portfolio)	Number of assets	Maximum innaccuracy (MW) (30MW portfolio)
EV	7	2%	4	143	0.17%	4286	0.03%
EV	7	10%	100	143	0.84%	4286	0.15%
Home BESS	14	2%	4	72	0.24%	2143	0.04%
Home BESS	14	3.5%	13	72	0.41%	2143	0.08%
Heat Pump	3	3.5%	13	334	0.19%	10000	0.04%
Heat Pump	3	10%	100	334	0.55%	10000	0.10%
Solar PV	5	2%	4	200	0.14%	6000	0.03%
Solar PV	5	10%	100	200	0.71%	6000	0.13%

The LLN is a fundamental principle in probability theory and statistics, it states that as the sample size increases, the sample mean converges to the expected value (population mean) of the distribution.

$$Total\ error[kW] = \sqrt{\sigma_{x1}^2 + \sigma_{x2}^2 + \cdots + \sigma_{xn}^2 + \sum_{j=1}^{n-1} \sum_{k=j+1}^{n} correlation_{jk}}$$

When errors are independent (correlation =0) and have the same standard deviation (σ_{xi}) this equation simplifies to $Total\ error\ [kW] = \sigma * \sqrt{n}$ Therefore, the relative error reduces with the number of assets (n):

$$Relative\ error = \frac{relative\ error\ per\ asset}{\sqrt{n}}$$

Relying on individual error being randomly positive or negative and some magnitude σ. If the sensor error is systematic and correlated 100% the relative total error will not reduce but this is never the case.

DNV

COP11 Accuracy Impact

Minimum CER portfolio size required to meet COP11 accuracy standards through aggregation, for each generation capacity category defined in COP11

The COP 11 metering standard applies to the metering of circuits where the energy volumes for settlement are calculated by subtracting the reading of a difference meter from that of the main meter. This approach is often used in complex sites or where there are embedded generators. Accuracy requirements for metering equipment under COP11 vary based on the circuit capacity (which corresponds to generation capacity in the context of generators). The standard defines different accuracy classes for various capacity ranges.

- For circuits ≥100 MW: Overall accuracy of ±0.5%
- For circuits ≥10 MW and <100 MW: Overall accuracy of ±1.0%
- For circuits ≥1 MW and <10 MW: Overall accuracy of ±1.5%
- For circuits ≥0.1 MW and <1 MW: Overall accuracy of ±1.5%

These accuracy requirements are traditionally applied to individual meters. However, in the context of aggregated Consumer Energy Resources (CERs), the question arises: How many individual CER assets, each with potentially lower individual accuracy, would need to be aggregated to achieve an equivalent level of accuracy for the portfolio as a whole? The result tables provide the answer for EVs and Heat Pumps, with sensor accuracy of 2% and 10% respectively.

The results show that sensor inaccuracy at the aggregated level is quickly reduced by the law of large numbers, reducing to below 0.5% with a portfolio of 400+ heat pumps having individual sensor inaccuracy of 10%.

EVs

2% accuracy 7 kW

Number of aggregated assets needed to meet requirements analoguous to COP11

ACCURACY – Current % of rated measuring current 120% to 10% inclusive	CAPACITY: 1MW	10MW	100MW	100MW+
1.5%	2	x	x	x
1.5%	x	2	x	x
1.0%	x	x	4	x
0.5%	x	x	x	16

Heat Pumps

10% accuracy 3 kW

Number of aggregated assets needed to meet requirements analoguous to COP11

ACCURACY – Current % of rated measuring current 120% to 10% inclusive	CAPACITY: 1MW	10MW	100MW	100MW+
1.5%	45	x	x	x
1.5%	x	45	x	x
1.0%	x	x	100	x
0.5%	x	x	x	400

Applying the law of large numbers when portfolios are only partially activated

Even if only a small number of assets are activated, sensor error is significantly reduced

- One caveat to consider is that our analysis assumes the whole portfolio is activated, in reality only a sub-set of the assets in the portfolio are likely to be activated in any single instruction.
- For errors and standard deviations which decrease with the law of large numbers, what is important is the number of assets which are activated rather than the total portfolio size which includes assets which have not been activated.
- Assuming most CER's will have a maximum capacity of 10kW, this sets the minimum portfolio size for CER portfolios at least 100 assets to meet 1MW per GSP group requirement. In reality, portfolios would need to be significantly larger since not all assets will be available at all times.
- Even with only 100 assets, reducing the error by $1/\sqrt{n}$ according the law of large numbers results in the error associated with sensor inaccuracy and standard deviation reducing by a factor of 10, so that a 2% inaccuracy would be reduced to 0.2%.
- Therefore, these errors quickly reduce to insignificance – especially in comparison to errors contributed by meter read interval and communication latency which are significantly more impactful.

H.2 MeterRead Interval Impact

An impact assessment was devised to assess effect of meter read interval on accuracy of data received by ENCC

DNV's investigation used the most comprehensive EV charging dataset available to create synthetic datasets for mathematical modelling. As the distributed flexibility market grows the amount of data to support further analysis will increase.

Data received:

The analysis used records from an EV smart charging portfolio that met minimum requirements to support our analysis:

- Tens of assets
- Lower frequency measurements (≤60-second intervals)
- One-day time range
- No dispatch instruction data

DNV examined additional data sources across other technologies, but found no other suitable datasets, reflecting the early stage of this market.

Analysis Method:

The EV charging data allowed us to build synthetic datasets and mathematical models examining how meter read interval and portfolio size affect overall accuracy. This is described on slide "Design of meter read interval Impact Assessment (IA)".

We then assessed how these findings would apply to other technologies, using the statistical data we received from a second aggregator. This is described in the section "Comparison of Technology Types".

Future Development:

As the distributed flexibility market grows to include a wider variety of asset types and larger portfolio sizes, new datasets may become available which could enable testing of real world performance using larger datasets and including dispatch signals, as well as detailed analysis of technologies other than EV smart chargers.

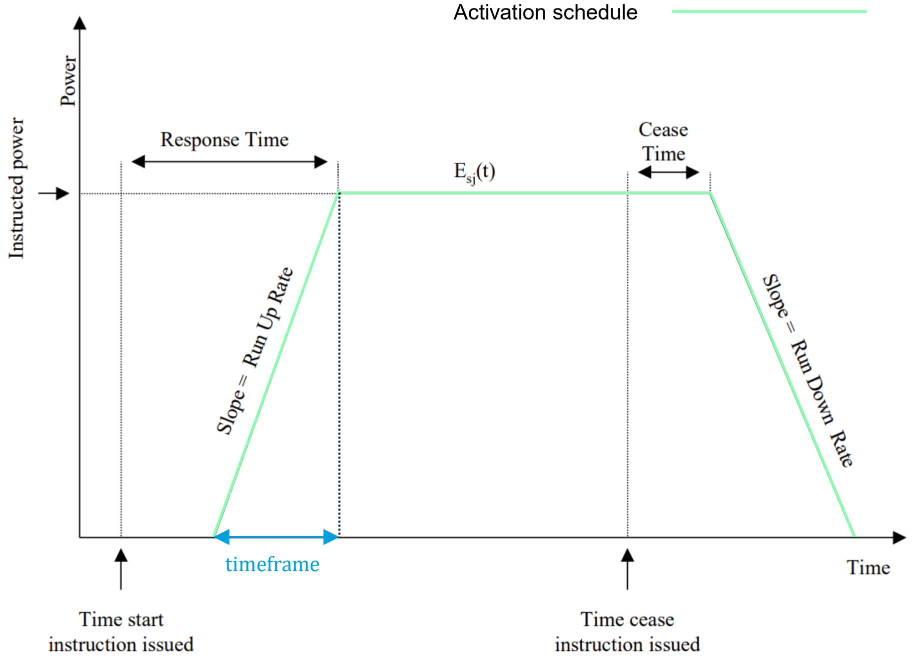
The ideal dataset to conduct such an analysis would include:

- Thousands of assets
- High-frequency measurements (1-10 second intervals)
- Extended time range (up to one year)
- Timestamped dispatch instructions and list of assets dispatched

Glossary of terms

- Activation schedule = instruction sent by aggregator to the portfolio
- Active power delivered = actual active power delivered by the portfolio (sum), assumed to precisely following the activation schedule in our analysis
- Aggregate $\mathrm{meter\ reading/signal}$ = the aggregated (sum) meter reading of a portfolio
- $\mathrm{mean\ error}$ = The difference between the aggregated readings and the active power delivered, averaged over a 1000 Monte Carlo runs
- $\mathrm{timeframe\ (of\ ramp)}$ = length of time over which the portfolio is ramped
- $\mathrm{readinterval}$ = meter update interval of the asset meters e.g. 10s, 30s, 60s
- Signal interval = interval of meter updates that are making up the subset of latest readings aggregated signal. Meter updates received in the latest signal interval seconds will be used to generate the signal.
- $\mathrm{timelag}$ = latency caused by meter read interval, found by $\frac{readinterval-1}{2}$
- ramp = difference in aggregated meter signal over the timeframe period
- n = number of assets
- P = capacity per asset

These can be mathematically predicted (in the text "expected" is added before when that is the case)



Design of meter read interval Impact Assessment (IA)

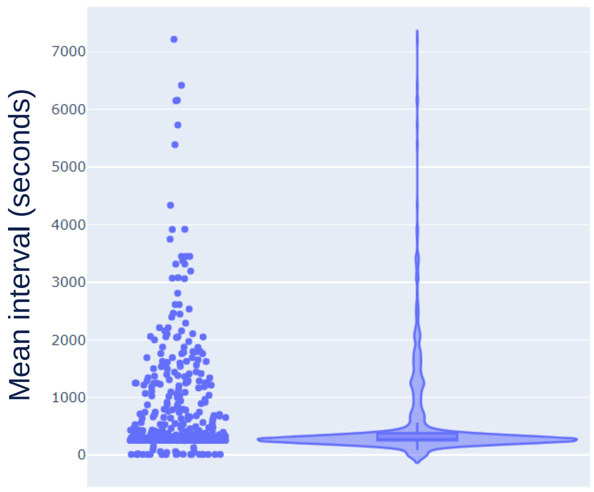
Due to limited availability of suitable real data, it was necessary to create a synthetic dataset to analyse the impact of meter read interval

The update frequency of the assets within the CER portfolio can add significant inaccuracies at the aggregate level under certain scenarios.

The inaccuracies of the aggregate meter signal increases as a function of:

1. Asset meter readinterval (e.g. readinterval 10s, 30s, 60s)
2. Variability in the number of assets updating each second, which causes a standard deviation in the mean readinterval error
3. Variability in asset power under stable operating conditions (variation in real power output between meter readings)
4. Portfolio ramping speed (time taken for the portfolio to ramp to full delivery)

These sources of error are explored in the following section Meter Read Interval Error Components, and on slide Ramp Timeframe.



Violin distribution of measurement interval

The impact assessment aimed to quantify the inaccuracy due to meter update frequency (readinterval) for all asset types, and understand the performance of different solutions which could be used to reduce the inaccuracy. Minimum data requirements to achieve this with real data were individual asset data at 10s resolution for a large portfolio of assets, including a timestamped dispatch signal and list of assets dispatched.

Data for analysis was provided by an EV smart charging aggregator

Initial data overview:
•719 EV chargers
•64,138 rows of data
•Metrics included: voltage, current, active power, operational state, and measurement timestamp

The measurement interval of the chargers was 10s, however they only provided 10s updates when switched on. A basic data analysis indicated that the time between two measurements of these chargers ranged from 10 seconds to 7,000 seconds, see upper-right chart. For our analysis, chargers with measurement intervals beyond 60 seconds (which were likely switched off during the data collection period) are not relevant.

Data was filtered to reduce the dataset to meters with 10s update frequency since this was the minimum frequency that would enable analysis of 10s, 30s, and 60s, options. Filtering resulted in **only 24 assets remaining**. Although 24 assets is rather low to provide findings with solid statistical significance, it is still informative for the purpose of this study.

Since the data did not include a dispatch signal, to assess the error during ramping periods a synthetic dataset was constructed.

Design of meter read interval Impact Assessment (IA)

Error from meter read interval can be expressed as an error in MW seen in control room versus real instantaneous power delivery, or as an additional latency (or "lag") in the aggregated signal. We chose to represent this as an error in MW for ease of analysis.

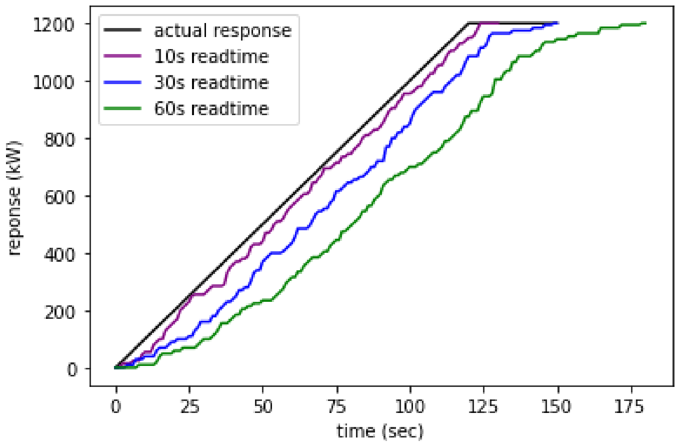
The synthetic dataset was created to assess expected deviation between:

1) Instantaneous active power **and** **2) the aggregated meter reading**

The true, instantaneous amount of electrical power being consumed or delivered by an asset or portfolio at any given moment. This is the power output that would be observed if the asset or portfolio could be monitored continuously and without any inaccuracy or latency.

The collective power measurement reported for a group of assets, which is subject to two key factors:

a) Discreet measurement: each individual asset's meter reports its power reading at set intervals (e.g., every 10, 30, or 60 seconds), not continuously. This creates a lag between the actual power state and when it's reported.
b) Aggregation: The readings from multiple assets are combined to give a total power figure for the portfolio. The "delayed aggregated meter reading" is therefore a composite value that represents the sum of the most recent readings from all assets in the group, even though each of these readings might be slightly outdated due to the asset meter update interval.



Simulation Structure

Individual asset measurement time:

- Each asset's measuring time is randomly created using a uniform distribution (uniform distribution of meter readings is supported by findings of the EV Energy Asset Metering Report trial and by data provided by aggregators for analysis in this project).
- Example: For a 30-second read interval, each asset's measurement time is randomly set between second 0 and second 30.
- **The validity of our analysis relies on the assumption that aggregated portfolios will have a uniform distribution of measuring times**

Aggregated meter reading:

- The aggregated meter reading is updated every second. Each update includes new data from approximately (100% / read interval) of the portfolio.
- Example: With a 30-second read interval, about 3.33% of asset's update each second. With readinterval =30 [s] and 3000 assets, on average 100 assets will report a new value every second, however due to random variation for some seconds it can also be 90 updates or 110 updates.

The dataset has an expected (mean) aggregated read signal with a random walk around it (see figure). To empirically determine the standard deviation around this mean read signal a Monto Carlo simulation was performed (with 1000 runs). In each run, the individual EV chargers have different measuring time, while the activation schedule is not changed.

Design of meter read interval Impact Assessment (IA)

Monte Carlo simulations provide a reliable method to empirically assess both the mean error and its standard deviation

Understanding errors in aggregated meter readings

There is an **expected (mean) error** between actual active power and the aggregated meter reading. This error occurs because the assets have a meter real interval >1s, so their meter readings lag behind their actual power.

Around this mean error, there's also a **standard deviation**, caused by variations in:

- The number of meters in the portfolio updating per second
- The number of activated meters (how many assets responding to a dispatch instruction – particularly relevant for “staggered dispatch” where activation is spread out over a period time to meet the desired ramp curve, or reduce instantaneous aggregated meter error)

To illustrate this point, let's consider an example of a 21 MW EV portfolio (3000 assets) and a 30 second readinterval:

- Variation in meter updates: In some seconds, there might be 90 asset meter updates, in other seconds, there could be 110 updates.
- Variation in activated meters: The percentage of activated assets among those 90 or 110 meter updates can differ from the average.

Mathematically assessing the standard deviation around the mean error is highly complex. Theories as Bates distribution or random sampling from a finite population can give some indication but are not ideal in every situation we investigated. With Monte Carlo simulations we can empirically assess the standard deviation around the mean error (and also check the expected mean error).

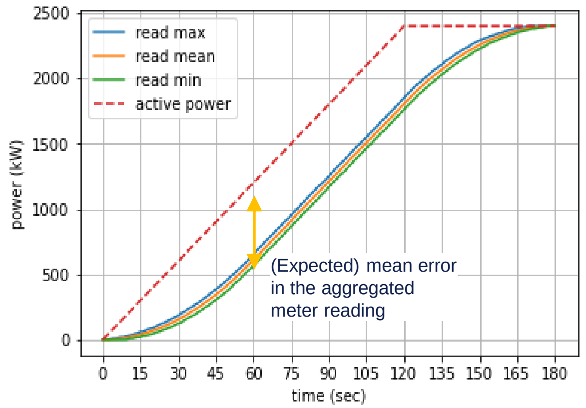
Goal: Empirically determine relationship of standard deviation around the mean error with number of assets (n), power per asset (P), readinterval [s] for uncorrected meter readings and potential solutions.

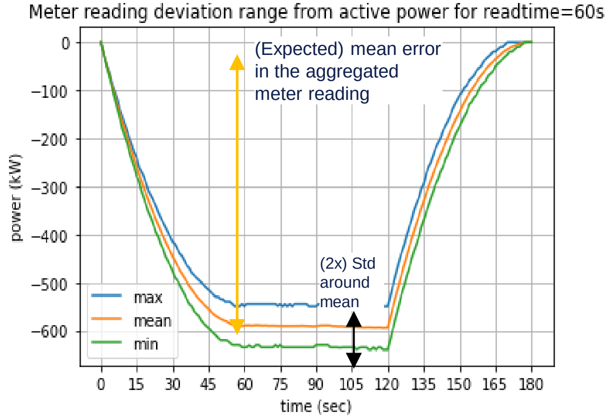
Monte Carlo Simulation Method:

- Run the same portfolio 1000 times to avoid skewing by outliers
- In each run the activation schedule and meter read interval of each asset is fixed, but the meter read time is varied (e.g. for 30s readinterval, read time is randomly selected value between 1 and 30).

The results are visualised as follows:

- Red dotted line: Requested response. In our simulation the total portfolio will exactly follow this request, so this is also the actual active power delivered by the portfolio.
- Orange line: Average of 1000 aggregated meter readings (per second)
- Green and blue lines: 16th and 84th percentiles of the 1000 runs. There is a 68% probability that the aggregated meter read signal will be between the green and blue line, corresponding to the range of ±1σ in a normal distribution.





Error in aggregated meter reading vs. real active power (aggregated meter reading minus dashed red active power line).

H.3 Meter Read Interval Error Components

There are four components of error from meter read interval

In addition to meter read interval, there are three other error components which are influenced by meter read interval

The four error components from read interval are, in order of importance:

1. Portfolio ramping speed (time taken for the portfolio to ramp to full delivery)
2. Meter read interval causing a lag in aggregate signal
3. Standard deviation in the meter read interval error, caused by variability in the number of assets updating each second
4. Variation in power between measurements (for EVs will be shown to be insignificant and therefore excluded from modelling using the EV data provided for the study. It is quantified for other technologies in section Comparison of Technology Types)

These are discussed in detail on the following slides.

A longer meter read interval causes a larger error

Comparison of 10s vs 30s vs 60s read-interval for simultaneous activation illustrates the effect of read interval on aggregated meter error

This slide compares the impact of different meter read intervals (10s, 30s, and 60s) on measurement accuracy for a 2500 kW simultaneous activation scenario.

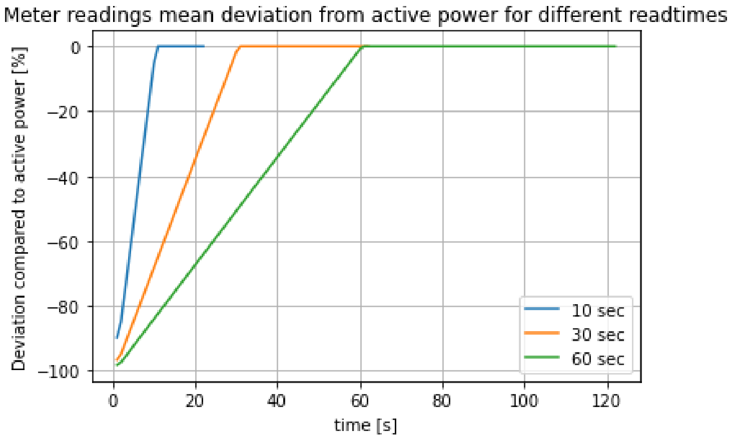
Key Points:

The error from meter read frequency starts at nearly 100% during ramp initialisation and reduces to 0% over a time period equal to the read interval.

The main graph shows the meter readings' mean deviation from active power for different read times:

- 10-second interval (blue line)
- 30-second interval (orange line)
- 60-second interval (green line)

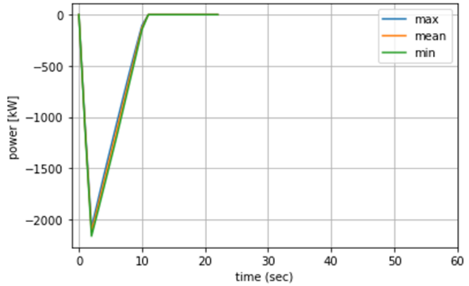
All three scenarios show an almost linear reduction in error from 100% to 0% over their respective intervals.



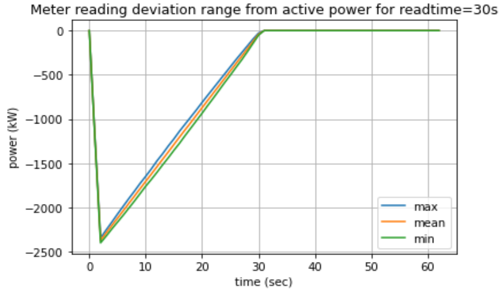
2500 kW portfolio (simultaneous activation)

The results show an almost 100% deviation at the start. This is almost linearly reduced to 0% at t = read frequency (because ramping is completed, and all meters have been read).

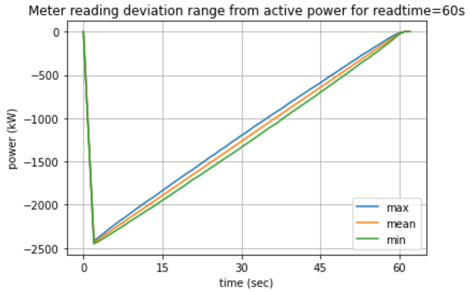
10s



30s



60s



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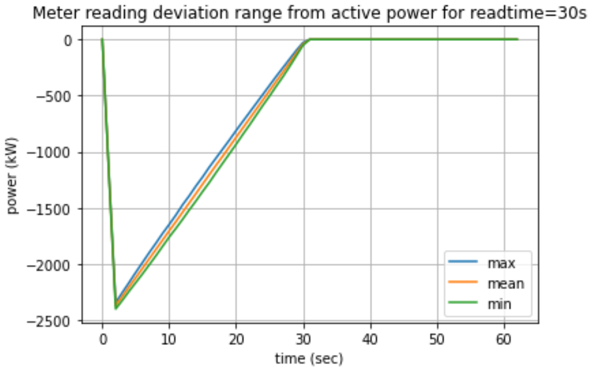
Variation in number of assets updating each second creates a standard deviation of the mean read interval error

The maximum standard deviation occurs when exactly half the meters have updated, which happens at the midpoint of any interval.

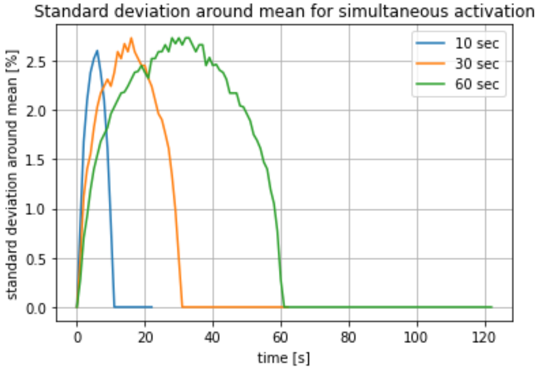
Error vs active power with 30s meter read interval (simultaneous activation)



The standard deviation around the mean meter error is relatively small. It grows to 2.7% for readinterval = 30 [s] at the point t=15 [s].

- Yellow Line (Mean): Represents the average error in aggregated meter readings caused by measurement interval across the 1000 Monte Carlo simulations.
- Blue Line (Max - 86th Percentile) and Green Line (Min - 14th Percentile): Represent the 86th and 14th percentiles of standard deviation in mean meter interval error, caused by variations in:
    1. The proportion of meters in the portfolio updating per second
    2. Of those updated meters, the proportion which are activated

St. deviation around the mean meter interval error (10s, 30s, 60s readinterval, (simultaneous activation)



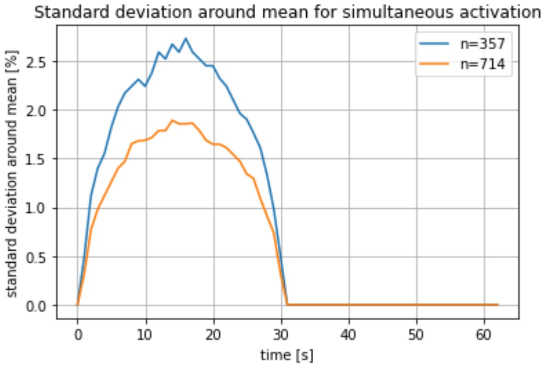
This chart focuses specifically on the standard deviation of the mean read error for different read intervals during simultaneous activation of a portfolio assets.

The standard deviation is caused by variability in the number of assets updating each second, and can be considered a measure of how choppy or smooth the meter signal is over time. In our analysis we consider the worst-case impact of standard deviation during the ramping period (the second where the most, or least, number of meters provide an update, and the error is furthest from the mean).

The approximately uniform distribution of meter read times across the ramp timeframe leads to a consistent statistical behaviour, regardless of the duration of the ramp. The maximum deviation occurs when exactly half the meters have updated, which happens at the midpoint of the ramp. From a statistical perspective this is when there's the greatest uncertainty about the state of the system.

For simultaneous activation, since all assets are dispatched simultaneously, the underlying "true" state change is identical across all scenarios. The only variable is when each meter captures this change.

The standard deviation around the mean reduces if you increase # of assets



Standard deviation around the mean error (caused by differences in meter measuring times) reduces as the number of assets increases.

This follows from the law of large numbers: the reduction in standard deviation is approximately proportional to the square root of the increase in asset numbers.

Impact of standard deviation therefore reduces as portfolio size increases. Results of analysis into the impact of standard deviation will be discussed later in the report.

Additional error is caused by variability in asset power between measurement two points

In EVs this error is very small, and further reduced to insignificance by the law of large numbers, therefore it was excluded from modelling. Data received later in the project showed this error to be a larger component for Solar PV and Heat Pumps (see Technology Comparison) .

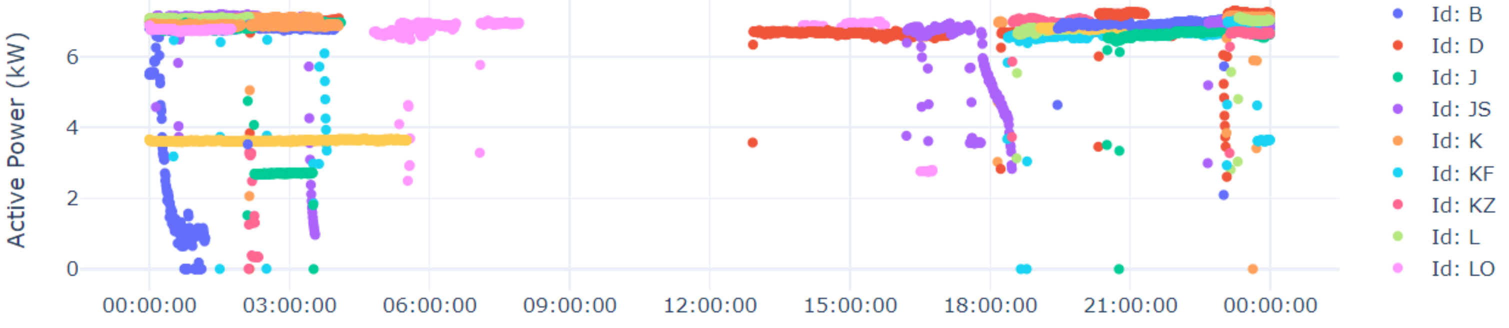
This analysis addresses the question: How much can the actual power vary between two measuring points when the asset is operating under stable load (i.e. not off or ramping)? It highlights the impact of inter-sample variation (where fluctuations in active power occur between measurement intervals and are thus not captured by the meter) on the accuracy of the power measurement. The top-right chart visualises the effect of inter-sample variation.

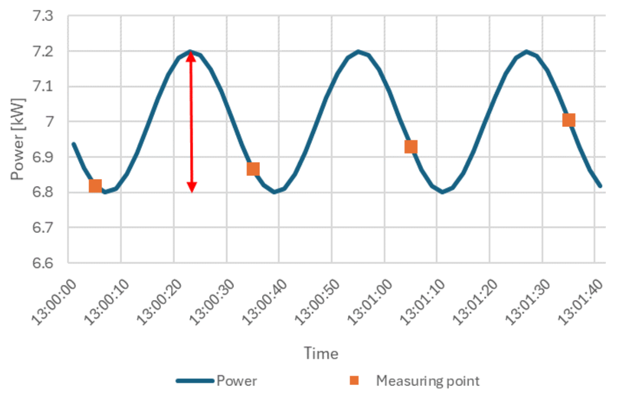
Error Analysis Method: To evaluate error propagation and systemic consequences of these inter-sample variations, we analysed active power variations during stable operation. The bottom-left chart plots the active power registered by 24 chargers against the measurement timestamp.

Statistical Analysis: The bottom-right chart shows a KDE (Kernel Density Estimation) density distribution of the standard deviation for all chargers. The 84th percentile, marked 31.5 W, is indicated by a dotted red line. This distribution helps quantify the extent of measurement variability caused by inter-sample variation. Another database of EV's show 45 W (0.7%) variability and one with mostly 1 minute readinterval which had a variability of <2.2%.

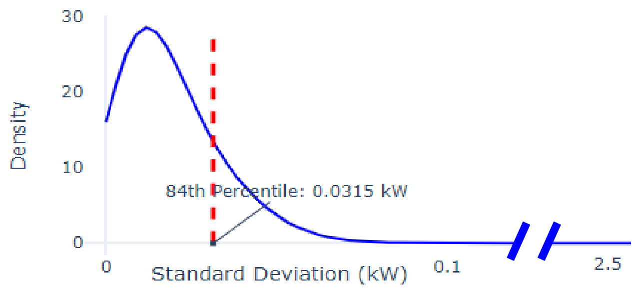
Key Takeaway: during stable operation, the load of a 7kW EV charger is likely to be within ± 0.04 kW compared to a measurement at maximum 30 seconds ago. This represents a maximum error of 0.6%; the error grows with increasing measurement interval, possibly up to 2.2% for 1-minute measurement intervals. The error reduces with increasing portfolio size according to the Law of Large Numbers in the same way as demonstrated in the Accuracy Impact analysis and for EVs can therefore be considered insignificant at the aggregated level.

Active power in KW/s of the 24 EV Chargers that met the measurement frequency requirement





Fluctuations occurring within measurements are not registered by the meter.



A KDE density distribution of the standard deviation of all chargers

H.4 Communication Latency Impact

Communication latency error is important but there is no mechanism in place to quantify and validate

Communication latency results in a similar error to the meter read interval, however there are no post processing options to reduce this error, and it is difficult to quantify

Operational Metering Requirements require a communication latency of less than 5 seconds from the meter to NESO. There is currently limited ability to validate communication latency, however based on interviews conducted in this study it is thought to be well below 5 seconds.

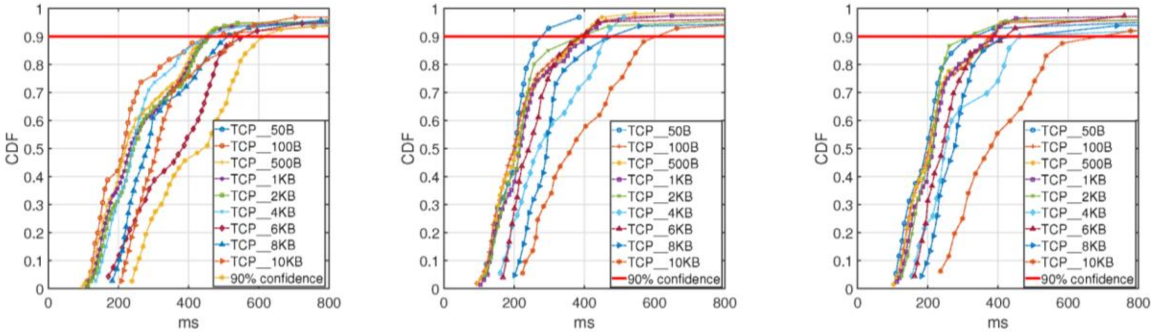
Aggregated assets such as CERs are likely to have additional communication latency compared to traditional assets due to the distributed nature of assets, reliance on an increased number of communication technologies and interfaces between the assets and NESO, as well as additional processing time to create the aggregated meter signal. It is possible that there may be more than one intermediary between the CER and NESO (e.g. CER to CER OEM to aggregator to NESO).

Following discussions with NESO and aggregators we conclude that there is no empirical evidence currently available on ability of CERs (or traditional assets) to achieve an end-to-end communication latency <5 seconds. Interview responses on this topic generally supported ability of CERs to meet 5 second latency with one exception. Aggregators reported that further optimisation could be carried out to reduce communication latency.

The magnitude of communication latency is influenced by many factors, some experimental work (Zeinali et. Al. 2023) has been carried out for public charging infrastructure which found communication latency to be influenced by:

- Wifi network performance: in public charge points the number of EVs connected to the EV Smart Chargers in the parking lot can lead to media-access delays resulting from Wi-Fi collisions .
- The congestion management and active queue-management algorithms used in the network.
- The number of routers and switches in the network.
- The signal strength and bandwidth of the communication links.
- The size of the transmitted data packets and the reporting rate per second.
- The preferred transport layer protocol (TCP or UDP).

Latency of various data packet sizes (TCP) between EVSEs and a mock control room on UK 4G network with different signal-strength levels in distinct parking lots (Zeinali et. Al. 2023) .



(a) Poor Signal Level (b) Medium Signal Level (c) Strong Signal Level

The experiment design used in the study differed significantly from the systems architecture of a commercial aggregator, and the scale assessed was a small fraction of that proposed for EV grid services even today. However, the results suggest that latency from CERs to NESO of below 5s are technically achievable given sufficient investment in communication and IT systems. The study found that both 4G TCP and 4G UDP “can sometimes achieve sub 100 ms latencies for single-PEV scenarios, even when accounting for Wi-Fi link delays. However, at a 90% confidence level, the latency of TCP is generally significantly lower than for UDP, at around 500 ms.”

Latency impact on error in control room

Communication latency results in a similar error to the meter read interval

For simultaneous activation there is a substantial initial error, calculated as the number of assets multiplied by power per asset $n * P_{asset}$, which persists for the duration of the latency lag. After that it drops to zero in the time it took to ramp up (in this case 2 seconds)

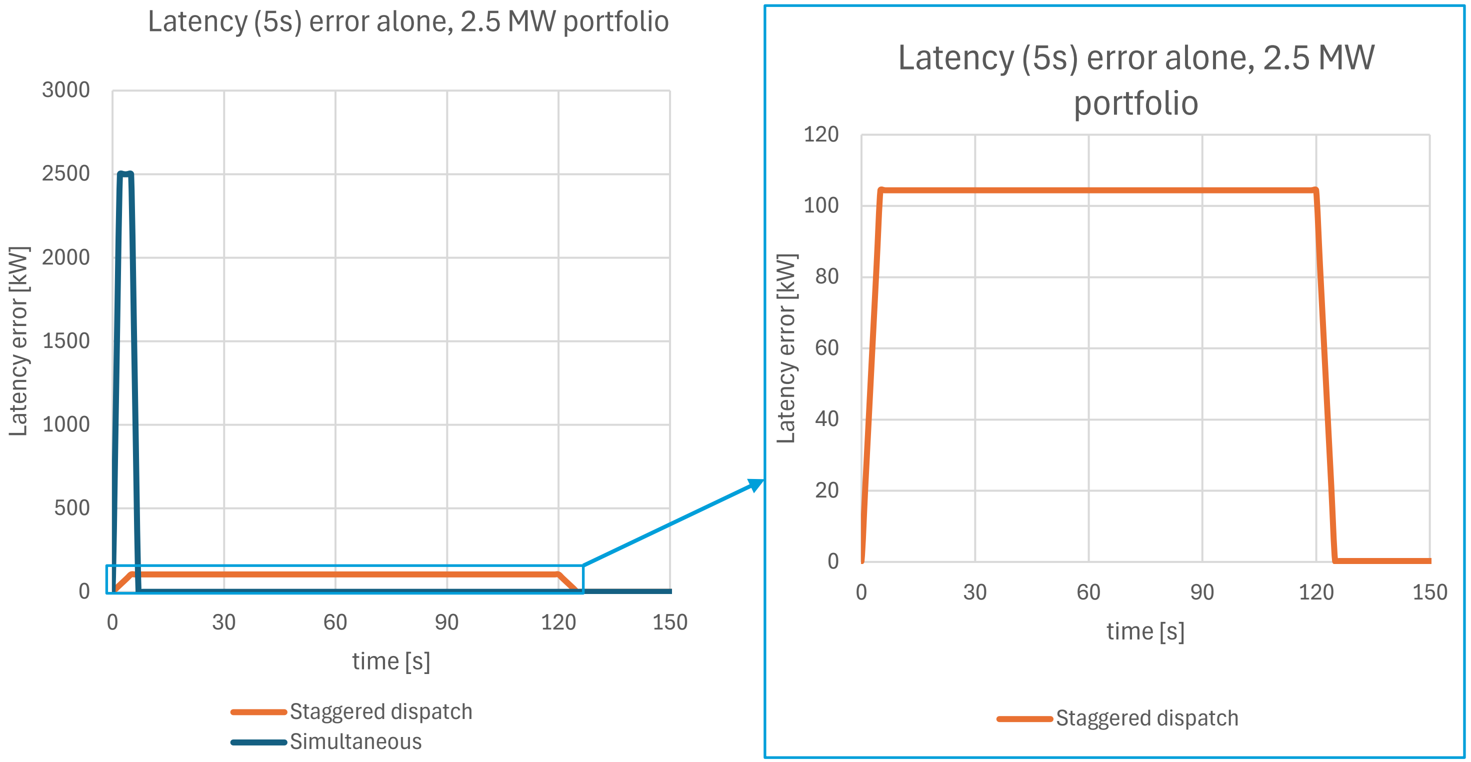
This latency “error” is not easy to mitigate, the timestamps can be time-shifted back in time by the latency lag duration (timestamp to t = -latency lag). This method maintains accurate historical data, but does not mitigate the real-time error seen in the control room. The most effective way to meaningfully reduce the magnitude of the latency error is through the reduction of ramp up and down rates. This involves avoiding quick simultaneous activation and extending the timeframe required for full activation.

Mathematical definition of latency used in our study:

Latency error = $\int_{t=0}^{latency\ lag} ramp(t)\ dt$

With staggered dispatch this simplifies to:

$$\text{ramp} * latency\ lag = \frac{n * P_{asset} * latency\ lag}{timeframe}$$ [kW]



Above: effect of ramp time on communication latency error in control room using 5s latency as an example. Simultaneous dispatch (2 second ramp) results in very high (100%) error. Staggered dispatch (2 minute ramp) significantly reduces the maximum absolute error seen in control room, but the error persists for the duration of the increased ramp time.

H.5 Formulation of total error in real-time

Formulation of total error in real-time

In most situations the error from meter read interval is significantly larger than the other error components

Total error is formulated by the expression $Total\ error = \Delta readinterval\ mean\ error + \Delta latency + \sqrt{(\Delta readinterval\ std\ around\ mean)^2 + \Delta accuracy^2 + \Delta power\ variability\ between\ measurements^2}$

Both communication latency and meter read interval cause a delay (timelag) in the meter reading reaching control room. The timelag in the meter signal can be represented as an error between the portfolios true active power at any given instant, and the meter reading seen in control room.

- The timelag of readinterval is determined by the meter read interval divided by 2.
- The timelag of latency is the actual lag between real-time measurement and arrival in the control room.
- Both have the highest error during ramping periods, because error is calculated as average ramp in the last period * timelag. Also, for adjusted aggregate metering, the ramp value used in adjustment of the reading (difference between aggregate meter reading at t=0 and t=-1) is higher during ramping.

Accuracy error (sensor error in the actual power measurement) is largely independent of the error due to communication latency and meter read interval (i.e. correlation is negligible).

- The accuracy error is therefore modelled as being independent, resulting in the total error formula being expressed as a sum of errors.

In most situations the error from meter read interval is significantly larger than the other error components

- Exceptions to this would be for example if meter read interval is very fast (≤10 seconds) and latency is high (>5 seconds), then latency could start to become the predominant source of error
- As will be shown in the following slides, although it is possible to reduce the readinterval error with some methods, it cannot be totally reduced to zero
- For communication latency, the only way to reduce the magnitude of error is by limiting ramp rate. Prediction based on aggregated measurement or using a subset of readings cannot reduce this error further
- The sensor accuracy error is the smallest error component, and it decreases with increasing number of assets
- An additional source of error from underlying variability in asset power between measurements, this error component is small enough to be considered insignificant, especially in large portfolios, and is therefore not included above.

Appendix I: Reducing errors & evaluating methods – summary

DNV

I.1 Methods to reduce meter errors – summary

Overview of options assessed

Two activation schedules and four methods of aggregating the meter signal were modelled. Two additional approaches are discussed.

Our analysis has identified that meter read interval is the most significant error competent, that there are no options to mitigate communication latency error in real time (other than by reducing the ramp rate), and that accuracy error is insignificant. Therefore, the options assessed focus on mitigating meter read interval error.

Activation schedules assessed	Meter aggregation methods assessed
Simultaneous Activation (fastest possible ramp up rate)	Aggregate metering
	Subset of latest readings
Staggered Dispatch (slower ramp up rate)	Aggregate metering
	Adjusted aggregate metering
	Subset of latest readings
	Timeshifted aggregation
	Other solutions discussed:
	Report on change*
	Synthetic meter readings

*not modelled because reporting with a 1s meter read interval on activation results in no meter lag, and the remaining error is caused by the meter reporting threshold which requires more investigation – see Report on Change

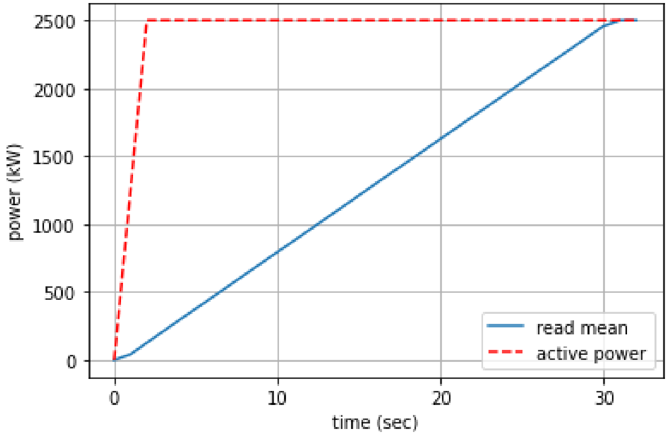
Activation Schedules: Simultaneous activation of the portfolio

Simultaneous activation (with all assets activated within 2 seconds) results in a maximum error of ~95%

Large aggregated portfolios are generally not capable of simultaneous activation today due to limitations in the assets and because communication and IT systems have not been optimised. However, it is likely that this capability will develop in future since enabling faster response times to be offered to the BM and other markets will provide additional revenue streams.

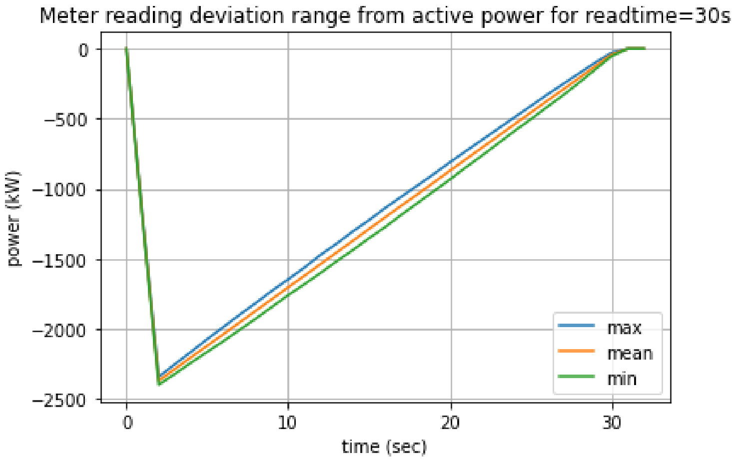
- All assets are fully activated within 2 seconds, therefore the ramp rate of the portfolio is very high. This is shown by the dotted red line in the first graph, which denotes both the activation schedule and the real power delivery of the assets (since portfolios are assumed to perfectly follow their activation schedule in these simulations)
- The mean error is approximately 95% at all assets have ramped up (t=2s) and gradually reduces to 0 at t=read interval (when all assets have finished ramping and their meters have updated).

Active power and mean aggregated read signal (of 1000 monte carlo runs) metered power vs. time



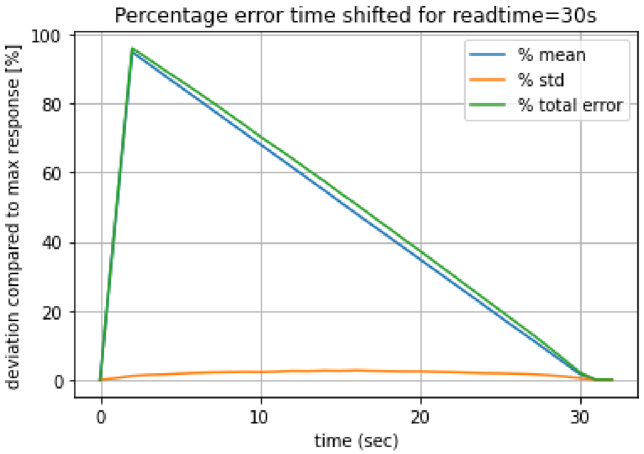
Aggregated read signal is a linear line between t=0 and t=read interval (blue line). On average n/read interval new updates will be sent every second

Error in active power (kW) due to read interval



Mean of 1000 monte carlo runs, max = 86th percentile, min = 14th percentile. This demonstrates the effect of random variability in the distribution of individual meter read times across the read interval (30s in this case)

Error in active power (% of max. portfolio response during delivery)



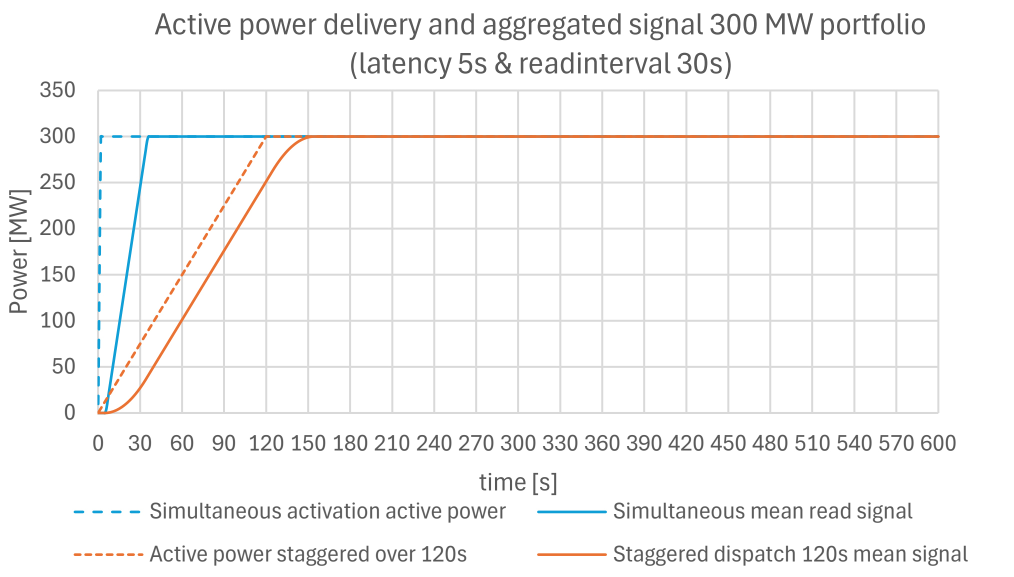
Error of both the (expected) mean deviation and from variability in measuring time of individual assets. The latter is provided as a standard deviation component (yellow)

Activation Schedules: Staggered dispatch of assets to limit the portfolio ramp speed

Assets are activated step-by-step over a longer time period (in this case 2 minutes), reducing the absolute error at any single timestep

The staggered dispatch activation method involves spreading out the activation of assets or groups of assets in portfolio over time to meet a pre-defined ramp rate, rather than dispatching all assets in the portfolio simultaneously. The ramp rate could be defined by NESO if procuring specific products (e.g. Dynamic Services) , or by the aggregator if the portfolio is responding to price signals. This approach allows for a more gradual and predictable change in the portfolio's active power, which can be designed to more closely match the measurement capabilities of the metering system to detect the change in power:

- The magnitude of measurement error is directly related to a) the rate of power change (ramp rate) and b) the meter read interval and communication latency of the assets.
- With simultaneous dispatch there will be 100% error for a length of the latency time minus ramp up time. After which it reduces from ~95% to almost 0% in a timelenght of the readinterval.
- By spreading activation over a longer timeframe (e.g., 2 minutes), the maximum ramp rate is reduced, thereby reducing the absolute error in MW observed in the control room.

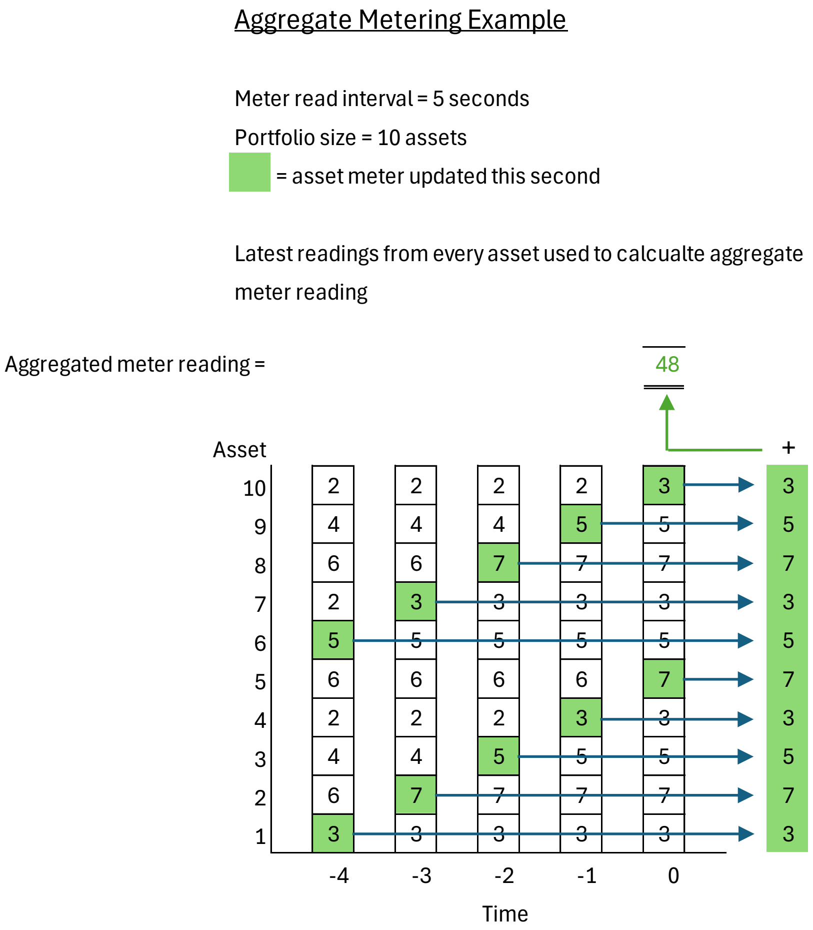


Aggregated meter readings (solid lines) and active power delivery (dashed lines) for the same portfolio with simultaneous activation versus staggered dispatch (including the effect of 5 second communication latency).

Meter aggregation method: Aggregate metering

The latest reading from each asset in the portfolio is used to calculate the aggregate meter reading

Solution Option	Metering Basis	Description
Simultaneous dispatch with aggregate metering (counterfactual, potentially quick simultaneous activation)	Real measurements	All assets are fully activated simultaneously (in our analysis within 2 seconds). The resulting ramp rate of the portfolio is very high. Error is very high (>95%) in the first seconds after ramping begins, since the portfolio achieves its maximum response faster than the measurement interval of most of the asset meters within the portfolio.
Staggered dispatch with aggregate metering	Real measurements	In staggered dispatch activation the assets is spread out over time rather than happening simultaneously. The change in active power of the portfolio occurs gradually and predictably, which enables the ramp to be approximately matched to the capability of the meter read interval to detect changes in portfolio active power. The error from meter read interval is not eliminated, but is spread over a longer ramping period, reducing the magnitude of maximum absolute error observed with simultaneous activation.



Meter aggregation method: Adjusted aggregate metering

The aggregate meter signal is adjusted to correct for error resulting from meter read interval

Solution Option	Metering Basis	Description
Adjusted aggregated metering (ramp error correction). This method performs best in combination with staggered dispatch	Real measurements plus artificial adjustment (based on ramp of aggregate meter read signal)	A weighted average smoothened ramp factor is added to the aggregate meter signal, this compensates for error from readinterval, especially during ramping. This adjustment is based on the change in aggreged portfolio power in the previous x seconds (2.5-15 seconds was analysed during our study, depending on readinterval). The above approach is one method to adjust the aggregate meter error, it is possible that other methods exist which might have better performance.

<u>Adjusted aggregate metering example</u>

Meter read interval = 5 seconds

Portfolio size = 10 assets

= asset meter updated this second

Aggregate meter reading = current sum + (smoothened ramp x timelag)

Smoothened ramp = ramp x (weights (1, 1/2) / sum of weights)

timelag = (meter interval - 1) / 2 = (5-1)/2 = 2 seconds

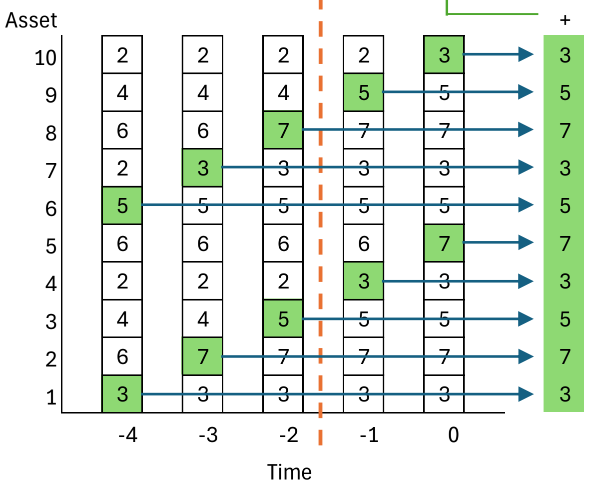
<u>Adjustment calcuation for t=0</u>

ramp		x	weights		sum (t=0, t=1)		smoothened ramp
t=0	2	x	(1) / (3/2)	=	0.66	=	2
t= -1	2	x	(1/2) / (3/2)	=	+ 1.33		

sm'd. ramp	x	timelag	=	adjustment
2	x	2	=	4

	current sum	+	adjustment	=	current sum
Aggregated meter reading =	48	+	4	=	52

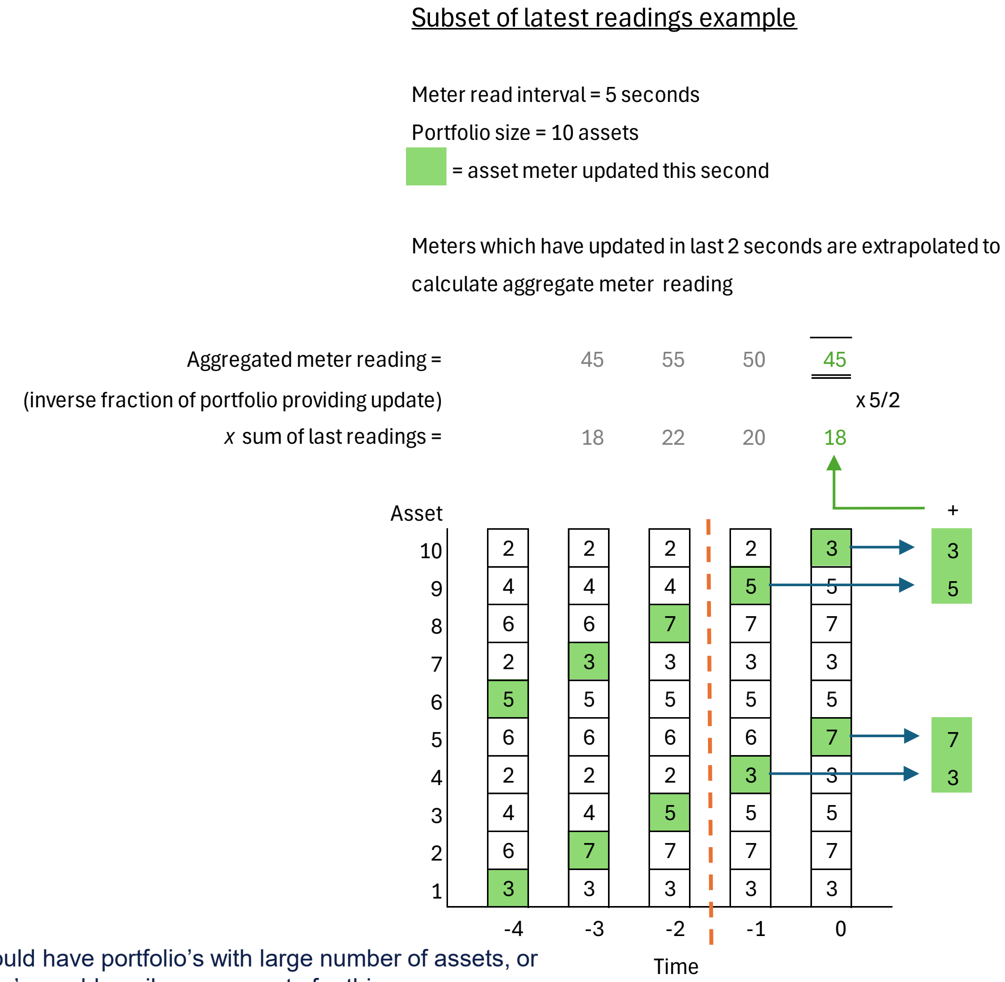
ramp (change in power / sec) =		2	2	2	2
sum of last readings =	40	42	44	46	48



Meter aggregation method: Subset of latest meter readings

The most recent asset meter readings received (e.g. within 3-10 secs) are extrapolated to calculate the portfolio meter reading

Solution Option	Metering Basis	Description
Subset of latest meter readings with staggered dispatch	Most recent real measurements multiplied by a factor (total portfolio power / assets within latest signal range) to estimate total portfolio power output	Latest readings from the previous x seconds (3, 5, 6 and 10 seconds was analysed in our study, depending on readinterval) are used to establish the aggregated meter reading, for instance 10% of the portfolio. The output of those assets is multiplied to estimate the total power output of the portfolio. Using the latest updates will reduces the timelag between active power and visibility in the meter readings but increases the standard deviation around the remaining mean error. All measurements are taken into account even if it is not different compared to the last measurement.
Subset of latest meter readings with simultaneous activation	As above	Method as above. Subset of latest meter readings techniques is applicable to both short and long ramp timeframes, and so its performance was assessed with simultaneous activation.



10 assets are shown just to show how the method works. In reality, you would have portfolio's with large number of assets, or the impact of 1 portfolio on the system would be so small that other portfolio's would easily compensate for this error.

Meter aggregation method: Timeshifted

The time lag introduced by meter read interval of the assets is calculated, and the timestamp of the aggregated signal is changed accordingly. This solution does not correct the error in real-time; it provides an accurate reading after a delay equal to timelag.

Solution Option	Metering Basis	Description
Staggered dispatch plus timeshifted aggregation	Real measurements plus artificial adjustment at beginning and end of ramp	With staggered dispatch, the aggregate meter reading lags behind by (readinterval-1)/2 seconds. By shifting timestamps earlier by this lag amount, we can largely eliminate the mean error. At the start and end of the timeframe, additional synthetic adjustments are necessary. **The timeshifted signal is not available in real time (available timelag seconds later)** **It works best with a gradual ramp, because an error remains at the point of ramp change (i.e. especially at the start and end of ramping).** **Because this solution is not available in real-time it is not compared with the real time options in the results section which follows.**

Timeshift Example

Meter read interval = 5 seconds

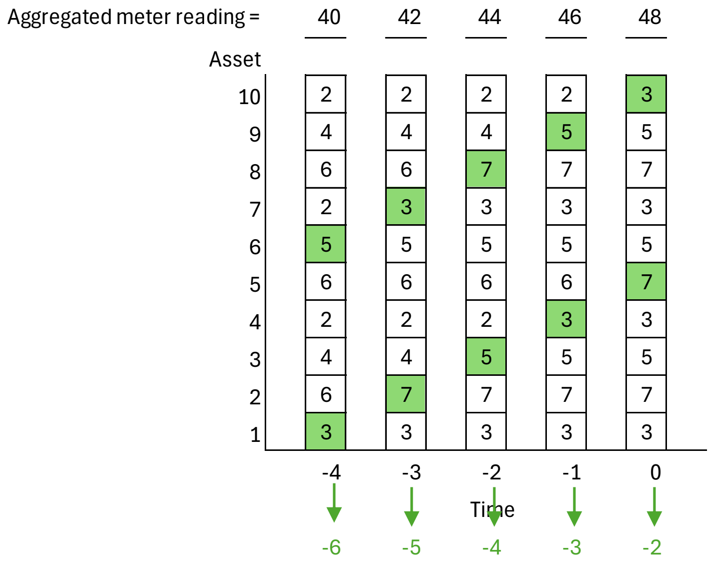
Portfolio size = 10 assets

= asset meter updated this second

Timestamps are changed to account for lag in aggregate meter reading.

An additional adjustment is used to reduce the error at the beginning and end of ramp (not shown here)

timelag = (meter interval - 1) / 2 = (5-1)/2 = 2 seconds



I.2 Performance of meter error reduction solutions for meter read interval

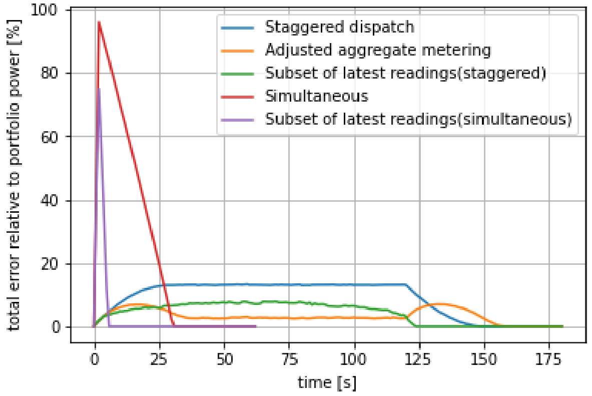
DNV

In this study meter read error is presented as either % of total portfolio power, or as its power equivalent in kW or MW

Two methods of calculating error were compared: as a % of total portfolio power (left) and as % of active power at each 1s timestep (right)

30 second read frequency; 2500 kW portfolio example

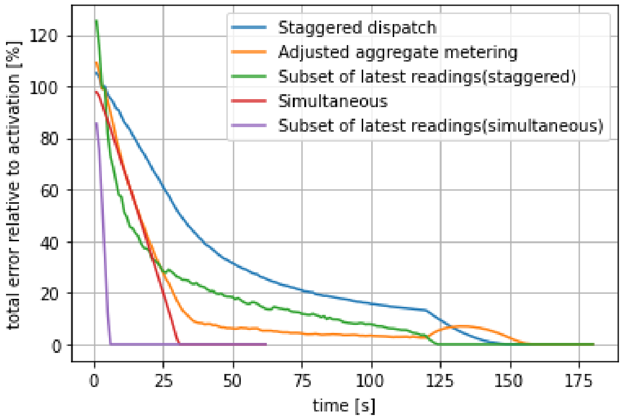
Error as % of portfolio power capacity $= absolute\ error\ /\ 2500\ kW\ *\ 100\%$



Readinterval=30s,
power = 2500 kW

The plot of absolute error (shown here as % of total portfolio) shows that the options assessed reduce the magnitude of the error during the initial ramp. However, this is achieved by spreading the inaccuracy over a longer ramp period (by staggering dispatch of assets). The y-axis could be changed to kW / MW and the chart would look identical.

Error as % of assets activated at timestep $= absolute\ error\ (kW)\ /\ active\ power\ at\ timestep\ (kW)\ *\ 100\%$



Readinterval=30s,
power = 2500 kW

When error is calculated as a % of active power at each timestep, the options assessed do not appear to be effective at reducing the inaccuracy from read frequency. However, this presentation of the results does not communicate that the absolute error during ramping has been reduced by activating fewer assets, so in kW this error would be significantly smaller.

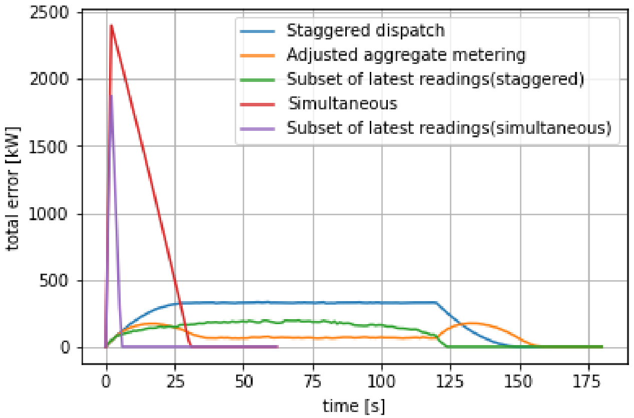
DNV chose to present the results of our analysis as per the left-hand chart ‘Error as % of portfolio power capacity’, or as the equivalent error in kW / MW (which is interchangeable). This portrayal of the results was chosen since it gives the most informative view to ENCC of the true magnitude of the error.

The total meter read error consists of both meter mean error and standard deviation

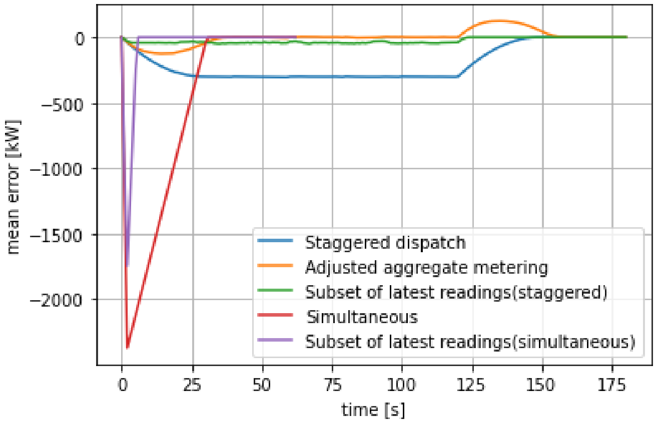
The total meter read interval error consists of two components: error related to the read interval, and a std. deviation caused by variation in the number of assets updating each second

30 second meter read interval, 2500 kW portfolio example

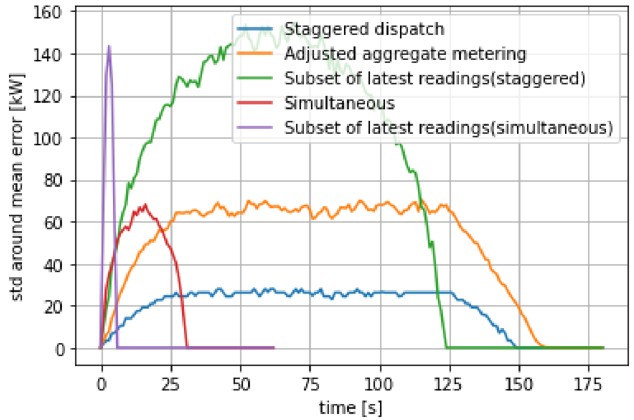
Absolute error in kW



Expected mean error (from read interval)



Std deviation around mean (from variability number of active assets updating / second)



Staggered dispatch: Error is spread over the ramp period, so that the magnitude of the maximum error is significantly reduced, but a smaller error persists over an extended ramp duration.

Staggered dispatch plus adjusted aggregate metering: Error is significantly reduced, especially during the middle of the ramp when the rate of increase in power is stable

Staggered dispatch plus subset of latest readings: Error is significantly reduced throughout the ramp period

Simultaneous dispatch: Error is very high (>95%) in the first seconds after ramping begins, since the portfolio achieves its maximum response faster than the measurement interval of most of the asset meters within the portfolio.

Simultaneous dispatch plus subset of latest readings: Maximum error is still very high (~85%) in the first two second after ramping begins, but once ramping is completed the error quickly reduces zero (in a time equal to the number of seconds before the present time included in the sampling range – in the example above, 5 seconds).

Solution performance is affected by meter read interval, with some solutions performing better than others

Subset of latest readings solutions, among the simultaneous and staggered dispatch methods, perform best over a wide range of read intervals
Adjusted aggregate metering performs best at short read intervals (approximately 15s and under)

Mean error (left chart)

Increasing readinterval results in increased mean error for all solutions, however the two variations of ‘subset of latest readings’ perform significantly better than other solutions especially at longer read intervals. (‘Smaller subset of latest readings’ means that the number of previous seconds of data which is used to extrapolate the meter reading is reduced).

Adjusted aggregate metering is effective at read intervals below 15s but performance reduces as readinterval increases beyond that

Staggered dispatch is the worst performing solution shown here, whilst simultaneous activation is not shown since it performs much worse than the other options and would shrink the y-axis scale if plotted.

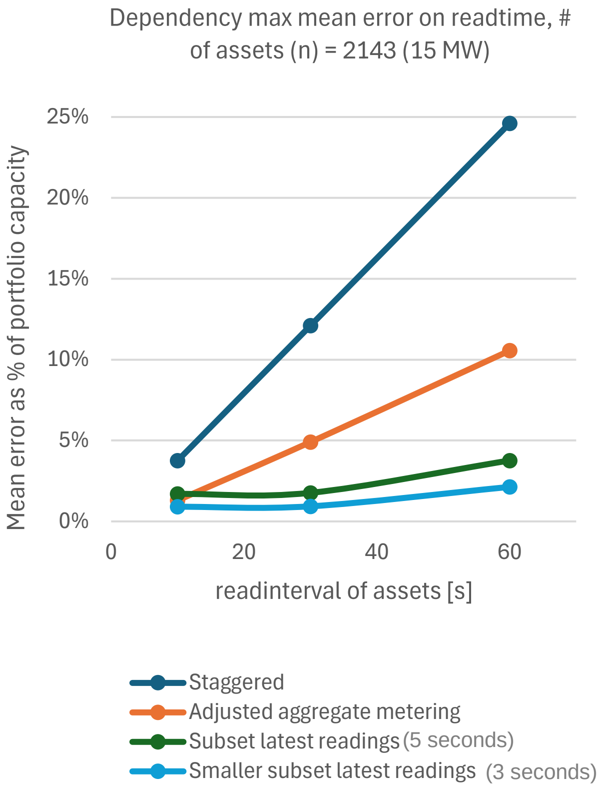
Standard deviation around mean error (right chart)

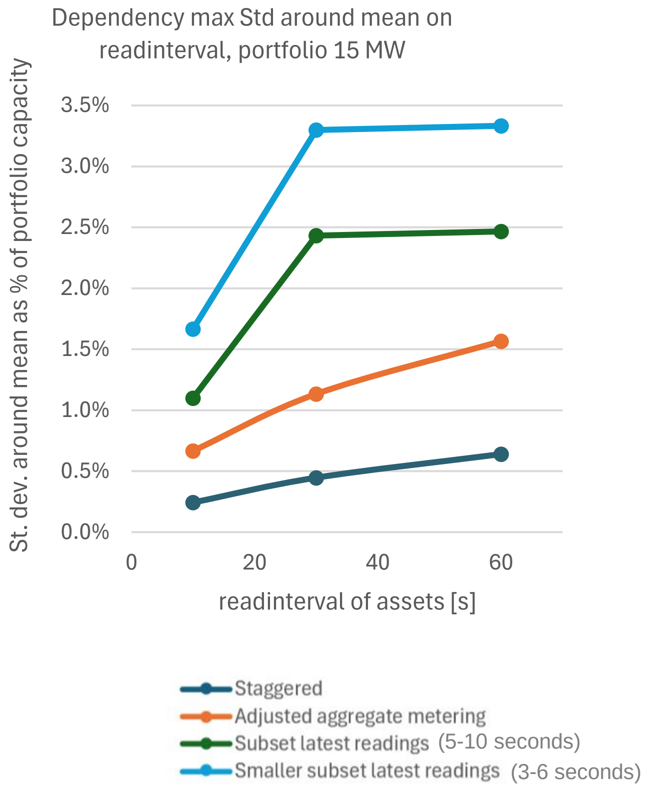
Standard deviation around the mean increases with readinterval. The performance of the solutions in terms of minimising the standard deviation in the mean error are inverted from the left-hand chart, so that staggered dispatch is the best performing solution, and smaller subset of latest readings is the worst.

Subset of latest readings is unique because the relationship between read interval and the proportion of assets used to extrapolate the aggregated signal determines the magnitude of standard deviation. A key observation is that the ramp timeframe's influence on the standard deviation becomes negligible.

$$maximum\ \%\ std\ around\ mean\ error\ for\ subset\ of\ latest\ readings \approx 0.5 * \sqrt{\left(\frac{readinterval}{signal\ interval} - 1\right)/n},$$

For most solutions the standard deviation error is a smaller, but still significant, contributor to total error compared to readinterval error. The exception is subset of latest readings solutions for which the standard deviation is the largest error component.





Solution performance improves with portfolio size because standard deviation error component is minimised by the LLN

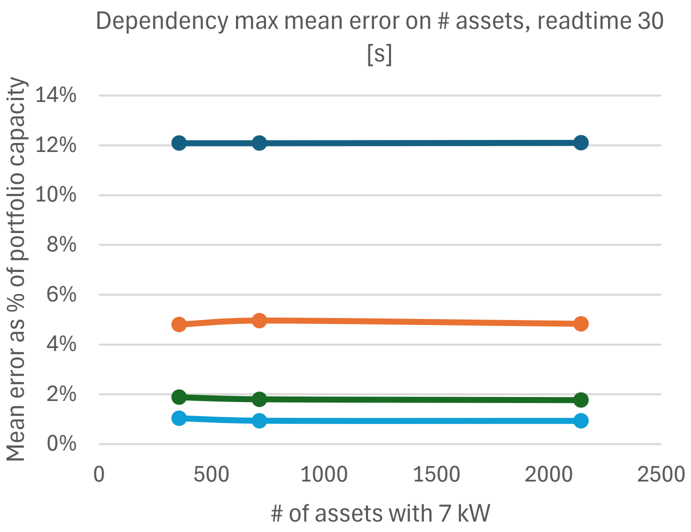
Mean error is largely independent of the number of assets in the portfolio, standard deviation reduces with increasing portfolio size

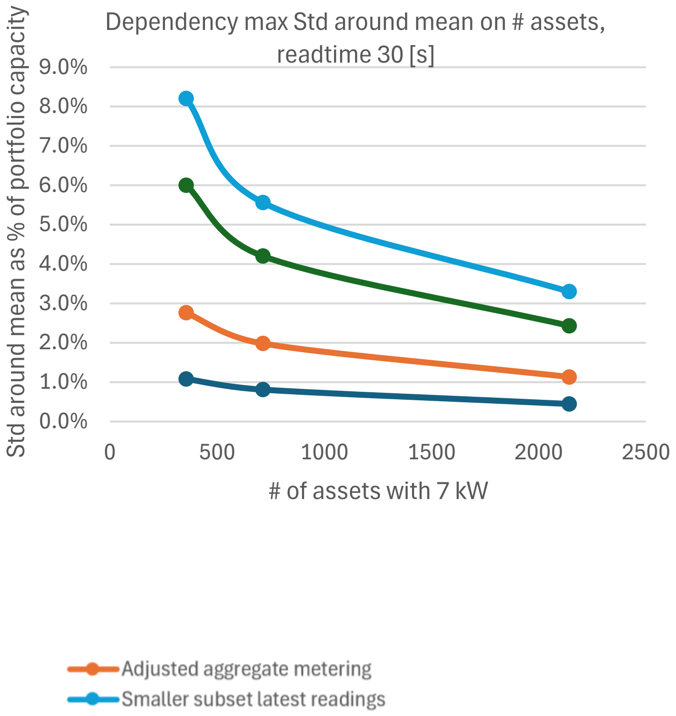
In terms of mean error, all solutions show stable performance with increasing number of assets in the portfolio (shown here as portfolio sizes from 357 to 2143 EV Smart Chargers).

The standard deviation error component can be almost 8% of portfolio capacity for smaller subset of latest readings solutions at portfolio size of 350 assets, however this reduces to approximately 3% once the portfolio reaches 2000 assets.

The error contribution from standard deviation is the worst-case scenario and would be most likely to occur once per ramp period at the mid-point of the ramp (see earlier discussion of standard deviation).

For standard deviation, all solutions demonstrate a common characteristic: the maximum standard deviation decreases with increasing portfolio size according to a $\sqrt{1/n}$ relationship, similar to the law of large numbers.





Error from meter read interval can be reduced to <3% with ramp limits and a subset of latest reading metering solution

Using subset of latest readings or adjusted aggregate metering an error of <3% is achievable with a read interval of 10 seconds, whilst error of <6% can be attained even with 1 minute ramp and 30s meter read interval

		Metering solution and resulting maximum error (15MW portfolio) (error is shown as % of portfolio capacity, fully dispatched portfolio)			
		Meter Read Interval	Aggregate Metering (no correction)	Small Subset of atest Readings	Adjusted Aggregate Metering
Portfolio Ramp Timeframe	**Simultaneous Dispatch (2s ramp)**	10s	81%	42%	50%
		30s	94%	43%	87%
		60s	96%	69%	95%
	Staggered Dispatch (1 minute ramp)	10s	7.8%	3.3%	3.2%
		30s	25%	5.0%	10.9%
		60s	50%	7.4%	22%
	Staggered Dispatch (2 minute ramp)	10s	4.0%	2.5%	1.7%
		30s	12.6%	4.3%	5.7%
		60s	25%	5.5%	11.6%

Ramp timeframe has a significant impact on absolute aggregated meter error

Slower ramping through staggered dispatch significantly reduces absolute aggregated meter errors compared to simultaneous activation

Influence of ramp time on maximum error

- Maximum error decreases linearly as ramp timeframe increases, with relationship ${}^{1}/_{timeframe}$
- For example, extending ramp time from 1 to 2 minutes cuts maximum error roughly in half
- Trade-off: Lower peak errors but sustained over longer period

Solution performance is affected by ramp timeframe

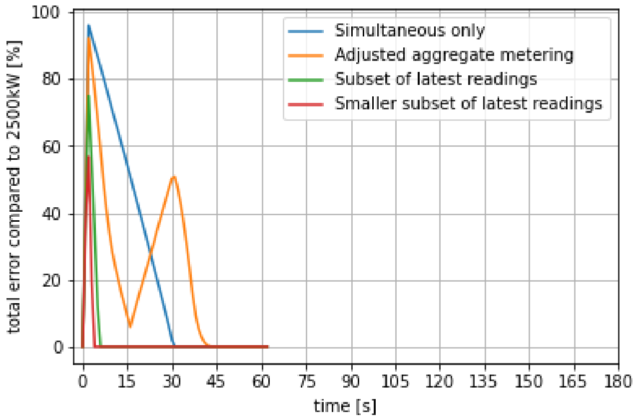
- For rapid response times: "Subset of latest readings" method performs best (can be used with simultaneous activation)
- This method is unique in that the maximum error is mainly driven by the standard deviation around the mean, rather than meter read interval.
- Standard deviation remains constant regardless of ramp timeframe, so this method maintains effectiveness even with fast ramping

Limitations of alternative approaches for fast ramping

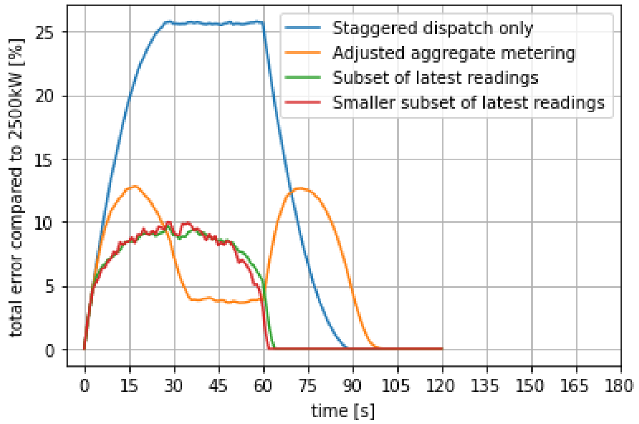
- Ramp adjustment method: Shows minimal benefit for rapid response times, same maximum error as without adjustment. Initial improvement followed by overcompensation
- Timestamp adjustment: Ineffective for rapid changes. Produces inaccurate estimates at ramp start and end. Best suited for gradual ramp profiles.

Short ramp timeframe, higher error — Long ramp timeframe, lower error

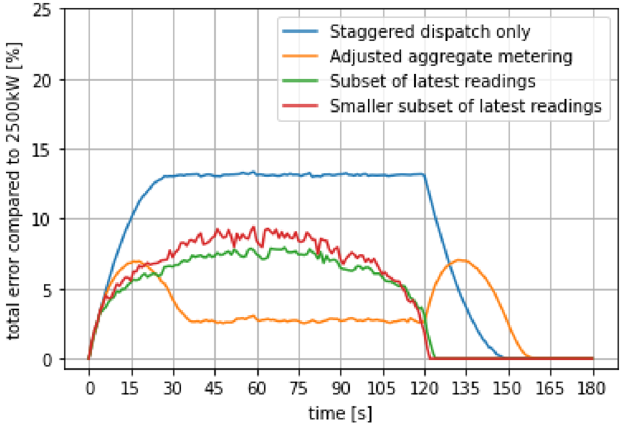
Simultaneous activation in 2 seconds



Staggered dispatch over 1 minutes



Staggered dispatch over 2 minutes



All examples are for a 2500kW portfolio

Report on Change is a viable alternative solution, especially for EV Smart Chargers

Report on change can eliminate or significantly reduce meter read interval error, however there are possible implementation challenges

Report on change refers to asset meters being configured to send more regular updates when the power output changes above a certain threshold. This is how many EV Smart Chargers are configured at present, only sending meter readings when the chargers are active. Provided that meter read intervals are very short (1-5 seconds) during active periods, this could be a very effective solution to minimising aggregate meter error and data costs. However, it is more suited to technology types with low utilisation rates since utilising report on change with a small meter read interval will be data intensive for assets which regularly change their output (e.g. rooftop solar which is constantly changes output during daylight hours).

Benefits:

The primary benefit is that very short meter read intervals (1-5s) can be provided on substantial load changes, which significantly reduces read interval error (or eliminates it with 1s read interval).

Implementation Challenges:

The asset meter must be capable of measuring and transmitting data with an interval of 1-5s. All modern EV charge point equipment is capable of this, but for other technology types this may not be the case if the firmware was not programmed to provide measurements with this frequency.

Setting the appropriate update threshold is crucial:

- Too low a threshold leads to excessive data transmission
- Too high a threshold introduces unacceptable uncertainty
- For EV smart charging, even a small threshold of 0.07 kW (1%) proves valuable

Limitations:
This approach becomes less suitable when load changes are frequent and significant. In such cases, aggregators face a trade-off between:

- Managing excessive data transfer
- Accepting higher inaccuracy due to threshold settings (where inaccuracy per asset = threshold / active power)
- It is possible that some asset types and communication protocols may be limited in their ability to implement a report on change solution

This method was not modelled because the chosen threshold determines the majority of the error. Further analysis on this option should focus on determining the appropriate thresholds and suitability of this approach to different technologies (especially on how quickly power can change, and capability to measure at 1s intervals when the threshold is activated)

Synthetic meter readings are a potential solution but there are risks from adopting this approach

Submitting a synthetic meter reading, followed by a real reading several seconds later, may be the optimum solution to resolve both real-time and offline data uses, however more data on the performance of aggregated CERs is needed to determine the viability of this approach

A potential solution to the problem of aggregated meter error impacts on the control room is to submit two meter feeds:

1. A synthetic meter feed based on the activation schedule of the portfolio, submitted <5 seconds before the portfolio is activated. This would be similar to submitting a PN with more granularity (e.g. secs), however this approach could have similar issues with accuracy similar to PN's.
2. A traditional meter reading, potentially using timeshifted aggregation, submitted timelag seconds later (or as an alternative to this option, submitted ex-post)

The advantages of this approach are that:

- The synthetic meter reading would enable control room to make real-time decisions without concern over the effect of aggregated meter error and would avoid impacts on the demand predictor.
- The traditional or timeshifted meter feed would enable correction of the synthetic feed within timelag seconds (i.e. likely 1 minute or less) and would maintain an accurate record of actual performance for model training, fault investigations and other uses of historic data.
- If limited to the purposes of validation and accurate record keeping, this data could also be provided as ex-post data submission to NESO. This option would significantly reduce costs for aggregators.

Disadvantages of this approach are that:

- There is a risk that the portfolio fails to accurately follow its activation schedule producing an error of a different nature, or that the portfolio does not activate at all. Should a small percentage of assets fail to activate the impact would be relatively small, and these could be quickly replaced by the aggregator by activating assets held in reserve.
- In the worst-case scenario the entire portfolio might fail to activate, even though a meter reading has been submitted indicating the portfolio has begun ramping.
- The control room would not be aware that the synthetic meter feed was inaccurate until the traditional meter feed updates the record after timelag seconds (or if data is submitted ex-post, until well after the event).
- Submission of synthetic meter readings erodes the value of operational metering as an accurate measure of generation/demand.
- This approach would likely require significant changes to NESO systems to implement.

The viability of synthetic meter readings depends on the reliability and accuracy of aggregated portfolios in following their activation schedules, understanding the risk of portfolios failing to activate, and the risk appetite of control room in utilising a synthetic meter reading. In our interviews with control room opinion on the benefits of this solution was split. This option could be explored as more data is collected on the performance of different market participants and aggregated CER technology types.

I.3 Combined Accuracy, Frequency and Latency Impact

Combined Accuracy, Frequency and Latency Impact

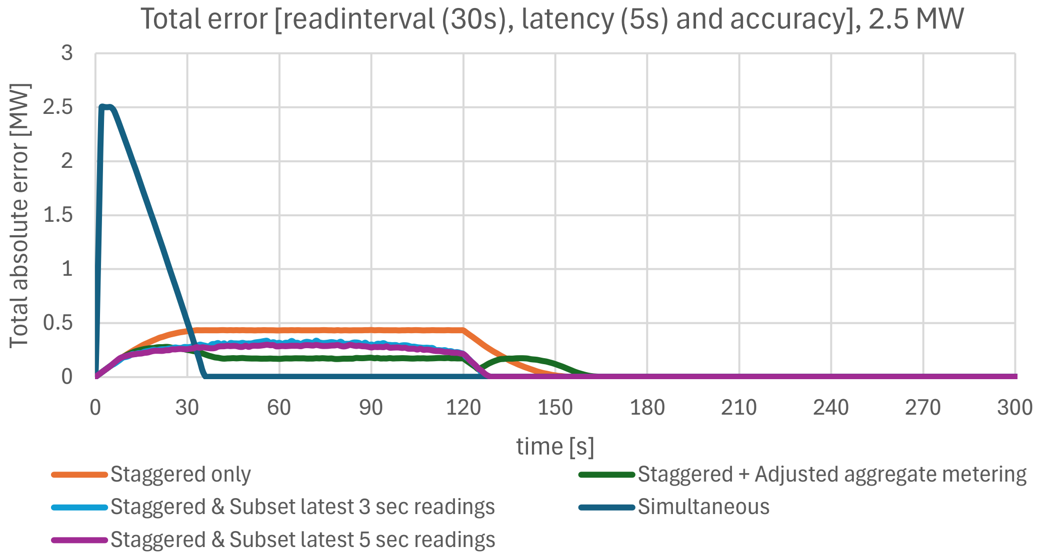
Cumulative error over the dispatch period is a useful metric for comparing solution performance

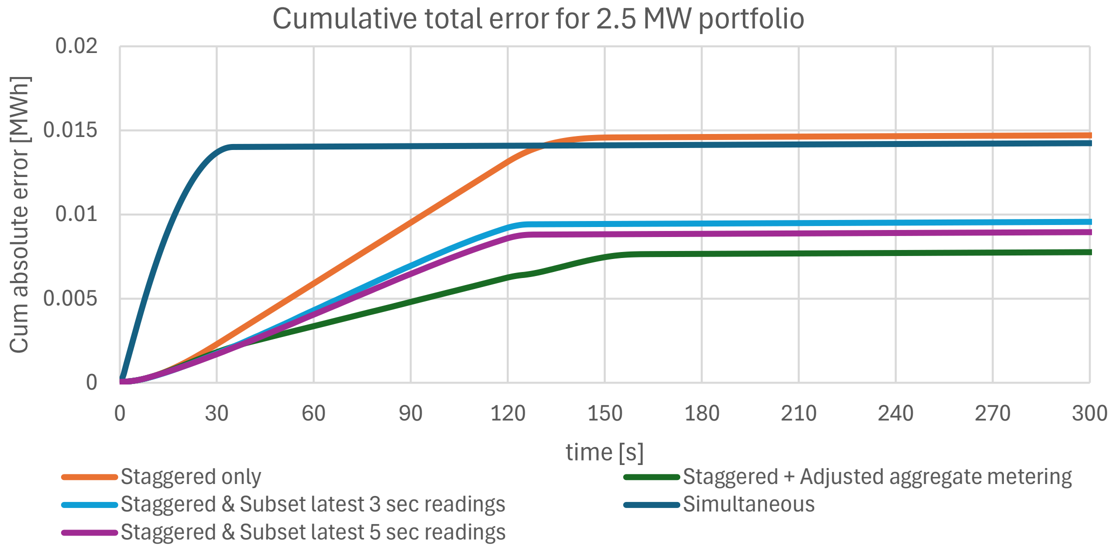
The charts below show a medium-term energy balancing scenario in which a 2.5MW EV Smart Charging portfolio is fully dispatched for 300 seconds. The scenario considers sensor accuracy, communication latency (5s), and meter read interval (30s). The left chart shows the total instantaneous error, and the right chart shows the cumulative error in MWh over the dispatch period.

The conclusions which can be drawn from these charts is that:

1. Limiting the ramp rate of the portfolio through staggered dispatch of the assets resulting in a lower instantaneous error compared to simultaneous dispatch, with total instantaneous error being 2.5MW for simultaneous dispatch and only 0.33MW for staggered dispatch. However, as can be seen from the right chart, the total error over the dispatch period is roughly the same for both dispatch methods, because limiting the ramp speed spreads out the error over time rather than correcting it.

2. The alternative metering solutions, subset of latest readings and adjusted aggregate metering, can reduce both the instantaneous error and the cumulative error over the dispatch period. Therefore, these appear to be promising solutions reducing the impacts of meter error from aggregated CERs on the control room.

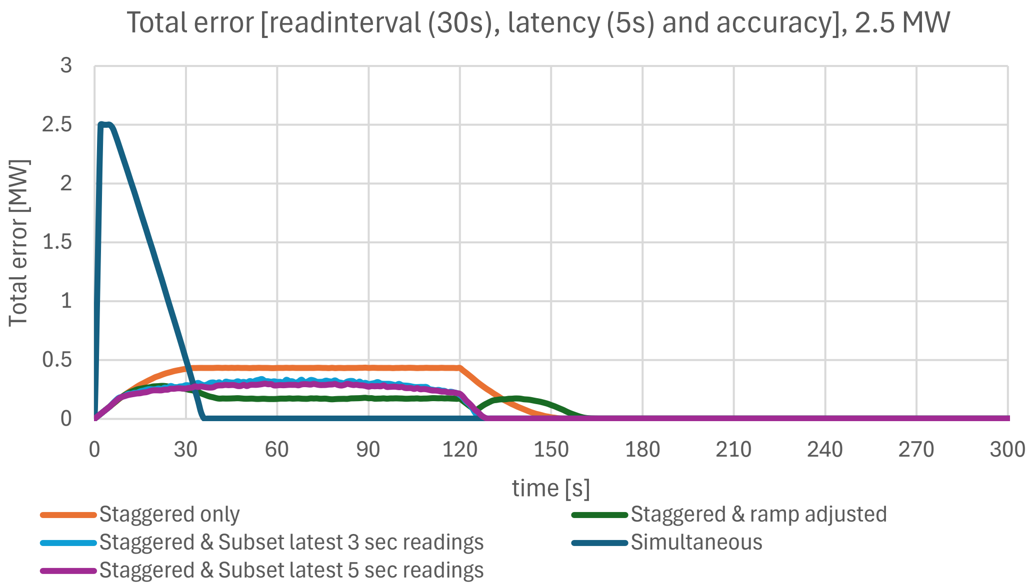


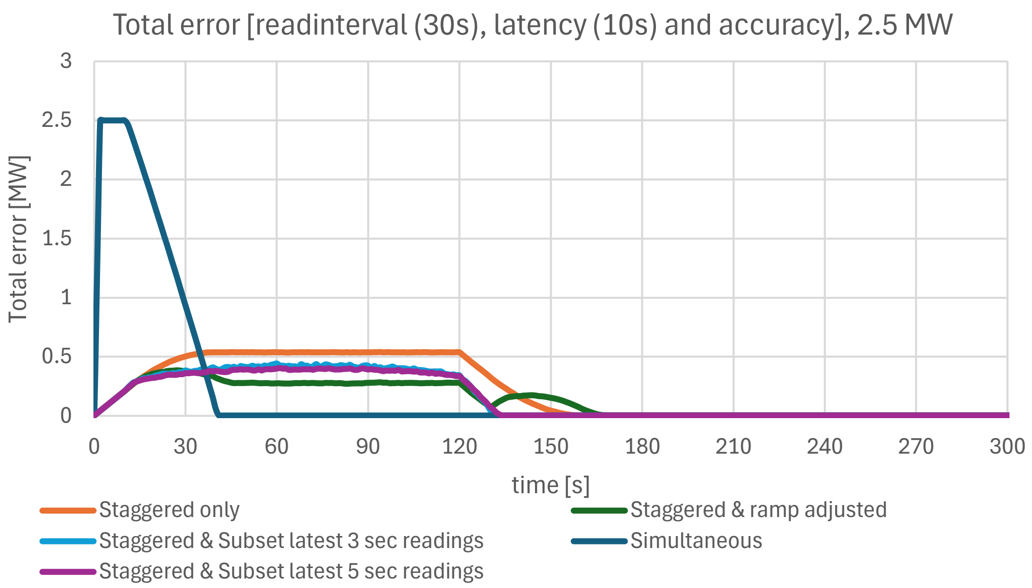


Combined Accuracy, Frequency and Latency Impact: 5 Second vs. 10 Second Communication Latency

Most stakeholders interviewed for this study reported that 5s communication latency was achievable, this is supported by independent research. However, the below charts illustrate the hypothetical impact of 5s vs 10s latency on the maximum total error.

2.5MW portfolio dispatched for 300 seconds.





The impact of increased communication latency is that for staggered dispatch the duration over which the error persists and is at its maximum is increased by 5s. For other solution with a limited ramp speed as a result of staggered dispatch of the assets the magnitude of the error contributed by communication latency is doubled. However, for a 30s read interval shown here, the meter read interval is still the largest error component.

I.4 Evaluation of different meter error reduction solutions

Evaluation of options to improve aggregate meter accuracy

Staggered dispatch combined with adjusted aggregate metering or subset of latest readings were the best performing solutions

Activation Schedule	Meter Aggregation Solution	Relative maximum error	Pros	Cons
Simultaneous dispatch	Aggregate metering (counterfactual)	Highest	Most CER can ramp up very quickly and therefore provide balancing services very quickly. No adjustments to readings.	High absolute (MW/kW) errors.
Staggered dispatch	Aggregate metering (counterfactual)	High	Relatively simple to implement Provides flexibility for aggregators to enter faster responding services by increasing the asset meter update frequency to enable a faster ramp time	Increases the total time required to fully dispatch the portfolio, which may prevent assets capable of participating in faster services from doing so
Staggered dispatch	Adjusted aggregate metering	Low (especially combined with lower readinterval and lower ramp rate)	Error in mean is largely eliminated for most of the time (only at large ramp fluctuations not, e.g. start and end of ramping)	Semi-synthetic meter reading which involves predicting the behaviour of the assets based on latest meter readings.
Staggered dispatch	Subset of latest meter readings	Low	Reduces error with any activation schedule. Error in mean is greatly reduced due to a lower timelag, Also Std around the mean is independent of the timeframe of ramp therefore it is very suited for situation where large ramps are required. Can be applied to both simultaneous activation and staggered dispatch.	There is a trade-off between reducing error due to readinterval timelag and the standard deviation around the mean error. Std deviation around the mean error becomes very large when time range of assets in the aggregated signal decreases compared to readinterval.

Evaluation of options to improve aggregate meter accuracy

Timeshift aggregation is effective at reducing error but not available in real time.
Report on change may be effective for EVs but not for other technology types (e.g. Solar PV). Submitting synthetic readings has higher risk.

Activation Schedule	Meter Aggregation Solution	Relative maximum error	Pros	Cons
Staggered dispatch	Timeshift aggregation	Lowest	Very accurate measurements possible. Only a little manipulation of aggregated read signal with longer timeframe of ramp (based on activation schedule).	**Not available in real time** (available after readinterval/2 seconds) or requires large synthetic mark-ups based on activation schedule send to assets. Less suitable when having large fluctuation in ramp in a short period (simultaneous activation).
Not modelled (lack of data)	Report on change	Likely to be low if 1s read interval is used whilst active, but additional error is provided by threshold for meter activation (not modelled)	Direct notification when there is a significant change in power. No manipulation. Error is largely dependent on the threshold chosen.	Requires meter capability to measure every second (while not having to send updates every second). Question of where to put the threshold? Might not be useful for assets that have a lot of different load levels in a minute.
Not modelled	Synthetic Meter Readings	Since the activation schedule is submitted as a meter reading, the error is the difference between the activation schedule and real power delivery	Enables control room to make real-time decisions without uncertainty over effect of aggregated meter error / latency on situational awareness. Does not prevent a traditional meter reading being submitted with a delay as a back-up, or submission of data ex-post for performance validation.	Operational metering no longer based on real readings but on expected behaviour of the portfolio. If there are any problems activating the portfolio there will be a delay to notify the control room that previously sent data was incorrect.

Best performing solutions for a 300 MW EV Smart Charger considering all sources of error

At 10s meter read interval error is mainly caused by communication latency, and adjusted aggregate metering performs best.
Above 10s read interval, meter read interval is the most significant error component, and subset of latest readings solution performs best.

		Timeframe to full delivery		Comment
Meter read interval		60 seconds	120 seconds	
10s	**Best Solution**	**Staggered dispatch, Adjusted aggregate metering**	**Staggered dispatch, Adjusted aggregate metering**	Most of the error at this point comes from communication latency. With staggered dispatch plus adjusted aggregate metering there is a small period when the maximum error is larger than subset of last 3 seconds, but overall, adjusted aggregate metering is the better solution here.
	Maximum % Error	11.2%	5.7%	
30s	**Best Solution**	**Staggered + Subset of latest readings (last 3s)**	**Staggered + Subset of latest readings (last 3s)**	Subset of latest readings readings has reduced the effective meter read interval timelag to just 1 second. Thereby heavily reducing the mean error. Standard deviation of the mean is the highest of all solutions, but reduces significantly with large number of assets according to the law of large numbers.
	Maximum % Error	10.9%	6.1%	
60s	**Best Solution**	**Staggered + Subset of latest readings (last 6s)**	**Staggered + Subset of latest readings (last 6s)**	The number of prior seconds sampled in subset of latest readings should be increased with a larger readinterval. At 60 readinterval using the latest 6 seconds of meter updates to calculate the total portfolio output shows the best results.
	Maximum % Error	13.3%	7.2%	

Appendix J: Other technology types assessment

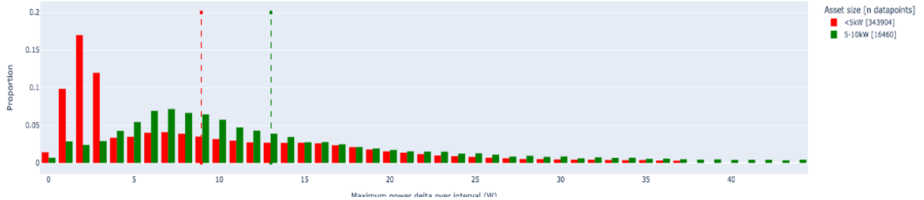
Additional information was provided enabling qualitative analysis of other CER technologies

Detailed data on other technologies was not available due to privacy concerns, however some additional data analysis was received

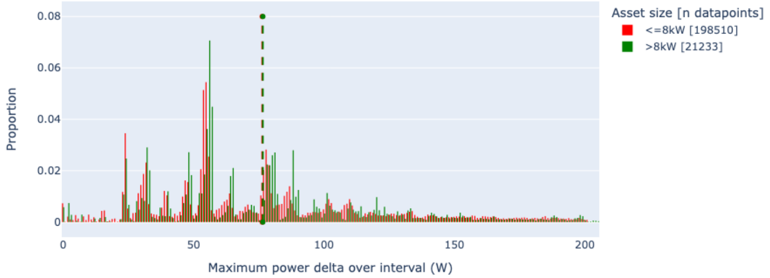
- Detailed recent datasets on portfolios of aggregated assets with measurement intervals <60 seconds could only be accessed for EVs during this study due to privacy concerns.
- DNV were able to secure limited data analysis from a market participant analysing the variability of power outputs of portfolios of the following technology types:
  - Home BESS
  - Home BESS + Solar PV
  - EV (EV's control via. Automotive OEM API)
  - EVSE (control via. Electric Vehicle Supply Equipment (EVSE) API – EVSE is referred to as EV Smart Charger elsewhere in this report)
  - V2G EVSE (control via. EV Smart Charger OEM API)
  - Heat Pumps
- This data analysis enabled DNV to understand the variability in power output that determines the standard deviation component of metering error described earlier. The magnitude of this standard deviation is especially important when utilising the sub-set of latest readings solution as described in the slide on impact of read interval on solution performance. The analysis was used to draw conclusion on the applicability of the modelling results for EV Smart Chargers to other technology types, discussed on the following slide.
- The data provided did not enable DNV to assess the response times of Heat Pump, Home BESS, or Solar PV portfolios, however a qualitative comparison is made later in this section.
- In addition, DNV were supplied with a 2019 V2G portfolio dataset. The measurement interval of assets in this dataset was not sufficient to enable detailed analysis of ramping, however it was used to validate the findings of our analysis of the EV Smart Charging dataset and to uncover additional insights on the probability distribution of power outputs of a V2G portfolio.

Example of information received on variability of power output

Home BESS



EV



Our modelling is more representative of EVs and Home BESS, and less representative of Heat Pumps and Solar PV

Technology	Findings from data received	Validity of applying EV modelling conclusions for this technology	Suggestions for further analysis
Home Battery	<1% variability between measurements (expected to behave similarly to EVs), based on 5 minute readinterval, mostly. On a sub-minute level it is unlikely to be larger than this 1% and much more likely to be less.	The home battery data analysis suggests that similar conclusions would apply as was found in the EV Smart Charger modelling because: 1. Portfolio error reduction follows the same law of large numbers (LLN) principle 2. The measurement variability component is very small compared to reading interval and latency errors 3. Home batteries have an advantage over EVs: they can operate at multiple power levels, allowing more assets to provide the same response level. This particularly benefits the "subset of latest readings" method by reducing variability around the mean error.	The measurement interval in the dataset was mostly 5 minutes. This has to improve to enable quick provision of balancing mechanism products , but this is likely to be achievable. BESS can operate on a different load levels within its capacity,
EV (communication directly with vehicle) EVSE, V2G EVSE (EVSE refers to EV smart charge points)	Slightly higher variability compared to other datasets but still marginal at maximum 2.2% for smaller EV chargers based on 1 minute readinterval . Very distinct load levels, but more than only on/off	The EV, EVSE, and EVSE V2G data analysis suggests that similar conclusions would apply as was found in the EV Smart Charger modelling because: 1. Portfolio error reduction follows the same mathematical LLN principle 2. The measurement variability component is very small compared to reading interval and latency errors. V2G might have duration constraints, which might be solved by having more V2G units in the portfolio than in the reserve bid.	Research on how many EV chargers will be in use at any given time to determine how large portfolios should be to guarantee x MW of response, and ramping error for all EV chargers in the system (e.g. for demand forecasting).
Heat Pumps	Potential variability up to 6% between measurements, based on 5 minute readinterval, mostly. On a sub-minute level it is unlikely to be larger than this 6% and much more likely to be less.	Measurement variability could remain a significant factor in total portfolio error as weather events might cause dependencies between “normal operation” error from measurement variability, and the error per asset starts off higher compared to EV and V2G (3-6% per asset). Heat pumps will have a slower ramping than EV’s and there will be more operational constraints e.g. internal control logic. These could be solved by having more assets.	Confirm in WP4 ability to measure at 1s to 1 minute interval and the (operational) ramping constraints of heat pumps and how this can be handled to provide (fast) reserve. Availability and use is very seasonal and potentially with a daily cycle, therefore extra attention on consumer behaviour would be good to improve load forecasting.
Household Solar PV	Potential variability up to 6% between measurements, based on 5 minute readinterval, mostly. On a sub-minute level it is unlikely to be larger than this 6% and much more likely to be less.	Measurement variability could remain a significant factor in total portfolio error as weather events might cause dependencies between “normal operation” error from measurement variability and the error per asset starts of higher compared to EV and V2G (3-6% per asset). The operational characteristics of solar PV create additional complexity. While solar panels operate in a binary on/off state similar to EV chargers, their output when "on" varies continuously based on weather conditions and cannot be precisely controlled.	Relation of error due to weather. Confirm in WP4 ability to measure at 1s to 1 minute interval. Focus on BESS + Solar PV, as BESS could buffer variability in solar PV and provide upward reserve as well, where solar PV alone can likely only provide downward reserve. Confirm that solar PV can extend the availability of BESS to provide reserve e.g. BESS charging while providing energy.

Batteries show very little variation between measurement points

Standard deviation of power output between measurement points was found to be 0.2% of asset capacity. At the aggregated portfolio level this standard deviation is reduced by the law of large numbers.

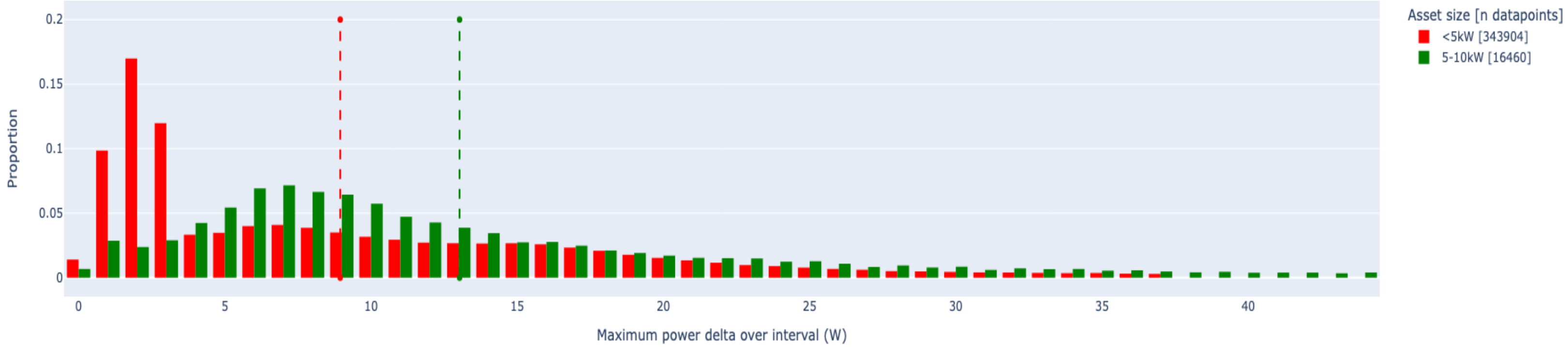
Stakeholders provided DNV with a histogram of deviation in power from one measurement point to the next (snapshot measurements) during “stable” operation (without response to a signal).

- Batteries are characterised in two groups 0-5 kW capacity and 5-10 kW capacity.
- The readinterval between two measurement points was mostly 5 minutes.

The vertical lines show the x variation on which 75% of the datapoints are below this x (9 Watts for smaller BESS and 13 Watts for larger BESS). DNV has taken a larger percentage to determine the standard deviation given in the table.

Batteries show very little variation (<1%) when they are not reacting to an external signal. Unfortunately, the data only allowed readintervals of 5 minutes, however given the large dataset and the datapoints being snapshot, DNV is confident that the variation during “stable” operation is not significantly larger when looking at shorter readintervals, it is more likely to be smaller than this. This standard deviation is further reduced according to the law of large numbers when they are combined in a portfolio ($\sqrt{1/n}$).

Furthermore, this 0.02 kW mark could be a useful threshold for report on change as well, where “stable” operation will not trigger an update, thereby greatly reducing the update frequency, while still having a maximum error of 0.02 kW per asset.



Capacity	<5kW	5-10kW
St. Deviation [kW]	0.02	0.02
Error	0.4%-1.0%	0.2%-0.4%
Most with 5 min readinterval		

EV, EVSE, and V2G EVSE also have low variability between measurement points

St. deviation was 1.4-2.2% and 0.9-1.7% of asset capacity for EV/EVSE and V2G respectively, and reduced by the LLN at portfolio level

Stakeholders have provided DNV with a histogram of deviation in power from one measurement point to the next (snapshot measurements) during “stable” operation. Without response to a signal.

EV / EVSE charging (where EVSE the communication is done via the charger, while EV shows the result of communication with the EV itself) is characterised by 0-8 kW capacity and >8 kW capacity.

- The readinterval between two measurement points was mostly 1 minutes.

EV/EVSE show very little variation (<2.2%) when they are not reacting to an external signal. Given the large dataset and the datapoints being snapshot with mostly 1 minute readinterval, DNV is confident that these variations also hold on shorter readintervals. The datasets shown before confirm this statement with even lower variation in the range of less than 1% for sub 1 minute readintervals.

Vehicle to Grid (V2G) is characterised by up to 3 kW capacity and 3-8 kW capacity.

- The readinterval between two measurement points for V2G was mostly below 1 minutes.

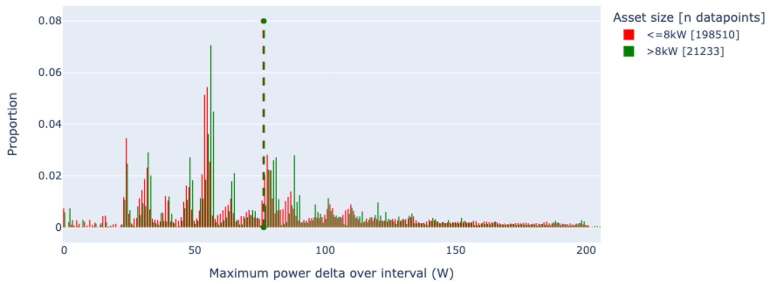
V2G shows even better results with shorter readinterval and lower variation.

This standard deviation is further reduced according to the law of large numbers when they are combined in a portfolio ($\sqrt{1/n}$). Also here these “stable” operation variability could be an useful threshold for report on change, limiting the updates that will be send and having this threshold as a maximum error per asset.

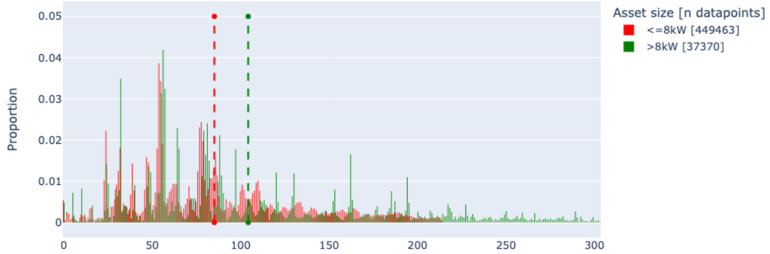
Capacity EV / EVSE	<=8kW	>8kW
EV St. Deviation [kW]	0.11	0.13
Error	1.4%-2.2%	<=1.7%
EVSE St.Deviation [kW]	0.11	0.16
Error	1.4%-2.2%	<=2.0%
Most with 1 min readinterval		

Capacity V2G EVSE	<3kW	3-8kW
St. Deviation [kW]	0.025	0.04
Error	0.9%-1.7%	0.5%-1.4%
Most with sub 1 min readinterval		

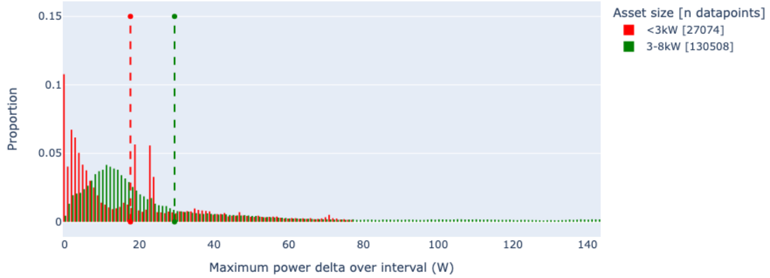
EV



EVSE



V2G EVSE



Heat Pumps have larger variation between measurement points compared to batteries and EVs

St. deviation was 3-6% of asset capacity for Heat Pumps, though most variations are in the range 1-2%.
Error reduction through the LLN at portfolio level may not apply due to weather correlation of heat pumps.

Stakeholders have provided DNV with a histogram of deviation in power from one measurement point to the next (snapshot measurements) during "stable" operation. Without response to a signal.

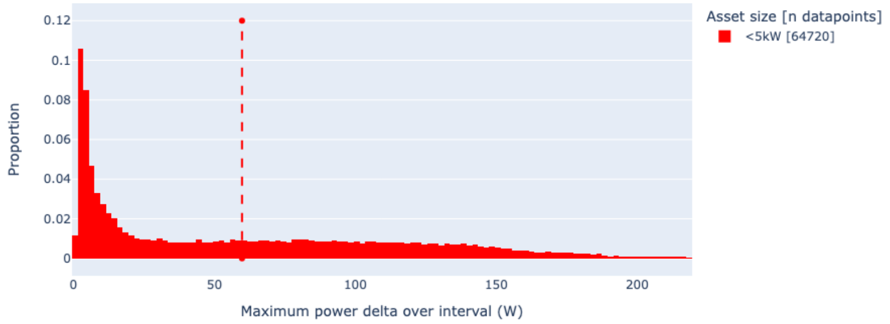
Heat pumps are available in several sizes and typically not larger than 5 kW.

- The readinterval between two measurement points was mostly 5 minutes.

Heat pumps show somewhat larger variation (3-6%) when they are not reacting to an external signal, although most deviations are located <50 Watts, which corresponds to a variation of 1-2%. Given the large dataset and the datapoints being snapshot with mostly 5 minute readinterval, DNV is confident that these variations also hold on shorter readintervals.

This standard deviation is further reduced when aggregated over a large number of assets (law of large numbers), however it is likely that these errors are not completely independent, given their temperature relation. A decrease of $\sqrt{1/n}$, is likely to be too optimistic. Weather events may cause that this error is not normally distributed around zero.

Conclusions from EV's are likely applicable for Heat Pumps as well, but consideration around this variability in "stable operation", might have some impact. The flexibility potential of Heat Pumps is likely to be considerably less than EVs due to less flexible consumer behaviour in relation to home temperature and technical limitations on response time of heat pumps, leading to more complex analytics to assess flexibility volumes.



Capacity	<5kW
St. Deviation [kW]	0.15
Error	3.0%-6.0%
Most with 5 min readinterval	

Solar PV has larger variation between measurement points compared to batteries and EVs, but similar to Heat Pumps

St. deviation was 2.8-6% of asset capacity for Solar PV.
Error reduction through the LLN at portfolio level may not apply due to weather correlation of Solar PV

Stakeholders have provided DNV with a histogram of deviation in power from one measurement point to the next (snapshot measurements) during “stable” operation. Without response to a signal.

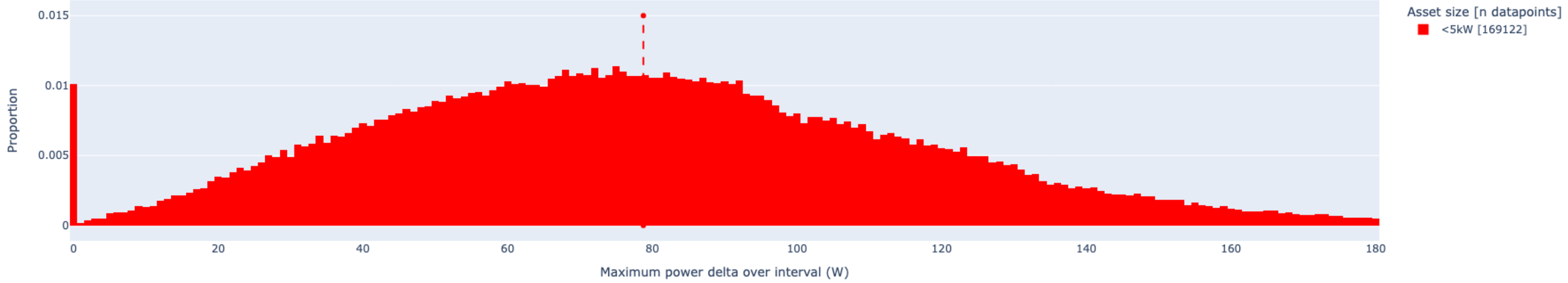
Solar PV systems are available in several sizes, and typically not larger than 5 kW for household rooftop.

- The readinterval between two measurement points was mostly 5 minutes.

Solar PV (inverters) show somewhat larger variation (2.8-6%) when they are not reacting to an external signal. Given the large dataset and the datapoints being snapshot with mostly 5 minute readinterval, DNV is confident that these variations also hold on shorter readintervals.

Similar to Heat pumps, this standard deviation reduces when aggregated over a large number of assets (law of large numbers), however their error is likely to be even more correlated to weather than in the case of heat pumps. Solar PV without BESS also does not have a buffer to compensate this as is mostly the case for (large or small) boiler vessels in combination with heat pumps. Furthermore, these Solar PV without BESS is likely only available for down reserve.

Therefore, DNV sees potential differences in the case of solar PV with earlier conclusions from EV chargers. This “stable” operation variability error can have a major contribution in the total error and a large share of the portfolio can act differently than expected and in the same offset direction.



Capacity	<5kW
St. Deviation [kW]	0.14
Error	2.8%-6.0%
Most with 5 min readinterval	

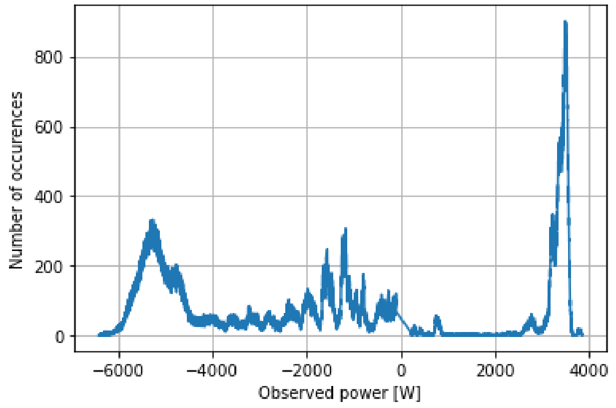
An additional V2G dataset was analysed, providing possible power demand / delivery from EV V2G portfolios

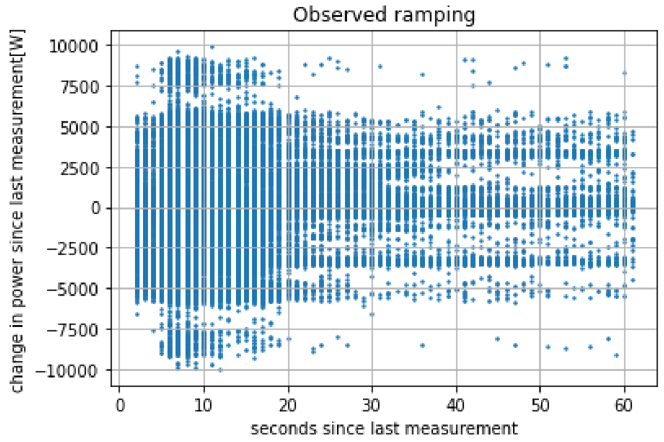
Analysis of V2G data showed that ramping from full charging to V2G discharge or vice versa was observed to be possible within 5 seconds

- A third dataset from 2019 with EV charging and vehicle to grid show similar variation from one measurement point to the next during stable operation.
- This dataset show possible actual charging for 50 EV chargers. Although we have assumed 7 kW charging as being standard before. This dataset suggests also other possible states. Full charging in this 2019 test was somewhere between 4.5 and 6 kW. With spikes around 1950 kW, 1550 kW and 1200 kW.
  - In reality EV’s will have different power demand depending on the point in the charge cycle they are at.
  - Either more EV’s are needed to achieve the desired response, or EV’s not at desired response would need to be excluded from the portfolio. If more EV’s are added to the portfolio this would improve the meter accuracy.
- If the charging power would be known beforehand by the aggregator than this will not change our earlier conclusions for EV’s. Also using additional chargers to compensate for a few that are below expected would also not have larger deviations than simultaneous activation of many EV’s at the same time.
- Illustrates the potential complexity in forming a portfolio of required size.

V2G findings

- Another conclusion DNV found in this dataset is the quick ramping that is possible (see figure on the right) even from full charging to V2G discharge or vice versa was observed to be possible within 5 seconds.
- This dataset has very little values between 60 and 3100 W. Therefore, it can be inferred that EVs ramp within the length of a readinterval (these were even up to 1 second, especially after a ramping up/down event).





Response times may vary significantly across CER types with implications metering error and flexibility value

While Home BESS and Solar PV can respond within seconds, V2G EVs and Heat Pumps may face technical constraints that limit their response times. Longer response times will likely reduce instantaneous meter error but narrow the market opportunities for these assets.

Technology	Response time from receipt of dispatch signal	Implications for Operational Metering
Home BESS Inverters	Very Fast (<5 seconds) Data on Home BESS ramping behaviour could not be secured for this study due to GDPR concerns. However, interviews with market participants and technology providers suggests that the response time for Home BESS is likely to be equal to or faster than for EVs. Home BESS are expected to be rapidly dispatchable, potentially able to respond more quickly than EV's due to simpler control logic and interface compared to most other CER types.	The very fast response time of Home BESS systems potentially enables participation in a wide range of grid services however it also poses challenges at the portfolio level since the faster the power output of the portfolio changes, the greater the error between the true power output of the portfolio and the meter reading visible in the control room. Limiting the ramp rate could be an option to reduce maximum error.
Heat Pump	Slow (1-30 minutes) Data on Heat Pump portfolio ramping behaviour was also unavailable for this study. Interviews with market participants and technology providers suggested that the response time for heat pump portfolios is likely to be significantly slower than for other CER types. Heat pumps are complex systems of valves, pumps, compressors, and control hardware. They are less efficient and wear faster when cycled quickly. Manufacturers often include minimum run time logic into control systems which prevent the heat pump from being turned off within a set period of time (e.g. 30 minutes).	When offering demand turn down, Heat Pumps portfolios are likely to have a wider temporal distribution of available activation schedules of assets (due to mis-aligned minimum run times of already operating HP systems). This would either reduce the size of the portfolio that the aggregator can offer or significantly increase the portfolio response time. In addition, all heat pump systems are expected to have longer response times to activation signals (due to more complex hardware system and control logic). Taken together this suggests that the response time of heat pump portfolios will be slower than for other assets and the impact on control room from ramping of HP portfolios is likely to be much lower than for faster responding assets.
EV, EVSE and V2G	Fast (5 seconds to 5 minutes) Control of EV charging typically depends on control of separate hardware and software systems on both the smart charger and the EV. For demand turn up response time may be longer since EV's typically require battery pre-heating before initiating charging, and regulations require randomised delay on initiation of charging (note that randomised delay does not apply for assets responding to flexibility services).	The implications of background variability of EV Smart Charger behaviour, as well as ramping behaviour, have been analysed in this study. Datasets show that fast response is already achievable but having more discrete load levels. Gradual ramping can still be achieved with staggered dispatch when needed/desired. EV owners typically put constraint on the use of their EV battery, but EV batteries are typically >4h duration compared to charger power capacity. Furthermore, charging can typically be delayed (i.e. reserve up) for more than an hour, especially during the evening/night. V2G availability is likely to be constraint by EV battery state of charge and owner constraints.
Solar PV Inverters	Very Fast Similar to Home BESS, Solar PV Inverters are able to respond quickly to control signals. Where homes have both a battery and Solar PV the system may be configured to have either separate "AC coupled" inverters, or a single shared "DC coupled" inverter controlling both systems simultaneously (e.g. Tesla Powerwall).	Combining solar PV with Battery Energy Storage Systems (BESS) can significantly enhance fast response capabilities and extend the availability of BESS. However, solar PV inverters alone may only be capable of providing a response down. Additionally, solar PV generation is highly dependent on weather conditions, which can change unexpectedly, even within an hour. When such changes occur, they are likely to affect multiple PV installations simultaneously. The dataset also shows considerable variation. Moreover, due to these weather dependencies, the law of large numbers does not apply straightforwardly to solar PV, as the errors are likely correlated rather than independent.

Comparison with traditional technology types

With ramp limits and metering solutions applied, CER portfolios result in roughly double the error of interconnectors assuming a 5s communication latency for all technologies

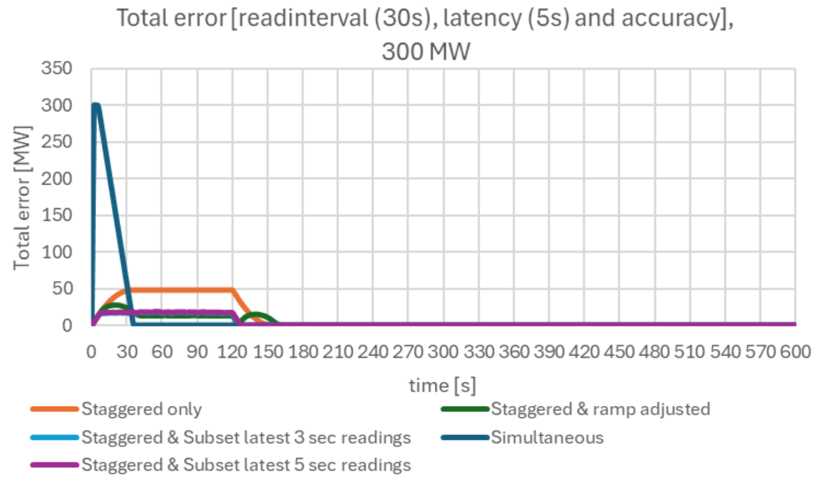
The approach taken to modelling CERs in this study considers a worst-case scenario for the error in control room contributed by sensor accuracy, communication latency, and meter read interval. Traditional generators have requirements to meet a 1% sensor accuracy and 5s latency. To make a fair comparison the worst-case error from traditional technology types (represented by CCGT, interconnector, and grid scale BESS) is shown on this slide.

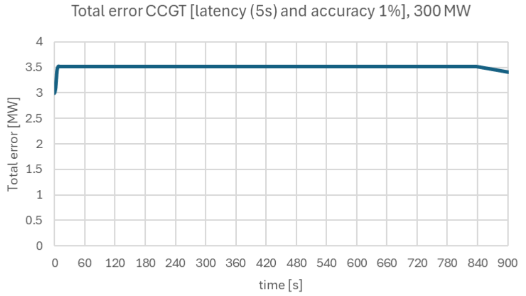
Ramp rates were chosen based 300MW dispatch volume for all technology types, with ramp rates selected on the following basis: research into CCGT ramp rates, with an average value of 20MW / min selected; the maximum ramp rate allowed for interconnectors of 100MW / min ramp; grid scale batteries with an instantaneous ramp based on wholesale market participation (batteries do have ramp rate limits in the balancing mechanism).

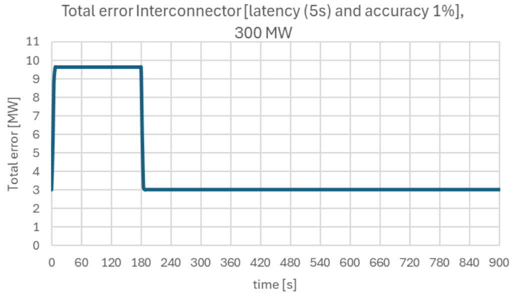
The results show that metering errors from CERs, when using a metering correction solution, are of the same order of magnitude errors from interconnectors with a similar ramp limit (in this example the CERs ramped in two minutes and the interconnector in three minutes).

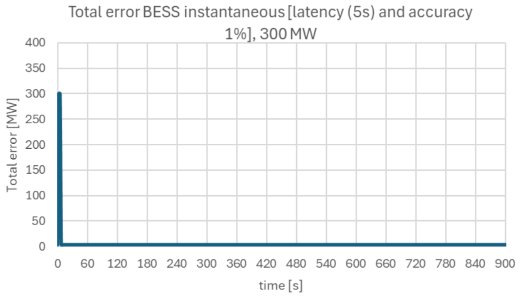
Meter error from CCGTs is relatively small given the inherently slow ramp rate, whilst in our example assuming instantaneous ramping in the wholesale market grid scale BESS has a similar error 100% error to a simultaneously dispatched CER portfolio, but the error lasts for only 5 seconds.

One important caveat is that this assumes all technologies have a 5s communication latency, whereas traditional technology types are highly likely to have a lower communication latency than aggregated CER portfolios which have added latency for communication from assets to the control point.









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https://electricityproduction.uk/plant/gas/
https://www.agora-energiewende.de/fileadmin/Projekte/2017/Flexibility_in_thermal_plants/115_flexibility-report-WEB.pdf

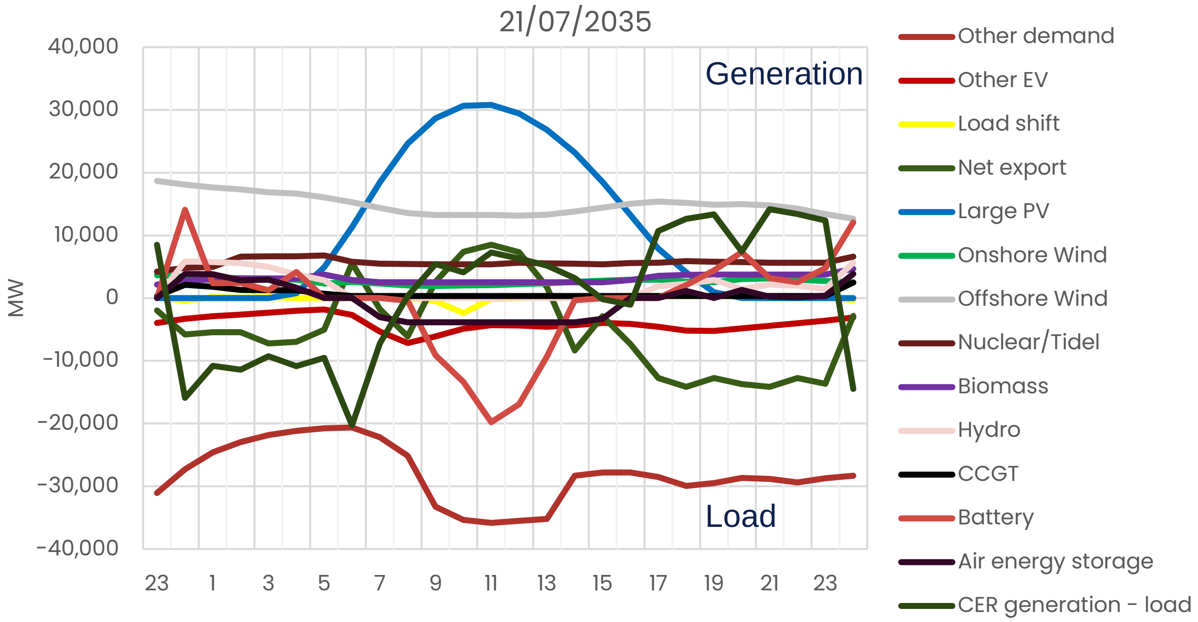
Appendix K: Counterfactual

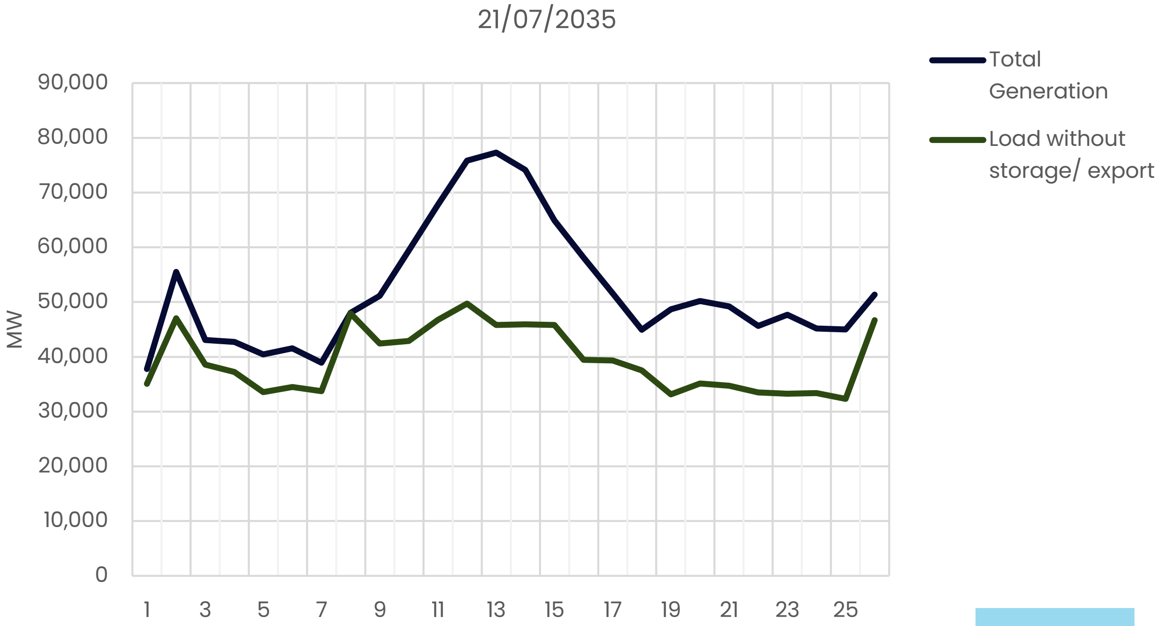
A counterfactual scenario with no CERs in the BM was assessed for resulting impact on balancing prices

Scenario chosen: 21-July 2035, almost highest CER generation at 11am, and highest evening demand at 8pm

Method used:

- Assess generation mix, upward and downward reserve
- Using previous studies, online resources and analysis conducted on BOAs, develop a merit order based on different generation type
- Balance generation and demand using the HT data considering 2 scenarios (1- Market Long, 2- Market short)
- Balance generation and demand assuming: (1- CERs are part of BM, 2 - CERs available in BM)
- Comment on quantitative impact (price/savings) + qualitative impact (visibility/market liquidity)





Counterfactual merit order (over 60 minute) - 2030

A merit order was determined based on data from a project DNV carried out in S. Europe and prices seen in the BM

Downward merit order

	DOWNWARD	Price EUR/MWh	BM All BOAs price Apr-Oct 24	Prices £/MWh	Normalised
1	Large Battery	-27.17	96.56	-95.56	-1.00
2	CCGT	-78.06	54.32	-54.32	-0.57
3	Home_BESS	-27.17		-22.90	-0.24
4	V2G	-24.60		-20.73	-0.22
5	Hydro	-21.45	19.57	-19.57	-0.20
6	Electrolyzers	-17.17		-14.47	-0.15
7	EV	-5.74		-4.84	-0.05
8	Res_HP_Flex	-5.74		-4.84	-0.05
9	Wind		63.09	63.09	+0.66
10	PV				

Upward merit order

	UPWARD	Price EUR/MWh	BM All BOAs price Apr-Oct 24	Other Sources*	Prices £/MWh	Normalised
1	Home_BESS	6.04			5.09	0.05
2	V2G	6.67			5.09	0.05
3	EV	17.17			14.47	0.15
4	Res_HP_Flex	17.17			14.47	0.15
5	Electrolyzers	86.3			72.73	0.76
6	Large Battery	6.04	37.55	78	78	0.81
7	Hydro	7.65	103.39		103.39	1.08
8	CCGT	91.08	105.80		105.8	1.11
9	Wind		-15.08		999	
10	PV				999	

* modoenergy

Negative pricing indicates a cash flow from the generator to NESO, whereas positive pricing reflects a cash flow from NESO to the generator.

- When an asset participates in the BM by consuming electricity (i.e., providing downward capacity), it avoids consuming energy later during its originally scheduled time. The energy that was initially scheduled can instead be sold in the intraday (ID) market.
- EV Chargers: Typically scheduled during periods with low wholesale prices. As a result, the value of the energy that can be sold in the ID market is relatively low. Home_BESS and V2G Assets: Can strategically choose to sell energy during periods with higher ID prices. Despite, additional costs from round-trip inefficiency and obligations to meet day-ahead (DA) trading positions. These assets still yield higher revenues, thus willingness to pay is therefore higher:

Counterfactual Input (Holistic Transition Day Peak)

21-July at 11 am with overall demand = 71,073 MW (assuming the market is 8% long with surplus of 5685 MW of generation)

Generation Mix

	Generation Mix	MW
1	CCGT	334
2	Large Battery	-19788
3	Home_BESS	-1468
4	V2G	-5199
5	Hydro	20
6	Electrolyser	0
7	EV_engaged	0
8	Res_HP_Flex	-463
9	Wind	15346
10	PV	45207
	Net import	**8502**
	Other generation	**7884**
	Total generation	**77294**

Bid/Offer merit order

Merit Order		Type	Normalised Bid Prices	Downward Reserve (MW)	Normalised Offer Prices	Upward Reserve (MW)
Down	Up					
1	6	Large Battery	-1.00	1625	0.81	41201
2	8	CCGT	-0.57	234	1.11	8797
3	1	Home_BESS	-0.24	282	0.05	2653
4	2	V2G	-0.22	217	0.05	10606
5	7	Hydro	-0.20	16	1.08	8036
6	5	Electrolyser	-0.15	0	0.76	0
7	3	EV_engaged	-0.05	5042	0.15	0
8	4	Res_HP_Flex	-0.05	6468	0.15	7000
9	9	Wind	+0.66	15346	0.00	0.00
10	10	PV	+0.66	45207	0.00	0.00

Counterfactual Result (HT Day Peak)

In this specific scenario, including CERs in the BM reduces the cost of this balancing instruction by roughly 75%.
Grid-scale battery dominates volume instructed, followed by CCGT, Home BESS, EV, EV V2G, and Pumped Hydro.

Merit order and bids

Merit Order Down	Type	Bid Prices	Downward Reserve available (MW)	Downward bid accepted inc. CERs (MW)	Downward bid accepted exc. CERs (MW)
1	Large Battery	-1.00	1625	1625	1625
2	CCGT	-0.57	234	234	234
3	Home_BESS	-0.24	282	282	
4	V2G	-0.22	217	217	
5	Hydro	-0.20	16	16	16
6	Electrolyser	-0.15	0	0	
7	EV_engaged	-0.05	5042	3311	
8	Res_HP_Flex	-0.05	6468	0	
9	Wind	+0.66	15346	0	3811
10	PV	+0.66	45207	0	

Instructions sent

With CERs

	Instructions (inc. CERs)	Bid/Offer	Amount (MW)	Price (£)
1	Large Battery	Bid	1625	-1625
2	CCGT	Bid	234	-133.38
3	Home_BESS	Bid	282	-67.68
4	V2G	Bid	217	-47.74
5	Hydro	Bid	16	-3.2
6	EV	Bid	3311	-165.55
	Total		**5685**	**-2042.55**

Without CERs

	Instructions (exc. CERs)	Bid/Offer	Amount (MW)	Price (£)
1	Large Battery	Bid	1625	-1625
2	CCGT	Bid	234	-133.38
3	Hydro	Bid	3.2	-3.2
4	Wind/PV	Bid	3811	2515.26
	Total		**5685**	**753.68**

Result

Scenario	Price (£)	Reserve (MW)	Savings (£)
Offer inc. CERs	-2042.55	74421	2797
Offer exc.CERs	753.68	62412	

Assumptions: the market is long with surplus of 5685 MW of generation; actions taking purely based on prices and not considering other requirements

Counterfactual Input (Evening peak)

21-July at 8 pm with overall generation = 45,670 MW and assuming demand = 54,804 MW (8% higher, market is short 8 % short)

Generation Mix

	Generation Mix	MW
1	CCGT	334
2	Large Battery	7335
3	Home_BESS	111
4	V2G	7331
5	Hydro	1439
6	Electrolyser	0
7	EV_engaged	0
8	Res_HP_Flex	18005
9	Wind	4
10	PV	-13726
	Net import	**11111**
	Other generation	**45670**
	Total generation	**334**

Bid/Offer merit order

Merit Order		Type	Normalised Bid Prices	Downward Reserve (MW)	Normalised Offer Prices	Upward Reserve (MW)
Down	Up					
1	6	Large Battery	-1.00	28747	0.81	14078
2	8	CCGT	-0.57	234	1.11	8797
3	1	Home_BESS	-0.24	1861	0.05	1074
4	2	V2G	-0.22	21687	0.05	7025
5	7	Hydro	-0.20	1151	0.76	6617
6	5	Electrolyser	-0.15	0	1.08	0
7	3	EV_engaged	-0.05	13365	0.15	0
8	4	Res_HP_Flex	-0.05	6930	0.15	6537
9	9	Wind	+0.66	18005	0.00	0.00
10	10	PV	-1.00	4	0.00	0.00

Counterfactual Result (Evening peak)

In this specific scenario, including CERs in the BM reduces 16 times the cost of this balancing instruction.

Assumptions: the market is short of 3653 MW of generation; actions taking purely based on prices and not considering other requirements

Merit order and bids

Merit Order Upward	Type	Offer Prices	Up Reserve available	Up offer accepted (inc. CERs)	Up offer accepted (exc. CERs)
1	Home_BESS	0.05	2653		
2	V2G	0.05	10606	3653	
3	EV	0.15	0		
4	Res_HP_Flex	0.15	7000		
5	Electrolyzers	0.76	0		
6	Large Battery	0.81	41201		3653
7	Hydro	1.08	8036		
8	CCGT	1.11	8797		
9	Wind	0	0		
10	Solar	0	0		

Instructions sent

	Instructions	Bid/Offer	Amount (MW)	Price (£)
Offer inc. CERs	V2G	Offer	3653	182.65
Offer exc. CERs	Large Battery	Offer	3653	2958.93

Result

Scenario	Price (£)	Reserve (MW)	Savings (£)
Offer inc. CERs	730.72	79293	2776.28
Offer exc.CERs	7398.54	58034	

DNV

Integrating CERs in the BM delivers broad system benefits across operational and market dimensions.

CERs in the BM will increase reserve capacity, reduce costs, improve visibility for control operations, boost market liquidity, and provide a flexible resources against large system swings

Quantitative Assessment

Reserve Capacity

The integration CERs into the BM substantially increases the system’s available reserve, strengthening grid flexibility and resilience.

Financial Impact

Integrating CERs into the market has the potential to deliver system-wide savings, particularly given that CER pricing is expected to be lower than that of large-scale batteries and other conventional generators e.g. CCGT enabling more cost-effective of balancing services

Qualitative Assessment

Visibility

Visibility of CERs in the BM improves situational awareness for the ENCC, enabling more informed and timely decision-making. This reduces the risk of misattributing frequency deviations and supports more accurate forecasting and dispatch.

Market liquidity

Integrating CERs in the BM will allow greater market liquidity. Market liquidity enhances the efficiency and responsiveness of the energy system by enabling more dynamic price formation, increasing competition among participants, and improving the visibility and valuation of flexible assets such as CERs.

Availability of resources

The availability of CERs within the BM provides a critical resources against large system swings by increasing the volume and diversity of responsive assets. With sufficient visibility and integration, CERs can act as a distributed, fast-acting reserve that complements traditional assets, reducing reliance on centralised interventions and improving overall system resilience