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BEST PRACTICES IN SMART GRID DESIGN FOR LOCAL FLEXIBILITY SERVICES: LESSONS FOR ASEAN

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Forewords

Delivering a successful energy transition of course needs more renewable energy; it also needs the right power systems to support it. The *Best Practices in Smart Grid Design for Local Flexibility Services: Lessons for ASEAN* Playbook is a timely contribution to this objective, and reflects ASEAN's ambition to build the resilience, efficiency, and future-readiness of its power systems through smart-grid technologies.

Local flexibility services will be key to supporting ASEAN's growing renewable energy ambitions while ensuring reliable and secure electricity systems. The UK's own experience underscores the importance of flexibility in modern power systems, enabling greater integration of renewable energy while maintaining secure and reliable electricity supplies. Drawing on international best practices, the Playbook provides practical guidance for enabling and scaling emerging grid services.

The development of this Playbook has benefited from the dedication and expertise of many partners. I would particularly like to recognise the ASEAN Secretariat, the ASEAN Centre for Energy, and the Heads of ASEAN Power Utilities/Authorities for their leadership, alongside Economic Consulting Associates, KPMG Malaysia, Castlerock Consulting, and Palladium for their technical contributions. Their collective efforts have helped produce a practical resource for ASEAN's evolving energy landscape.

The UK remains committed to supporting ASEAN Member States in advancing an energy transition that extends beyond renewable energy deployment to the development of smarter, more flexible and resilient power systems.

Helen Fazey
UK Ambassador to the Association of Southeast Asian Nations (ASEAN)

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Abbreviations and acronyms

ACE	ASEAN Centre for Energy
AEMO	Australian Energy Market Operator
AMI	Advanced metering infrastructure
AMS	ASEAN Member States
APAEC	ASEAN Plan of Action for Energy Cooperation
APG	ASEAN Power Grid
ASEAN	Association of Southeast Asian Nations
DOEs	Dynamic operating envelopes
DSO	Distribution system operator
ECA	Economic Consulting Associates
EMA	Energy Market Authority (Singapore)
EMS	Energy management system(s)
ERC	Energy Regulatory Commission (Philippines)
ESCOs	Energy service companies
EV	Electric vehicle(s)
HAPUA	Heads of ASEAN Power Utilities/Authorities
IEA	International Energy Agency
MW	Megawatt
PTH	Pulau Tenaga Hijau (Smart Green Island project, Malaysia)
PV	Photovoltaic
RE	Renewable Energy
SCADA	Supervisory Control and Data Acquisition
SSEN	Scottish & Southern Electricity Networks
TNB	Tenaga Nasional Berhad
TPDDL	Tata Power Delhi Distribution Limited
TSO	Transmission system operator
UK	United Kingdom
VPP	Virtual power plant
VRE	Variable renewable energy

Executive summary

Purpose of the playbook

ASEAN's priority should not be smart grid deployment as an end in itself, but the use of smart grid capability to deliver clearly defined flexibility services with measurable system value. This playbook sets out how ASEAN Member States (AMS) can use smart grid capability and flexibility services to support higher shares of variable renewable energy (VRE), improve the efficiency and resilience of electricity systems, and create practical pathways for more active participation by distributed energy resources (DER).

The playbook is framed around services rather than technologies, and around local flexibility mechanisms rather than markets alone. Smart grids are treated as enabling capability; flexibility as resources' ability to change their normal operation; flexibility services as the outcomes delivered when that flexibility is used; local flexibility mechanisms as the wider set of arrangements through which those services are coordinated, procured or rewarded; and local flexibility markets as a subset of those mechanisms.

The central question is therefore not whether a system has a local market, but whether it can identify a service need, value that service credibly, and use a workable mechanism to deliver it. Across ASEAN, utilities and policymakers are increasingly investing in smart grid technologies and digital capability. The practical challenge is to ensure that these investments are tied to defined operational problems and value cases, rather than being pursued as technology deployment in the abstract.

Why this matters for ASEAN now

Flexibility matters because ASEAN power systems are facing increasingly diverse operational pressures, but those pressures differ materially across countries and locations. A transition away from coal-dominated systems and the increase in VRE, along with increasing regional integration through initiatives such as the ASEAN Power Grid (APG), necessitates a holistic approach to the transition to maintain the resilience of the systems. Smart grids are an enabling layer to support resilience. However, the priorities will vary across ASEAN: in some systems, the key challenge is integrating rising solar, storage, electric vehicles (EVs) and other DER into networks designed for one-way power flows, while in others, the main issues remain reliability, system strengthening, geography, islanded operation, voltage and frequency management, or the operational consequences of rapid VRE growth.

This diversity means ASEAN does not need a single model; it needs a practical framework for matching service needs to system conditions. Flexibility services can help power systems absorb more VRE, manage congestion and peak demand, reduce curtailment, improve use of network assets, support resilience and, in some contexts, defer or avoid network reinforcement. But these benefits depend on identifying the service being sought, understanding its value, and choosing a delivery mechanism that fits the technical, institutional and commercial conditions of the system.

The playbook therefore treats differentiated national starting points as a feature of good policy design rather than as a sign of uneven ambition. Some systems will move first through utility-led operational flexibility, others through administered or intermediary-supported pilots, and only a subset through more structured commercial experimentation.

Main lessons from international experience

International experience does not point to a single ideal model; it points to the need to start from the service problem, understand the value of the service, and choose the simplest workable delivery mechanism. Across the international cases reviewed, useful flexibility services have been delivered through utility-operated optimisation, direct control, bilateral contracts, administered procurement, tariff- and operating-envelope-based coordination, aggregator-led programmes, and more structured procurement or market-based arrangements. The main lesson is not a fixed sequence towards formal local markets, but a problem-led and context-specific approach in which the service need is identified first and the delivery model is then chosen accordingly.

Utility-led flexibility is often an entirely appropriate starting point, especially where systems are vertically integrated, islanded, weak-grid, or not yet ready for broad third-party participation. International practice shows that valuable flexibility can be created without a local market at all. In systems with strong utility authority but limited competition, weaker intermediary ecosystems, or more basic digital capability, the most credible starting points may include utility-operated storage dispatch, managed charging, direct demand-side programmes, controlled export arrangements, or other centrally coordinated services.

Targeted market-oriented, quasi-market and intermediary-led experimentation is often desirable, not because formal markets are always the endpoint, but because experimentation helps reveal service value and test alternative delivery models. This is particularly important in ASEAN, where one of the current risks is not only premature market design, but also investment in digital and smart grid capability without sufficiently clear use cases, or value frameworks. Well-designed experimentation can help the identification of which services are valuable, which customers or intermediaries can provide them reliably, and whether more decentralised coordination adds value over utility-only provision in specific contexts.

Four lessons are especially transferable to ASEAN, regardless of the model applied. First, know the problem that **countries** are trying to solve. Second, match the technology to the problem rather than starting from a technology list. Third, know the value of the service, including avoided reinforcement, reduced curtailment, reliability value or other measurable system benefits. Fourth, determine whether intermediaries exist, or whether reliance must initially be placed on direct control, managed programmes and tariff signals.

ASEAN's differentiated starting points

Readiness for flexibility depends on both technical or functional capability and institutional or commercial capability, and the two do not always develop together. The playbook distinguishes clearly between technical or functional readiness (such as visibility, forecasting, coordination, and verification), and institutional or commercial

readiness (such as buyer authority, intermediary roles, contracting routes, cost recovery and room for commercial experimentation). A system may have one without the other.

The relevant threshold for action is targeted sufficiency, not complete maturity. It is often possible to begin useful pilots before either dimension is fully developed, provided that the service need is clear and targeted readiness is sufficient for the use case being tested. A system may, for example, have enough feeder visibility, metering and utility authority to test a managed charging or export management pilot in a constrained area, even if intermediary participation rules or settlement systems remain underdeveloped.

This distinction is particularly important in ASEAN, where waiting for complete readiness across all dimensions would risk delaying useful learning and service value discovery. Pilots can therefore play a dual role in testing service delivery under real operating conditions and identifying what additional technical, regulatory or commercial conditions are needed for wider adoption.

ASEAN is not starting from zero, but countries are starting from different combinations of system pressure, technical capability and institutional readiness. Smart grid deployment is already under way across much of the region, but the functions it currently serves differ significantly. In some AMS, digital capability is still used mainly for reliability, monitoring and engineering control. In others, it is beginning to support more active coordination of DER, storage, demand response or managed charging. Flexibility opportunities therefore differ by country, locality and use case. This playbook applies an analytical lens to take stock of the different dimensions of readiness as well as the flexibility pressures and system needs across the eleven AMS. Based on this the most practical pathways for introducing flexibility mechanisms are identified. These pathways do not intend to rank countries, nor are they mutually exclusive as countries may exhibit characteristics of more than one pathway.

Singapore and the Philippines have multi-actor systems, offering the strongest scope for more structure piloting and intermediary participation. However, this should not be read as these countries already having mature local flexibility markets. Instead, the institutional and commercial readiness, combined with emerging flexibility pressures, provides the strongest current basis in ASEAN for testing constrained-zone procurement, managed EV charging programmes, intermediary-led demand response and more structured commercial experimentation. Even here, however, the case remains use case specific, and structured procurement should be introduced selectively rather than treated as a system-wide default.

Malaysia, Thailand, and Viet Nam are better understood as utility-led exploratory systems with growing flexibility needs and scope for targeted pilots. Their near-term opportunities are more likely to lie in managed charging, controlled exports, flexible industrial load, tariff-based demand response, utility-partnered programmes and other exploratory mechanisms tied to clear service needs. Here, “exploratory” means that the utility remains central, but the immediate value lies in testing alternative delivery, coordination or procurement models for specific services, rather than primarily in optimising flexible assets already under direct utility control. The aim in these systems should be to prove service value, improve readiness and build evidence for later standardisation where justified.

Indonesia is a more strongly utility-led system, likely to rely first on optimisation, direct service delivery and administered or quasi-market experimentation. The practical opportunities include storage-backed optimisation, controlled exports, community batteries, local service pilots, flexible industrial loads and other utility-centred or administered mechanisms. These systems may use more than one mechanism family across different regions or use cases, but they should not be characterised as broadly advanced distributed-flexibility systems at this stage.

Cambodia, Lao PDR, Brunei Darussalam, Myanmar and Timor-Leste are better approached through foundational digitalisation, engineering-based flexibility and utility-centred services. In these systems, the immediate priority is less about sophisticated local flexibility mechanisms and more about embedding flexibility into reliability improvement, resilience, storage for stability, feeder automation, mini-grid optimisation and broader system-strengthening strategies.

Strategic implications for ASEAN

The practical task is to identify high-value service problems, build targeted readiness around them, and use the mechanism that best fits the use case and sector structure. ASEAN should begin with service needs such as local congestion relief, voltage management, managed EV charging, export management, peak reduction, balancing support or resilience in islanded and weak-grid systems. Once these problems are defined, the next steps are to establish value anchors, deploy targeted enabling capability, and select the simplest workable mechanism for coordinating or procuring the service.

This implies five strategic priorities for the next phase of flexibility development in ASEAN. First, identify service problems and value cases more clearly. Second, pursue targeted digitalisation rather than broad technology rollout without a use case. Third, create room for pilot-stage experimentation under partial readiness. Fourth, build intermediary and customer participation routes where relevant. Fifth, strengthen treatment of flexibility as a planning option and non-wires alternative.

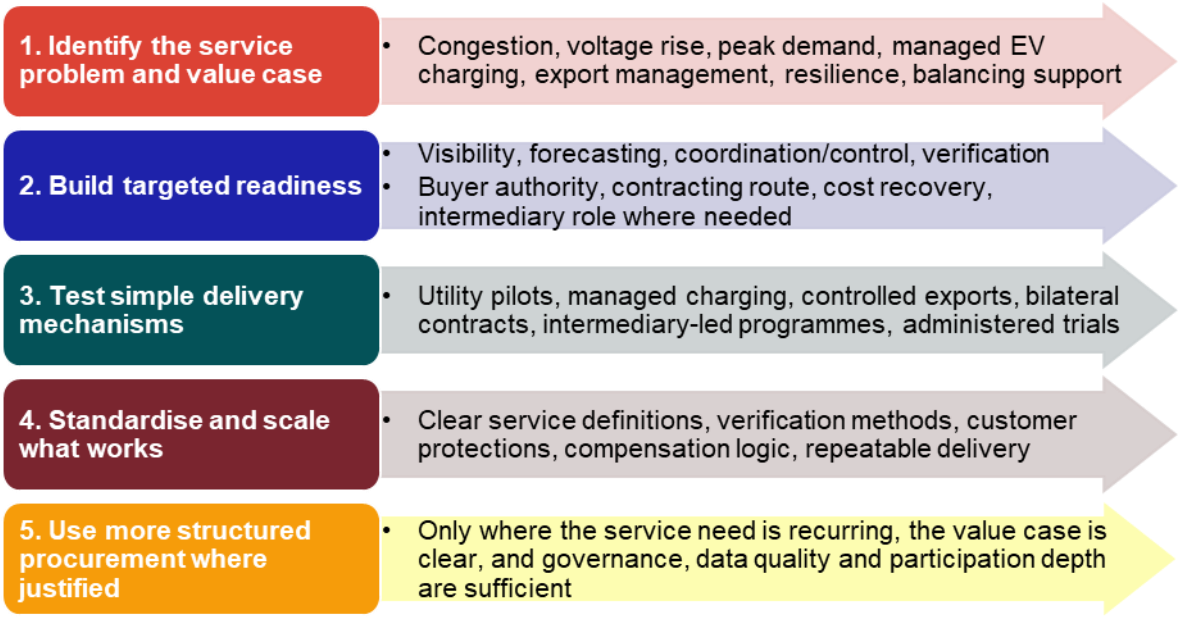
Experimentation should be treated not only as a transitional step, but also as a discovery tool. In ASEAN, targeted experimentation with administered, intermediary-supported, quasi-market and more market-oriented mechanisms can help reveal service value, test alternative delivery models, stimulate service innovation, and avoid assuming in advance that centralised utility control is always the optimal model. This is especially relevant where smart grid investment is already occurring, but the practical value of flexibility services has not yet been fully established.

Priority implementation pathway

Implementation should proceed from service problem and value case to targeted readiness, to simple delivery models, and only then to more structured procurement where justified. The recommended pathway for ASEAN is not a fixed ladder towards formal local flexibility markets. It is a practical sequence for organising action.

Figure ES-1 summarises the practical implementation sequence recommended in this playbook, beginning with service definition and value identification, and moving toward more structured procurement only where justified.

Figure ES-1: From service problem to fit-for-purpose flexibility delivery



1. Introduction

1.1 About the ASEAN-UK Green Transition Fund

The ASEAN-UK Green Transition Fund (GTF) is the UK's flagship programme to accelerate ASEAN's transition to a clean and climate-resilient economy by reducing emissions in key sectors, supporting green economic growth, and improving the livelihoods of vulnerable people. The GTF is structured around five pillars, spanning climate policy, green finance, energy, sustainable cities and transportation, and nature-based solutions, with the objective of delivering technical assistance through capacity-building, knowledge-sharing and peer-to-peer learning. It also pilots transformational technologies and facilitates evidence-based climate mitigation actions and policies, with climate adaptation as a co-benefit.

As part of the GTF clean and just energy transition pillar, the Green Grids Rising initiative aims to strengthen the flexibility and resilience of ASEAN's energy infrastructure and regulatory frameworks. It aims to facilitate a transition away from coal-dominated grids and support the integration of variable renewable energy (VRE), including by supporting regional trade and initiatives such as the ASEAN Power Grid (APG). The initiative aims to achieve this by enhancing the capacity of regional and national stakeholders to implement policies and market mechanisms which will address current barriers to the energy transition. It is closely aligned with the ASEAN Plan of Action for Energy Cooperation (APAEC) 2026-2030

1.2 Introduction to this playbook

This playbook is intended as a practical guide to how ASEAN Member States (AMS) can use smart grid capability and flexibility services to support higher shares of VRE, improve the resilience of electricity systems, and create pathways for more active participation by distributed energy resources (DER). The playbook is framed around services rather than technologies, and around local flexibility mechanisms rather than markets alone.

That framing reflects both the international and the ASEAN evidence reviewed in this playbook. In practice, the value of smart grid development lies not in the installation of individual devices or digital platforms as such, but in how these capabilities are used to deliver operational services: better visibility of local network conditions, more accurate forecasting, more active coordination of distributed resources, more efficient management of voltage and congestion, more flexible demand, and more reliable verification of system response. The playbook therefore distinguishes between **smart grids as enabling capability**, **flexibility services as the operational outcomes that capability makes possible**, **and local flexibility mechanisms as the ways those services may be organised, coordinated, procured or rewarded**, of which local flexibility markets are one subset.

The primary focus of this playbook is the distribution level given this is where flexibility pressures are emerging in a particularly acute manner and where a broad range of local flexibility services are available. However it also supports the broader objectives of the APG, with greater visibility, increasing flexibility, and more active coordination of DER facilitating the integration of higher shares of VRE while enhancing system reliability and resilience.

The playbook has four main purposes. **First, it clarifies concepts.** It sets out what is meant in this playbook by smart grids, flexibility and flexibility services, and explains how these ideas relate to one another. In doing so, it places local flexibility markets in context: not as the starting point for reform, but as one possible commercial mechanism for valuing and procuring flexibility services where the service need is clear and the targeted technical, institutional and commercial conditions are sufficient.

Second, it translates international experience into an ASEAN-relevant framework. The playbook reviews a set of international case studies, drawn from developed and emerging markets, to show how smart grid capabilities have been combined to deliver new services, how those services have supported renewable integration, and how different commercial and institutional models have been used to procure or coordinate flexibility. A central lesson is that there is no single best model. Different systems have used utility-led optimisation, administered procurement, aggregator-led programmes, tariff- or operating-envelope-based coordination[1] and, bilateral contracts and in some cases, more structured local procurement or market-based arrangements.

Third, it takes stock of current conditions in ASEAN. The playbook recognises that there is significant heterogeneity between AMS and that the appropriate approach will vary. It identifies where AMS are already deploying smart grid capabilities, where DER and VRE integration pressures are becoming material, and where governance, buyer authority and wider commercial structures are conducive to different flexibility mechanisms. The objective is not to rank countries, but to identify practical entry points and implementation pathways that reflect actual system conditions.

Fourth, it provides an implementation lens. Building on the international and ASEAN assessments, the playbook sets out how different AMS might move from foundational digitalisation and engineering-based flexibility toward fit-for-purpose coordination or procurement models over time.

[1] Operating-envelope-based coordination means coordinating DER by setting time-varying upper and/or lower limits on how much they may import from or export to the network, rather than dispatching each device directly. These limits are set by the network operator to reflect local network conditions and available headroom, so that customers or intermediaries can optimise within those boundaries while the network remains within safe operating limits. In distribution networks, these are often described as dynamic operating envelopes (DOEs).

2. Smart grids, flexibility, and local flexibility mechanisms

2.1 Introduction

This playbook is not primarily about individual technologies, and it is not only about markets. Its central concern is **how digital and operational capabilities can be combined to create flexibility services** that help power systems integrate higher shares of VRE, use networks more efficiently, and improve resilience. The focus is therefore on the **services** that smart grid capability makes possible, rather than on any single device, platform or market design.

For that reason, this section begins with smart grids as an enabling capability, then defines flexibility and flexibility services as the practical outputs of that capability, before showing how local flexibility mechanisms fit within the wider picture. This matters because many power systems may begin delivering flexibility services before formal local flexibility markets are realistic. In those systems, the key question is not whether a market exists, but whether a clear service need has been identified and a workable mechanism exists to deliver it. **The central message is therefore problem first, not technology first**: smart grid capability should be judged by the service problems it helps solve.

2.2 A working definition of smart grids

A useful working definition is the International Energy Agency's (IEA's) definition[2] of a smart grid:

> "A smart grid is an electricity network that uses digital and other advanced technologies to monitor and manage the transport of electricity from all generation sources to meet the varying electricity demands of end users. Smart grids coordinate the needs and capabilities of all generators, grid operators, end users and electricity market stakeholders to operate all parts of the system as efficiently as possible, minimising costs and environmental impacts while maximising system reliability, resilience, flexibility and stability."

This definition is well suited to the purposes of this playbook because it focuses on what smart grids **enable**, rather than on a fixed list of components. It also makes clear that smart grids are not only about communications or automation. They are about improving how the system is observed, coordinated and operated. What matters is not simply that these capabilities exist, but that they allow operators and users to **identify system needs more clearly and respond to them more actively** through better coordination of supply, demand and storage.

[2] IEA. 2023. Smart Grids, accessed February 2026.

Consequently, it is more helpful to think of smart grids in functional terms than as a checklist of hardware. A system does not become 'smart' merely because it has smart meters, automated substations or digital platforms. It becomes smart when those capabilities are used to deliver better operational outcomes. The most relevant outcomes for this playbook are:

- Improved **visibility** of local network conditions;
- Better **forecasting** of demand, generation and emerging constraints;
- More **active coordination or control** of DER, storage and flexible demand;
- More precise **management** of congestion, voltage and peak loads; and
- More reliable **verification** of whether a flexibility action was delivered.

2.3 Defining flexibility and flexibility services

Existing definitions often describe flexibility as a change in generation or consumption in response to a signal to support the energy system. For this playbook, a broader definition is more useful, as flexibility may also be activated through direct control, managed charging, utility programmes, bilateral contracts, tariffs or centrally optimised storage dispatch.

> **Flexibility** is the ability of generation, demand, storage or other network-connected resources to change their normal pattern of operation in timing, location or magnitude to support the power system more efficiently or reliably.

This definition captures both market- and non-market-based arrangements, making it particularly relevant to ASEAN, where flexibility is likely to emerge through mixed models rather than fully developed local markets.

A flexibility *service* is the specific operational outcome or system benefit delivered when flexibility is activated. A local flexibility *mechanism*, by contrast, is the arrangement through which a flexibility service is coordinated, procured, dispatched or rewarded. In other words, flexibility is the capability; the flexibility service is the operational use of that capability; and the local flexibility mechanism is the means through which that use is organised. The most relevant flexibility services are shown in Table 1 below.

These services can create identifiable operational value, for example, by reducing curtailment, avoiding or deferring network reinforcement, improving network utilisation, reducing peak stress and strengthening resilience. Their relevance also varies by context: peak and local network management may be most important in urban areas, while resilience and reliability services may be particularly relevant in rural or islanded systems.

Table 1: Indicative taxonomy of flexibility services

Service category	What the service does	Illustrative examples	Typical value anchor
Peak management	Reduces or shifts demand during periods of network or system stress	Managed EV charging; demand response events; large customer load reduction	Avoided peak capacity cost / reduced stress at critical times
Local network management	Relieves congestion, voltage issues or thermal constraints in specific locations	Controlled exports; community battery dispatch; feeder-level congestion relief	Avoided or deferred reinforcement / congestion relief/voltage management value
Renewable integration	Helps the system absorb more variable solar and wind output	Battery charging/discharging; flexible export; curtailment avoidance	Reduced curtailment / increased hosting capacity / improved renewable utilisation
Balancing and system support	Supports efficient operation of the wider system	Fast demand response; distributed storage response; coordinated DER dispatch	Avoided balancing costs/ improved system stability
Resilience and reliability	Supports continuity and quality of supply in weak or isolated systems	Island system optimisation; backup storage; local voltage and frequency support	Avoided outage cost / improved continuity of supply / weak-grid support value

Flexibility and flexibility services are increasingly important as the share of VRE in energy systems increase. Solar and wind output vary with weather and time of day, while demand patterns also become more variable as end uses electricity. This increases the value of resources which can shift consumption, change or store exports, and respond quickly when local or system conditions changes.

This is especially relevant at the distribution level, although the lessons can also be transferred to the transmission level. As rooftop solar, batteries, EVs and other DER grow, the key operational challenge increasingly shifts from one-way power delivery to active coordination of two-way flows. **Flexibility services help manage that transition more efficiently**. Once these flexibility services have been identified, the next question is which local flexibility mechanism is most suitable for coordinating, procuring or rewarding them in practice.

2.4 Where local flexibility mechanisms fit

For this playbook, a **local flexibility mechanism** is best understood as:

> A local flexibility mechanism is any operational, contractual, tariff-based, commercial or market-based arrangement through which local flexibility services are coordinated, procured, dispatched or rewarded in response to local network or system needs.

These mechanisms can take a range of forms, from direct utility programmes and bilateral contracting through to tariff signals, intermediary-led offers, administered procurement and more formal local markets. That is, the mechanism may comprise:

- Direct control or a utility programme;
- Bilateral contracting;
- An administered procurement programme;
- A dynamic tariff or price signal;
- Retailer- or aggregator-led flexibility offers;
- Platform-supported procurement; or
- A local auction, tender or market.

In many ASEAN contexts, the near-term question is which mechanism is simplest, **workable and proportionate to the service need**, while allowing scope for more market-based approaches where feasible. Different models, from administered and tariff- to intermediary-supported and market-oriented mechanisms, can help reveal service value, stimulate innovation and test delivery models (Table 2).

This wider interpretation reflects international experience, where local flexibility is delivered through auctions, dynamic prices, utility-led optimisation and other approaches rather than formal spot markets.

Table 2: Indicative local flexibility mechanisms and when they may be suitable

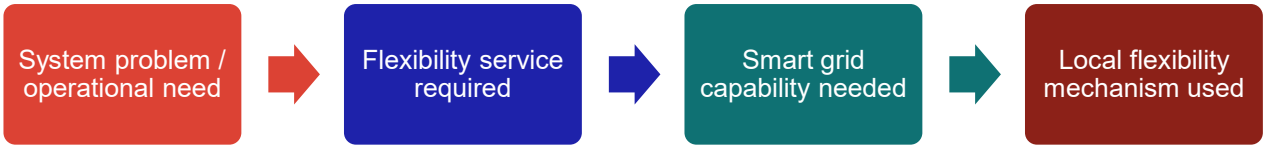
Mechanism type	What it means in practice	Typical use case	Typical suitability conditions
Direct control / utility programme	Utility or system operator directly controls or schedules flexible resources under predefined terms	Managed EV charging, utility-operated storage dispatch, direct load control for peak reduction, feeder-level congestion relief in vertically integrated systems	Utility authority is strong, service need is clear, and market / intermediary ecosystem is weak
Bilateral contracting	Buyer contracts directly with one or more providers for a defined local flexibility service	A constrained feeder or substation area where one or a few customers, batteries or generators can provide a known service	A small number of providers can solve a defined local problem

Administered procurement	Buyer procures flexibility through defined service terms, eligibility rules and payment arrangements, without a fully open market	Pilot procurement for peak management, local congestion relief or VRE integration where the buyer can define the service	The buyer can specify service needs but competition remains limited
Dynamic tariff or price signal	Time- or location-varying prices encourage customers or intermediaries to adjust their behaviour	Time-of-use or dynamic network tariffs, flexible export incentives, managed demand shifting in areas where response can be induced through pricing	Customer responsiveness exists and verification is feasible
Intermediary-led programme	An aggregator, retailer or other intermediary coordinates multiple customers or DER to provide flexibility	Household or small business demand response, managed EV charging portfolios, coordinated battery response, community-based flexibility offers	Retailers, aggregators or other customer-facing actors can recruit and coordinate response
Platform-supported procurement	A digital platform supports registration, offers, dispatch, validation and potentially settlement across participants	Multi-provider flexibility pilots, standardised local procurement processes, or schemes where visibility and coordination across many assets are needed	Registration, dispatch and validation need to be standardised across multiple participants
Local auction or market	Eligible providers compete to supply a defined local flexibility service under structured rules	Recurring local procurement where the service is clearly defined, multiple providers exist, and comparative price discovery is useful	Service definitions, participation rules, verification and competitive depth are sufficiently developed

2.5 The relationship between smart grids, flexibility services and local flexibility mechanisms

Figure 1 summarises the conceptual relationship used throughout this playbook, showing how identified system problems give rise to flexibility service needs, which in turn determine the smart grid capabilities and local flexibility mechanisms required.

Figure 1: From system problem to flexibility service, smart grid capability and local flexibility mechanism



For the rest of this playbook, the relationship is as follows:

- **Smart grids** are the enabling capability base.
- **Flexibility** is the ability of generation, demand, storage or other network-connected resources to change their normal pattern of operation.
- **Flexibility services** are the operational outcomes delivered when that flexibility is used to solve a defined system or network problem.
- **Local flexibility *mechanisms*** are the operational, contractual, tariff-based, commercial or market-based arrangements through which those services are coordinated, procured or rewarded.
- **Local flexibility *markets*** are one subset of those mechanisms.

This means the key policy question is not whether a system has a local market, but whether it can identify the service problem clearly, value the service appropriately, and use the simplest workable mechanism to deliver it, while leaving room for more structured or market-based discovery where that becomes useful.

3. International best practice in local flexibility and smart grid-enabled services

Key takeaways

- **There is no single ideal model.** Start with a defined service problem, identify the flexibility service required, and choose the simplest workable local flexibility mechanism for the technical and institutional conditions at hand.
- The **most transferable practices for ASEAN** are targeted digitalisation, simple products linked to specific network needs, explicit service value, and early use of aggregators or other intermediaries where small DER participation is expected.
- More structured procurement or local markets may suit some systems, but **liquidity, data quality, cost recovery, settlement and TSO-DSO coordination** remain key constraints. Pilots can begin before full maturity where the use case is clear and technical and institutional conditions are sufficient.

3.1 Introduction

The international evidence reviewed for this playbook[3] suggests that there is no single 'best' model for local flexibility. The stronger lesson is that successful initiatives begin by **identifying a specific operational problem**, defining the flexibility service needed to address it, and then building only the capabilities required to deliver that service credibly.

This is especially relevant in ASEAN because many jurisdictions still combine vertically integrated utility structures, regulated tariffs, uneven digitalisation and early-stage DER growth. In that context, the practical policy question is **how to build the minimum technical, institutional and commercial conditions under which flexibility can be coordinated or procured credibly**. The discussion below draws out cross-cutting lessons on technical or functional readiness and institutional or commercial readiness, technology selection, product design, value anchoring and customer or intermediary participation. Further details on the case studies reviewed for this playbook can be found in Annex 1.

[3] This evidence is drawn from the detailed case studies, covering Project Edith and Project EDGE (Australia), Enera (Germany), Project TRANSITION (Great Britain), the Urja Arpan Scheme (India), Pulau Tenaga Hijau (Malaysia), and Resi-Flex (New Zealand). These case studies were selected following a broad scoping review which sought to identify local flexibility pilots and mechanisms in electricity systems globally. Focus was given to ensuring the case studies came from a diverse range of countries, including both emerging and developed economies, and power systems with different flexibility pressures. The availability of data and transparent reporting of outcomes was a further factor determining the selection of case studies.

3.2 Three broad local flexibility mechanism models emerging internationally

The case studies reviewed can be stylised as belonging to one of three broad models for local flexibility mechanisms (Figure 2). The models are not rigid nor exhaustive and should not be interpreted as being the only models available for local flexibility mechanisms. They aim to provide a typology which helps distinguish between different ways which are available to coordinate or procure flexibility. Each of these models can be appropriate depending on the service problem, the value case, and the technical and institutional conditions.

Figure 2: Three broad local flexibility mechanism models



The first model is **utility-operated optimisation without a market**. Malaysia's Pulau Tenaga Hijau project is the clearest example. It combines storage, renewable generation and centralised control to optimise isolated island systems, but it does not use a local flexibility market or third-party procurement mechanism. In such cases, the relevant flexibility services are internal operational services (such as balancing, ramp management, peak shaving, renewable smoothing and reliability support) delivered through a utility-operated energy management system (EMS) rather than through bids or contracts. This model is particularly relevant where systems are islanded, weak-grid, vertically integrated, or too small for meaningful competition or third-party coordination to emerge quickly.

Box 1. Malaysia - Pulau Tenaga Hijau: utility-operated flexibility without a local market

Pulau Tenaga Hijau demonstrates flexibility in an island microgrid where the priority is reliability, reducing diesel dependence and managing renewable variability, rather than market design. The project combines renewables, battery storage and centralised EMS control, with Tenaga Nasional Berhad (TNB) Distribution Network acting as system owner, operator and dispatch authority. Services include balancing, renewable smoothing, ramp management, peak reduction and reliability support. For ASEAN, the key lesson is that islanded, weak-grid, vertically integrated or small systems may benefit first from storage-backed, EMS-enabled utility control rather than a formal flexibility market.

Source: TNB. Green Energy | Smart Green Island (Pulau Tenaga Hijau), accessed February 2026.

Another relevant international example is the Urja Arpan scheme implemented in New Delhi. The initiative leverages existing communication channels with smart meter connected customers to elicit demand side flexibility during peak summer demand periods.

Box 2. New Delhi, India – Behavioural demand side flexibility with the Urja Arpan Scheme

Urja Arpan is a behavioural demand response programme launched around 2022 by Tata Power Delhi Distribution Limited (TPDDL) in New Delhi. It targets smart-metered consumers through mobile messaging and social media to encourage voluntary load reduction or shifting during peak periods. The programme uses behavioural engagement rather than direct capacity payments, supported by smart meters and high customer engagement. It involves around 90,000 mainly residential consumers, with

some commercial customers, and has recorded peak-time reductions of up to 560 MW in later periods. It demonstrates how low-cost, utility-led approaches can unlock demand-side flexibility in emerging markets.

Sources: TPDDL. Company Profile, accessed April 2026 and Anto, Robins, et al. 2026. "Leveraging Enhanced Consumer Engagement to Achieve Demand Response and Flexibility in an Indian Energy Community." Utilities Policy, vol. 98, p. 102077.

The second model uses **tariff or price signals**, often combined with operating envelopes or similar constraint signals, to coordinate response without direct dispatch or a full local market. Of the case studies reviewed, project Edith in Australia is the clearest example for this model. It does not create a local auction or exchange. It instead combines dynamic operating envelopes (DOEs), a time-varying operating limit that outlines how much DER can import and export, with dynamic network prices and leaves aggregators to optimise customer portfolios in response. The network operator signals where headroom exists and where constraints are tightening, but does not dispatch household assets directly

Box 3. Australia - Project Edith: coordinating flexibility through dynamic prices and DOEs

Project Edith tests a distribution-level flexibility mechanism using dynamic network pricing alongside DOEs. Rather than auctions or direct device dispatch, the network operator provides time- and location-specific signals while aggregators optimise customer portfolios. The main service is local network constraint management, particularly congestion and voltage support. The project demonstrates an intermediate model between static export limits and formal procurement, allowing networks to signal local constraints without creating a full market. For ASEAN, this may be relevant where rooftop solar is growing and static limits are becoming inefficient, but formal procurement is not yet feasible. Key considerations are pricing complexity, customer protection and the risk of wider market signals overriding local incentives.

Sources: Ausgrid. 2025. Project Edith Insights Report.

This type of mechanism can also serve as a **form of value discovery** by revealing when and where local response is commercially and operationally meaningful, even before formal procurement is justified.

The third model is **structured procurement and market-based mechanisms**. Project TRANSITION in Great Britain, project EDGE in Australia and Enera in Germany all fall into this family, despite important differences in maturity and design.

Taken together, these examples show that more structure procurement and market-based arrangements can be useful where the service need is clear and recurring. However, they should be understood as one family of local flexibility services rather than as the default destination for all systems. In these cases, the flexibility explicitly aimed to solve a local network problem and the design of the mechanism emerged from this. They also clearly show that the 'market layer' is only one component of a broader operational package, which includes forecasting, network models, asset registries, data exchange, and rules for interactions with existing markets. These models are often useful where flexibility is being treated explicitly as a non-wires alternative or as a recurring local service need, but they are also the most demanding in both technical and institutional terms.

The practical implication for ASEAN is that the choice between these models should follow from **system structure and readiness**, not from a presumption that formal local markets are superior.

Box 4. Great Britain - Project TRANSITION: building repeatable DSO procurement processes

Project TRANSITION is one of the clearest examples of moving from innovation to more repeatable distribution system operator (DSO) procurement of local flexibility. It developed common product structures, qualification rules, baselining methods, settlement logic, contracting processes and platform interfaces for distribution-led flexibility procurement. The products addressed distinct needs such as peak demand management, generation peak management, network constraint support and outage-related services.

This case shows what it takes to turn flexibility procurement into an operational process rather than a one-off pilot. Its strongest lesson is not that local markets become liquid automatically, but that process design matters. A caution is equally important: even with relatively advanced digital capability and strong institutional support, thin liquidity and participation costs remain constraints.

Sources: SSEN.2023. Electricity Network Competition. SSEN05 Project Transition.

Box 5. Australia - Project EDGE: coordinating local and wholesale services within network limits

Project EDGE is an advanced proof-of-concept for coordinating DER participation in both wholesale and local services within distribution limits. Using DOEs, interval metering, scalable data exchange and aggregator portfolios, the project tested how the same DER assets could pursue wholesale value while also providing local demand or voltage support. The 'Local Services Exchange' acted as a distribution-level coordination and service procurement layer rather than a wholesale market.

The case is important because it shows that the critical issue is not simply whether DER can provide more than one service, but how the trade-off is governed. EDGE demonstrates that DOEs are not themselves the flexibility service; they are the operational constraint layer that makes local service delivery and wider market participation technically credible at the same time. For ASEAN, the key lesson is that role clarity, feeder-level visibility, portfolio optimisation and interoperable data exchange matter more than building a marketplace first.

Sources: AEMO. 2022. Project EDGE Public Interim Report, AEMO. 2022, Project EDGE Lessons Learnt Report #2, and AEMO. 2023. Project EDGE Final Report.

Box 6. Germany - Enera: what a formal local congestion market requires

Enera tested a comparatively advanced exchange-based local flexibility market for congestion management in a region with very high renewable penetration and recurrent curtailment risk. It combined an exchange platform with a broader digital architecture including smart metering, substation monitoring, asset registry and multi-level coordination among the transmission system operators (TSOs) and DSOs. This case shows both the promise and the complexity of a formal local congestion market. It demonstrated that coordinated procurement of local flexibility across multiple network levels can work in principle, but only with deep digitalisation, strong asset qualification, clear coordination rules and substantial institutional effort. For ASEAN, Enera is best treated as a longer-term reference model rather than an entry point.

Sources: FEVER. 2020. Flexibility related European electricity markets.

3.3 Institutional and commercial readiness

Across the international cases, **institutional and commercial readiness matters at least as much as technical capability**. The more successful initiatives were not necessarily those with the most advanced platforms; they were those in which roles, buyer authority, contracting routes, payment and verification rules, cost recovery and commercial experimentation were sufficiently clear for parties to act. The key prerequisites for a credible flexibility services framework are:

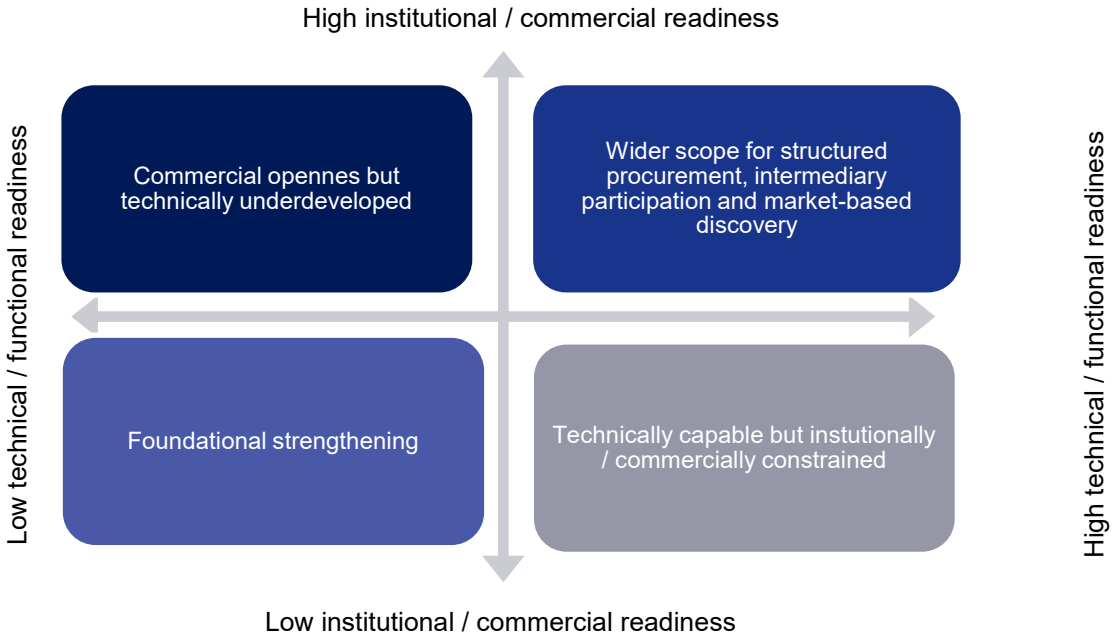
- **There must be a clearly authorised buyer of flexibility**, usually a utility, network operator, or DSO. This provides a credible route for identifying the service need, procuring the service, or bearing responsibility for delivery.
- **Providing a lawful and workable role for aggregators or other portfolio operators** where small DER, households or dispersed commercial loads are expected to participate. A coordinating layer is often needed to recruit customers, manage asset data, communicate activation signals and aggregate delivery.
- **Workable contracting and payment arrangements are needed**. Even where full market rules are absent, a flexibility service cannot be scaled unless there is a credible way to define service obligations, specify payment terms, allocate delivery risk and compensate providers or intermediaries.
- **Data access and verification rules must be workable enough for delivery to be measured**. This includes access to interval data or telemetry where needed, workable baselining or direct measurement approaches, and clarity on who can use customer data.
- **There must be a clear route for cost recovery** where flexibility substitutes for capital expenditure or improves reliability. Flexibility is unlikely to scale where utilities can recover network investment more easily than flexibility procurement. Utilities and network operators should therefore be able to recover the efficient operational cost of procuring flexibility as a non-wires alternative.
- **There must be a defined arrangement for interaction with other market or tariff mechanisms** so that local services do not simply conflict with wider incentives. Under the current market structures in many AMS, procuring local flexibility services comes at the expense of dispatching the utility's own dispatch, limiting its incentive to do so.
- **There must be room for pilot-stage experimentation** where full institutional arrangements are not yet in place. In many systems, flexibility begins through innovation allowances, regulatory derogations, utility-administered programmes or limited trials rather than through fully codified market design.

Where one or more of these elements is absent, pilots can still proceed, but the appropriate model is usually a targeted trial or utility-administered arrangement rather than an attempt to launch a scaled market framework immediately. The implication is that **institutional and commercial reform should usually be staged, with initial pilots used to clarify gaps before more formal procurement or market rules are introduced**.

Figure 3 sets out this broader readiness distinction. Technical or functional readiness concerns whether the system can identify, forecast, coordinate or control, and verify a flexibility response in operational terms. Institutional or commercial readiness concerns whether there is a lawful and workable route to

procure, contract, pay for, recover the cost of that service. The two dimensions are related but distinct: a system may have one without the other. This distinction matters because pilots do not always require full maturity on both dimensions. **Pilot design should be based on targeted sufficiency across both dimensions**, rather than on waiting for full maturity across all conditions.

Figure 3: Technical or functional readiness and institutional or commercial readiness



Source: ECA under the Green Grids Rising Workstream I, ASEAN-UK GTF – Clean and Just Energy Transition.

3.4 Technology selection: service first, not technology first

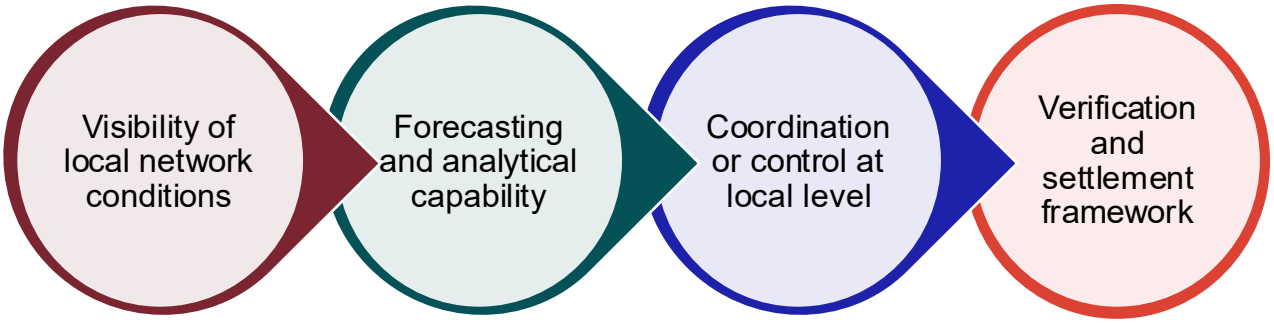
The clearest international **mistake** is to start with a technology list rather than a service problem. Stronger cases begin with a **specific operational need**, such as export congestion, peak growth, curtailment, feeder overload, EV clustering or island-system balancing, and then deploy only the smart grid capabilities needed to identify, coordinate and verify the service. Four capabilities recur most consistently across the cases (see Figure 4).

The first is **visibility**, usually through interval metering, feeder monitoring, or device telemetry, so that the network operator can observe what is happening locally. The second is **forecasting and analytics**, including local headroom estimation and forecasting of DER output or load. The third is **control or coordination**, whether through an EMS, Distributed Energy Resource Management System (DERMS), managed EV charging, or aggregator optimisation. The fourth is **verification**, which can be baseline-based, where delivery is measured against an estimate of what consumption or generation would otherwise have been, or telemetry-based, where actual metered response to a dispatch instruction or event is measured directly. Commercial settlement may then be layered onto that verification process, but it should not be confused with the underlying operational capability.

Smart grid maturity should therefore be judged by functional use, not procurement volume or installation counts. Capability has value only when it is actually used to solve a defined operational problem. A key lesson is that advanced metering infrastructure (**AMI**) **does not need to be universal** before flexibility begins. Targeted rollout in constrained feeders, DER-dense suburbs, EV hotspots, industrial estates or island systems is often a more credible starting point. Interoperability also matters more than

sophistication at early stages: a modest architecture that can reliably link enrolment, interval data, dispatch, and settlement is usually more valuable than a more advanced platform that cannot exchange data across parties.

Figure 4: Core operational capabilities for flexibility services



3.5 Product design, procurement and customer participation

International experience suggests early products should be narrow, local and operationally clear, linked to specific network needs such as export management, peak reduction or managed EV charging. Products becoming too complex too early can reduce participation.

At early stages, bilateral contracts, retailer- or aggregator-led programmes, utility-administered tenders, shadow-priced trials[4], and other simple procurement arrangements may be more effective than repeated auctions or fully developed local markets. The key is a credible, proportionate procurement mechanism. The Great Britain example also shows the value of **anchoring willingness to pay to avoided reinforcement costs or measurable reliability value**, particularly where local markets are thin and transaction costs are high. Knowing the value of the service provides a basis for compensation and a benchmark for future market-based approaches (Box 7).

Box 7. Valuing flexibility

The value of flexibility depends on the service provided and the alternative cost avoided, such as network reinforcement, VRE curtailment, balancing costs or reliability impacts. In Great Britain, Project TRANSITION linked its flexibility ceiling price to avoided reinforcement costs, providing one example of this value-based approach.

Where flexibility is being valued as an alternative to additional network or system capacity, the assessment should consider how much flexibility can reliably be delivered when and for as long as needed. This means distinguishing between technical potential, operationally deliverable capacity after accounting for availability, forced outages, response and ramping capability, and duration, and commercially procurable capacity.

Illustrative example: if 15 MW of technical flexibility is available, operational constraints reduce this to 12 MW, and 80% can be reliably procured, the effective contribution is 9.6 MW. This should be compared with the alternative cost rather than the headline 15 MW. The value case should also be tested against key sensitivities, including VRE penetration, demand growth and network constraints.

[4] By shadow-priced, this playbook means arrangements in which flexibility is rewarded or evaluated through an administratively determined local service value, rebate, event payment or shadow settlement process, rather than through a fully liberalised retail tariff or competitive market price.

A consistent lesson is that **small DER rarely participates efficiently on a standalone basis.** Aggregators, retailers, energy service companies (ESCOs), EV charging operators or utility programme operators can recruit customers, manage asset data, communicate activation signals and coordinate dispatch. Intermediaries can therefore enable participation even before formal local flexibility markets are feasible.

Customer participation should not be assumed. Trials perform better when offers are simple, customers have clear override rights, and value-sharing is transparent. **Consumer protection should therefore be an explicit design parameter.**

3.6 A practical roadmap for ASEAN

The aim for ASEAN is not to move every system toward a market, but from a clearly defined service problem to repeatable delivery arrangements suited to local technical and institutional conditions. The following text summarises this sequencing as four recurring implementation patterns. It is distinct from the ASEAN implementation pathway in Section 5 and simply illustrates how systems can progress towards **repeatable flexibility delivery without assuming a common end-state**

Stage 1: Define the problem and targeted enabling conditions. In practice, this may include targeted interval metering and feeder visibility in constrained areas, basic asset registers and network analytics, and legal clarity on who can procure, coordinate or activate flexibility.

Stage 2: Pilot simple delivery models closely tied to identifiable local problems such as managed EV charging, export management, behavioural peak reduction, community battery operation, retailer-partnered household flexibility, or utility-operated microgrid optimisation.

Stage 3: Scale repeatable procurement or coordination. Scale repeatable coordination or procurement through standardised service definitions, basic qualification rules, workable verification methods and clearer value recovery. This is where the lessons from Project EDGE and TRANSITION are most relevant, particularly on product definition, platform processes, verification and the limits created by weak liquidity.

Stage 4: Use more structured procurement or market-based mechanisms where justified. Adopt these approaches where the service need is recurring, the value case is clear, and data, verification, governance and participation are sufficiently mature. The German experience shows that liquidity, onboarding costs and regulatory alignment can still pose significant risks.

3.7 Conclusions

International best practice does not support a single preferred model for local flexibility. For ASEAN, that means both avoiding premature market design and **positively encouraging targeted market-oriented, quasi-market and intermediary-led experimentation** where it can reveal service value, test delivery models, and show whether utility-led coordination is sufficient or whether more decentralised procurement adds value. It supports a **problem-led and context-specific approach in which the service need is identified first, the value of that service is understood, and the simplest workable local flexibility mechanism is then chosen**.

The clearest international ‘mistake’ is over-specifying the market model or technology before the operational basics are in place. Platforms are unlikely to succeed without procurement authority, data

access, verification, customer protection and cost recovery. Similarly, advanced smart grid investments can deliver limited value without a clearly defined service need. For ASEAN, the priority should therefore be to establish the minimum technical, institutional and commercial conditions needed to coordinate or procure a defined flexibility service, then scale the mechanism that best fits the service and sector structure.

Lessons most transferable to ASEAN

- **Start with the problem**. Define the operational need before choosing technologies or market models.
- **Match technology to the problem**. Deploy only the capabilities needed to identify, coordinate and verify the service.
- **Know the service value**. Anchor compensation to avoided network costs, curtailment, reliability or other measurable benefits.
- **Assess the role of intermediaries.** Where they are absent, start with direct control, utility programmes or tariff signals as appropriate.
- **Do not jump straight to a market**. Use the simplest workable coordination or procurement model, with scope to introduce more market-based approaches over time.

4. Current status in ASEAN

Key takeaways

- **ASEAN is not starting from zero**. Smart grid deployment is already under way across most AMS, but what matters is not simply whether technologies have been installed, but what operational purposes they are actually serving.
- Readiness for flexibility depends on the interaction of **system pressure**, **technical or functional capability**, **and institutional or commercial conditions**, not on technology deployment alone.
- In most ASEAN systems, the most credible near-term pathway is likely to be **utility-led flexibility**, **targeted pilots**, or **administered and intermediary-supported mechanisms,** rather than formal local flexibility markets.
- The most relevant priorities are likely to be **targeted visibility**, constrained-area pilots, clearer authority to procure or coordinate services, and **better understanding of the value of the services being sought.**

4.1 Introduction

Smart grid development is now visible across almost all AMS, but it remains **uneven in both maturity and purpose**.[5] In most countries deployment is still concentrated in developing the foundational layers of digitalisation: smart metering, feeder and substation monitoring, Supervisory Control and Data Acquisition (SCADA) upgrades, and selected automation investments. A small group of AMS are moving beyond this towards a more active use of distributed flexibility, such as demand response, storage coordination or managed EV charging. Some ASEAN systems remain at an earlier stage, where the priority is still system strengthening, reliability and access rather than advanced flexibility services.

For the purposes of this playbook, **the critical question is not whether a country can be said to have a smart grid, but how far smart grid capability is being used to support flexibility**. In some ASEAN systems, digitalisation is still primarily about improving reliability and operational awareness. In others, it is beginning to support balancing, distributed resource coordination and higher shares of VRE. This distinction matters because local flexibility mechanisms only become credible once the underlying monitoring, forecasting, control and verification capabilities are sufficiently in place. This section therefore assesses the current ASEAN position through **four linked dimensions,** as outlined in Figure 5.

[5] Section 4 has been prepared from publicly available sources and is intended as an evidence-based synthesis rather than a comprehensive catalogue of all country measures. The analysis relies principally on regional publications from the ASEAN Centre for Energy, supplemented by publicly available roadmaps, regulatory documents and programme material issued by relevant national authorities, regulators and utilities, including EMA (Singapore), EGAT (Thailand), TNB (Malaysia), PLN (Indonesia), EVN (Viet Nam), and the ERC (Philippines).

Figure 5: ASEAN flexibility readiness lens

System pressure	Technical / functional capability	Institutional / commercial capability	Likely pathway
How are VRE growth, DER uptake, electrification, geography creating a need for flexibility	How are smart grid technologies being deployed	Which actors are able to plan, procure, activate flexibility	Which model is most realistic in the near term

4.2 Where flexibility pressure is emerging in ASEAN

A first distinction is between systems where **DER and VRE integration pressures are already materia**l and those where the issue remains more prospective. These groupings do not directly determine the institutional or implementation pathways used later. A system may face high flexibility pressure while still being better suited to utility-led or administered mechanisms. Flexibility becomes a pressing policy issue only once renewable growth, electrification or geography begins to strain existing operating models.

A **first group** comprises systems where renewable integration, distributed solar, electrification or local network stress are already making flexibility operationally relevant. **Singapore** is the clearest example, with **Malaysia** and **Viet Nam** also facing growing integration and coordination pressures. The issue here is increasingly **how to integrate new capacity efficiently**, rather than simply promoting it.

A **second group** comprises systems where DER and VRE growth is increasing, but structural, commercial or network constraints remain more significant. **Thailand** and **Indonesia** broadly fit this category, while **the Philippines** shares some characteristics but is treated later as a more multi-actor context.

A **third group** comprises systems where grid-connected DER remains limited and distributed resources are more closely associated with rural electrification, resilience, storage or utility-led programmes. **Lao PDR, Cambodia, Myanmar, Brunei Darussalam and Timor-Leste** are better characterised this way. Here, the immediate priority is **building the physical and digital foundations** for future flexibility.

These categories are not absolute; flexibility pressures can vary significantly between utilities and local systems within the same country. Across ASEAN, key constraints include **grid readiness and system flexibility**, particularly the ability to observe, forecast and manage resources at the grid edge.

Geography and generation mix create further differences. Lao PDR must manage seasonal hydro imbalances; Brunei Darussalam has historically faced less pressure to diversify from gas; Singapore's land constraints increase the importance of floating PV, storage and imports; Indonesia's archipelagic structure creates highly varied flexibility needs; and Timor-Leste remains focused on basic system strengthening.

Finally, **policy and regulatory constraints** remain significant. Many systems lack clear commercial arrangements for ancillary services, local flexibility or aggregated DER participation. Viet Nam's rapid solar expansion illustrates how policy-driven growth can outpace network readiness, leading to congestion and curtailment. These constraints may not prevent pilots, but they can limit scale-up. Table 3 brings these differences together.

Table 3: Flexibility pressure and main constraint types across ASEAN

ASEAN member state	Current flexibility pressure	Main driver	Main constraint type
Singapore	High	Solar integration, electrification, land constraints, system balancing	Structural constraints, system flexibility, policy design for non-traditional solutions
Malaysia	High	Distributed solar growth, island system optimisation, system modernisation	Grid readiness, operational control and coordination
Viet Nam	High	Rapid solar growth and VRE integration	Congestion, curtailment, forecasting and stability challenges, network readiness
Thailand	Medium-high	Growing DER and EV relevance, broader smart grid transition	Network readiness, governance and commercial arrangements, structural constraints still material
Indonesia	Medium-high	DER and VRE growth across fragmented island systems	Geography, uneven network readiness, and commercial/regulatory uncertainty
Philippines	Medium-high	Renewable expansion, local network stress, evolving DER uptake	Network readiness, reinforcement needs, layered governance and commercial arrangements
Cambodia	Medium	Rising VRE penetration and operational complexity	Voltage and frequency management, engineering-based flexibility needs, grid strengthening
Lao PDR	Low-medium	Hydro-dominated system, seasonal balancing, evolving digitalisation	Seasonal imbalance, grid strengthening, limited coordinated distributed flexibility arrangements
Brunei Darussalam	Low-medium	Gradual diversification pressure from gas-dominated system	Limited immediate VRE pressure, system modernisation and engineering readiness
Myanmar	Low	Reliability, access and basic system adequacy	Reliability, generation adequacy, foundational digitalisation
Timor-Leste	Low	System strengthening, access and resilience	Foundational infrastructure, reliability and electrification needs

4.3 How far are smart grids already being used for flexibility?

A second question is how far smart grid capability is already being used for flexibility-related purposes. Here, a functional distinction is useful. This functional progression describes current functional use of smart grid capability in ASEAN systems; it should not be read as a reform roadmap in the same sense as the sequencing frameworks used in Sections **Error! Reference source not found.** and 5, or as e vidence that the same system is already prepared for formal procurement or local market mechanisms. The function progression, described as “layers” are discussed in detail in Table 4 below.

This three-layer view is useful because it helps distinguish readiness for local flexibility from general smart grid modernisation. Many ASEAN systems are moving forward on smart grid modernisation, but fewer are yet in a position to implement structured local flexibility mechanisms at scale.

Monitoring and reliability enhancement remain the dominant function in most ASEAN power systems. Here smart grids provide visibility and increase awareness but not yet amount to active flexibility procurement or distributed orchestration. Some AMS have moved into the second layer in which smart grid technologies are used to support operational flexibility through centralised or utility-led mechanisms. Finally, some AMS have begun early experimentation with coordinated distributed flexibility, such as initial demand response or managed charging pilots.

Table 4: Functional application of smart grids for flexibility

Functional layer	What the smart grid is doing	Illustrative AMS
Monitoring and reliability enhancement	Smart meters, feeder monitoring, SCADA and automation primarily improve outage management, visibility and operational awareness	Elements across all AMS; Myanmar; Timor-Leste
Engineering-based flexibility	Storage, automated substations, feeder control and other utility-led tools provide voltage support, frequency control and centralised balancing	Cambodia; Lao PDR; Brunei Darussalam; parts of the Philippines
Early coordinated distributed flexibility experimentation	Digital systems begin to support demand response, managed charging, aggregation, coordinated DER participation or VPP-type activity in selected pilots or service areas	Singapore; Thailand; limited or emerging elements in Malaysia, Indonesia and Viet Nam

Note: This table describes current functional use of smart grid capability, not formal procurement readiness or evidence of mature local flexibility mechanisms. Several systems sit between layers and may show different levels of maturity across utilities, locations or use cases.

4.4 Institutional and commercial conditions

Institutional and commercial conditions are equally important. Smart grid deployment across ASEAN is still predominantly utility-led, but what matters is not only the degree of institutional separation. It is also whether there is a workable route to activate flexibility operationally, procure it commercially, contract for it, verify it and recover its cost. Those conditions vary significantly across ASEAN, and, as shown in Section 3.3 they affect which local flexibility mechanisms are actually feasible.

In vertically integrated or strongly utility-led systems, such as **Indonesia, Malaysia, Brunei Darussalam, Lao PDR, Cambodia, Myanmar and Timor-Leste**, implementation can often proceed relatively quickly for core digital infrastructure such as advanced metering infrastructure (AMI), feeder automation, SCADA and selected control upgrades.

However, where the same institutions remain responsible for planning, operation and much of the commercial interface, flexibility is more likely to emerge first through utility-led optimisation, direct contracting, tariff-based approaches or administered pilots than through more formal market-based mechanisms.

Thailand and **Viet Nam** are better understood as utility-led exploratory systems with growing need for flexibility and some scope for experimentation, but not yet as clearly advanced cases of structured local flexibility procurement. Here the immediate opportunity is more likely to lie in managed charging, targeted demand response or export-management pilots, utility-partnered programmes, and other exploratory mechanisms tied to specific use cases. This also increasingly applies to Malaysia, given its smart grid developments to date and changes in the market providing increased scope for experimentation.

Singapore and the **Philippines** are better understood as the more multi-actor contexts in the region, although for different reasons and with different limitations. These settings may offer more scope for intermediary participation, targeted procurement trials or more differentiated contractual arrangements. However, this should not be overstated: neither case should be read as evidence that mature local flexibility markets are already in place.

The key implication is that the scope for flexibility mechanisms depends not only on technology, but also on **who is allowed to procure, activate, verify, contract for and pay for flexibility**. That is why institutional and commercial conditions are as important as smart grid investment in determining the feasible pathway for each country

4.5 Strategic pathways across ASEAN

Viewed as a whole, the evidence suggests that ASEAN smart grid development is best understood through a small number of broad implementation pathways. These pathways are not sequential stages. Rather, they describe the broad directions in which different ASEAN systems are currently moving, based on the interaction of system pressure, technical or functional capability, and institutional or commercial conditions. Unlike the functional progression in Section 4.3, these pathways are intended to indicate what kinds of local flexibility mechanisms may be most realistic in the near to medium term.

The first pathway is **utility-led optimisation and targeted flexibility testing**. This is likely to remain the most relevant pathway for a large part of ASEAN, especially where systems are vertically integrated, weak-grid, islanded or still building core digital capability. It includes storage-backed operational flexibility, managed charging, direct load programmes, controlled export arrangements and other utility-led mechanisms tied to clear operational problems. Malaysia, Indonesia and many island or weak-grid systems are better understood through this lens.

The second pathway is **utility-led systems with scope for administered or quasi-market experimentation**. The distinction from utility-led optimisation is that the emphasis here is not only on direct utility control of flexible assets, but on testing alternative coordination and procurement arrangements around clearly defined service needs, even while the utility remains the central actor. Here, the system is beginning to face more local flexibility pressure and may be able to test targeted procurement, tariff-based mechanisms, intermediary-supported programmes or constrained-zone pilots,

even if formal local markets are not yet realistic. Thailand and Viet Nam fit more naturally here. Depending on the use case, some parts of the Philippines may also exhibit features of this pathway, but the Philippines is better treated overall as one of the more multi-actor contexts in ASEAN. Emerging developments in the Malaysian market also provide scope for such experimentation.

The third pathway is **more multi-actor systems with stronger scope for intermediary-led or structured pilot mechanisms**. In these systems, the combination of system pressure, digital capability and institutional differentiation may make it easier to test retailer- or aggregator-led participation, constrained-zone procurement trials, or more structured contractual arrangements. Singapore is the clearest example, with the Philippines also better grouped here overall, albeit with important practical constraints and variation by use case.

A fourth cross-cutting pathway is **foundational digitalisation and engineering-based flexibility**. In some AMS, the immediate value of smart grid investment still lies mainly in reliability, system strengthening, monitoring, storage for stability, and local resilience rather than in more coordinated distributed flexibility. Cambodia, Lao PDR, Brunei Darussalam, Myanmar and Timor-Leste are better understood through this lens.

Overall, countries facing stronger DER and VRE pressure, with growing smart grid capability and more differentiated governance, are more likely to test more active forms of distributed flexibility coordination. Countries with significant pressure but more utility-led governance may be better suited in the near term to targeted operational pilots or utility/partner-led coordination. Countries with weaker near-term flexibility pressure, or more basic system needs, are more likely to benefit first from engineering-based flexibility and foundational digitalisation (see Table 5).

Table 5: Indicative implementation pathways across ASEAN

Implementation pathway	Core planning focus	Illustrative AMS
Utility-led optimisation and targeted flexibility testing	Operational problem-solving through utility-led control, storage, managed charging, direct contracts, export management and targeted pilots	Malaysia; Indonesia; selected island and weak-grid systems; elements in Viet Nam and Thailand
Utility-led systems with scope for administered or quasi-market experimentation	Constrained-zone pilots, administered procurement, tariff-based signals, intermediary-supported programmes and service value discovery	Malaysia; Thailand; Viet Nam
More multi-actor systems with stronger scope for intermediary-led or structured pilot mechanisms	Retailer / aggregator participation, structured pilot procurement, managed EV charging, constrained-zone flexibility trials	Singapore; Philippines

Foundational digitalisation and engineering-based flexibility	Reliability, monitoring, storage for stability, local resilience, system strengthening and basic digital architecture	Cambodia; Lao PDR; Brunei Darussalam; Myanmar; Timor-Leste

Note: These pathways are broad analytical groupings based on currently documented conditions. They do not imply uniform maturity across all utilities, regions or customer segments within a country, and they do not imply that all systems should move toward formal local flexibility markets.

4.6 Conclusions

Three implications follow from the current ASEAN position.

First, **ASEAN is not starting from zero**. Smart grid deployment is already under way, and some systems are beginning to use these capabilities for flexibility. The key question is whether they are sufficiently targeted and operationally used to support new services and delivery models.

Second, **readiness for local flexibility mechanisms varies substantially**. Singapore appears best placed for more structured pilots and intermediary participation, with the Philippines offering some scope depending on the use case. Malaysia, Thailand and Viet Nam are better viewed as utility-led exploratory systems, while Indonesia may progressively test administered or quasi-market approaches. Cambodia, Lao PDR, Brunei Darussalam, Myanmar and Timor-Leste are likely to benefit first from engineering-based flexibility and core digitalisation. These are directional judgements, not rankings.

Third, **flexibility needs are likely to emerge first where DER, VRE or electrification are already creating network pressures**. The appropriate response is not necessarily a full local market, but may include targeted AMI, managed EV charging, controlled exports, utility-led procurement or intermediary-supported pilots in constrained areas.

Key implications for ASEAN

- **Assess smart grid maturity by use**, particularly for visibility, forecasting, coordination, control and verification of defined services.
- The near-term divide is between systems needing **foundational digitalisation**, those suited to **engineering-based and utility-led flexibility**, and those ready to test more active coordination.
- **Utility-led flexibility is often the practical entry point**, especially in vertically integrated, islanded and weak-grid systems, but need not be the long-term model.
- **Market-oriented pilots** can help test service value, intermediary roles and alternative delivery models before formal markets are feasible.
- ASEAN systems will naturally progress through **different flexibility mechanisms**, reflecting local conditions rather than differing ambition.

5. Opportunities for ASEAN

Key takeaways

- **ASEAN should not replicate a single foreign model**, but match flexibility services to local needs, conditions and smart grid capabilities.
- Near-term opportunities are likely to centre on utility-led optimisation, administered procurement and intermediary-led programmes, rather than formal local markets.
- **Targeted commercial and quasi-market pilots** can help deliver services, reveal value and test alternative delivery models.
- More structured procurement or platform-based models are likely to suit only systems with stronger digital, institutional and verification capabilities.
- Pilots should be kept simply, focus on one service, in one constrained area, with a manageable set of actors

5.1 Framing the opportunity

The opportunity for ASEAN is not simply to identify which systems are ready for local flexibility markets, but to **address clearly identified system and network needs using fit-for-purpose flexibility mechanisms**. Smart grid capability can enable services that efficiently manage congestion, peak demand, and VRE integration, boosting reliability and resilience. International experience shows these can be delivered through utility-led optimisation, bilateral or administered procurement, aggregator-led programmes, dynamic tariffs, and, where appropriate, more structured local markets. The key question for ASEAN is therefore **which service is needed, what value it creates, and which mechanism is simplest and workable under current conditions**.

This is particularly important given **the diversity of ASEAN power systems**. Differences in market structure, regulation and the roles of different actors will shape which mechanisms are feasible. Flexibility services can also strengthen the business case for smart grid investment by creating value from otherwise difficult-to-monetise assets, supporting investment through regulated asset bases, commercial models or concessional finance.

This section translates these findings into **implementation choices**. It sets out a suitability framework for ASEAN, considers appropriate models for different industry structures, and outlines staged pathways, institutional roles and minimum prerequisites. It concludes by identifying priority opportunities across ASEAN country groupings and recommending a regional pathway that starts with **service definition and value identification rather than market design**.

5.2 Suitability framework for ASEAN

A practical way to assess opportunity in ASEAN is to apply the three broad families of local flexibility mechanisms first set out in Section 3.2 and summarised in Figure 6 below. While these should not be understood as a fixed maturity ladder, it can act as a useful framework to identify which model works where considering the service problem, technical and functional readiness, and institutional and commercial readiness.

Figure 6: Three broad local flexibility mechanism models



Table 6 summarises these three mechanism families by linking typical service problems and readiness conditions to the flexibility mechanisms most likely to be workable in practice. The table is intended as a guide to mechanism fit, not as a maturity ranking. The key point is that suitability should be understood as **fit-for-purpose mechanism choice**. A country may be well suited to one type of local flexibility mechanism and not another. It may also use **more than one mechanism family at the same time** across different regions, networks or customer segments.

Table 6: Indicative local flexibility mechanism families for ASEAN

Mechanism family	Typical service problems	Technical or functional readiness needed	Institutional or commercial readiness needed	Likely near-term ASEAN relevance
Utility-led optimisation and direct service delivery	Island balancing, reliability support, renewable smoothing, local constraint management, managed charging, peak reduction	Targeted visibility, coordination or control capability, basic verification	Utility authority, basic contracting where needed, route for cost recovery	High in vertically integrated, islanded and weak-grid systems
Administered, tariff-based and intermediary-supported mechanisms	Urban feeder congestion, voltage management, EV clustering, constrained-zone demand	Visibility, forecasting, verification, some coordination layer	Buyer authority, tariff or contracting route, intermediary role where needed, cost	Medium to high in utility-led exploratory and multi-actor systems

	response, local export management		recovery and customer protection	
Structured procurement and more market-based mechanisms	Recurring non-wires alternatives, repeated constrained-zone procurement, standardised local service products	Visibility, forecasting, qualification, verification, platform support where useful	Clear buyer, defined products, contracting routes, settlement rules, cost recovery, intermediary participation and sufficient depth	Selective, mainly for specific pilots or more advanced contexts

Note: These categories describe fit-for-purpose mechanism options, not a linear sequence that all ASEAN systems should follow. The same system may rely on more than one mechanism family depending on the service problem and location.

5.3 Which models fit which industry structures?

Industry structure matters, but it is not the only determinant of what flexibility mechanisms are feasible. In practice, the choice of implementation model follows from the combination of sector structure, buyer authority, contracting routes, intermediary roles, cost recovery and technical capability.

In **vertically integrated or utility-led systems**, the most realistic near-term mechanisms are often utility-led optimisation, direct service delivery, tariff-based coordination, simple bilateral arrangements or administered pilots. This remains the dominant pattern across much of ASEAN, including Malaysia, Indonesia, Brunei Darussalam, Lao PDR, Cambodia, Myanmar and Timor-Leste, with elements of the same logic also relevant elsewhere depending on the use case. In these settings, flexibility is likely to begin as a utility-run operational or administered service rather than as an open market product. Suitable models include direct procurement of batteries, managed EV charging programmes, curtailment avoidance schemes, local network support contracts with large customers, and contracted services delivered through a small number of certified intermediaries. The main advantage of this route is that it does not require deep market reform before useful services can begin. It should not be treated as a second-best option in itself. The main limitation is that competition, transparency and third-party participation may remain narrower unless regulatory and commercial arrangements evolve over time.

In **more differentiated or multi-actor systems**, there may be greater scope to test intermediary-led participation, targeted procurement trials and more explicit commercial signals. Singapore is the clearest ASEAN example. The Philippines may also offer some scope for this kind of experimentation. The benefit of this model is that it allows clearer separation between buyer, service provider, regulator and, where relevant, platform operator. Even so, the relevant question is not whether these systems should immediately adopt formal local markets, but whether the service problem is sufficiently clear and the value case sufficiently strong to justify more structured mechanisms.

In **hybrid ministry-regulator-operator structures**, the likely route is staged coordination rather than rapid movement toward formal local procurement. Thailand and Viet Nam are better understood as utility-led exploratory systems with growing need for flexibility and some scope for administered, tariff-based or intermediary-supported experimentation. In such systems, local flexibility can still develop through targeted pilots that align network needs, digital deployment and regulatory reform, but it is more cautious to frame the opportunity around managed charging, demand response, export management or constrained-zone service pilots than around formal local procurement.

5.4 Implementation pathways: from targeted pilots to scaled delivery

This subsection sets out a practical ASEAN implementation pathway that applies the international lessons from Section **Error! Reference source not found.** to the differentiated starting points identified in Section REF _Ref224209683 \r \h * MERGEFORMAT **Error! Reference source not found.**. It should not be read as a fixed maturity ladder or as a universal route to formal local markets. Its purpose is to show how implementation can evolve from clearly defined service problems toward more repeatable delivery arrangements, while recognising that the efficient mature model may still remain utility-administered, tariff-based or intermediary-led. The pathway begins not with market design, but with service definition and value identification.

For many AMS, the clearest near-term opportunity lies in **targeted mechanisms that solve a specific operational problem in a limited geography**. International and regional experience suggests a practical implementation pathway, discussed below and summarised diagrammatically in Figure 7. This pathway translates the broad logic set out in Section **Error! Reference source not found.** into an applied ASEAN c ontext, taking account of the different starting points described in Section **Error! Reference source not found.** and recognising that not all systems will move toward the same mature delivery model.

Figure 7: Indicative implementation pathway from service definition to scaled delivery



Note: The pathway describes how implementation may evolve within a given system, but it does not imply that all ASEAN systems should converge on the same end-state model or on formal local markets.

The first stage is to **define the service problem and value case**, and then test targeted delivery mechanisms. These are suitable where the immediate task is to determine whether flexibility can solve a specific local problem under real conditions and create measurable operational or economic value. Relevant mechanisms include utility-led flexibility pilots in constrained areas, intermediary-led programmes under utility oversight, DOEs, controlled export arrangements, managed charging programmes, bilateral contracts with larger users, or shadow-priced local service trials. Typical services at this stage include managed EV charging, targeted peak reduction, community battery dispatch, solar export management, or contractual demand response with commercial and industrial users. These pilots are especially suitable in solar-dense feeders, industrial estates, fast-growing urban load pockets, and islanded or weak-grid systems.

The second stage is to **standardise and scale repeatable delivery where pilots demonstrate value and feasibility**. Here, the objective is no longer simply to prove that flexibility exists, but to repeat and refine delivery through standardised service definitions, verification methods, contractual terms and cost recovery treatment. At this stage, the utility or network operator may run recurring administered programmes or tenders, or may work through retailers, aggregators, ESCOs or other portfolio operators.

Settlement may still sit outside a formal market, but delivery becomes more repeatable and more transparent. This is likely to be the most relevant medium-term model for much of ASEAN.

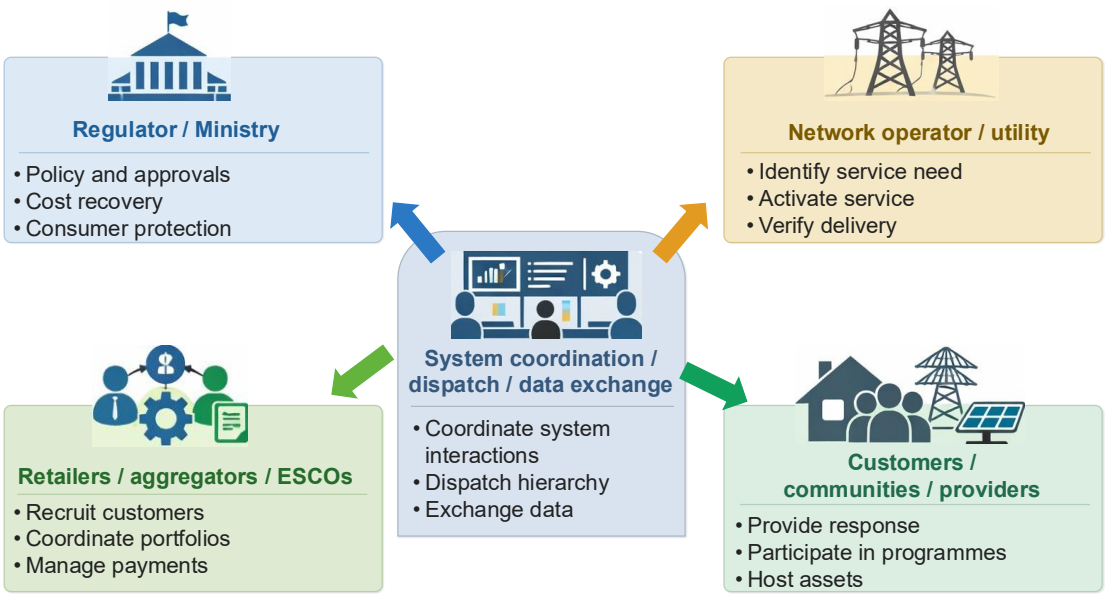
The third stage is to **adopt more structured procurement or market-based mechanisms** only where justified. This involves standardised products, clearer qualification and settlement rules, and some form of recurring local procurement process or platform support. In practice, only a subset of ASEAN systems is likely to be ready for this in the near term. Singapore is the clearest candidate for such experimentation, while the Philippines may also offer scope in selected cases, and selected urban or distribution zones in Thailand, Malaysia, Indonesia or Viet Nam may become candidates over time depending on the use case. However, the international case studies caution against assuming that a more formal mechanism is automatically superior. Thin liquidity, high transaction costs and weak data quality can undermine performance if the structure is introduced too early. The mature model need not be a continuously traded market, and in many ASEAN contexts it may more appropriately remain a repeatable utility-administered, tariff-based or intermediary-led scheme with standardised products and clear verification.

The lesson is that **a more developed model does not necessarily mean a full market**. For several ASEAN countries, the appropriate mature model may still be a robust utility-administered, tariff-based or intermediary-led procurement scheme rather than a continuously traded local platform.

5.5 Roles of different entities

A clear allocation of functions is central to any implementation model, regardless of whether the mechanism takes a utility-led, administered, intermediary-supported or more market-based form. Figure 8 should therefore be read primarily as a functions map rather than as a stakeholder map.

Figure 8: Core functions in local flexibility delivery and procurement



The **regulator or ministry** must define whether flexibility is recognised as a legitimate alternative to reinforcement, whether pilots are permitted, how customer protection will be handled, and how costs and benefits can be recovered. This also includes responsibility for data governance, including what data may be shared, with whom, for what purpose, and on what consent or access basis. In more advanced cases, the regulator may also approve product standards, aggregator participation rules or sandbox conditions. This role is particularly important where local flexibility is not yet clearly embedded in sector law or tariff regulation.

The **network operator or utility** usually remains the primary buyer or activation authority for local flexibility because it is the entity closest to the local constraint. It identifies the service need, defines the relevant location and timeframe, verifies whether the service was delivered, and determines whether flexibility can substitute for other network actions. In vertically integrated systems, that role may also extend to direct operation of the enabling digital infrastructure.

Retailers, aggregators, ESCOs or other intermediaries become important once participation moves beyond a small number of large users. Their role is not limited to bidding into markets. They may recruit customers, maintain asset data, coordinate portfolios, translate system needs into customer offers, communicate activation signals, manage device response, and handle payments, rebates or bill credits. In many ASEAN jurisdictions, these intermediaries may initially be utility affiliates or specially certified service providers rather than fully independent aggregators. This intermediary function can be valuable even before formal local flexibility markets are viable, because it helps lower participation barriers and reveal practical response capability.

Customers and local energy communities can participate directly only in limited cases. More often, they participate through an intermediary or community operator. The key issue is not simply access, but the existence of a workable governance and value-sharing arrangement.

System operators or market operators, where institutionally distinct, become more relevant once the same asset may be used for both local and system services. In such cases, dispatch hierarchy, data exchange and avoidance of double counting become material design issues. These questions become more important as countries move from pilots toward more structured procurement.

Clear assignment of these functions matters more than the legal label of each entity. In some systems the roles will sit across several institutions; in others they may sit largely within one utility group.

5.6 Minimum prerequisites by implementation stage

Minimum prerequisites should be tailored to the stage of implementation and separated clearly into technical or functional prerequisites, institutional prerequisites, and commercial prerequisites.

For **targeted pilots**, the minimum requirement is not a full smart grid rollout but whether the relevant enabling conditions exist in the pilot's specific geography. This is targeted readiness for a defined use case. In practice, the technical or functional prerequisites may include some combination of interval metering or device telemetry, feeder or substation visibility, a means of sending activation signals, and verification. Commercially, a simple event payment, rebate, shadow settlement or other temporary compensation route may be sufficient. In many ASEAN settings, that can be delivered through targeted AMI rollout rather than nationwide deployment.

For **repeatable administered or intermediary-led models**, the prerequisites expand across all three dimensions. Technically, the system needs more reliable data exchange, repeatable verification and at least basic interoperability. Institutionally, it needs clearer authority to procure flexibility, simple product

definitions, and workable contractual arrangements for intermediaries or partners. Commercially, it needs transparent treatment of customer compensation, a basic cost recovery pathway and enough clarity on willingness to pay. The system does not yet need a formal market platform, but it does need enough legal and operational clarity to move beyond one-off trials.

For **structured procurement models**, the prerequisites become more. Technically, this means standardised qualification, interoperable data systems, stronger telemetry, clearer network modelling and workable verification at scale. Institutionally, it means clearer coordination between distribution and system operation, defined procurement authority and role clarity across actors. Commercially, it means standard products, settlement rules, cost recovery treatment and at least the prospect of sufficient participation to avoid a procurement process with no real liquidity. International experience suggests that these conditions should not be assumed; they need to be built deliberately.

It should be noted that **flexibility is not always the efficient answer**. Where the need is large, persistent and highly predictable, conventional reinforcement may remain the better option. The purpose of staged implementation is therefore to identify where flexibility creates genuine operational or economic value, not to assume that it should always substitute for network investment. Table 7 summarises the minimum technical or functional, institutional and commercial prerequisites associated with each stage.

Table 7: Minimum technical or functional, institutional and commercial prerequisites by implementation stage

Stage	Technical prerequisites	Institutional prerequisites	Commercial prerequisites
Targeted pilots	Interval metering or telemetry; feeder/substation visibility; activation or control signals	Clear pilot authority; utility or network lead; basic customer protection	Simple event payments or rebates; clear allocation of pilot costs
Repeatable administered / intermediary-led models	More reliable data exchange; repeatable verification methods; basic interoperability	Authority to procure flexibility; intermediary participation rules; clearer roles	Standard contracts; transparent compensation; basic qualification and cost recovery
Structured procurement	Stronger telemetry; interoperable data systems; standardised qualification; stronger network modelling	Clear role separation; coordination with system operation; defined procurement authority	Standard products and settlement; recurring tenders/platforms; value-based willingness to pay

5.7 Priority opportunities by ASEAN country grouping

For present purposes, the most useful way to translate this framework into ASEAN opportunities is to identify broad country groupings with similar implementation conditions, rather than to impose a rigid ranking. These groupings should be treated cautiously and as directional only. They do not imply uniform

maturity within countries, and they do not imply that any one group is necessarily moving toward formal local markets as the preferred end-state.

For **Singapore** and the **Philippines**, the immediate opportunity is more structured piloting and intermediary-supported experimentation. These are the strongest candidates for testing more formal local flexibility products, managed EV charging programmes, constrained-zone procurement approaches, and differentiated intermediary roles, although the basis and scale of that opportunity differ between them. The key issue is less basic digitalisation than product design, consumer protection, coordination across actors and evidence of service value. Even in these systems, more formal procurement should be introduced selectively and problem-first, rather than as a system-wide default.

A promising first step could be the introduction of intermediary-led demand response products, building on the existing market structure and current focus on improving the flexibility of systems to absorb additional solar.

For **Thailand** and **Viet Nam**, the opportunity is utility-led exploratory flexibility and administered or intermediary-supported pilots. These systems are likely to benefit first from targeted service deployment in constrained zones: managed EV charging, controlled exports for rooftop solar, flexible industrial load, tariff-based demand response, or other utility-partnered pilots. The objective should be to prove local service value and build the evidence needed for later standardisation, not to assume early readiness for structured local procurement. In this grouping, “exploratory” means that the utility remains central, but the immediate value lies in testing alternative delivery and coordination models for specific services, rather than relying primarily on utility optimisation of assets already under direct operational control. An initial high-value move could be to pilot a managed EV charging pilot in an urban area with local substation constraints. This would require limited institutional changes while offering the opportunity to develop an evidence base on the value of flexibility and customer buy-in to such services.

For **Malaysia** and **Indonesia**, the opportunity is utility-led optimisation combined with targeted administered or quasi-market experimentation. These systems are likely to benefit first from controlled exports, community batteries, managed charging, local service pilots, flexible industrial load and other utility-centred or administered mechanisms. The objective should again be to prove service value and identify where more structured mechanisms add enough value to justify their complexity. Here a first step could be the introduction of community battery programmes delivered by vertically-integrated utilities, supporting ongoing efforts to increase distributed solar uptake.

For **Cambodia, Lao PDR, Brunei Darussalam, Myanmar and Timor-Leste**, the opportunity is foundational digitalisation, engineering-based flexibility and utility-led operational services. Here, the priority is to embed flexibility into grid strengthening, resilience and electrification strategies: storage for stability, smart metering in targeted areas, feeder automation, mini-grid optimisation and utility-led operational flexibility. These systems may still create significant value from flexibility services, but the appropriate commercial model is likely to remain utility-centred for some time. In such systems smart metering and demand response for large commercial and industrial customers, led by utility efforts, could be an initial starting point to pilot and advance flexibility services.

Across all four groupings, a further cross-cutting opportunity lies in **DER-dense pockets**: selected urban feeders, industrial estates, island systems, and solar-dense housing estates or private developments.[6] In

[6] This may include housing estates, mixed-use developments, or other privately managed developments with concentrated DER, common infrastructure, or local supply arrangements. In some ASEAN contexts, such developments may provide a more practical setting for testing local flexibility or peer-to-peer style coordination than the wider public distribution network.

these locations, the practical case for flexibility may emerge earlier than national averages suggest, and highly targeted pilots may therefore be justified regardless of overall national market maturity.

Table 8 applies this logic to broad ASEAN groupings by distinguishing between the most suitable near-term trial-stage models and the more developed models that may become feasible over time. These should be read as indicative opportunity directions, not as a fixed ranking.

Table 8: Priority implementation opportunities across ASEAN

ASEAN grouping	Indicative ASEAN Member States	Most suitable trial-stage mechanisms	Most suitable more developed mechanisms
More structured piloting and intermediary-supported experimentation	Singapore, Philippines	Managed EV charging; intermediary-led demand response; constrained-zone procurement pilots; retailer or aggregator trials	Structured procurement, recurring standardised tenders, or platform-supported procurement where justified
Utility-led exploratory systems with scope for administered or intermediary-supported pilots	Thailand, Viet Nam	Managed charging; tariff-based demand response; export-management pilots; utility / partner programmes	Administered procurement, intermediary-supported programmes, or selected structured procurement trials
Utility-led systems with scope for targeted administered or quasi-market experimentation	Malaysia, Indonesia	Utility tenders; controlled exports; community battery pilots; flexible industrial load; managed charging; local service pilots	Utility-administered or intermediary-led procurement with standard contracts and clearer qualification rules
Foundational digitalisation, engineering-based flexibility and utility-led operational services	Cambodia, Lao PDR, Brunei Darussalam, Myanmar, Timor-Leste	Utility-led storage dispatch; mini-grid optimisation; feeder automation; commercial and industrial demand response; local resilience pilots	Utility-administered flexibility as part of grid strengthening and reliability planning
Cross-cutting opportunity in DER-dense pockets	Selected urban feeders, industrial estates, island systems, solar-dense communities across several AMS	Highly targeted pilots regardless of national market maturity	Zone-based procurement, administered local services, or managed-service models

5.8 Recommended pathway for ASEAN

Taken together, Sections 5.2 to 5.7 point to the following practical implementation logic for ASEAN. The sequence below is not a fixed maturity ladder and does not imply that all ASEAN systems should converge on formal local flexibility markets. It is intended to show the order in which key questions are most usefully addressed: **service need first, targeted readiness second, simple delivery mechanisms third, and more structured procurement only where justified**. In this context, experimentation is not merely transitional. It is also a discovery tool: it helps utilities and regulators identify which services are valuable, which customers or intermediaries can provide them reliably, and which combinations of utility-led, administered and market-oriented delivery are most effective.

- **Stage 1: identify the service problem and value case**. Start with a specific local problem, such as feeder congestion, voltage rise from rooftop solar, EV-driven peak growth, weak-grid balancing or resilience support, and identify the avoided cost, reliability value or other measurable benefit that can anchor the case for flexibility.
- **Stage 2: build targeted technical and institutional readiness**. Deploy metering, visibility, communications, pilot authority and contracting routes where the service is most valuable, rather than waiting for full national rollout.
- **Stage 3: test simple delivery mechanisms**. Use utility pilots, managed charging, controlled exports, community batteries, shadow settlements, intermediary-led programmes or direct contracts before attempting more complex procurement structures.
- **Stage 4: standardise and scale what works**. Once a service proves valuable, standardise the product, verification method, customer protections, compensation logic and participation rules.
- **Stage 5: use more structured procurement only where justified**. Move to repeated tenders, structured procurement or platform-supported arrangements only where participation, data quality, governance and the value case are strong enough to support them.

Figure 9: Recommended pathway to flexibility development in ASEAN



This sequence is consistent with the international logic set out in Section **Error! Reference source not found.** and with the differentiated ASEAN starting points described in Section **Error! Reference source not found.**. It reduces the risk of introducing an institutionally complex model before the underlying service need, data architecture and governance framework are ready. It also recognises that, in many ASEAN contexts, the efficient mature model may remain utility-administered, tariff-based or intermediary-led rather than a formal local flexibility market.

Key implementation implications for ASEAN

- **Start with the service need and its value**, not with the market form.

- Judge smart grid maturity by **functional use and service delivery**, not by installation counts.
- Most ASEAN systems are likely to **benefit first from utility-led, administered or intermediary-supported flexibility**, not from formal local markets.
- **Intermediaries should be introduced early** where small DER or households are expected to participate, including in non-market delivery models.
- **Targeted pilots in constrained areas** are likely to generate more useful learning than broad but shallow national schemes.
- More **structured procurement** should be introduced only where governance, verification, participation depth and the value case are strong enough to support it.

5.9 Conclusions

This playbook has argued that the central issue for ASEAN is not whether to adopt smart grids as a general aspiration, nor whether to establish local flexibility markets as an end in themselves. The more practical question is **how AMS can use digital and operational capability to solve clearly identified system and network problems through flexibility services** that support higher shares of VRE, improve network efficiency and resilience, and create new opportunities for DER and, where relevant, local energy communities.

Unlocking such flexibility services can support the energy transition across ASEAN, helping deliver value for technologies, such as storage and synchronous condensers, which are critical to maintaining resilient systems as thermal baseload is phased down and VRE penetration increases. Several findings follow.

First, smart grids are best understood through the services they enable. Technologies such as smart meters, monitoring, forecasting, automation, etc. matter because they enable active coordination of supply, demand and storage. Their value lies in services such as congestion relief, peak reduction, voltage management, managed EV charging, flexible exports and local reliability. Smart grid maturity should therefore be judged by functional use, not installation counts.

Second, flexibility services should be the core concept, with local flexibility mechanisms as the broader delivery category and markets as one subset. International experience shows flexibility often starts through utility-led optimisation, administered procurement, bilateral contracts, managed charging, DOEs, tariffs or aggregator-led programmes. Formal local markets are appropriate only where service needs are clear and recurring, and digital, governance and participation conditions are sufficiently mature.

Third, ASEAN is not starting from zero. Some AMS are beginning to test more active flexibility coordination, while others are using smart grid investments mainly to support renewable integration, reliability improvement, resilience, grid strengthening or electrification. The relevant opportunity therefore differs by country, locality and use case.

Fourth, readiness for flexibility mechanisms varies across ASEAN and should be assessed through both technical and institutional/commercial readiness. Singapore appears best placed for more structured and intermediary-led pilots, with the Philippines offering some scope depending on the use case. Thailand and Viet Nam are better suited to utility-led, administered, tariff-based or intermediary-supported approaches, while Malaysia and Indonesia may test administered or quasi-market mechanisms

selectively. Cambodia, Lao PDR, Brunei Darussalam, Myanmar and Timor-Leste are likely to benefit first from engineering-based flexibility, foundational digitalisation and utility-led models.

Fifth, sequencing matters, but not as a fixed path toward markets. Targeted market-oriented, quasi-market and intermediary-led pilots can help reveal service value, stimulate innovation and test delivery models. The core lesson is to start with a defined service need and value, build the required readiness, test simple mechanisms, and move toward structured procurement only where justified. Starting with market reform rather than service need risks adding complexity without delivering operational value.

5.10 Future directions for ASEAN

The next phase of work in ASEAN should **focus on operational learning, targeted digitalisation, service valuation and institutional preparation**. The priority is to build the evidence, capability and authority needed to deliver clearly defined flexibility services, rather than designing complex markets in the abstract.

A first priority is to **identify service problems and value cases more clearly**. ASEAN systems need clearer evidence on where flexibility creates genuine value relative to reinforcement, curtailment or unmanaged operation, and on how that value can be quantified for different services such as congestion relief, peak reduction, export management, managed charging and resilience support.

A second priority is to **pursue targeted digitalisation** rather than waiting for universal rollout. Targeted interval metering, feeder visibility, basic asset registers, forecasting tools and verification capability in constrained areas are likely to create more practical value in the near term than broad but shallow deployment.

A third priority is to **create room for pilot-stage experimentation** under partial readiness. Pilots should be used not only to test service delivery, but also to clarify procurement authority, contracting routes, cost recovery, customer protection and intermediary roles before more formal frameworks are considered.

A fourth priority is to **build intermediary and customer participation routes** where relevant. Where small DER, households or dispersed commercial loads are expected to participate, ASEAN systems will often need retailer, aggregator, ESCO or equivalent programme-operator roles to recruit customers, manage portfolios and lower participation barriers.

A fifth priority is to **strengthen treatment of flexibility as a planning option and non-wires alternative**. Utilities, regulators and ministries should increasingly assess whether flexibility can defer, avoid or better target conventional reinforcement in specific locations, while remaining clear that flexibility is not always the efficient option.

Emerging from this are a series of practical next steps and priorities for ASEAN institutions and Member States. These include:

- **Support pilot projects** using this playbook's framework to demonstrate its value and refine its application**.**
- **Integrate the framework into regional capacity-building programmes.** The ASEAN Centre for Energy (ACE) and Heads of ASEAN Power Utilities/Authorities (HAPUA) can help mainstream the playbook's concepts and recommendations and build wider understanding of local flexibility services

- **Treat local flexibility as part of the wider energy-transition toolkit**. As systems become more digital, distributed and interconnected, flexibility services can complement other measures to maintain system resilience.

5.11 Closing message

The central message is that **smart grid investment is most valuable when tied to a clearly defined service problem**. Utility-led models will often be the entry point in ASEAN, while administered, tariff-based and intermediary-supported approaches can enable experimentation before formal markets are feasible. **More structured procurement should be pursued where justified by the use case, rather than assumed in advance**. For ASEAN, the task ahead is therefore not to choose a single model, but to **build clearer service definitions, stronger value frameworks, targeted readiness and workable local flexibility mechanisms that fit diverse national starting points**. That is the more practical route from smart grid aspiration to operationally valuable flexibility services.

Annex 1 Country case studies

The case studies below provide the detailed evidence base for the international review in Section **Error! Reference source not found.** of the main report. Summary boxes in the main text draw s electively on these annexed cases to make the international chapter readable on a standalone basis.

Annex 1.1 Australia, Project EDGE

Years: 2020-2023

Geography: AusNet distribution area, Victoria

Lead entities: Australian Energy Market Operator (AEMO), AusNet Services, Mondo, University of Melbourne, EY, Australian Renewable Energy Agency (ARENA)

1. Problem addressed and new service created

System need. Rapid growth in rooftop solar, batteries and other DER was creating local voltage and congestion issues on distribution networks, while also raising a broader coordination problem: the same customer assets could potentially provide both wholesale energy services and local network support, but there was no business-as-usual framework for doing this in a coordinated way within distribution limits. In Project EDGE, "wholesale services" meant DER being used through aggregator portfolios to participate in Australia's National Electricity Market's (NEM's) energy trading and dispatch processes, while "local services" meant DER being used to address distribution-level needs such as local demand constraints or voltage issues.

Service created. Project EDGE tested an off-market, proof-of-concept DER marketplace in which aggregators coordinated DER portfolios for both wholesale participation and local network services, while DOEs constrained dispatch to what the local network could safely accommodate. Within that architecture, the Local Services Exchange (LSE) was developed as a coordination and procurement function for distribution-level support services between the DSO - or Distribution Network Service Provider (DNSP) as referred to in Australia - and aggregators; it was not a wholesale market and not a business-as-usual regulated procurement regime.[7]

Why it matters for the playbook. EDGE is useful because it goes a step beyond cases that only manage DER exports at the connection point. It tests how a common DER portfolio can simultaneously pursue market value and provide local network support, with DOE limits acting as the coordination layer that prevents those activities from breaching distribution network constraints. That makes it a strong example for explaining how local flexibility services and wider market participation can be coordinated within one architecture.

2. Starting conditions and design drivers

Network context. The trial focused on parts of AusNet's network in Victoria where high PV uptake and growing DER volumes were creating voltage management and export congestion issues. The project distinguished between the low-voltage customer level, where DOEs were calculated for active customers, and broader distribution network needs, where local support services were being explored.

Market and digital baseline. Victoria's widespread smart meter rollout was an important enabler because it provided a strong interval data base relative to many other jurisdictions. The project also assumed a market structure in which aggregators could already pursue wholesale value streams, but there was no settled DSO/DNSP flexibility procurement model for local services. That is why EDGE was structured as an off-market proof-of-concept rather than a mature operating scheme.

Scale and maturity. EDGE moved from concept and architecture design into a substantial field trial. AEMO reports that more than 320 residential and commercial/industrial customers participated in an 11-

[7] AEMO. 2022. Project EDGE Public Interim Report, AEMO. 2022. Project EDGE Lessons Learnt Report #2, and AEMO.2023. Project EDGE Final Report.

month trial, providing around 3.5 MW of flexible capacity from more than 400 DER devices, coordinated in real time by three active aggregators. AEMO also notes that the three active aggregators, AusNet and AEMO built and operated the systems and processes needed for DOE publication, DER fleet forecasting, coordination and visibility, and scalable data exchange. This is therefore better described as an advanced proof-of-concept than as a settled commercial market design.[8]

3. Intervention overview: smart grid enablers and local flexibility mechanism

Smart grid enablers. The enabling stack combined interval metering, scalable data exchange, DER fleet forecasting, coordination and visibility tools, and DOE calculation. In practical terms, EDGE required the DNSP and market actors to exchange data on network conditions, DER capability, planned dispatch and service delivery in a way that could support both local services and wholesale participation.

Local flexibility mechanism. The LSE was not a wholesale exchange. Rather, it was a platform concept through which the DNSP could define local service needs, aggregators could enrol and offer DER capability, and the parties could coordinate service definition, delivery, verification and reporting. For the demand services tested in the field trial, procurement, delivery and validation were coordinated through the EDGE DER data exchange hub; voltage services were tested more narrowly, with direct communications between the DNSP and aggregator because voltage-service field testing was more limited.

How the wholesale/local nexus worked. The core design issue was not simply whether DER could provide both wholesale and local services, but who should manage the trade-off. EDGE explored a model in which aggregators remained responsible for optimising their portfolios across value streams, while the DOE and local service processes imposed the network constraints and service obligations that had to be respected. In other words, wholesale participation continued through existing market arrangements, but only within the local network limits and commitments established through the EDGE architecture.

4. Flexibility service design

Roles and platform. AusNet's role was to identify local constraints, calculate and publish DOEs, and define local service needs. Aggregators enrolled participating DER, forecast and optimise their fleets, and sought to stack wholesale and local value streams. AEMO remained the wholesale market operator; EDGE did not replace wholesale dispatch or settlement. The LSE sat alongside existing market arrangements as a distribution-level coordination and service procurement layer rather than as a new wholesale market.

Product definition. The field trial tested three local services: Demand High Firmness, Demand Low-Firmness and Voltage High Firmness (VHF). This is more precise than describing the products only as 'high' and 'low' firmness in general. The demand services were coordinated through the LSE workflow, while VHF was trialled on a more limited basis. The substantive service categories were therefore local demand management and local voltage support, rather than a single undifferentiated flexibility product. The distinction between high- and low-firmness services was important. For low-firmness services, the LSE design explicitly notes that aggregators were not obliged to deliver; they could assess their "willingness to deliver" in response to a service need. By contrast, the High Firmness service design included a more structured lifecycle with enrolment, offers, service agreement, arming, notice, delivery verification and reporting.

[8] Ibid.

Participation and verification. Participation was primarily through aggregators, which was necessary to assemble many small household and small business devices into portfolios large enough to provide meaningful services. Verification and reporting were embedded in the project's data exchange architecture. For demand services, the LSE design includes explicit stages for service verification and reporting; for voltage services, the design notes that field testing was more limited and communications were manual.

Key design lesson. EDGE shows that DOEs are not themselves the flexibility service. Rather, they are the operational constraint layer that makes simultaneous participation in local service arrangements and wider market activity technically credible. The service is the local demand or voltage support being procured or coordinated; the DOE is what keeps DER dispatch inside network limits while that happens.

5. Enablers, barriers, and pilot-to-scale pathway

Key enablers. The most important enablers were Victoria's strong smart meter base, active aggregator participation, institutional backing from AEMO and ARENA, and the development of a scalable, decentralised data exchange approach. These elements allowed multiple actors to share the operational information needed for DOE publication, DER visibility, local service coordination and verification.

Main barriers. The main barriers were institutional and commercial as much as technical. Project material highlights the unresolved question of future DNSP/DSO-type coordination roles, especially who should be responsible for coordinating or co-optimising wholesale and local services, and how service prioritisation should work when local network needs and wholesale incentives diverge. The trial also exposed the need for better interoperability across network, market and aggregator systems. These are not minor implementation details: they are core design issues that determine whether local flexibility can move from pilot architecture to business-as-usual operation.

Pathway to scale. EDGE's main contribution was preparatory. It produced working architecture, tested roles and data flows across multiple parties, and generated evidence for future reform on DER integration, value stacking and local services procurement. Its scaling value lies less in having created a durable market-ready LSE product and more in having shown what institutional capabilities, data exchange and role clarity would be needed to operationalise such a framework at scale.

6. Outcomes and evidence

Evidence available. EDGE's clearest demonstrated outcome is end-to-end technical feasibility. AEMO states that the project successfully coordinated DER operations between participants and demonstrated the real-time functions needed for DER system and market integration, including DOEs, fleet forecasting, coordination and visibility, and scalable data exchange. It also achieved a material field trial scale, with 320-plus customers, 3.5 MW of flexible capacity and three active aggregators.

Evidence caveat. EDGE is best read as an advanced proof-of-concept rather than a mature operational local flexibility market. The strongest evidence is on end-to-end technical feasibility, role design, and coordination architecture across the DNSP, market operator and aggregators. By contrast, long-run commercial arrangements, enduring procurement rules, and quantified customer or system benefits should be treated more cautiously, as the project remained an off-market trial intended to inform future reform rather than establish a business-as-usual service model.

7. Transferable lessons for ASEAN

Replicable practice. The most transferable lesson is sequencing. EDGE suggests that the first requirement is not a local market platform, but a credible operational layer: feeder visibility, interval data,

DER portfolio coordination, and a method such as DOEs for translating network constraints into usable operating limits. Once that exists, a local service coordination or procurement layer can be added; tighter integration with wholesale or system services can come later. The case is particularly useful for showing that coordination architecture and governance can matter as much as the existence of a market interface.

What needs adaptation. Many ASEAN systems will not replicate Australia's institutional separation between DNSP, market operator and competitive aggregators. But the underlying logic still transfers: one actor must define local network constraints, another must optimise DER portfolios against multiple value streams, and the governance must clearly determine which obligations take priority when they conflict. In vertically integrated systems, those roles may sit within one utility group rather than across separate entities.

Minimum prerequisites and risks. At minimum, utilities need feeder-level visibility, interval metering or equivalent telemetry, a credible method for calculating local operating limits, and a trusted route for portfolio optimisation and data exchange. Without those foundations, a local market layer risks being administratively elaborate but operationally weak. The principal risks are unclear roles, poor interoperability, and unresolved service-priority rules between local network needs and wider market participation.

Annex 1.2 Australia, Project EDITH

Years: 2021 onward

Geography: Ausgrid distribution area, New South Wales

Lead entities: Ausgrid, Reposit Power, Australian National University (ANU), Zeppelin Bend

1. Problem addressed and new service created

System need. High uptake of rooftop solar and household batteries was creating local voltage constraints and midday export congestion on distribution feeders. Static export limits protected the network but restricted customer value and did not reflect actual network conditions.

Service created. Project Edith tests a distribution-level flexibility mechanism based on dynamic network pricing used alongside DOEs. It is not a local auction market. Instead, the DNSP publishes time and location-specific network signals and aggregators optimise consumer energy resources (CER)[9] portfolios in response.

Why it matters for the playbook. The project shows how customer-owned VRE and batteries can, in principle, improve hosting capacity and reduce pressure for near-term augmentation where the network can signal local constraints and headroom.

2. Starting conditions and design drivers

Network context. The trial focused on feeders experiencing reverse power flow, voltage rise and congestion associated with high CER uptake. Static export limits of 5 kW for single-phase and 15 kW for three-phase customers formed the baseline control regime.

Market and digital baseline. The wider Australian NEM context mattered: small customers could already participate in wholesale markets through aggregators and VPPs, so the distribution mechanism had to complement rather than distort wholesale participation. Participating customers had interval metering, and the project built on ANU's existing 'Evolve' capability for calculating and publishing DOEs, which Project Edith then extended to support dynamic pricing.

Scale and maturity. Project Edith followed a staged pathway. Ausgrid's December 2025 Stage 3 Insights Report describes Stage 1 as running from May 2021 to June 2023, Stage 2 from July 2023 to June 2024, and Stage 3 from July 2024 to June 2026, with later stages still upcoming. The same report notes 200 customers in Stage 1 and expansion to around 1,200 customers in Stage 2 across multiple customer agents. Stage 3 also moved to testing pricing across simulated feeders reflecting different weather zones. This staged design matters because the project was testing customer agent roles, tariff design, and settlement pathways, not only the pricing concept itself.[10]

3. Intervention overview: smart grid enablers and local flexibility mechanism

Smart grid enablers. The essential enablers are DOE capability, interval metering, forecasting of local network conditions, and communication arrangements able to carry both export limits and pricing signals.

[9] CER are user-owned, behind-the-meter technologies that generate, store, or manage electricity, such as rooftop solar, home batteries, EVs, and smart appliances.
[10] Ausgrid. 2025. Project Edith Insights Report.

Local flexibility mechanism. Ausgrid calculates and publishes short-interval import/export prices linked to local network headroom. Aggregators act as the customer-facing optimisation layer, dispatching batteries, solar exports and flexible loads so as to maximise customer value while staying within network limits.

Institutional design choice. The mechanism is deliberately decentralised: there is no marketplace, no auction and no DSO direct control of household assets. That makes Edith a useful case of local flexibility coordination by price signal rather than bidding or direct dispatch.

4. Flexibility service design

Roles and platform. Ausgrid calculates and publishes dynamic prices and DOEs. Aggregators enrol customers, maintain core asset and participation data needed for optimisation, and optimise dispatch. ANU provided the DOE engine used in the trial, and Zeppelin Bend hosted the underlying data and publication infrastructure.

Product definition. The effective service is local network constraint management, including congestion and related voltage management support, delivered through dynamic import/export price signals rather than direct dispatch.

Procurement and pricing. Prices are linked to local network headroom and forecast asset loading. In this context, headroom means the remaining spare capacity on a network asset, such as a transformer, before it reaches its technical limits. When headroom is ample, a low default tariff applies; as forecast headroom tightens, dynamic import or export prices apply, subject to customer protection guardrails. Dynamic prices are triggered when forecast headroom falls below 20%, and the price cap applies once the relevant asset reaches 100% forecast utilisation.[11] Ausgrid's Stage 3 Insights Report states that the current trial uses a relatively low cap of about AUD 1.10/kWh, while higher caps are discussed only as future options for investigation. The trial also tested customer protection guardrails, including limits on exposure to prolonged high-price events and, in earlier stages, a no-worse-off arrangement under which customers were reimbursed if the dynamic tariff would otherwise have left them paying more in network charges than under the underlying static tariff.

Participation and settlement. Customers participate through aggregators rather than directly. Settlement in early stages was off-market and reconciled against interval metering data. Stage 4 of the published pathway is intended to move toward on-market network billing and an opt-in 'subthreshold' tariff, but these are described as upcoming steps rather than completed features of the trial. Because the mechanism is incentive-based rather than firm contracted flexibility, there is no standard non-delivery penalty regime in the public trial reporting.[12]

5. Enablers, barriers, and pilot-to-scale pathway

Key enablers. Important enablers include existing DOE capability, interval metering, experienced aggregators and communication arrangements able to carry both export limits and pricing signals.

Main barriers. The central challenge is behavioural and commercial complexity: CER response depends on customer behaviour, battery state of charge, retailer offers and aggregator algorithms. A second challenge is interaction with wider market incentives. Customer agents may respond more strongly to wholesale spot-price opportunities than to local network signals, especially when wholesale prices materially exceed the network price signal. This matters because the distribution mechanism is intended

[11] Ibid.
[12] Ibid.

to complement, not distort, wholesale participation. Ausgrid's published reporting also highlights distributional and customer understanding issues, and notes that some price designs can create unintended incentives. In particular, earlier experiments with asymmetric pricing created a risk that batteries could charge under one pricing condition and discharge to collect export rewards during the same event, without delivering the intended net system value. Later trial design therefore moved toward more symmetric pricing to reduce this gaming risk.[13]

Pathway to scale. The project moved from proving that CER can respond to dynamic prices, to broader customer agent participation, and then toward more transparent customer-facing tariff structures and metering or billing integration. Later-stage features such as on-market network billing and removal of the no-worse-off safeguard should still be treated as planned rather than implemented.[14]

6. Outcomes and evidence

Evidence available. The strongest public evidence from Project Edith is on mechanism design, staged trial learning, tariff evolution, and proof-of-concept customer response, rather than on a large, published set of audited performance indicators. Public reporting indicates that dynamic network pricing can influence CER behaviour and, in principle, help flatten network load profiles, improve hosting capacity, and reduce pressure for near-term augmentation.

Evidence caveat. Public reporting is more limited on quantified long-run network savings, customer bill impacts, and distributional outcomes. These effects are therefore indicative and still evolving, rather than being settled evidence from a mature commercial model.

7. Transferable lessons for ASEAN

Replicable practice. Project Edith is most relevant where rooftop solar is rising but full local flexibility markets are not yet realistic. A sensible sequence is to start with DOEs or dynamic export management, then test shadow or pilot dynamic tariffs in constrained zones. This is especially relevant where the system wants a more dynamic alternative to static export limits without requiring direct dispatch of household assets.

What needs adaptation. In vertically integrated or less liberalised systems, utilities may need to appoint or certify one or more aggregators or similar intermediaries rather than rely on a competitive field of market-based aggregators. The customer-facing offer can remain simple while optimisation sits with the intermediary.

Minimum prerequisites and risks. The minimum prerequisites are interval metering, feeder-level visibility, a credible method for calculating envelopes or asset headroom, and basic customer safeguards. The main risks are price complexity, weak transparency over how value is shared between the network, intermediary and end-customer, and poor alignment with wider retail or wholesale incentives. In Edith, the clearest example of that alignment risk is the possibility that wholesale price opportunities dominate local network signals, weakening the intended local response. In systems that are not ready for full retail tariff reform, one practical adaptation is to start with shadow billing or rebate-style credits so that customers can be rewarded for network-supportive behaviour without immediately redesigning the full retail tariff structure.

[13] Ibid.
[14] Ibid.

Annex 1.3 Germany, Enera

Years: 2017-2020

Geography: East Frisian peninsula, Lower Saxony

Lead entities: EWE, EPEX SPOT, TenneT, Avacon Netz and EWE NETZ

1. Problem addressed and new service created

System need. Enera was designed for a region with very high renewable penetration, frequent grid bottlenecks and recurring curtailment risk. The underlying problem was not only technical congestion, but also the cost and inefficiency of relying on redispatch and curtailment in a system where renewable generation in northern Germany often exceeded local demand and available export capacity. In the pilot area itself, renewable generation exceeded local consumption by around 235%, making it an unusually demanding test case for local congestion management.[15]

Service created. Enera tested a regional flexibility market in which system operators could procure congestion management flexibility through an exchange-based platform rather than relying only on administrative intervention. The market was operated by EPEX SPOT, the European power exchange, acting as a neutral market intermediary between system operators and flexibility providers. The objective was to allow system operators to buy short-term commitments to adjust generation or consumption in order to relieve local bottlenecks and reduce uneconomic curtailment.[16]

Why it matters for the playbook. Enera is useful because it represents a comparatively advanced European attempt to combine deep digitalisation, formal market design, and TSO-DSO coordination in a local flexibility setting. It therefore shows both what an exchange-based local congestion market can achieve technically and why such a model is demanding to scale in practice.[17]

2. Starting conditions and design drivers

Network context. The pilot covered the counties of Aurich, Friesland and Wittmund and the town of Emden on the East Frisian peninsula. The region was selected because it combined very high renewable generation with a highly interconnected network structure across transmission, high-voltage distribution, medium-voltage and low-voltage levels. TenneT operated the extra-high-voltage grid, Avacon Netz operated the 110 kV high-voltage distribution grid, and EWE NETZ operated the medium- and low-voltage networks. This multi-operator structure made coordination a design necessity from the outset.[18]

Digital baseline. Enera did not begin with all of the required infrastructure already in place. The project had to build much of the digital architecture needed for a local flexibility market, including smart metering, substation monitoring, communications links, and a central data platform. The original project materials describe installation of more than 700 smart meters, retrofitting of 92 substations with measurement and control technology, and creation of a dedicated communication network to support data exchange.

Design implication. Enera was not simply an exchange pilot layered onto an already digitalised grid. The market concept depended on prior or parallel creation of the operational architecture needed to observe the network, forecast congestion, register flexible assets, and coordinate action across several

[15] FEVER.2020. Flexibility related European electricity markets.
[16] Ibid.
[17] Ibid.
[18] Ibid.

system operators. In practice, the market layer was only one part of a broader smart grid programme built around the three pillars of network, market and data.

3. Intervention overview: smart grid enablers and local flexibility mechanism

Smart grid enablers. Enera created an end-to-end digital architecture including a Smart Data and Service Platform (SDSP), a flexibility registry, monitoring and forecasting capability, and new interfaces linking assets, data systems and control centres. The SDSP acted as the central data hub for structured and unstructured information from market, network and asset sources. The flexibility registry was effectively the ledger of certified assets and their key characteristics, maintained by the relevant connecting system operator so that only technically suitable assets could participate in the market.

Local flexibility mechanism. Trading took place through a platform operated by EPEX SPOT, using local order books linked to defined market areas. EPEX SPOT's role was to provide a neutral and transparent exchange-like environment modelled on intraday trading rather than a bilateral contracting system. Only system operators bought flexibility; providers sold commitments to change generation or demand in order to relieve congestion. Importantly, the exchange did not perform every operational function. Asset registration, technical certification, measurement and some validation functions sat outside the exchange and were handled through the project's digital infrastructure and the relevant network operators.

Institutional significance. Enera combined advanced digitalisation with a formal market layer. That distinguishes it from simpler schemes based on bilateral procurement, utility administration, or network price signals. It was an explicit attempt to test whether a local congestion problem could be addressed through a transparent market structure, while still relying on extensive non-market infrastructure behind the scenes.

4. Flexibility service design

Roles and platform. The buyers of flexibility were the relevant DSOs and TSO; flexibility demand came from TenneT, Avacon Netz and EWE NETZ. EPEX SPOT operated the trading platform as a neutral intermediary. The connecting system operator was responsible for registering and certifying eligible assets, while onboarding of market participants to the exchange followed dedicated market access procedures. This means Enera was not a fully self-contained platform: the trading screen, technical qualification, and operational validation functions were distributed across different entities.

Product definition. The products were short-term congestion management products tied to local network geography. Trading was organised through 23 local market areas, broadly linked to high-voltage/medium-voltage substations, and the minimum tradeable unit was 15 minutes. The available activation horizon was short, broadly in the range of 15 minutes to one hour, consistent with the project's aim of providing near-real-time congestion management rather than long duration capacity procurement.

Participation and verification. Participation was in principle open to a wide range of flexible technologies, including wind, solar, biogas, storage, power-to-gas, power-to-heat and industrial demand-side assets. Aggregators were permitted. By late 2019, the project reported around 361 MW of certified capacity, including approximately 50 MW from demand-side flexibility. However, while participation rules were formally broad, the practical evidence suggests that participation was easier for larger and more sophisticated assets, and that community-style participation remained limited.

Verification, incompatibility and gaming. Verification did not rely on a single simple rule. For wind and solar, the project used weather-based baseline methods to estimate what output would have been without flexibility activation; for other technologies, measurement was compared against schedules provided by

flexibility providers. The project also had to address the risk of incompatible activations, because the same underlying asset might participate in more than one market or service. In that case, the flexibility service provider was responsible for avoiding double activation. Enera also developed an ex-post methodology for strategic behaviour that creates or exploits congestion to earn compensation, reflecting concern that market-based congestion management can create incentives for strategic behaviour if participants can profit from creating or exploiting congestion.

Key design lesson. Enera shows that a sophisticated local flexibility market requires far more than a trading interface. Asset registries, technical prequalification, baselining or telemetry methods, TSO-DSO coordination rules, and market surveillance arrangements were all central to making the pilot operationally credible.

5. Enablers, barriers, and pilot-to-scale pathway

Key enablers. The most important enablers were the project's end-to-end architecture: the SDSP data hub, the exchange platform, the flexibility registry, congestion forecasting and active network management capability, and explicit governance arrangements for coordination between the TSO and DSOs. Enera therefore created a full local flexibility environment rather than testing a market screen in isolation.

Main barriers. The main barriers were liquidity, participation cost, and regulatory fit. Recruiting flexibility providers proved difficult, partly because participation required technical onboarding, digital integration and certification. There were also regulatory barriers: a lasting market-based route for congestion management was not established in Germany, while subsequent reforms such as 'Redispatch 2.0'[19] took a more regulatory and conservative approach. Concerns about strategic bidding around congestion also weighed against straightforward scale-up of an open exchange-based model.

TSO-DSO coordination challenge. The project also highlighted the operational difficulty of coordinating system operators across voltage levels. There was a cascading, top-down coordination logic, in which upstream operators communicated congestion to downstream operators and downstream operators indicated the amount of flexibility available to support the upstream network. In practice, this meant downstream operators had priority over flexibility needed in their own networks, which is a critical institutional design issue for any multi-level flexibility market.

Pathway to scale. Enera remained a pilot and the platform was shut down in 2020 after the demonstration phase. Its value therefore lies less in proving a durable business-as-usual market and more in showing the institutional and digital conditions that would be required before an exchange-based congestion management mechanism could scale. In that sense, its legacy is both constructive and cautionary.

6. Outcomes and evidence

Evidence available. Enera is relatively well evidenced as a pilot. Project material reports around 250 participating plants, more than 100,000 kWh of flexibility delivered, around 4,000 bids and more than 130 transactions on the flexibility market.[20] Separate project documentation reports around 361 MW of certified flexible capacity by December 2019,[21] and EPEX SPOT reported a successful April 2020 field

[19] Redispatch 2.0 is Germany's formal congestion management regime. Rather than creating an open local flexibility market, it extends coordinated redispatch obligations and information exchange across grid levels so that network operators can manage bottlenecks in a more standardised, plan-based way.
[20] Enera. 2021. Project magazine, Final report of the consortium.
[21] Enera. 2020. Improving redispatch thanks to flexibility platform experience.

test in which 24 MW of flexibility was activated within one hour by Avacon Netz, EWE NETZ and TenneT in a coordinated manner.[22]

Interpretation. Enera demonstrated that a local flexibility market with exchange trading, asset certification, multi-operator coordination and real activations could be built and operated. It also showed that such a system can coordinate a substantial short-term flexibility activation in response to congestion risk.

Evidence caveat. The case is weaker as evidence of a readily scalable or easily replicable commercial model. The project ended as a pilot; settlement arrangements and long-run commercial rules are less clearly documented than the architecture and trading design; and the persistence of liquidity, cost and regulatory barriers means Enera should be read as an advanced demonstration rather than as proof that exchange-based local flexibility markets are straightforward to roll out at scale.

7. Transferable lessons for ASEAN

Replicable practice. Enera is most useful as a longer-term reference model for jurisdictions that may eventually want a formal, exchange-based local congestion market. Its main transferable insight is that market-based congestion management can, in principle, work across multiple technologies and network levels if the operational foundations are strong enough. Enera also demonstrates that exchange-based procurement does not remove the need for substantial non-market infrastructure 'behind the scenes.'

What needs adaptation. Most ASEAN systems would need a lighter first step. Bilateral or administered procurement, or utility-led flexibility, will usually be more realistic than immediate Enera-style exchange trading. The Enera model assumed deep digitalisation, explicit TSO-DSO coordination, a neutral market operator, and a relatively sophisticated group of flexibility providers. Those conditions will not exist in most ASEAN systems at the outset.

Minimum prerequisites and risks. The minimum prerequisites are deep enough digitalisation to observe local network conditions, a registry of qualified flexible assets, credible prequalification procedures, and clear rules for coordination across network operators. The principal risks are thin liquidity, high transaction costs, and strategic behaviour. Enera is therefore best treated as a model for where a system might go later, not as the default entry point for systems that are still building the foundations of flexibility.

[22] EPEX SPOT, 15 April 2020. Largest activation of flexibilities on enera market performed successfully.

Annex 1.4 Great Britain, Project TRANSITION

Years: 2017-2023

Geography: Oxfordshire

Lead entities: Scottish & Southern Electricity Networks (SSEN), with support from project partners including Northern Powergrid, Electricity North West, Elexon, Atkins and others

1. Problem addressed and new service created

System need. Project TRANSITION addressed the need for non-wires alternatives to conventional reinforcement as electrification, DER, and low-carbon technologies increased pressure on local networks. In the Great Britain (GB) context, this meant finding workable ways for a DSO to buy flexibility from third parties rather than automatically upgrading network assets.[23]

Service created. The project tested and then operationalised local flexibility procurement arrangements for DSO use, building on the Energy Networks Association's Open Networks programme. Open Networks was the cross-industry programme through which GB network operators developed common approaches to the transition from passive distribution network operation toward more active distribution system operation, including common flexibility products, commercial terms and interoperability work.

Why it matters for the playbook. TRANSITION is one of the clearest GB examples of trying to move local flexibility procurement from innovation trials toward business-as-usual operation. Its importance lies less in any single market event and more in the fact that it developed the commercial documents, platform logic, settlement processes and operational interfaces needed for repeatable DSO procurement.

2. Starting conditions and design drivers

Network context. The trials were run across different voltage levels and increasing technical and commercial complexity, including 132/33 kV Bulk Supply Points (BSP) and 33/11 kV primary substations. Oxfordshire was chosen after a multi-criteria site-selection exercise because it offered a useful combination of relatively high congestion relevance, strong interconnection between key substations, a diverse mix of domestic, commercial and industrial load, and synergies with other local smart energy projects.

Digital and institutional baseline. TRANSITION did not start from a blank page. It sat alongside wider DSO transition work on forecasting, network modelling, baselining, platforms, and standardisation. It also ran alongside other GB innovation projects on forecasting and flexibility market processes, and drew on that wider work rather than developing every tool from scratch. That wider programme context matters because TRANSITION was not simply testing a marketplace interface; it was developing the broader tools and rules needed to make DSO flexibility procurement credible.

Design implication. The project ran through three market trial periods (TP1 to TP3), each increasing in scope and complexity, followed by a technical trial. By the final market trial, the project had expanded the number of market participants, procurement horizons and locations, and had started to test service stacking and different routes to market. This makes TRANSITION better understood as a late-stage operational trial designed to inform business-as-usual arrangements, rather than as an initial proof-of-concept exercise.

[23] SSEN.2023. Electricity Network Competition, SSEN05 Project Transition.

3. Intervention overview: smart grid enablers and local flexibility mechanism

Smart grid enablers. The enabling mechanisms included forecasting tools, a digital network model, power system analysis tools, metering and monitoring, baselining methods, and settlement processes. Additional low-voltage monitoring was introduced for verification, while forecasting work helped identify flexibility needs across both short-term and near-real-time horizons.

Local flexibility mechanism. The project tested a Neutral Market Facilitator (NMF) model. In practical terms, the NMF was a central market and process layer through which flexibility providers could register assets, qualify, contract, receive dispatch instructions and settle with the DSO on a non-discriminatory basis. TRANSITION also tested interaction with Piclo, an independent flexibility marketplace used by GB network operators to advertise and procure flexibility opportunities. By linking NMF and Piclo, the project explored whether more than one marketplace interface could coexist and whether this improved participation and liquidity.

Institutional significance. The practical contribution of TRANSITION was to convert policy ambition into usable market processes. It developed market rules, service descriptions, registration and qualification steps, baselining options, settlement logic, price evaluation methods, and interoperability arrangements that were directly relevant to later GB flexibility market standardisation.

4. Flexibility service design

Roles and platform. The DSO procured flexibility services. The platform layer supported provider registration, qualification, contracting, dispatch and settlement. The NMF served as the core facilitated market process, while Piclo acted as an additional route to market for some products, especially peak management services. TRANSITION was testing not only products, but also how a DSO might interact with more than one market interface.

Product definition. The project tested several flexibility products linked to distinct network needs:

- Peak demand management, typically linked to winter evening peaks, procured on season-ahead, week-ahead and day-ahead horizons;
- Generation peak management, aimed at periods of high export such as summer solar output, procured on week-ahead and day-ahead horizons;
- Network constraint management, procured around forecast constraints;
- Outage-related services, intended to support restoration or manage conditions following unplanned outages.

Response times varied by product, broadly from 30 minutes to 12 hours, and products could involve either upward or downward flexibility depending on the service.

Procurement and pricing. Across the three market trial periods, the project ran 412 auctions. Services were procured across seasonal, week-ahead, day-ahead and shorter horizons depending on the product. Payments combined availability and utilisation elements, with a ceiling price linked to the avoided cost of reinforcement using the Electricity Network Association's 'Common Evaluation Methodology' cost-benefit framework. The project increased the price cap between trial periods when early evidence suggested that initial values were too low to stimulate participation.

Participation and verification. Participation broadened over time and aggregators became more important as the trials matured. Technologies included batteries, solar PV, EVs, vehicle-to-grid, demand-

side response, hydro and heat pumps. Community and locally owned assets also participated, including a community-run DER portfolio and a large community-owned solar park. Verification relied on metering data and two alternative baseline approaches: a historical baseline based on past usage patterns, and a nominated baseline provided by the participant. Settlement was monthly following DSO-calculated event results. The project also refined practical participation rules. These included rules on declaring asset unavailability, submitting metering data in consistent time-stamped formats for settlement, and checking that assets could provide a minimum credible level of service before taking part.

Key design lesson. TRANSITION showed that an effective local flexibility market depends on product design, qualification rules, baseline methodology, dispatch logic, settlement rules, contract structure, and the ability to integrate DSO and market-facing systems without excessive transaction cost. That is why the project's outputs were as much about process design and standardisation as about procurement itself.

5. Enablers, barriers, and pilot-to-scale pathway

Key enablers. TRANSITION produced several outputs that were directly useful beyond the project: commercial templates and market rules, a facilitated platform architecture, a ceiling price evaluation method, a system-coordination approach, a network model, forecasting tools, and select-and-dispatch logic. In that sense, it was a system-building project as much as a market trial.

Main barriers. Liquidity remained a recurring problem. The project found that participation was constrained by contract complexity, the need to integrate different DSO, platform and data systems through automated digital interfaces, relatively high participation costs compared with expected revenue, and initially limited aggregator involvement. This helps explain why some markets remained thin: providers faced non-trivial enablement costs and uncertain revenues, particularly for smaller assets. TRANSITION's own learning materials note that liquidity improved after aggregators were brought in more fully, but did not become deep enough for strong price discovery.

Pathway to scale. The project helped move local flexibility toward business-as-usual by testing end-to-end market processes in real conditions and feeding those lessons into wider GB standardisation work. But it also showed that a technically sound platform does not, by itself, create a liquid market. Commercial simplicity, interoperable systems, and early aggregator involvement matter just as much as the platform architecture.

6. Outcomes and evidence

Evidence available. TRANSITION is well evidenced by trial period reports and close-down documentation. Across the three market trial periods, the scale of procured flexibility increased materially, from around 750 kW tendered in Trial Period 1 (TP1), the first market trial, to around 49 MW in Trial Period 3 (TP3), the final and most advanced market trial.

What the evidence shows. The strongest evidence is not that TRANSITION created a highly liquid market, but that it created and tested the architecture, documentation and processes needed for DSO-led flexibility procurement. Participation was stronger in week-ahead auctions than in season-ahead or day-ahead auctions, likely because these gave providers a better balance between certainty and effort. In the final trial period, peak management and secure constraint services attracted more contracts than import/export capacity products. Also, in TP3, BSP-level auctions generally attracted responses more often than primary-substation auctions, but primary-substation auctions sometimes achieved a higher proportion of the requested volume when they did receive bids. The project attributes this partly to SSEN requesting much larger volumes at BSP-level to ensure all DERs had a chance to participate, whereas some primary-level auctions were smaller and more targeted.

Evidence caveat. TRANSITION should not be read as proof that local flexibility markets naturally become liquid once a platform is in place. Market depth remained limited, fulfilment was uneven, and price discovery was often weak because bids tended to cluster near the ceiling price in thin markets. The project is therefore best understood as a case of system-building and standardisation, rather than as evidence of a mature and self-sustaining local market.

7. Transferable lessons for ASEAN

Replicable practice. The most transferable elements are standardised products, relatively simple contractual pathways, a clear route for aggregators, and a transparent willingness to pay ceiling linked to avoided reinforcement costs. Those features can make local flexibility procurement workable even before a highly liquid market exists. It is therefore better understood as a system-building case than as evidence that local flexibility markets naturally become liquid once launched.

What needs adaptation. In vertically integrated settings, the same functions may sit within one utility rather than across a DSO, neutral facilitator and separate marketplace. But the underlying design challenge remains: the buyer must be able to define local needs, qualify providers, dispatch services, and verify delivery at manageable cost. Piclo-like marketplace functionality is not essential at the outset; what matters first is a clear and workable end-to-end process.

Minimum prerequisites and risks. A working network model, sufficiently granular data, a verification method, and a clear route for cost recovery of procured flexibility are the minimum requirements. The main risks are thin liquidity, excessive contractual and IT complexity, and weak economics for smaller providers unless aggregators or other intermediaries are involved early.

Annex 1.5 India, Urja Arpan Scheme

Years: 2022 onward

Geography: New Delhi, India

Lead entities: Tata Power Delhi Distribution Limited

1. Problem addressed and new service created

System need. Peak electricity demand has reached record levels in New Delhi, especially during summer months. This is driven largely by widespread use of air conditioning during evening hours when residents return home from work. These coincident peak places significant stress on the distribution network and increases reliance on peaking generation, including fossil fuel-based supply resources.

Service created. TPDDL, a major distribution utility serving approximately 2 million customers[24], launched the Urja Arpan pilot programme. The initiative targets primarily residential, and some commercial, consumers, encouraging voluntary reduction or shifting of electricity use during peak periods through behavioural demand response. Demand response events typically last around two hours and are communicated via existing utility communication channels, including SMS and other digital platforms.

Why it matters for the playbook. The project shows how utility-led, low-cost solutions can elicit flexibility within existing technology frameworks provided proper customer engagement and awareness is focused upon.

2. Starting conditions and design drivers

Network context. The Department of Power in New Delhi advised its four utilities to plan for a 9 GW peak load in summer 2025. Delhi's demand is around two-thirds residential, with roughly half driven by cooling. The number of air conditioners is projected to reach 4.6 million by 2030, adding an estimated 2.5 - 4.5 GW to peak residential demand[25].

Market and digital baseline. TPDDL is one of the major distribution service companies in New Delhi with a customer base of 2 million. The scheme employed about 100,000[26] customers with existing smart metering facility.

Scale and maturity. The pilot of Urja Arpan started in 2022 with scaled enrolment taking off in mid-2023.

3. Intervention overview: smart grid enablers and local flexibility mechanism

Smart grid enablers. The scheme focused on engaging customers to switch consumption away from peak hours with the key message of environmental consciousness. The message was delivered via customer awareness programmes, in schools and through residential and commercial associations.

Local flexibility mechanism. The scheme utilised behavioural demand response implemented by the utility. In practice this was done by TPDDL identifying peak-demand periods and issuing event notifications to customers with smart meters, requesting voluntary load reduction or shifting. Flexibility was coordinated directly by the utility rather than through a marketplace. Participation was non-

[24] TPDDL website, accessed May 2026
[25] Anto, Robins, et al. 2026. "Leveraging Enhanced Consumer Engagement to Achieve Demand Response and Flexibility in an Indian Energy Community." Utilities Policy, vol. 98, p. 102077. https://doi.org/10.1016/j.jup.2025.102077
[26] Ibid.

contractual and primarily encouraged through behavioural engagement, customer awareness campaigns, and limited recognition instead of formal market payments.

Institutional design choice. Initial enrolment in the programme was limited following its 2022 launch but participation increased significantly after enhanced utility-led engagement efforts. Between April and July 2023, commercial enrolment rose from 16,000 to 30,000 customers and residential participation increased from 44,000 to 70,000 customers[27].

4. Flexibility service design

Programme Design. Urja Arpan is a utility-led behavioural demand response programme designed as an event-based flexibility service, where the utility identifies peak demand periods and notifies the participating smart-meter enabled customers to reduce load on a voluntary basis.

Customer participation model. The scheme is open to residential, commercial, and industrial customers with smart meters. Participation is non-contractual and does not rely on direct financial compensation. Instead, customers are enrolled through utility engagement processes and respond to peak-event notifications delivered via SMS, mobile messaging, and digital communication channels.

Customer outreach. Customer outreach is delivered through existing utility communication infrastructure, as well as broader engagement platforms such as school campaigns, residential association outreach, and community engagement programmes. In addition, participants are invited to regular consumer conferences and meetings, where awards and recognition are presented to sustain engagement and encourage continued participation in the demand response events.

5. Enablers, barriers, and pilot-to-scale pathway

Key enablers. Key enablers include the existing rollout of smart meters, which allowed the utility to identify participating consumers, and TPDDL's established customer engagement infrastructure. Additionally, broader policy and public discourse around sustainability, energy conservation, and responsible electricity consumption helped support customer participation and behavioural engagement.

Main barriers. Key barriers include the voluntary and behavioural nature of participation, which can create uncertainty around the reliability and predictability of delivered flexibility during peak events.

6. Outcomes and evidence

Evidence available. In 2022 the demand response programme accumulated 7.69 MW of flexibility achieved through the participation of 1,990 consumers. By 2024, this accumulated flexibility was 560 MW achieved through approximately 91,000 unique consumers participating in demand response events[28]. The estimated savings is calculated using difference to baseline wherein baseline refers to the average of the past 10 days' peak usage before the demand response event.

7. Transferable lessons for ASEAN

Replicable practice. The Urja Arpan scheme demonstrates that utilities can deploy behavioural demand response using existing smart meters and established communication channels. Core practices that are

[27] Ibid.
[28] Ibid.

directly transferable to ASEAN include peak demand signalling, large-scale customer engagement through digital platforms, and the use of community outreach.

Customer engagement. In ASEAN contexts, similar schemes would need adaptation to reflect differences in tariff structures, regulatory frameworks, and levels of smart meter rollout. Behavioural programmes particularly, might need to be combined with clearer price signals or modest financial incentives in markets where consumer responsiveness to non-monetary engagement is lower.

Minimum prerequisites and risks. Minimum prerequisites include at least partial smart metering roll out, reliable customer communication infrastructure, and utility's capability to forecast peak events. Key risks include uncertain and non-firm flexibility delivery due to voluntary participation.

Annex 1.6 Malaysia, Smart Green Island (Pulau Tenaga Hijau) Project

Years: Ongoing

Geography: Off-grid islands including Pulau Perhentian, Pulau Redang and Pulau Tioman

Lead entities involved: Ministry of Natural Resources and Environment and Climate Change in collaboration with the Energy Commission, TNB

1. Problem addressed and new service created

System need. Malaysia's small islands are electrically isolated systems that have historically depended heavily on diesel generation. That creates high fuel and logistics costs, exposure to fuel price volatility, and reliability risks as demand rises with tourism and local economic activity. Official project material presents Pulau Tenaga Hijau (PTH) as a response to these conditions through a cleaner and more reliable electricity supply model for remote islands.

Service created. PTH is best understood not as a local flexibility market but as an infrastructure-led flexibility scheme. It combines renewable generation, battery storage and centralised smart grid control to provide operational flexibility within island microgrids. The formal project objectives are to enhance system reliability, apply smart grid technology, and reduce operating cost through greater use of RE sources. TNB's project description also highlights the introduction of Energy Storage Systems (ESS) and an EMS to coordinate storage and generation resources.

Why it matters for the playbook. The case is useful because it shows that in weak-grid or off-grid settings, flexibility may first emerge through utility-led hybrid optimisation rather than through a market mechanism. In other words, the first flexibility service is operational balancing inside the microgrid itself, not a tradeable local product. The case also broadens the playbook's use of the term 'local' beyond feeders and substations to include island systems and microgrids as legitimate units of flexibility analysis.

2. Starting conditions and design drivers

Network context. The project covers isolated island systems rather than feeders on an interconnected mainland grid. TNB states that it supplies Pulau Perhentian and Pulau Redang using diesel generation rated at 1,400 kW and 2,000 kW respectively, while hotels, chalets and resorts on those islands have also relied on private generators with additional capacity. This matters because the relevant design unit is the island microgrid as a whole, not a feeder-level congestion zone.[29]

Market and governance context. This is a vertically integrated utility environment. Official materials identify the Energy Commission as lead agency and TNB Distribution Network as implementing agency, with no published aggregator framework or local flexibility procurement model. That naturally favours centralised planning and dispatch rather than competitive flexibility acquisition.

Design implication. Because the problem is island-wide balancing, reliability and fuel displacement, the design centres on coordinated dispatch of generation and storage assets across the microgrid. The case is therefore closer to a smart, utility-operated hybrid system than to a feeder-based local flexibility market.

[29] TNB. Green Energy | Smart Green Island (Pulau Tenaga Hijau), accessed February 2026.

3. Intervention overview: smart grid enablers and local flexibility mechanism

Smart grid enablers. The core enablers are ESS, an EMS, and broader smart grid upgrades that improve visibility and controllability across the island systems. In this context, ESS refers to battery storage used to absorb and release energy as system conditions change, while EMS refers to the central control system used to optimise dispatch across generation and storage assets. TNB describes the project as introducing ESS and EMS to improve interoperability between storage and generation systems.

Local flexibility mechanism. There is no local flexibility market, auction or competitive procurement arrangement. Flexibility is delivered through centrally controlled optimisation and dispatch of storage and generation assets within the island systems. TNB, as system owner and operator, makes the balancing and dispatch decisions directly.

Operational logic. The relevant service is therefore internal operational flexibility: balancing variable renewable output, smoothing ramps, reducing reliance on fossil generation, and supporting stable operation of isolated microgrids. In practical terms, the project uses storage and control systems to improve how the island system responds to changing load and renewable output, rather than paying third parties to provide a formal flexibility product.

4. Flexibility service design

Roles and platform. The buyer, asset owner and activation authority is effectively TNB, acting as utility operator within the island systems. There is no independent market platform or intermediary. Dispatch, validation and performance monitoring appear to sit within utility operations rather than in an external settlement or procurement system.

Product definition. Although flexibility is not formalised as tradeable products, the services delivered can still be described functionally. These include island-wide balancing, renewable smoothing, ramp management, peak reduction, and reliability support. Because the islands are isolated systems, these services are defined at the microgrid level rather than by feeder or substation zones.

Evidence on assets deployed. Official TNB material confirms deployment of a 2 MWh battery energy storage system and, by 2025, five community energy storage systems (CESS) rated at 150 kW / 430 kWh across Pulau Perhentian, Pulau Redang and Pulau Tioman. TNB also reports broader renewable and smart grid investments under the project, including building-integrated solar PV installations on public sites and the planned implementation of EMS on Tioman. TNB further reports a 676.27 kWp solar PV system at four Tioman locations, generating 313 MWh as of August 2025[30, 31]

Procurement and pricing. The assets appear to be deployed directly by TNB under a programme model rather than procured through a flexibility-specific payment structure. Consumers remain on the prevailing regulated tariff, and there is no published indication of separate availability or utilisation payments for flexibility.

Boundary of the case. This is best described as a utility-operated operational flexibility model, not a demonstrated local market or community trading scheme. While consumers and local businesses may benefit from improved reliability and cleaner supply, the public evidence does not show a formal mechanism for third-party flexibility bidding or community-led dispatch.

[30] TNB. Green Energy | Smart Green Island (Pulau Tenaga Hijau), accessed February 2026, and TNB. Energy Storage Solutions, accessed February 2026.
[31] Ibid and TNB. 2024. Sustainability Report.

5. Enablers, barriers, and pilot-to-scale pathway

Key enablers. The main enablers are utility control over planning and dispatch, a public policy mandate to improve island electrification, and capital investment in storage, renewables and digital control systems. In this setting, vertical integration is an advantage because it allows the implementing utility to combine network operation, generation planning and operational optimisation within one delivery model.

Main barriers. The clearest barrier is capital intensity. Island decarbonisation through hybrid systems requires significant upfront investment in storage, renewable generation, control systems and supporting infrastructure. A second operational challenge is the complexity of integrating multiple generation types and standby assets while maintaining stable supply in isolated systems with growing and seasonal demand.

Pathway to scale. The available evidence suggests that the scaling logic is geographic replication rather than market deepening. In other words, the model is to replicate the hybrid architecture across more island systems, improve visibility and control, and deepen renewable integration over time. That is an inference from the way the project is described and implemented across multiple islands, rather than a formally published 'market roadmap.'

6. Outcomes and evidence

Evidence available. The strongest public evidence concerns programme objectives and asset deployment, rather than audited operating outcomes or quantified market results. Official sources confirm the project's three formal objectives, island coverage, the role of TNB as implementing agency, and the deployment of storage and smart grid components. TNB also reports specific project assets including the 2 MWh BESS, five CESS units, building-integrated PV installations, and the Tioman solar deployment.

Evidence caveat. The public record is much stronger on what has been installed and what the project is trying to achieve than on audited operational outcomes such as reliability improvement, fuel savings, renewable curtailment reduction or comparative system costs. The case is therefore evidence of a utility-led smart grid flexibility pathway for island systems, rather than a fully quantified performance case.

7. Transferable lessons for ASEAN

Replicable practice. For islanded or weak-grid systems, the most transferable lesson is to start with EMS-enabled hybrid optimisation, storage-backed balancing and improved system visibility before introducing any formal market layer. This is especially relevant where the immediate challenge is reliability and diesel displacement rather than local market design.

What needs adaptation. In more liberalised power sectors, the same technical architecture could eventually coexist with third-party service provision. But that is a later-stage option, not a prerequisite. The Malaysia case suggests that centralised utility dispatch can be an effective first step where systems are small, isolated and operationally fragile.

Minimum prerequisites and risks. The minimum requirements are clear dispatch authority, sufficient operational visibility, and a viable cost recovery route for storage and control infrastructure. The main risks are high upfront cost, implementation complexity, and the challenge of integrating multiple resources in isolated systems without strong operational coordination.

Annex 1.7 New Zealand, Resi-Flex (Residential Flexibility)

Years: 2022-2027

Geography: Orion (Central Canterbury, including Christchurch) and Wellington Electricity service areas

Lead entities: Orion, Wellington Electricity, Octopus Energy, Ecotricity

1. Problem addressed and new service created

System need. Rapid electrification, especially growing EV uptake and additional residential electric load, is expected to create local congestion and make winter peak management more difficult on distribution networks. New Zealand distribution companies already rely on legacy ripple-controlled hot water load for some peak management, but that tool is not sufficient on its own to address emerging flexibility needs associated with EVs, household batteries and changing residential demand patterns.

Service created. Resi-Flex develops and trials residential flexibility services aimed at low-voltage peak reduction and congestion management through three main routes: behavioural demand reduction events, managed EV charging, and battery-enabled export during peak windows. Rather than creating an open local flexibility market, the project uses retailer-partnered offers to test which commercial mechanisms can induce useful household flexibility.

Why it matters for the playbook. The scheme is useful because it shows a practical route for unlocking residential flexibility before moving to a more formal local procurement model. It does so through customer offers delivered by retailers or other flexibility partners, while the distribution companies learn which products, payment structures and verification methods are capable of producing network-relevant response.

2. Starting conditions and design drivers

Network and market context. The project focuses on constrained or potentially constrained low-voltage areas within the Orion and Wellington Electricity networks. New Zealand's competitive retail structure made it feasible to trial retailer-led flexibility offers, while the distribution companies retained responsibility for identifying the local network use cases they wanted flexibility to address.

Digital and commercial baseline. A strong metering base was already in place. New Zealand has very high smart meter penetration (around 95%+ of consumers) which makes household-level flexibility measurement much more feasible than in many jurisdictions. Resi-Flex proceeded as an innovation-led, learning-by-doing programme rather than as a settled procurement regime.[32]

Scale and maturity. The project has moved through a staged pathway. Phase 1 identified user requirements and priority network use cases. Phase 2 focused on commercial mechanisms and the barriers to residential flexibility. Phase 3 moved into trial design and live testing, with Phase 3a completing a first set of customer trials and Phase 3b moving toward a larger-scale rollout. Orion's February 2026 report states that Phase 3a is complete and Phase 3b is in progress. This makes Resi-Flex better understood as a structured trial programme designed to identify scalable commercial models, rather than as a business-as-usual flexibility service.

Practical design driver. The design deliberately emphasised customer-facing simplicity. Households receive a familiar offer from a retailer or flexibility partner (such as a savings event, managed charging

[32] Orion. 2026. Resi-Flex Phase 3 Report and Orion, Resi-Flex project web page.

arrangement or premium export rate) rather than being asked to participate directly in a local market. The distribution companies then assess whether those offers produce flexibility of a kind and scale that is actually useful for the network.

3. Intervention overview: smart grid enablers and local flexibility mechanism

Smart grid enablers. The essential enablers are interval metering, baseline analytics, device-specific telemetry for EVs and batteries, and the ability of retailers or flexibility partners to send event signals or charging instructions to customers and devices. In practice, this means the project relies on smart meter data to measure household response, and on partner systems to deliver signals such as demand response events, charging schedules or export incentives.

Local flexibility mechanism. Resi-Flex is not an open local market. It is a set of administered retailer-partnered flexibility programmes in which the distribution company identifies network-relevant use cases and retailers translate those into customer offers. The retailer or partner handles customer recruitment and communication, while the distribution business evaluates whether the response delivered useful peak reduction, load shifting or export support.

Commercial logic. This design keeps customer engagement relatively simple and uses existing retail relationships rather than requiring households to learn a new market interface. It also allows the distribution business to test several commercial mechanisms in parallel and compare which ones are most effective for network purposes at acceptable transaction cost.

4. Flexibility service design

Roles and platform. The distribution business defines the network use case, supports trial design and evaluates the results. Retailer or flexibility partners recruit customers, communicate event instructions or charging settings, and provide the customer-facing offer. Settlement and analysis rely on baselines or metered outcomes rather than on a dedicated market platform.

Product definition. The core products tested are:

- behavioural demand reduction events during morning or evening peaks;
- managed EV charging, designed to shift charging away from peak windows; and
- battery-enabled export during peak periods, supported by a premium export payment.

Here, the premium export payment means a trial export rate above the normal export credit, offered to encourage battery-equipped households to export at times when that support is useful for the local network. In the Ecotricity-linked trial, customers receive 60c/kWh during the relevant peak export periods, with Ecotricity contributing 51c and Orion contributing 9c.[33]

Procurement and pricing. The Phase 3 report describes:

- Savings Sessions: direct payments of NZD 3/kWh saved against baseline;
- Shift to Win: customers who save against baseline are entered into a NZD 50 prize draw rather than paid per kWh;

[33] Ecotricity, Resi-Flex project web page.

- Managed EV charging: a 5c/kWh network contribution from Orion plus NZD 10 per month from Octopus; and
- Battery-supported peak export: a 60c/kWh peak export incentive.[34]

Savings Sessions and Shift to Win are therefore simply two different ways of rewarding behavioural demand reduction: one through direct pay-for-performance, the other through lottery-style rewards.

Participation route. Participation is through retailer or partner offers rather than direct bids into a local platform. In this context, the partners are mainly retailers and other customer-facing flexibility providers able to recruit households, communicate events, and access the relevant device or metering data.

5. Enablers, barriers, and pilot-to-scale pathway

Key enablers. High smart meter penetration, retailer partnerships, and a phased innovation framework all supported implementation. Just as importantly, the project had a governance pathway through New Zealand's regulatory allowance processes, which helped move it from early design into larger live trials.

Main barriers. The Phase 3 material points to several barriers to wider rollout: limits on direct device control, complexity in sharing value across the retail and network layers, limited volumes of controllable household load, and the importance of customer trust and engagement. There is also a risk of secondary peaks if many customers shift in the same direction at the same time. A further challenge is the value stack: residential flexibility can create value for the network, the retailer and sometimes the customer at the same time, but the project still has to work out how that value is shared cleanly enough for each party to stay engaged.

Pathway to scale. Resi-Flex has progressed from user research to commercial mechanism design and then to live customer trials. The next scaling question is therefore not whether residential flexibility exists, but which customer offer, verification method and settlement model can scale at acceptable transaction cost.

6. Outcomes and evidence

Evidence available. Resi-Flex now has a relatively good public evidence base. Orion's February 2026 Phase 3 report provides concrete trial results for behavioural demand response, managed EV charging and the battery export offer. It reports that Savings Sessions delivered average savings of around 0.71 kW in morning events and 0.84 kW in evening events. It also reports that managed EV charging shifted 97% of charging outside Orion's peak windows. The report also gives indicative participation figures across the streams, including substantial enrolment in the behavioural programmes, more limited participation in managed EV charging, and an ongoing battery export trial.

Evidence caveat. Resi-Flex remains a trial-and-learning programme rather than a business-as-usual flexibility market. The evidence is strongest on customer response to different commercial mechanisms and on the operational feasibility of retailer-partnered delivery. It is less definitive on long-run commercial scaling, enduring settlement rules, or full value stack integration between network and retail layers.

7. Transferable lessons for ASEAN

Replicable practice. A strong early option for ASEAN is to begin with administered programmes in constrained low-voltage areas: simple savings events, managed EV charging and premium export tariffs

[34] Orion. 2026. op. cit., Orion, Resi-Flex project web page, and Octopus Energy programme web page.

for households with batteries. The main point is to start with offers that households can understand easily and that can be delivered through a trusted intermediary. Its strongest lesson is that residential flexibility often becomes workable through familiar customer offers and trusted intermediaries before it becomes workable through formal market participation.

What needs adaptation. Where competitive retailers are absent, utilities can appoint one or more partners to perform the same customer-facing role. The design principle is to minimise friction for households while still generating flexibility that is relevant to the network.

Minimum prerequisites and risks. The minimum requirements are interval metering, enough device telemetry to verify EV or battery response, and a basic consumer protection framework so customers understand how they are rewarded and what control arrangements apply. The main risks are low participation, secondary peaks, weak customer trust, and difficulty in sharing flexibility value clearly across the network, retail and customer layers.



The ASEAN-UK Green Transition Fund (GTF) is the UK's flagship programme to accelerate ASEAN's transition to a clean and climate resilient economy. ASEAN UK GTF works with ASEAN institutions and supports ASEAN Member States. This programme is delivered through the UK Partnering for Accelerated Climate Transition (UK PACT) mechanism.

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