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FACILITATING THE CROSS-BORDER PROVISION OF ANCILLARY SERVICES IN THE ASEAN POWER GRID

Green Grids Rising
ASEAN-UK Green Transition Fund

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KPMG

Forewords

The ASEAN Power Grid has the potential to deliver far more than increased electricity trade. As regional interconnections increase, they can also provide new opportunities to strengthen energy security, enhance system resilience, and support decarbonisation across ASEAN. The *Cross-Border Provision of Ancillary Services Playbook* explores how these wider benefits can be realised through greater regional cooperation and more efficient use o interconnected power systems.

Bringing this Playbook to fruition has required both strong regional leadership and technical expertise. I would like to recognise the ASEAN Secretariat, the ASEAN Centre for Energy, and the Heads of ASEAN Power Utilities/Authorities for guiding this work, while also thanking Economic Consulting Associates, KPMG Malaysia, Castlerock Consulting, and Palladium for their valuable technical contributions. Their shared commitment to regional cooperation has resulted in a practical resource that will help guide policymakers, regulators and system operators as ASEAN's power systems become increasingly interconnected.

Cross-border ancillary services can play an important role in supporting a more flexible and reliable power system, particularly as renewable energy deployment accelerates across the region. The Playbook highlights the opportunities that cross-border ancillary services can offer in maximising the value of regional interconnections and supporting more flexible power systems, including identifying the right model for the stage of market development. It also demonstrates the benefits of regional cooperation and shared learning in advancing a more connected ASEAN power system.

The opportunities presented by cross-border ancillary services demonstrate the broader potential of the ASEAN Power Grid as a platform for deeper regional cooperation. The UK is proud to support this journey and remains committed to partnering with ASEAN in accelerating ASEAN Power Grid development and supporting the practical measures needed to realise its full potential. Together, we can build a more secure, reliable and low-carbon energy future for the region.

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

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The Playbook has benefited immensely from the contributions of representatives of the Heads of ASEAN Power Utilities/Authorities (HAPUA) who provided technical insights through workshops and consultations undertaken as part of the Green Grids Rising programme. These contributions have been invaluable in grounding the playbook in the diverse circumstances, opportunities and challenges faced by power systems across the region.

The contributions of technical experts, regional and international partners, and other stakeholders who shared their knowledge and perspectives throughout the development of the playbook are also gratefully acknowledged.

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Abbreviations and acronyms

ACE	ASEAN Centre for Energy
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AMS	ASEAN Member States
AOF	Activation Optimisation Function
APAEC	ASEAN Plan of Action for Energy Cooperation
APG	ASEAN Power Grid
ASAPP	Ancillary Service Agreement Procurement Plan
ASPA	Ancillary Service Procurement Agreement(s)
BALIT	BALancing Inter-TSOs
BESS	Battery energy storage system(s)
BM	Balancing market
BOT	Build-operate-transfer
BPC	Berakas Power Company
BSS	Black start service
BSP	Balancing Service Providers
CA	Control Areas
CR	Contingency reserve
DAM	Day-ahead market
DES	Department of Electrical Services (Brunei)
DR	Dispatchable reserve
EBGL	Electricity Balancing Guidelines (EU)
EDC	Electricité du Cambodge
EDL	Électricité du Laos
EDTL	Electricidade de Timor-Leste
EE&C	Energy Efficiency and Conservation
EGAT	Electricity Generating Authority of Thailand
EMS	Energy management systems
EOR	Regional Operator (SIEPAC)
EPGE	Electric Power Generation Enterprise (Myanmar)
ERC	Energy Regulatory Commission (Philippines)

EVN	Viet Nam electricity
FCR	Frequency Containment Reserves
FERC	Federal Energy Regulatory Commission
FTR	Financial Transmission Rights
GTF	ASEAN-UK Green Transition Fund
HAPUA	Heads of ASEAN Power Utilities/Authorities
IDA	Intra-day market
IPP	Independent power producer
ISO	Independent system operator
LTMS-PIP	Laos-Thailand-Malaysia-Singapore Power Integration Project
LV	Low voltage
MEAS	Mutual Emergency Assistance Systems
MOEP	Ministry of Electric Power (Myanmar)
NEM	National Electricity Market (Australia)
NEMS	National Electricity Market of Singapore
NERC	North American Electricity Reliability Corporation
NLDC	National Load Dispatch Centre (Viet Nam)
NPT	National Power Transmission Company (part of EVN)
NYISO	New York Independent System Operator
OCGT	Open Cycle Gas Turbine
PEA	Provincial Electricity Authority
PLN	Perusahaan Listrik Negara
PPA	Power purchase agreements
RAA	Reliability Assurance Agreements
RE	Renewable Energy
RPS	Reactive power support
RR	Regulating reserve
RepR	Replacement reserves
RSA	Reserve Sharing Agreements
RTO	Regional Transmission Organisation
SADC	Southern African Development Community
SAPP	Southern African Power Pool
SIEPAC	Central American Electrical Interconnection System

TNB	Tenaga Nasional Bhd
TSO	Transmission System Operators
VRE	Variable renewable energy
WSEM	Wholesale electricity spot market

Executive summary

Purpose of the playbook

ASEAN should ensure that regional power trade is not limited to the flow of electricity, but also embrace the potential for reserves to be shared across borders. This playbook sets out how ASEAN Member States (AMS) can leverage interconnectors, including those being developed under the ASEAN Power Grid (APG) to share ancillary services, predominantly in the form of frequency control and response, between systems. Doing so will support the integration of higher levels of variable renewable energy (VRE), aiding national and regional climate ambitions, while improving the resilience of the grid and lowering overall system costs.

The playbook focuses on models for the cross-border trade of ancillary services suitable to the ASEAN context. It shows that countries do not require established, formal markets for ancillary services to be able to share and trade reserves across borders. Even comparatively simple models for sharing can bring about material cost savings and benefits to both systems by reducing the level of reserves that need to be maintained across the two systems. Delivering such trade does not necessarily require the establishment of new institutions and regional entities; significant gains can be unlocked through transmission system operators coordinating with each other.

The key recommendation is therefore to mainstream the consideration of reserves and ancillary services into discussions and plans on regional trade and the development of the APG as a core enabler of renewable-energy integration and power-sector decarbonisation.

Why this matters for ASEAN now

Ancillary services are increasingly importance to ASEAN power systems as the share of VRE in grids increases. Even where ancillary services are only defined informally, they play a critical role in maintain frequency and voltage control. As the share of VRE generation rises there is a growing need for ancillary services to respond to fluctuations in supply and compensate for the increase of generators which are not synchronised to the grid and unable to provide inertia. Without access to flexibility resources, higher renewable-energy deployment can become constrained, leading to continued dependence on fossil generators for balancing. The cross-border provision of ancillary services thus should be viewed as a strategic decarbonisation tool, enabling ASEAN power systems to integrate higher shares of renewable energy while reducing reliance on fossil-fuel-based generators for reserves and frequency control.

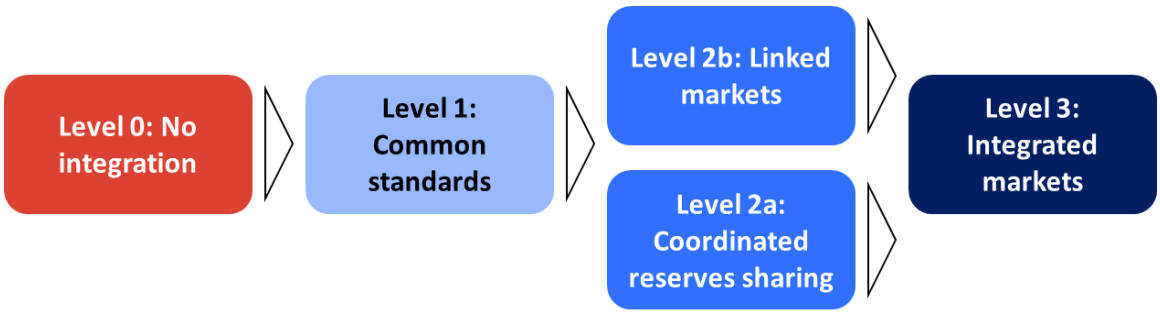
ASEAN is also advancing regional trade, including through the development of the APG. Introducing cross-border trading of ancillary services can support these efforts. It also offers an additional value stream for interconnectors, potentially supporting the development of business cases for the development of candidate APG projects.

This diversity of ASEAN power markets means that ASEAN does not require an integrated market or a single model for trade but instead a practical framework for trading ancillary services.

Models for cross-border sharing of reserves

This playbook outlines three different levels of integration for the sharing of ancillary services. The typology sets out five stylised models for the sharing of ancillary services, as shown in the figure below, which have been derived from a review of international experience in the cross-border trade of ancillary services and sharing of reserves. This review considers both developed and developing markets, including how the models in these countries has evolved over time. A particular focus is on identifying the institutional and commercial arrangements which underpin these models.

Stylised overview of different levels of ancillary service integration



The playbook shows that in **many cases the sharing of reserves commences through the establishment of common standards between synchronised grids**, with rules in place to prevent one system 'free-riding' on the reserves of another. **Such a model does not require formal market arrangements and is relatively simple to implement.**

The next stage requires closer coordination between TSOs on the sharing of reserves. This can be achieved either through close coordination between TSOs, allowing for the establishment of joint schedules or re-dispatch to optimise the sharing of reserves, or be coordinated through market mechanisms. The final stage in this stylised typology is an integrated market, in which energy and reserves, and their relevant allocation of interconnector capacity, are co-optimised.

Ancillary services in ASEAN Member States

The current approach to the provision of ancillary services across AMS varies significantly. While Singapore and the Philippines have explicit procurement mechanisms for ancillary services, and Viet Nam has explicitly defined ancillary service requirements and provides this through contractual obligations from generators, **the majority of AMS currently manage ancillary services implicitly**, with no explicit definition and provision managed administratively within vertically-integrated systems.

This playbook emphasises that there is not a 'one-size-fits-all' approach to the cross-border provision of ancillary services, and that different models are appropriate for different AMS reflecting different levels of commercial, institutional, and regulatory maturity and technical readiness. Crucially, **AMS should not hesitate to begin the cross-border sharing of ancillary services,** even if through comparatively simple models. While Singapore, the Philippines, and Viet Nam may be ready for the coordinated sharing of reserves, other AMS should begin by establishing common standards before looking at defining specific ancillary services products which could then be traded.

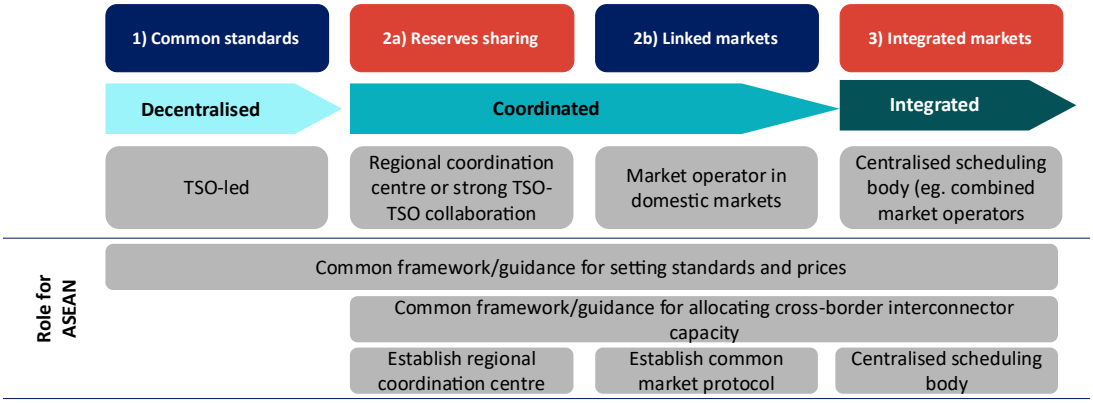
Next steps for ASEAN

The different levels have different technical, regulatory and institutional requirements. However, a **crucial first step is for AMS to explicitly recognise the role of ancillary service, and their importance in resilient power systems**. This will support the mainstreaming of ancillary services in power system planning and regional power integration projects.

ASEAN should **also begin exploring the role regional institutions can play** in supporting the delivery of the different levels of cross-border ancillary service sharing, as shown in the figure below. For example, the ASEAN Centre for Energy (ACE) or Heads of ASEAN Power Utilities/Authorities (HAPUA), can play a key role in developing common frameworks, and potentially acting as a regional coordination centre for this.

This can help accelerate the sharing of ancillary services across borders and **allow ASEAN to leap-frog the trajectory seen in other markets**, where ancillary service trade came at a much later stage, and boost the **resilience and efficiency of the ASEAN power system.**

Overview of institutional requirements for cross-border sharing of ancillary services



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). 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.

The Green Grids Rising initiative is structured around three key components:

- Developing a knowledge base on options for the repurposing of coal-fired power plants (CFPP);
- Identifying options for fostering cross-border power trade in the ASEAN Power Grid (APG), including developing appropriate business models; and
- Exploring options for unlocking the potential of smart grids to support VRE integration and ensure the resilience of power grids across ASEAN

1.2. Introduction to this playbook

This playbook is intended as a practical guide to how ASEAN Member States (AMS) can use increased interconnection between power systems, including through the ASEAN Power Grid (APG), to share ancillary services, in particular those for frequency control or response, and reserve provision across borders. To date regional power trade, and the discussions and plans around it, have largely been focused on facilitating uni-directional power flows and trading energy between countries. This playbook makes the case that interconnectors also play a valuable role in providing other services, such as ancillary services, and that their role in providing such services will become increasingly more important.

Facilitating the cross-border sharing of ancillary services can deliver tangible benefits for AMS, including:

- **Increasing grid flexibility** and, therefore, ability to accommodate increased levels of VRE, by relaxing requirements to run thermal generators at minimum levels to meet reserves requirements by instead drawing on connected grids.
- **Reducing the costs of reserves**, by reducing the quantity that needs to be hold and allowing utilisation of the lowest-cost sources of reserves.
- **Helping manage seasonality** on renewables-dominated systems, by reducing the need to maintain reserves to meet periods of extended low generation.

These show how the cross-border provision of ancillary services should be viewed as a strategic decarbonisation tool, enabling ASEAN power systems to integrate higher shares of renewable energy while reducing reliance on fossil-fuel based balancing resources.

A review of ancillary service provision in AMS shows that with the exception of Singapore and the Philippines, ancillary services tend not to be defined, formal products, and there provision is managed implicitly by the system operator. However, this playbook makes the case that you do not need a fully-competitive power market, including for ancillary services to offer such services across borders. Instead, it recognises the heterogeneity of power system, institutional, and market structures across ASEAN and offers a framework with models that can facilitate the trade of such services in different contexts.

By showing how the cross-border provision of ancillary services can increase resilience and lower costs it aims to mainstream the consideration of such services into discussions surrounding the planning, development, and operations of interconnectors, as well as the APG more broadly. Mainstreaming considerations surrounding the cross-border provision of ancillary services can also benefit the development of business cases of specific interconnectors by highlighting additional future revenue streams and secondary benefits, such as increased resilience and the potential to support VRE integration.

Note that this playbook focuses on grid-to-grid (G2G) connections and power trading. To date point-to-grid (P2G) connections and trade, where specific generators transfer power to neighbouring countries, have played a key role in several ASEAN sub-regions. They also have the potential to provide certain ancillary services to neighbouring countries. For example, pumped storage in Lao PDR could provide reserves to the Thai or Vietnamese grids. Such P2G connections are not considered in this playbook, although many of the lessons are relevant and are transferrable

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2. Ancillary services, the energy transition, and the role of interconnectors

This section provides high-level description of ancillary services, how requirements for ancillary services change with growing VRE penetration, and how interconnectors can help provide ancillary services and consequently increase system resilience and support higher levels of VRE. It aims to provide the necessary foundations for the remainder of this playbook.

2.1. What are ancillary services?

Ancillary services are services essential for the reliability and security of a power system, which are additional to the supply of energy to meet demand. Broadly speaking, these can be classified into three types (with many sub-services within each category):

- **Frequency control / response**. These are services related to maintaining frequency within a defined range or, if frequency moves outside of this range, restoring it. This is done by increasing energy injections or reducing withdrawals, if frequency is falling, or vice-versa if frequency is rising.
- **Voltage regulation**. These are services related to injecting or withdrawing reactive power, to maintain voltage levels at required standards.
- **Black start**. These are services related to the ability to restart the power system following a black-out, which requires power plants to have access to their own on-site means of generating electricity to power the various systems needed for the plant to operate.

While interconnectors can, in theory, supply all three types of service, we focus in this playbook on their role in providing frequency control and response services. This is their primary contribution in interconnected systems internationally.

2.2. How are frequency control and response services provided?

An illustration of the various frequency control and response services is provided below (Figure 1). While these may go by different names in different systems, the basic services remain the same across each:

- **Frequency regulation** (also frequency control). This is the management of small fluctuations in frequency. This is typically done through the inherent inertia in synchronised turbines (as used in thermal, hydro, and nuclear power plants). If

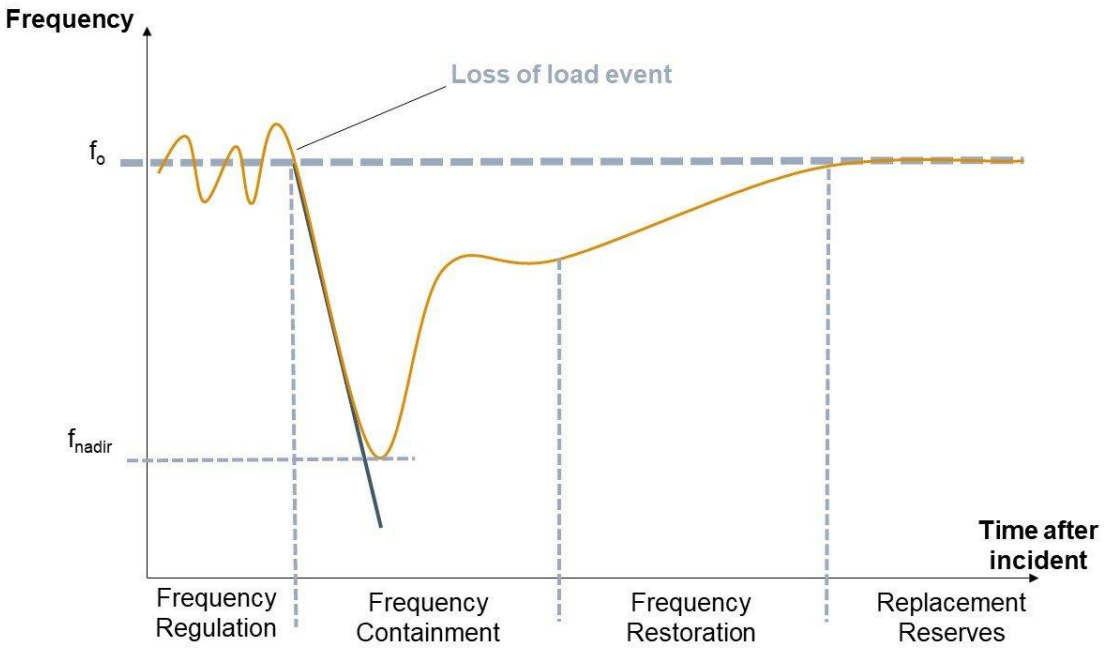
frequency drops, the turbine slows and releases stored kinetic energy, injecting this to the grid.

- **Frequency containment** (also primary control, primary response, or primary reserves). This is initially also provided through inertia. This slows the rate of change of frequency, although not arresting it, giving time for other responses to start-up. It is then followed within a few seconds by governor responses on synchronised generators, automatically increasing output where this is below capacity.

- **Frequency restoration** (also secondary response, or secondary reserves). This is the next set of responses, restoring frequency to the target level. This is provided through automatic generation control, where generator output targets are reset to the levels necessary to replace lost supply and return the frequency to its target. This is activated within minutes of the frequency drop

- **Replacement reserves** (also tertiary response, or tertiary reserves). These are slower-responding generators, which are started up or ramped up to substitute for generators providing frequency restoration services. This frees those generators to return to previous output levels, making them once again available to provide frequency containment and restoration if needed.

Figure 1 Frequency response services



Source: ECA, reproduced for the Green Grid Rising Workstream

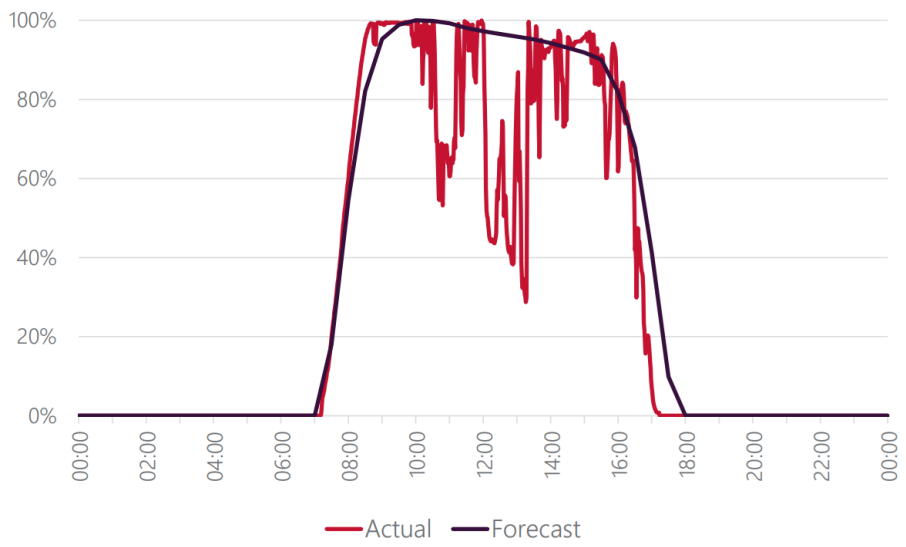
2.3. What are the impacts of variable renewable energy?

VRE is a core pillar of the energy transition in ASEAN, and gaining increasing importance with increasing levels of solar and wind being developed across the 11 Member States. As VRE penetration increases the need for reserves may grow as system operators work to

ensure green and resilient grids. Key challenges associated with increased levels of VRE penetration and the resulting role of reserves include:

- **Solar and wind power generators are inherently volatile**, with output potentially changing by large amounts in short time periods as weather conditions change (Figure 2). This can impose additional challenges for accurately forecasting supply. This means that it is necessary to have in place a reserve source of supply that can adjust sufficiently quickly to changes in output to maintain supply and demand in balance and consequently avoid divergences in system frequency.

Figure 2 Example of solar power volatility (Australia)

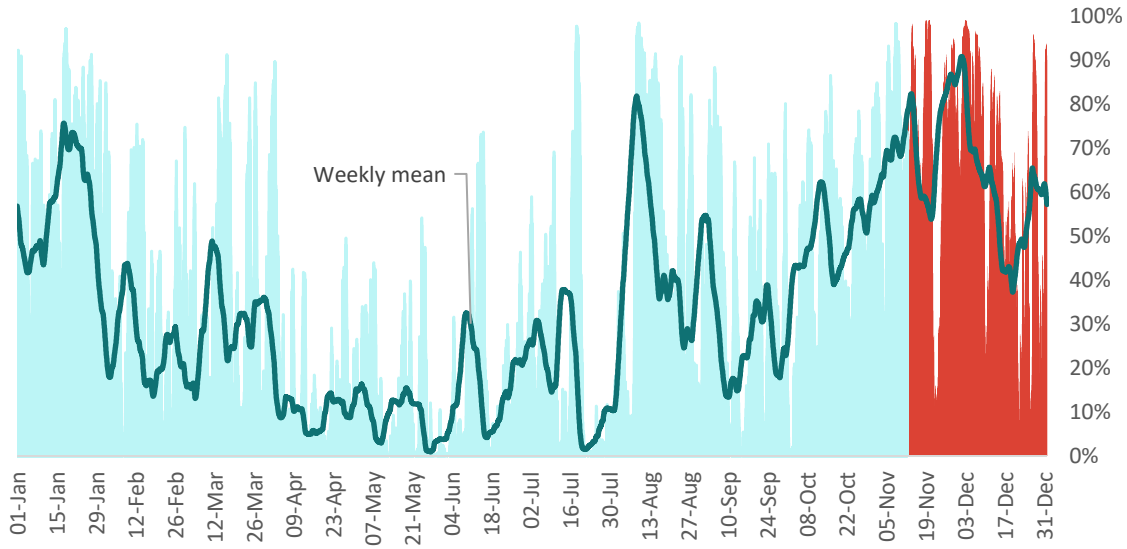


Source: AEMO. 2020. Variability and Uncertainty: An Overview of the RIS Appendix C

- **Wind and solar power generators are not synchronised to the grid** but, instead, connected to it through inverters converting the DC electricity generated to the AC electricity supplied by the grid. This means they are unable to provide either inertia or governor response. They are also, by their nature, generally not dispatchable – output responds to weather – which means they also cannot be responsive to automatic generation control. While it is possible to provide synthetic inertia and responses, these are still largely unproven.

- The **intermittency of wind and solar power** also poses challenges for system operators. Solar power, by its nature, is only able to supply during daytime hours. Wind power, while able to generate at night, can be highly seasonal and can also experience multi-day periods of lower generation (Figure 3).

Figure 3 Example of wind intermittency (Ilcos Norte, Philippines)



Source: ECA under the Green Grids Rising Workstream. Illustrative capacity factor (% of maximum) estimated using Renewables Ninja. The selected location is Lat 18.643 : Lon 120.846

The implications of this are that, to maintain system reliability and resilience as VRE penetration increases:

- There will be more requirements for fast-responding reserves from sources other than synchronised generators, as inverter-based generation increases.
- Some thermal generation may need to run at minimum levels to provide inertia and governor response, even if not needed to meet energy demand, reducing the 'headroom' for VRE generation.
- Systems may need to maintain strategic reserves of dispatchable or 'firm' generation, typically thermal, to be able to manage extended periods of low VRE output. While not an ancillary service as such, this still represents a new requirement for reserves resulting from growing VRE penetration.

2.4. How can interconnectors help?

The additional reserves and services needed to manage increased VRE integration are associated with costs. However, interconnectors enable one system to draw on reserves provided by another system. This can therefore support ASEAN's national and regional climate commitments by facilitating the integration of additional VRE at lower costs, and reducing the need for fossil-fuel based reserves.

Specific means by which this can be achieved include the automatic provision of frequency control and containment services or through the sharing of reserves:

- 'Automatic' delivery of frequency control and containment services, through inertia and governor response on one grid adjusting output to balance out fluctuations on another, interconnected and synchronised, grid.

- Sharing of reserves to lower required quantities on each grid, recognising that it is unlikely all interconnected grids will simultaneously experience outages leading to a loss of frequency, and so reserves on one grid can be used to support another grid in providing frequency restoration and replacement reserves services. This portfolio effect means the aggregate reserves required across coordinated and interconnected grids is less than the sum of reserves if each grid meets its requirements individually.

- Lowering the costs of reserves, by enabling the system operator of one grid to draw on lower-cost providers on another, interconnected, grid.

- Providing access to strategic reserves, which reduce the need to hold these on one grid. This delivers economies of scale at the regional level and is of particular importance as VRE integration increases.

These benefits are therefore relevant over different timescales. Frequency response and contingency reserves address short-term disturbances, while strategic reserves and access to firm capacity can support adequacy during more sustained periods of system stress. The value of sharing resources will depend on the extent to which conditions across interconnected systems are genuinely diverse. For example, simultaneous or correlated outages, common weather patterns or adverse hydrological conditions across several systems may reduce the amount of reserve that can reliably be shared.

Importantly, interconnection alone does not guarantee that these benefits can be realised. Sufficient transmission capacity must be available when support is required, and system operators need appropriate technical, operational and commercial arrangements to coordinate the provision and activation of reserves. Where interconnector capacity is heavily utilised for energy trading, there may also be a trade-off between using capacity for energy transfers and retaining or reserving capacity for cross-border reserve provision.

In principle, these benefits can be realised under either AC interconnections, which are automatically synchronised, or DC interconnections[1], where modern inverter technology enables the connection to operate as if synchronised providing, for example, the equivalent of inertia and governor response. In practice, as with synthetic response provided by inverter-connected generation, there may be concerns with relying on inverter-based supply for these services, although provision of replacement and strategic reserves remains feasible. This playbook does not distinguish between AC and DC interconnections in discussing mechanisms and models for trading ancillary services across interconnectors, but this difference should be borne in mind.[2]

[1] Modern interconnectors tend to be high voltage direct current (HVDC) due to higher efficiency over long distances relative to alternating current (AC) transmission. HVDC transmission losses are typically quoted at 3.5% per 1,000 km versus 6.7% for AC lines: Ardelean, M. and P. Pennebo, 2017, European Commission, Joint Research Centre. Institute for Energy Transport, 2015, HVDC submarine power cables in the world: state-of-the-art knowledge. European Commission, Joint Research Centre, Publications Office of the European Union.

[2] ENTSO-E has argued that the same general principles for transfer capacity reservation should be applicable to both AC and DC links and there is no reason to explicitly prohibit reserves trading on AC or DC interconnectors. Any differences, eg, the added cost of modern inverter technologies for DC links, only need to be considered as part of case-by-case social welfare assessments: ENTSO-E, 2011, Position Paper on Cross-Border Balancing, Prepared by Working Group Ancillary Services.

3. Models for cross-border ancillary services trade

Unlocking the opportunities presented by the cross-border sharing of reserves and ancillary services, including lower system costs and increased system resilience necessitates appropriate models to facilitate such sharing. This section provides a typology for cross-border models for cooperation in providing ancillary services, specifically in the form of sharing reserves. In doing so it draws on international examples, while outlining the institutional and commercial arrangements required to facilitate such models.

3.1. Typology of cross-border ancillary services sharing

We define five stylised models of cross-border trade in reserves, as illustrated below (Figure 4). Of these, the first, **Level 0**, represents no formal arrangements on the provision of ancillary services, including when not defined as such, between systems and we do not discuss further here. The others represent increased levels of integration, as listed below. Note that while in some cases reference is made to the 'trade' of ancillary services across borders this does not necessitate the establishment of a formal market and traditional trading transactions.

- **Level 1 – Common standards on synchronised grids**: Synchronised grids engaging in energy exchange also mutually cover frequency deviations, with rules in place to prevent any grid from 'free-riding' on other grids' reserves.
- **Level 2a – Reserves sharing under coordinated operation**: Grids coordinate with available transfer capacity to enable joint scheduling and / or redispatch of day-ahead and intraday dispatch, which effectively allows for reserves sharing.
- **Level 2b – Reserves sharing through linked markets**: Establish bilateral ancillary services sharing arrangements between two (or more) transmission system operators, offering spare reserves capacity to neighbours.
- **Level 3 - Integrated markets**: The most advanced cases see markets integrate ancillary service exchange either through dedicated markets for ancillary service provision or deploying co-optimisation algorithms such that ancillary service provision is embedded within energy market clearing.

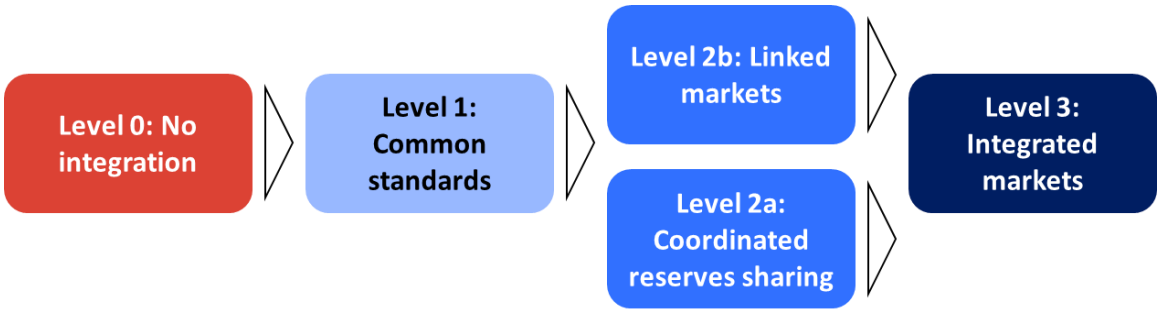
We describe each model in the below sections, accompanied by selected case studies. For each model we also consider the following aspects, which help determine the extent to which each of these stylised models is applicable for countries with different institutional and market structures, and differing levels of regulatory and commercial maturity:

- Whether the model requires separate **procurement, pricing, and settlement of ancillary services products** (frequency control and response)?

- Whether the model requires defined **interconnector capacity rights** and the ability to trade these between users?
- Whether the model requires **coordinated scheduling and dispatch** across two or more grids?
- **Who can provide cross-border ancillary** services?
- Where coordination applies, whether this is through **centralised system operation or through market mechanisms**

Simplified illustrative examples of how reserves requirements, prices, and costs compare across the models are provided in Annex A.

Figure 4 Evolution of ancillary service integration



3.2. Level 1: Common standards on synchronised grids

Dimension	Description
Mechanism (operational model)	• Interconnected grids operating on a synchronised frequency. • No explicit cross-border ancillary services exchange. • Frequency deviations managed locally or via implicit flows.
Institutional arrangements (coordination of scheduling / dispatch)	• TSOs follow agreed minimum standards for reserve sizing and activation. • No direct coordination of cross-border dispatch; each TSO is responsible for its own system.
Commercial arrangements (pricing and settlement)	• Ex post compensation (eg, inadvertent exchange settlements), in the form of reverse energy flows or financial settlement at an agreed reference price. • No formal market for reserves.
Examples	• Early synchronous pools, supported by 'inadvertent exchange' arrangements, as historically applied in the EU

Under this model, two (or more) synchronised grids formalise arrangements for managing exchanges for inadvertent transfers from one grid to balance supply and demand on the other in response to frequency changes. Typically, this will involve agreements on compensation (normally in the form of energy exchanges at an agreed rate) and the adoption of common standards for setting reserves requirements and for accepted frequency ranges etc. This prevents one system operator 'free-riding' on another grid by, for example, not holding its own reserves and relying on exchanges with the other grid to provide frequency response services.

In this sense, synchronised systems implicitly share contingency reserves, as a frequency disturbance in one system elicits a response across the synchronised area. However, each system remains responsible for maintaining its agreed reserve requirement and there is no explicit allocation or procurement of shared reserves.

This model has the lowest pre-requisites to implement. It does not require the separate procurement, pricing, and settlement of ancillary service products, beyond agreeing on the approach (physical or financial) and, where applicable price, to compensate for inadvertent exchange. Nor does it require the need to define capacity rights on the interconnector or coordinate scheduling and dispatch between systems. As a result, the timeline to implementing such a model can be comparatively short, so long as a common agreement can be reached on the level of compensation for inadvertent exchange and the common standards.



Case study 1:
European Union (pre-2017)

Prior to 2017, a common standards model was effectively in place for Europe's synchronous grids. If the frequency dropped in one control area in the synchronous system, then energy would be 'sucked in' from other control areas to even out the frequency. This is referred to as 'inadvertent exchange'.

Dating back to 1958,[3] ENTSO-E, the association of European transmission system operators, operated an accounting mechanism to compensate for such inadvertent energy exchanges ex post. Each TSO measured deviations between scheduled and actual cross-border flows, accumulating deviations between TSOs in an 'inadvertent energy' account. Periodically (usually the following week), the accumulated imbalance was either physically returned (via reverse flows) or financially settled at an agreed reference price.

Under this older approach, energy compensation for inadvertent exchange was treated as an implicit reserve provision, which was effectively activated ex post. Since 2017, this has been replaced by the Electricity Balancing Guidelines (EBGL) which provides for financial compensation at market prices (see Section 3.4).

[3] K. Kleinekorte et al, 2024, New Settlement Procedure for Unintended Exchange in Continental Europe, CSE 032.



Case study 2:
Southern African Power Pool

The Southern African Power Pool (SAPP) was established in 1995 under the Southern African Development Community (SADC) framework to promote regional cooperation and resource sharing across national power systems. It is the most advanced regional electricity market in the African continent and includes national utilities and independent participants from 12 countries. It operates regional forward, day-ahead, intraday, and balancing markets. SAPP consists of three synchronised Control Areas (CA) with nominated operators. For example, South Africa's Eskom is responsible for the Eskom CA, which contains South Africa, Botswana, Lesotho, southern Mozambique, Namibia, and Swaziland. Within each CA, TSOs engage in (relatively opaque) ex post physical or financial settlement for inadvertent flows between systems in each CA (similar to the Level 1 common standards model).

SAPP does not operate a regional ancillary services market,[4] but it does require members to maintain minimum requirements for operating reserves, reactive power, and black start capabilities, as detailed in the SAPP Operating Guidelines. This avoids members using the synchronised grids to, in effect, obtain access to uncompensated reserves.

Experience to date has shown active participation in the day-ahead market (DAM) to flow energy, but limited interest in using the markets for balancing demand and supply closer to real-time. Intra-day market (IDA) volumes have been thin and zero balancing trades have occurred since the launch of the balancing market (BM) in 2022. This does suggest a reluctance to rely on other grids for balancing and reserves, with reasons cited including inconsistent regulatory frameworks, transmission constraints, the dominance of single buyer models, and some SAPP members prioritising grid access and dispatch rights for domestic utilities and producers. The lack of liquid balancing markets has been cited as a primary barrier for VRE investment under SAPP, as it means these generators are left exposed to mismatches between contracted volumes and actual generation without any ability to hedge these.

3.3. Level 2a: Coordinated reserves sharing

Dimension	Description
Mechanism (operational model)	• TSOs coordinate reserve activation or redispatch bilaterally / regionally. • Even without explicit balancing arrangements, this implicitly allows for a degree cross-border reserve sharing.

[4] Cross-border AS trade has long been contemplated for SAPP (see Castalia, 2009, Electricity Exports and Imports in SADC: Potential Roles for National Electricity Regulators, Inception Report to the Regional Electricity Regulators' Association (RERA) and the World Bank, p 103-105), including proposals for common AS definitions and bilateral AS arrangements.

As of 2026, SAPP does still foresee a 'Regional AS Market' as a future market product (SAPP Coordination Centre, SAPP: The African Power Pools: Building Towards the African Single Electricity Market, ESMAP – AUC Webinar, 11 March 2026).

Dimension	Description
Institutional arrangements (coordination of scheduling / dispatch)	• TSOs directly coordinate dispatch and activation for cross-border flows and support. • Clear roles and responsibilities assigned for both emergencies and regular reserve sharing.
Commercial arrangements (pricing and settlement)	• Compensation linked to activation of shared reserves or compliance with reserve provision (ie, penalties for failing to maintain reserves).
Examples	• Implicit reserve sharing from regional dispatch on the Central American Electrical Interconnection System (SIEPAC) • Defined reserve sharing within and across USA power pools.

The next level of integration under our stylised models is regional coordination in sharing reserves and, consequently, frequency response services provided by these reserves. Coordination can apply both to the activation of reserves and to determining how much reserve capacity needs to be maintained across interconnected systems. The extent to which reserve requirements can be reduced through sharing depends on the diversity of risks across participating systems. In particular, reserve requirements should continue to provide protection against credible contingency events and more sustained periods of system stress, including adverse hydrological conditions and correlated outages across participating systems.

The two case studies illustrate two approaches to this. The first, that of the Central American Electrical Interconnection System (SIEPAC), illustrates the retention of national reserves requirements but the centralised coordination of scheduling of these to minimise costs of utilisation. The second example, that of a number of the American power pools in earlier years, takes a further step by setting requirements on a regional level as well as scheduling these, thus further reducing costs.



Case study 3
Central American Electrical Interconnection System (SIEPAC)

SIEPAC (Sistema de Interconexión de los Países de América Central) is a regional electricity market for Central America, developed in the early 2000s and spanning Guatemala, Honduras, El Salvador, Nicaragua, Costa Rica, and Panama. SIEPAC was specifically designed to accommodate different market structures, including structures varying from vertically integrated utilities to more liberalised market models.[5]

[5] Nord Pool Consulting AS and Ricardo Energy and Environment, 2021, Consultancy Services for the Design of the EAPP Power Market, 5.3.2.

SIEPAC coordinates scheduling and dispatch of generation across its members in three sequential stages:

- The first stage is the National Pre-Dispatch, in which each National System Operator carries out its own least-cost pre-dispatch using its own national mechanism, considering only domestic conditions and 'firm' cross-border import and export contracts.
- In the second stage, National Pre-Dispatch results are submitted to the Regional Operator (EOR), which performs Regional Pre-Dispatch, re-optimising the national schedules to reduce total regional costs while recognising cross-border transmission limits.
- The final stage is Regional Real-Time Dispatch, during which redispatching instructions, including revising cross-border flows, are issued as needed to meet demand given changes in constraints and availability.

A comprehensive regional grid code has been established, with common requirements which take priority over national rules. These include defining ancillary services requirements, including frequency regulation, reactive power, automatic load shedding, and black start capability.

While, under SIEPAC, frequency response and other ancillary services are not traded between system operators, the operation of SIEPAC in effect allows sharing of reserves and frequency response. This comes through both the process of regional scheduling, which selects the least-cost way of delivering energy and reserves across the region, and through the real-time dispatching arrangements, which uses the least-cost reserves in the region to balance supply and demand in the event of outages.



Case study 4
US power pools

Regional Transmission Organisations (RTOs) in the USA are an example of interconnected utilities engaging in coordinated market operations. Prior to the power sector reforms of the 1990s and 2000s, the various RTOs were comprised of vertically integrated utilities organised as power pools, holding monopoly rights over their service areas. Membership of a power pool was voluntary and its governing rules were developed by the participating utilities.

Probably the most widely recognised RTO, PJM, began in 1927 as a power pool of three utilities in the states of Pennsylvania, New Jersey, and Maryland (hence the name). During the 1950s and 1960s it saw continued growth in membership numbers.[6] Under the PJM Agreement of 1956, it introduced coordinated scheduling and dispatch through a single, regional control centre. In 1996, under Order 888 of the Federal Energy Regulatory Commission (FERC), PJM was required to introduced open access to its

[6] PJM, PJM History.

member utility grids and, in 1997, it transformed into an independent system operator (ISO), a regulated market operator separated from the founding utilities. In 2000, it became a RTOs, taking on responsibility for transmission planning and, during the 2000s, expanded geographically to cover parts of 13 states.

The economies of scale from reducing both operating and installed reserves was a central motivation for the PJM pool; in particular by optimising the allocation of a shared large hydro plant.[7] Under the 1956 Agreement, a formula allocated an 'equitable' share of the pool's capacity requirements to each member, adjusting for outage rates, large unit effects, and differing load shapes. Members had to submit generation capacity plans to a committee. For reserves, economies of scale combined with increasingly sophisticated operating reserve definitions, including frequency regulation provision. Individual systems may have required reserve margins equal to 25% of peak load; a pooled system could manage primary and secondary reserves at half that rate. Operating reserve requirements were allocated to each member based on their contribution to statistical peak load.[8]

As part of PJM's transition to becoming an Independent System Operator in 1996, this was succeeded by Reserve Sharing Agreements (RSA), and later Reliability Assurance Agreements (RAAs), to share capacity resources to reduce overall reserve requirements, provide assistance during emergencies, and shed load if system conditions so required. A Reserve Sharing Committee, formed of PJM member representatives, determined the pool's aggregate reserve requirements, accounting for forecast load, reserves for capacity resources becoming unavailable, load forecast uncertainty, maintenance outages, and the potential to access emergency reserves from neighbouring control areas. RSA parties were also required to coordinate on sharing capacity resources, providing reactive capability and voltage control, maintain required levels of load shedding, black start capability, and operating reserves. If a party failed to satisfy its capacity obligations or comply with system operator instructions to implement active load management, reduce voltage, or drop load.[9]

As part of the 1996 reforms, common ancillary services were defined by FERC across all regional pools, including scheduling, system control, and dispatch; reactive supply and voltage control; regulation and frequency response; energy imbalance; operating reserve-spinning reserve; and operating reserve-supplemental.[10] From 2006, the formerly voluntary industry standards body, now the North American Electricity Reliability Corporation (NERC), was given legal powers to set mandatory technical standards and guidelines to facilitate inter-ISO/RTO coordination, including for resource/demand balancing and interconnection reliability operations and coordination.[11]

This standardisation has helped facilitate the expansion of reserve sharing arrangements from within RTOs to between RTOs, including between RTOs located in the USA and

7 IEA, 2019, Establishing Multilateral Power Trade in ASEAN, p 55.

8 J.D. Lambert, 2001, Creating Competitive Power Markets: The PJM Model, p 24-28.

9 J.D. Lambert, 2001, Creating Competitive Power Markets: The PJM Model, p 47-48, 66-68

10 Promoting Wholesale Competition through Open-Access Non-Discriminatory Transmission Services by Public Utilities, Order No. 888, 1991-96 FERC Stats. & Regs., Regs. Preambles ¶ 31,036, at 31,703 (1996), order on reh'g, Order No. 8888-A, III FERC Stats. & Regs., Regs. Preambles ¶ 31,048, at 30,226 (1997)

11 IRENA, 2022, Grid Codes for Renewable Powered Systems, Section 6.1.

Canada. For example, PJM has an agreed Shared Reserves Activation procedure with ISO New England (ISO NE), the New York Independent System Operator (NYISO), and the Independent Electricity Market Operator (IESO Ontario), among other entities. This covers arrangements for cooperation in events such as joint activation of a portion of respective 10-minute reserves, generation or energy purchase contingencies greater than 500 MW occur, two or more resource losses below 500 MW occur within an hour of each other, or periods of significant mismatch of load and generation.[12]

Compared to the stylised 'level 1' model this model requires a higher degree of coordination between system operators. Critically the TSOs must be able to reserve, prioritise, or access interconnector capacity to facilitate joint scheduled dispatch or to access shared reserves. If this is not the case, for example because the interconnector is fully reserved for uni-directional energy flows, the implementation of this model will not be feasible. It also requires close cooperation between the system operators, or, where present, market operators, to schedule the dispatch, though the extent of this will depend on the time frame for the joint scheduling, with intraday scheduling requiring closer coordination than day-ahead scheduling. It also requires a clear mechanism on how to activate the shared reserves, which may include a centralised system operator. Shared reserve requirements should reflect system-specific risks, including hydrological conditions and the potential for correlated outages, while recognising the diversification benefits provided by interconnected systems.

3.4. Level 2b: Linked market

Dimension	Description
Mechanism (operational model)	• Cross-border procurement of standardised reserve products via TSO-TSO agreements or market mechanisms. • TSOs negotiate ancillary services sharing arrangements and/or enable cross-border participation in dedicated ancillary service markets. • Interconnector capacity explicitly allocated for reserves exchange.
Institutional arrangements (coordination of scheduling / dispatch)	• TSOs and/or market operators administer the ancillary services market/exchange, coordinate capacity allocation, and ensure technical feasibility of exchanges.
Commercial arrangements	• Under dedicated ancillary services markets, remuneration based on market clearing prices.

[12] PJM Manual 12: Balancing Operations, Revision 56, 1 October 2025, 4.2.

Dimension	Description
(pricing and settlement)	• Under bilateral TSO-TSO arrangements, price/valuation and settlement is arranged between TSOs.
Examples	• Stages of EU balancing developments: • Pre-EBGL, TSO-TSO bilateral arrangements and facilitation of cross-border ancillary services market participation. • Post-EBGL, integrated energy-balancing markets and cross-border capacity allocation mechanisms.

The Level 2a model summarised above coordinates the allocation of reserves requirements and the scheduling, and dispatch of reserves to manage contingencies through the use of a centralised control centre, either on a voluntary basis or a mandatory basis. The Level 2b model described here also coordinates between different systems but does so using market mechanisms rather than a centralised approach. The linked markets approach can entail the exchange of balancing energy and/or reserves.

Examples of such market-based coordination can be seen within the European electricity market, initially on individual bilateral arrangements between national transmission system operators (TSOs) and then, from 2017, under the European Union's Electricity Balancing Guidelines (EBGL), on a more formalised and uniform basis with common frequency response and other ancillary services products, centralised trading platforms, and harmonised rules for cross-border balancing. The pre- and post-2017 models are described further as case studies below.

In understanding the options for how such market-based coordination mechanisms operate, and how they can evolve from prior arrangements, it is useful also to consider the options assessed for these mechanisms in Europe. Discussions started in 2011 with a position paper[13] issued by the European Network of Transmission System Operators for Electricity (ENTSO-E). This considered four possible target models for cross-border exchanges of balancing energy (in effect, reserves):

- **Cross-border BSP-TSO approach**. A TSO sources balancing energy directly from Balancing Service Providers (BSP) located outside the TSO's control area (eg, in a neighbouring country). The TSO in the control area where the BSP is located must approve the delivery of the energy.
- **Bilateral TSO-TSO scheme**. Two TSOs manage balancing mechanisms in their individual control areas. The TSOs then offer surplus reserves that are not required to meet local security margins to each other through a coordinating market. The volume available for cross-border exchange therefore needs to reflect the reserves required to maintain domestic system security, including under credible contingency and stressed system conditions. A TSO can opt to procure surplus reserves offered

[13] ENTSO-E, 2011, Position Paper on Cross-Border Balancing, Prepared by Working Group Ancillary Services.

by another TSO into this market, in preference to reserves in their own control area, where this lowers costs.

- **Multilateral TSO-TSO scheme**. This approach simply extends the scope of the bilateral TSO-TSO model to include multiple TSOs.
- **Multilateral TSO-TSO mechanism with a common merit order**. TSOs procure reserves in a single market, incorporating all offers across their respective control areas rather than just those surplus to local requirements.

At the time of the position paper, a common merit order model was already being applied in the Nordic Balancing Market (since 2003) and the common balancing market between Germany's four TSOs. ENTSO-E identified this as being the optimal model for the future, but anticipated difficulties in establishing a central governance mechanism and a common approach to setting security criteria. Hence, it proposed establishing multilateral arrangements to trade surplus reserves without a common merit order which could subsequently move towards the common merit order model (which was eventually realised in 2017 in the form of the EBGL).



Case study 5
Examples of European bespoke market-based coordination, pre-2017

With over 30 TSOs, Europe's electricity market has evolved incrementally. Early cross-border balancing relied on a patchwork of bilateral and regional TSO arrangements, which gradually expanded over the 2000s and early 2010s. By 2012, multiple bilateral TSO-TSO cross-border ancillary services arrangements could be observed revolving France's TSO, RTE.[14]

- France and UK established the BALIT (BALancing Inter-TSOs) mechanism in 2009. The TSOs drew on excess local reserves to offer 50 MW blocks of firm, 1-hour cross-border balancing products with 30 minute activation time.
  - The BALIT mechanism was later extended to the Iberian peninsula, where it was explicitly seen as a first step for both establishing a cross-border balancing mechanism and gaining experience for the later adoption of a regional, multilateral TSO model.[15]
- France engaged in the BSP-TSO approach with Germany and Switzerland. This was a unique arrangement where German and Swiss BSPs benefited from a specific procedure allowing them to operate available interconnector capacity intraday (up to 30 minutes before real-time) based on an explicit allocation, and

[14] CRE, 2013, Cross-border electricity exchanges: Use and management of interconnections in 2012, p 58-66.

[15] REN, RTE, and REE, Deliverable I.4 Cross-border balancing model among TSOs -BALIT project-, 14th IG Meeting, Madrid, 25 February 2014.

thus directly issue balancing offers to RTE (rather than from their respective TSOs).

- RTE arranged Mutual Emergency Assistance Systems (MEAS) with multiple TSOs[16] to manually activate fixed, pre-agreed volumes of reserves during emergency situations. For example, MEAS were activated on the Italian and Belgian borders during tight supply conditions across Europe in winter 2017.[17]
    - Swissgrid has detailed that its MEAS with RTE and Terna (Italy) allows for calling on additional reserves of 400 MW and 300 MW, respectively, rising to 500 MW and 400 MW in exceptional circumstances.[18]



Case study 6
European Electricity Balancing Guidelines (EBGL), 2017 onwards

The EBGL were adopted by the European Commission in 2017 as part of the European Union's network codes framework. Their purpose is to harmonise and integrate the provision, activation, and settlement of balancing services across Europe, to foster a more integrated approach as opposed to the previous fragmented arrangements.

The EBGL standardise and harmonise balancing products, corresponding to different timescales and functions, such that they can be easily traded between TSOs:

- **Frequency Containment Reserves (FCR)** – automatically activated to stabilise system frequency within 30 seconds following a disturbance.
- **Automatic Frequency Restoration Reserves (aFRR)** – automatically activated within 300 seconds to restore frequency after a deviation.
- **Manual Frequency Restoration Reserves (mFRR)** – manually or semi-automatically activated within 750 seconds to rebalance the system after 15+ minutes.[19]

[16] ENTSO-E, 2012, Compliance Audit Report RTE – Reseau De Transport D'Electricite. This includes establishing protocols (including readily available and updated phone numbers and email addresses) for communicating to neighbouring TSOs when there are any periods where MEAS is unavailable.

[17] ENTSO-E, 2017, Managing Critical Grid Situations – Success & Challenges: ENTSO-E Report of the January 2017 Cold Spell. The report highlights the high degree of enhanced communication and cooperation between TSOs during this period, including a high volume of calls and information exchange, rescheduling of maintenance work, and reactivating mothballed capacity.

[18] Swissgrid, 2020, TSO report on balancing: Energy balancing guideline article 60, 4.7.3. (PDF download link)

[19] Replacement Reserves (RepR) were a further tertiary reserve used by some TSOs for slower response (30min), longer duration balancing energy. RepR was traded on the Trans European Replacement Reserves Exchange (TERRE), which pooled bids and optimised cross-border activation across participating TSOs. However, TERRE was decommissioned in 2025-26 as the Electricity Market Design Regulation (EMDR) introduced a mandatory intraday

FCR is procured through the cross-border FCR Cooperation platform. TSOs can procure aFRR and mFRR via dedicated trading platforms (PICASSO for aFRR; MARI for mFRR[20]), which combine supply offers and demand bids to determine least-cost schedules. Their activation across TSOs is centrally managed by an Activation Optimisation Function (AOF) algorithm, which selects the least-cost order subject to system constraints and available cross-border capacity. Settlement follows harmonised TSO-TSO settlement rules, with a single clearing price based on the marginal price offer accepted in each market.

A key remaining challenge lies in how to allocate scarce cross-border transmission capacity between energy markets and balancing services. Articles 40-42 of EBGL define alternative approaches: co-optimising with energy and reserves (Article 40), market-based allocation (Article 41), or simplified approaches justified by an economic efficiency analysis (Article 42). Partly owing to the inherent difficulties of coordinating across dozens of TSOs, implementation has varied in practice. Full co-optimisation may be the most economically efficient, but it has proven difficult to implement due to the added complexity of needing to integrate balancing requirements into day-ahead cross-border market coupling algorithms (eg, how bids reflect portfolio and reserve opportunity costs). Hence, the EU has not yet achieved fully integrated energy and balancing markets.[21]

This model does not need the extent of coordination between TSOs seen in level 2a, but instead requires an established market mechanism, with associated institutional arrangements. To enable such a market the TSOs are required to define common ancillary service products, which can then be provided either on a bilateral basis or through a market. As with 2a interconnection capacity must be reserved for the provision of reserves, though this can be performed either by the TSO or by market mechanisms. Cross-border reserve availability should reflect system conditions, including hydrology and correlated outages, helping TSOs make efficient use of reserve diversity across interconnected systems.

cross-zonal gate closure of at least 30 minutes before real-time, which was incompatible with the longer lead times required for RepR activation. Any redefinition of RR would start to overlap with faster mFRR products.

As part of the decision to discontinue TERRE, a TERRE Stakeholder Workshop estimated initial IT costs of €700k-€1,500k and a 14-month delivery period, plus €730k of costs per TSO, if attempting to modify RR to be settled every 15 minutes.

[20] PICASSO = **P**latform for the **I**nternational **C**oordination of **A**utomated Frequency Restoration and **S**table **S**ystem **O**peration. MARI = **M**anually **A**ctivated **R**eserves **I**nitiative.

[21] The preferred capacity allocation model is still under debate. A 2024 study for the Agency for the Cooperation of Energy Regulators (ACER) suggested €1.2bn of annual system-wide welfare benefits from co-optimising energy and balancing capacity (as under Article 40) compared to €159m of annual benefits from a market-based approach (Article 41). The All Nominated Electricity Market Operator (NEMO) Committee questioned the robustness of the ACER study's modelling simplifications and results. Given concerns about needing to significantly redesign day-ahead market coupling to fully accommodate the portfolio / asset cost structures and the added complexity of co-optimisation, the implementation methodology for Article 40 co-optimisation is still under development. In the meantime, market-based, multi-TSO approaches (under Article 41) have already been approved and implemented.

3.5. Level 3: Energy-reserves co-integration under central dispatch

Dimension	Description
Mechanism (operational model)	• Central dispatch co-optimises energy and reserve offers across multiple areas or TSOs. • Reserve provision is embedded within market clearing.
Institutional arrangements (coordination of scheduling / dispatch)	• Central operator, or tightly coordinated TSOs, determine system-wide dispatch and reserve activation, which includes the optimal allocation of interconnector capacity for energy versus reserves under a single control area.
Commercial arrangements (pricing and settlement)	• Integrated market pricing simultaneously values energy and reserves. • Cross-border capacity and reserve provision are priced and settled automatically within the market.
Examples	• USA's PJM • Australia's NEM

Some of the most advanced electricity markets have established co-optimised energy-reserve. Market participants submit both energy and reserve offers, which are co-optimised by a central operator to simultaneously meet both energy demand and reserve requirements, subject to transmission constraints within a single control area. The PJM Interconnection, a Regional Transmission Organisation (RTO) in the USA, and the Australian National Electricity Market (NEM) are modern examples of this approach.



Case study 7
PJM's energy-reserve co-optimisation under central dispatch

PJM has evolved from its historical pro rata reserves sharing approach (Section 3.3). PJM gradually replaced an administrative and cost-based reserves procurement mechanism with standalone ancillary service markets in the 2000s, followed by the implementation of energy-reserves co-optimisation under central dispatch for a single control area.[22] PJM also employs locational marginal pricing, which reflects transmission constraints within dispatch rather than requiring ex ante cross-border capacity allocation.

[22] PJM Connext, 2018, The Evolution of the PJM Market in the United States: Looking Back to Look Forward, Feasibility Study for ASEAN Multilateral Power Trade, slides 23 and 46-47.

Financial Transmission Rights (FTRs) are used within this framework as a financial instrument to hedge congestion costs.

Case study 8
Energy-reserve co-optimisation on Australia's National Electricity Market

Australia's National Electricity Market commenced in 1998, interconnecting five states under a single wholesale market. The Australian Energy Market Operator (AEMO) operates multiple separate AS markets.[23] Co-optimisation of energy and AS offers across regions under a single dispatch engine was progressively implemented in the 2000s.[24] NEM operates as a single control area with multiple pricing regions, but not separate balancing authorities. Interconnector flows between states (whether for energy or ancillary services) are part of the central dispatch optimisation rather than distinct cross-state trades subject to separate transmission capacity allocation rules.

3.6. Summary of models

The table below summarises the models, focussing on the key aspects which influence the extent to which they are applicable to the ASEAN and APG context.

Table 1 Responsibilities and institutional arrangements for cross-border ancillary services exchange by model

Question	Level 1: Common standards on synchronised grids	Level 2a: Coordinated reserves sharing	Level 2b: Linked markets	Level 3: Integrated markets
Is separate procurement, pricing, and settlement of ancillary service products (frequency control and response) required?	No. Ancillary services managed domestically. If inadvertent exchange is reimbursed financially, need to set a reference price.	Under coordinated dispatch reserves sharing is implicit. If explicitly sharing reserves, this would include jointly defined reserve standards.	Yes. TSOs first define common ancillary service products. These can then be exchanged across available transfer capacity either bilaterally or via dedicated markets.	Grid operators separately define ancillary service products and requirements but provision and remuneration is embedded within central dispatch energy-reserve market clearing.

[23] AEMO, 2025, Guide to Frequency Control Ancillary Services.
[24] AEMC, 2007, National Electricity Amendment: Efficient Dispatch of Regulation Services Rule 2007, Final Rule Determination.

Do interconnector capacity rights and the ability to trade between users need to be defined?	Not applicable.	To realise reserve sharing, TSOs must be able to reserve, prioritise, or access interconnector capacity for joint scheduled dispatch or for accessing shared reserves.	Yes. Interconnector capacity needs to be allocated for energy or reserve, whether by TSOs or market mechanisms.	Not applicable; interconnector capacity limits are accounted for in central dispatch and reflected in locational/nodal prices.
Is coordinated scheduling and dispatch across two or more grids required?	No. Each TSO schedules and dispatches independently.	Yes. Depends on extent of joint scheduling (day-ahead, intraday).	Not required but TSOs can jointly arrange balancing platforms with common merit orders.	Yes. Dispatch is centrally coordinated.
Who can provide cross-border ancillary services?	Not applicable. No explicit cross-border ancillary service provision. Inadvertent exchange settled between TSOs.	If only integrating spot markets, no direct participation in domestic ancillary service provision from external resources. Likely to be provided by TSOs in the explicitly shared reserves case.	TSOs or ancillary service markets can receive balancing offers either directly from external BSPs or from neighbouring TSOs (who build a portfolio of available BSPs), subject to access to available transfer capacity.	All eligible resources make combined energy-reserve offers on an integrated system.
If coordination applies, is this through centralised system operation or through market mechanisms?	Not applicable beyond adherence to common technical standards.	Day-ahead or intraday scheduling can be undertaken by system operators or markets. Activation of shared reserves likely undertaken by a central system operator.	Market mechanisms.	Centralised system operation.

4. Potential for cross-border ancillary services trading in ASEAN

This section evaluates the suitability of the models introduced in the preceding section for ASEAN. Recognising that there a diverse range of market and institutional structures across AMS, and that commercial, technological and institutional readiness also differs, it aims to identify which models are suitable for which AMS and, consequently, which are suitable for different interconnectors in the APG.

It first presents an overview of the current arrangements for procuring and delivering ancillary services in the 11 AMS, before providing an overview of the current status of regional power trade in ASEAN and how this will evolve as the APG is developed. Based on this we draw conclusions on the readiness of different markets for the adoption of different models.

4.1. Status quo of ancillary services across ASEAN

The current approach to the provision of ancillary services across ASEAN varies, as shown in the summary review of the current status of energy and ancillary service markets and of cross-border trading arrangements in Table 2 below. More details are provided in the review of how ancillary services are provided in individual in Annex B.

Most AMS power systems are structured as single-buyer models, with no markets for the provision of ancillary In many cases ancillary services are not defined, and where they are there definition is limited to statements in the grid code. In these cases ancillary service provision is managed implicitly by the system operator, sometimes supported by obligations stated in long-term power purchase agreements (PPAs) of. Consequently, there are no formal specific mechanisms for procuring ancillary service within the country, let alone through cross-border mechanisms.

Key exceptions are the Singapore and the Philippines, which both operate separate ancillary services procurement mechanisms:

- **Singapore** unbundles ancillary services provision from energy, with ancillary service provision separately bid and cleared in a dedicated ancillary service market that is open to all thermal, storage, and demand response resources. The ancillary service market is specifically designed to support high VRE, low-inertia conditions.

- In the **Philippines**, under its Ancillary Service Agreement Procurement Plan (ASAPP),[25] a reserve for AS is included in the wholesale electricity spot market (WSEM). Types of ancillary services products include regulating reserve (RR), contingency reserve (CR), dispatchable reserve (DR), reactive power support (RPS), and black start service (BSS), with required levels of provision and contract prices set out in the ASAPP. The system operator must procure 50% of the required RR, CR, and DR from existing, firm Ancillary Services Procurement Agreements (ASPAs), and the rest from a reserves market. RPS and BSS are procured through firm contracts.



Case study 9
Hybrid ancillary service procurement in the Philippines

The Philippines now operates a hybrid ancillary service procurement framework, with a mix of contract- and market-based procurement. Defined AS products are regulating reserve (RR), contingency reserve (CR), dispatchable reserve (DR), reactive power support (RPS), and black start service (BSS). Required levels of provision and contract prices are set out in the Ancillary Service Agreement Procurement Plan (ASAPP). The system operator must procure 50% of the required RR, CR, and DR from existing, firm ASPAs, and the rest from a reserves market. RPS and BSS are procured through firm contracts.

Notably, the Energy Regulatory Commission (ERC) has applied regulated price caps to some ASPA contract prices, as well as to its AS markets. The ERC has indicated that the price caps are only an interim measure, subject to review, to prevent 'inflated' prices and 'excessive profits' during the markets' initial phase,[26] while still ensuring that requisite AS-providing plants are financeable.[27]

However, neither country currently engages in cross-border sharing or trading of ancillary services. Singapore is interconnected to Malaysia but, as yet, Malaysia has not introduced competitive energy markets. The Philippines is not interconnected to other AMS.

[25] National Grid Corporation of Philippines, 2025, 2025-2034 Ancillary Service Agreement Procurement Plan.

[26] Power Philippines, 26 December 2024, ERC caps reserve market prices at ₱25/kWh.

[27] J. Barroco, 2021, Designing financeable ancillary services revenue contracts in developing economies: Learnings from the Philippines, Energy Policy 152, 112218.

Table 2 Current state of ancillary services provision and appropriate cross-border models by AMS

ASEAN Member State(s)	Description of ancillary service provision
Singapore	**Market-based procurement** • AS are explicitly defined and procured separately from energy. • AS are competitively bid and cleared through a market operated by the system operator. Pricing is market-based. • Providers may include thermal generators, storage, and demand response. • The structure is specifically designed to support high VRE, low-inertia conditions.
Philippines	**Hybrid model with increasingly market-based procurement of reserves** • AS reserves are procured through arrangements linked to the wholesale electricity market (WSEM), with reserve requirements integrated into market dispatch and scheduling. • Hybrid procurement approach: ancillary service products are distinctly defined for a dedicated ancillary services market, but at least 50% of reserves must be procured from firm contracts rather than the market. • Represents an intermediate stage of AS market development.
Viet Nam	**Contract-based ancillary service provision** • AS requirements are defined in system rules or grid codes, but not procured through competitive markets. • Provision is typically embedded within generators' PPAs or contractual obligations (such as specifying operational arrangements for Viet Nam's large, state-owned hydropower plants). • SO manages system security through contracted reserve capabilities, such as frequency control, spinning reserves, voltage support, and black start capability.
Brunei Darussalam, Cambodia, Indonesia, Lao PDR, Malaysia, Myanmar, Thailand, Timor-Leste	**Operational / implicit ancillary service provision within vertically integrated systems** • Ancillary services are not procured or priced separately. They are managed administratively within largely vertically integrated systems. • System stability (frequency control, reserves, voltage support, black start) is delivered implicitly through generator capabilities and operational dispatch.

4.2. Power trade and interconnection in ASEAN

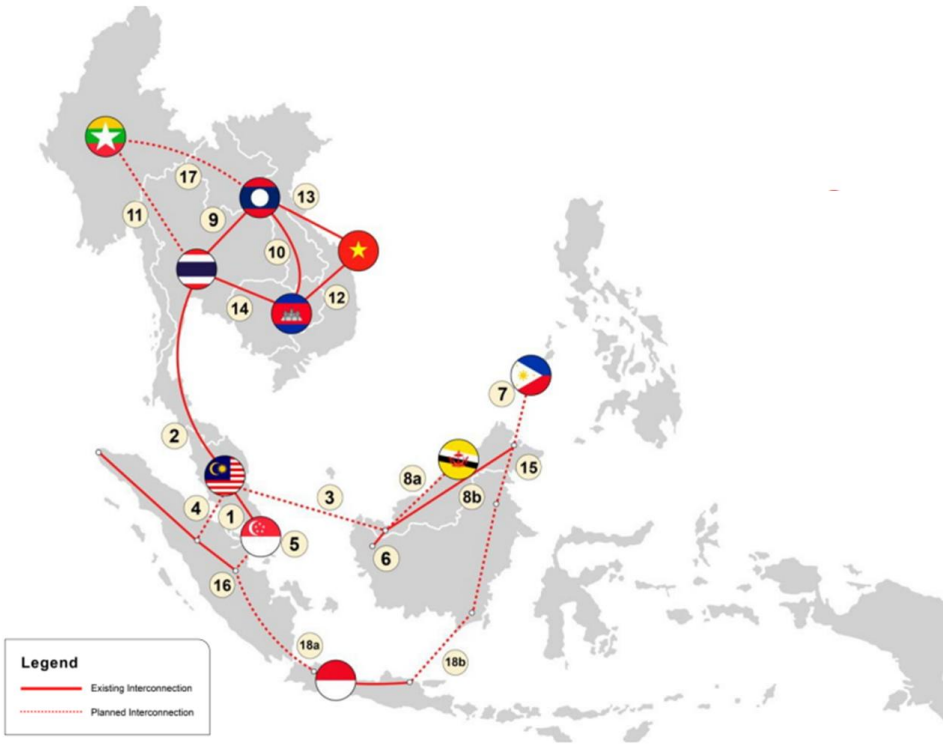
4.2.1. Interconnectors

An overview of existing and planned high voltage interconnections within ASEAN is provided below. These exclude P2G trading, notably from the various hydropower projects located in Lao PDR and exporting to Thailand and Viet Nam. An overview of the individual existing and proposed interconnectors is provided in Annex C.

Under the APG, an extensive expansion of interconnection is envisaged across all AMS. The ASEAN Interconnection Masterplan Study III (AIMS III) identifies 18 priority projects (including internal interconnections within Indonesia), plus other initiatives (direct Singapore interconnections with Viet Nam and Cambodia).

Across ASEAN, interconnectors are generally owned by the utilities concerned, with the exception being that between Thailand and Cambodia, which has been developed on a build-operate-transfer (BOT) basis by Cambodia Power Transmission Lines Co Ltd under a 30-year concession and was energised in 2007. However, given the scale of the expansion proposed under the APG means alternative models, including private participation in the development and operation of interconnectors will need to be explored.

Figure 5 Existing and proposed ASEAN interconnectors



Source: ACE. 2025. APG Updates 2025. P2G and LV interconnections are not shown

4.2.2. Regional trade

To date the most significant trade occurs within the Greater Mekong Subregion, in particular between Lao PDR and Thailand and between Lao PDR and Cambodia. In the case of Lao

PDR and Thailand the flows are bi-directional, with Lao PDR using imports from Thailand to balance seasonal hydro generation in the dry season) and occurs on the basis of an energy exchange, where a 'penalty' is applied when the imbalance between imports and exports by Lao PDR exceeds a given tolerance.

Most other flows across ASEAN are uni-directional, focused on meeting demand in the importing country rather than representing trade to minimise costs by taking advantage of arbitrage opportunities, including through the sharing of reserves. These tend to occur through power purchase agreements (PPAs) with fixed prices and volumes determined by the importing country's needs. A notable trade agreement is the Laos-Thailand-Malaysia-Singapore Power Integration Project (LTMS-PIP) agreement, under which electricity exported from Lao PDR is wheeled through the Thai and Malaysian grids for delivery to Singapore. The original two-year agreement, for up to 100 MW, expired in 2024 but was renewed in January 2026 for an increased quantity of up to 200 MW. In 2023, exports through this mechanism were 83 GWh (9% of the theoretical potential).

While both Viet Nam and, in recent years under the LTMS-PIP mechanism, Singapore import electricity into competitive power markets, these imports are insulated from the market itself. In Viet Nam, imports are contracted by Viet Nam Electricity's (EVN's) single buyer unit which is responsible for managing their scheduling in the market. In Singapore, imports under the LTMS-PIP mechanism are contracted to Keppel Electric which is one among a number of competing electricity retailers, and which manages their inclusion of these imports into the competitive market.

National system operators in each case are responsible for balancing supply and demand on their individual grids, including scheduling and dispatch of reserves. However, in practice, limitations on the ability to monitor system status and to control the operations of individual generators mean that the Lao PDR grid is primarily balanced using imports from and exports to Thailand, triggered by changes in frequency on the Lao power grid leading to unplanned flows over interconnectors.[28]

4.3. Potential forms of cross-border ancillary services trade

As outlined in Section 4.1, the current structure for ancillary service provision varies across AMS, which directly impacts which of the stylised models for cross-border ancillary service trade may be feasible in which market. This section evaluates which model is likely to be suitable for which AMS, and which may be suitable where interconnectors link AMS with different structures for the provision of ancillary services. It is critical to remember that all forms for cross-border ancillary service trade can bring tangible benefits to systems on both sides of the interconnectors, including increased resilience and lower system costs; AMS should not hesitate to begin trading ancillary services across borders, even if it is through comparatively simple models. Indeed, as shown through the European examples much of the trade in ancillary services was, until recently, through fairly straight-forward 'Level 1' type trade.

[28] JICA. 2025. Project for Power Quality Improvement through Upgrading Grid Code and Strengthening Its Enforcement System in Lao People's Democratic Republic: Project Completion Report

Table 3 Appropriate models for cross-border ancillary service trade by AMS

ASEAN Member State(s)	Current approach for domestic ancillary services procurement	Appropriate models for future cross-border ancillary service trade
Singapore	**Market-based procurement** • Ancillary services are explicitly defined and procured separately from energy. • Primary and contingency reserve are competitively bid and cleared, in a co-optimisation process, through the electricity market. . Pricing is market-based. • Other ancillary service products (eg. black start) are procured through contracts on an annual basis. • Providers may include thermal generators, storage, and demand response. • The structure is specifically designed to support high VRE, low-inertia conditions.	• Level 2a: Increase integration of cross-border energy exchange into wholesale spot markets to realise reserve sharing. • Level 2b: Enable neighbouring TSOs bidding into ancillary service market.
Philippines	**Hybrid model with increasingly market-based procurement of reserves** • Ancillary service reserves are procured through arrangements linked to the wholesale electricity market (WSEM), with reserve requirements integrated into market dispatch and scheduling. • Hybrid procurement approach: Ancillary service products are distinctly defined for a dedicated ancillary service market, but at least 50% of reserves must be procured from firm contracts rather than the market. • Represents an intermediate stage of ancillary service market development.	• Level 2a: Integrate cross-border energy exchange into day-ahead and intraday markets to realise reserve sharing. • Level 2b: Enable neighbouring TSOs to either bid into ancillary service market(s) or arrange firm ancillary contracts (ie, TSO-TSO bilateral arrangements). • *All subject to the Philippines first commissioning cross-border interconnections.

Viet Nam	**Contract-based ancillary service provision** • Ancillary service requirements are defined in system rules or grid codes, but not procured through competitive markets. • Provision is typically embedded within generators' PPAs or contractual obligations (such as specifying operational arrangements for Viet Nam's large, state-owned hydropower plants). • SO manages system security through contracted reserve capabilities, such as frequency control, spinning reserves, voltage support, and black start capability.	• **Level 2a**: Increase integration of cross-border energy exchange into wholesale spot markets to realise reserve sharing. (Relevant to Viet Nam spot market only). • **Level 2b**: With ancillary service provision already separately defined and contracted, can engage in bilateral ancillary services sharing arrangements with interconnected TSOs.

Brunei Darussalam, Cambodia, Indonesia, Lao PDR, Malaysia, Myanmar, Thailand, Timor-Leste	**Operational / implicit AS provision within vertically integrated systems**
	• Ancillary services are not procured or priced separately. They are managed administratively within largely vertically integrated systems.
	• System stability (frequency control, reserves, voltage support, black start) is delivered implicitly through generator capabilities and operational dispatch.
		• **Level 1**: For any existing or planned synchronous interconnections, work to achieve common standards to ensure no 'free-riding' and entry-level reserves sharing.
		• **Level 2b**:
		  • First, need to separately define ancillary services provision requirements and products
		  • Once ancillary service provision and products are defined, can engage in bilateral ancillary service sharing arrangements with interconnected TSOs.

5. Facilitating cross-border ancillary services trading

The preceding sections have shown that, subject to the development of interconnectors, all AMS have the potential to engage in the cross-border trading of ancillary services and sharing of reserves, and that doing so can increase the flexibility and resilience of power systems and reduce overall system costs. Implementing such cross-border trading does not necessitate large-scale reforms to a country's market structure nor does it necessarily require the establishment of new institutions, whether at the national or regional level. This reflects the notion that the model of cross-border trade should be appropriate for the prevailing conditions and readiness in the relevant AMS and that this may change over time as a country's power sector evolves.

This section sets out the requirements for facilitating cross-border ancillary services trade under the different models outlined in this playbook. It then discusses the institutional requirements to facilitate these pre-requisites before concluding with a discussion on the potential role for ASEAN and regional institutions in delivering these and support cross-border ancillary services trade.

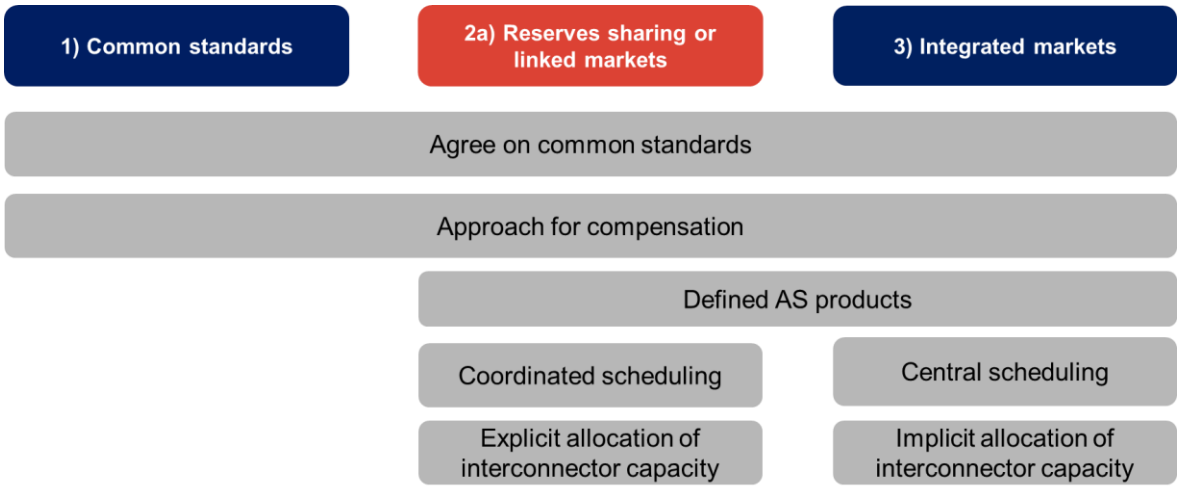
5.1. Requirements for facilitating cross-border ancillary services trade

Regardless of the available model, the first step is to explicitly **acknowledge the role ancillary services, in particular reserves, play** in ensuring a resilient power system and recognise that these services can, just like energy, be shared across borders. To date there has been no material engagement with this notion across ASEAN, with discussions on regional power trade largely focused on the trade of energy. While this is consistent with the early experience of now more developed markets, there is no need for ASEAN to follow a similar trajectory. Instead, AMS can gain material benefits if ancillary services and the sharing of reserves are explicitly considered from the onset as the APG is developed.

By mainstreaming the understanding that mutually beneficial outcomes can be achieved by sharing reserves across borders, AMS may also be able to strengthen the business case for the development of interconnectors. This can be achieved by highlighting potential future revenue streams arising from this and by emphasising the role that the cross-border ancillary service trading has on lowering system costs and emissions and facilitating the integration of increasing levels of VRE.

Once the potential for interconnectors to share ancillary services across borders is explicitly acknowledged focus can shift to the pre-requisites required for the different modalities of regional trade. These vary based on the level of integration and are summarised in Figure 6 below.

Figure 6 Overview of requirements for cross-border trade of ancillary services under different levels of integration



5.1.1. Level 1: Common standards on synchronised grids

Introducing 'Level 1' style cross-border trade of ancillary services does not require the establishment of new institutions, nor does it require a formal market. Instead the key requirements are:

- Agreeing on minimum standards for reserve sizing and activation.
- Determining the type of compensation to be provided for inadvertent exchange – should this be provided physically or as financial compensation.
- If financial compensation is to be provided an appropriate reference price needs to be agreed on.

Key challenges arise from the need for the entities to agree on minimum standards and the reference prices.

Determining the reference price for ancillary service provision

In the case of a TSO enabling cross-border access to its domestic ancillary services market, the value of the exchange is simply determined by the market clearing price. In the absence of an established market, the TSOs would need to determine a reference price. Options could include benchmarking against price outcomes in other AS markets (or spot markets, perhaps plus a mark-up) or publicly available ancillary service contract prices, or a cost-based approach, calculating the requisite costs of the main technology provider, eg, an open-cycle gas turbine (OCGT) or battery energy storage system (BESS), and ensuring that contract prices are sufficiently remunerative.

If benchmarking from external AS markets or contracts, this would need to be carefully mapped such that the price can be considered like-for-like in terms of both the AS product and the providing resource. For example, offers for rapid response AS from BESS in an advanced market would not be a relevant price benchmark for a TSO considering the value of long duration reserve provision from a cross-border hydro reservoir. Caution would also be needed as to whether the market outcomes in the benchmark are reasonably reflective of domestic market conditions, eg, a price spike in one market may be due to a local fuel price spike.

5.1.2. Level 2a: Coordinated reserves sharing

'Level 2a' type coordinated sharing of reserves requires closer cooperation between TSOs, who will be responsible for coordinating the dispatch and activation of reserves across interconnectors. The key requirements are:

- Clearly defined the ancillary service products which may be shared across borders.
- Clearly assigned roles and responsibilities for the sharing of reserves, which may differentiate between those which apply for emergency and regular sharing.
- Determine appropriate compensation for the activation of shared reserves or compliance with reserve provisions.
- An allocation of interconnector capacity to the (potential) provision of ancillary services.

5.1.3. Level 2b: Linked markets

'Level 2b' trade requires an established AS market in at least one of the systems or formal agreements between TSOs. The key requirements are

- For an established AS market, with clearly defined products, into which cross-border participants can bid into.
- For agreements between TSOs, agreed pricing principles and settlement processes.
- An allocation of interconnector capacity to the (potential) provision of ancillary services.

5.1.4. Level 3: Integrated markets

'Level 3' trade requires a more complex market to be established, which allows for centralised dispatch and the co-optimisation of energy and reserves. The key requirements are:

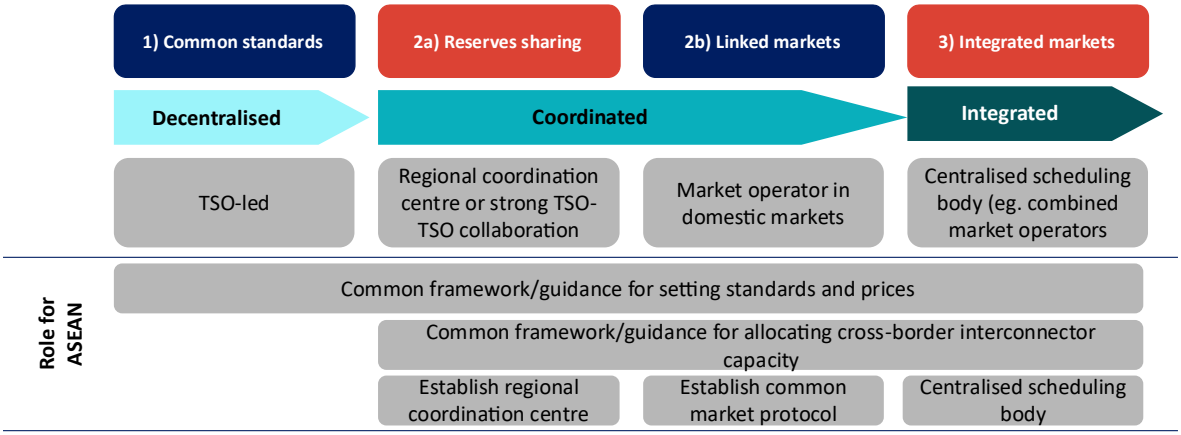
- Centralised scheduling, with co-optimisation of ancillary services and energy.
- Optimised allocation of interconnector capacity by a central operator or tightly coordinated TSOs

5.2. Institutional requirements

The delivery of the pre-requisites set out in the preceding subsection will require specific roles and responsibilities to be taken on by different actors. As shown in Figure 7 below, the typology can also be characterised as moving from a decentralised approach to a coordinated approach and finally to an integrated approach.

Regional coordination and integration is central to ASEAN's objectives. There are a range of roles and tasks which can be delivered at the ASEAN to support AMS delivering the institutional requirements and consequently support the deeper integration of regional power systems.

Figure 7 Overview of institutional requirements for cross-border sharing of ancillary services



5.2.1. Level 1: Common standards on synchronised grids

The common standards approach is generally led by the TSOs and there is no explicit requirement for coordination between TSOs in managing the systems. However, as indicated in the preceding subsection there are potential challenges associated with the need for TSOs to agree on common standards and a reference price.

This gives rise to a potential role for ASEAN who could, for example, develop a common framework which provides guidance on setting common standards and prices. While some regional markets, such as SAPP, have established regional guidelines (eg. the SAPP Operating Guidelines), the first step in ASEAN does not necessarily need to be prescriptive, given the level technical, commercial, and regulatory heterogeneity across ASEAN power systems. Instead, the framework could set out the key objectives and principles and support TSOs in reaching an agreement.

5.2.2. Level 2a: Coordinated reserves sharing

Coordinated reserves sharing requires strong coordination between TSOs. While this can be achieved bilaterally if two TSOs have ample capacity and a clear commitment for close engagement with the other TSO, a more effective approach may be to establish a regional coordination centre. This becomes particularly relevant when the sharing of reserves extends to more than bilateral flows and when an AMS shares reserves with more than one of its neighbours.

An example of this is the SIEPAC regional operator, which does not manage individual systems but conducts a regional re-optimisation, recognising cross-border transmission limits. A further example of a regional coordination centre can be found in SAPP (even if SAPP does not currently coordinate the sharing of reserves between members) in the form of the SAPP Coordination Centre. This is not a regional market operator per se, nor a regional regulator, but instead an entity which coordinates the SAPP utilities in managing the regional market, power system operations across interconnectors, while also coordinating long-term planning.

In ASEAN such a regional coordination centre could be housed within ACE, or through a dedicated secretariat within HAPUA, with staff initially seconded from national transmission system operators.

In addition to coordination on the sharing of reserves, this approach also requires the explicit allocation of interconnection capacity to the sharing of ancillary services. This could be supported through a common framework which provides guidance to TSOs or interconnector operators on how cross-border interconnector capacity should be allocated.

5.2.3. Level 2b: Linked markets

As 'Level 2b' style model relies on markets to share reserves there is no need for a regional coordination centre. Instead, it requires the institutions associated with operating a market, including market operators or a TSO with the capacity to manage a market. A key focus should be on establishing common market standards across the region, including a set of standardised ancillary service products.

5.2.4. Level 3: Integrated markets

Integrated markets require a central market operator who conduct a system-wide dispatch and, on this basis, allocate interconnector capacity and activate reserves. In some cases this could be performed through TSOs with very tight coordination, although international experience has shown that in most cases a specific entity is established to manage the market.

5.3. Future directions for ASEAN

This playbook shows that ancillary services play a critical role in ensuring resilient power systems, with their importance only increasing as VRE penetration increases across ASEAN. Sharing ancillary services across borders can support AMS by providing additional resilience and allowing these services to be delivered at a lower cost.

International experience shows that regional trade in ancillary services has often lagged between regional energy trade. However, there is no need for ASEAN to follow the same timelines, with clear and tangible benefits available by moving towards the cross-border sharing of ancillary services. In addition to supporting resilience, it can also contribute to the viability of the APG and the business case of interconnectors.

A first step must be to mainstream the role and importance of ancillary services across ASEAN. Making their role in the management of power systems explicit is a critical first step to moving towards the sharing of ancillary services between systems. Such mainstreaming should extend to national and regional level planning and also become a key pillar of discussions and plans surrounding the APG.

In developing the ability of cross-border sharing of reserves under models appropriate to the specific circumstances of each AMS, there is a role for an ASEAN institution, such as HAPUA to act as a coordinating entity, providing clear guidance and frameworks. One option is for selected interconnectors in the APG to be subject to a pilot for the sharing of ancillary services, which would act as a proof of concept and allow lessons learnt be transposed into a broader framework.

Annex A Illustrative models of shared ancillary services

The following simplified numerical examples as used to demonstrate how reserves requirements and pricing operate for different cross-border AS models.

Reserves requirement

The examples first show how reserves requirements change under each model. The simplified assumptions on requirements under each approach are set out below. For illustration, the calculations focus on contingency reserves, which provide capacity to respond to unexpected system events. These are distinct from strategic reserves, which provide additional capacity to maintain system adequacy during more sustained periods of system stress.

The 'common standards' requirement is set as the average of the two individual grid standards. The 'coordinated standard' delivers the same level of reserves as the highest required by either individual grid, representing the reserves required to manage the largest contingency event across the combined grids. In practice, reserve requirements would also reflect system-specific conditions, including generation availability, hydrological conditions and the potential for correlated outages.

Figure 8 Assumptions on reserves requirements for illustrative models

ASSUMPTIONS

Grid A

Standard = 5% of peak demand

Peak demand = 10,000 MW

Grid B

Standard = 10% of peak demand

Peak demand = 15,000 MW

Common standards

Standard = 7.5% of individual grid peak demand

Coordinated standard

Standard = 6% of combined peak demand

Apportioned relative to peak demand

The resulting reserves requirement by model are set out below:

- **No integration**: Each grid must rely on local resources to meet their respective reserve standard.
- **Common standards**: With synchronised grids, Grid A raises its reserves requirement and Grid B lowers its requirement, to apply the same standard (note that this example uses a common percentage requirement for simplicity, in actuality

standards are likely to be defined with reference to the size of contingency events and need to consider potential correlated outages and hydrological conditions across the two systems).

- **Reserves sharing**: This represents setting requirements to meet the largest contingency event across the combined grids, allowing the systems to benefit from diversity in their reserve needs. The appropriate requirement would also reflect system conditions that affect the availability of shared reserves.
- **Linked markets**: Reserve requirements are set individually, but bilateral TSO-TSO arrangements allow for Grid B to utilise excess (and lower cost) reserves from Grid A.
- **Integrated markets**: Reserve requirements are set for the combined grids with procurement from a common 'pool'.

Figure 9 Reserves requirements by illustrative model

	Grid A	Grid B	Total
No integration	500 MW	1,500 MW	2,000 MW
Common standards	750 MW	1,125 MW	1,875 MW
Reserves sharing	600 MW	900 MW	1,500 MW
Linked markets	500 MW	1,500 MW	2,000 MW
Integrated markets	600 MW	900 MW	1,500 MW

The illustrative calculations above assume that reserves are fully available across the interconnected systems. In practice, the benefits of reserve sharing will depend on system conditions. For example:

- Adverse hydrological conditions may reduce available capacity in hydro-dependent systems, increasing the reserves required to maintain system adequacy.

- Correlated outages or system stress may reduce the extent to which interconnected systems can rely on each other's reserves.
- Diverse system conditions can increase the benefits of sharing, as surplus reserve capacity in one system can support another system when required.

Reserve requirements should therefore be tested against credible system conditions to determine the volume that can reliably be shared.

Reserves pricing

The illustration of pricing and so cost of reserves under each model uses the assumptions below. Critical is that the price is assumed to be equal to the cost of the marginal provider. This may be a market-driven outcome (with providers submitting offers to provide reserves and the market price being set by the price of the highest offer needed to meet requirements). Alternatively, it can be interpreted as the opportunity cost (the cost of the marginal unit instructed to be available to provide reserves).

Figure 10 Assumptions on reserves pricing and capacity for illustrative models

ASSUMPTIONS

Grid A

Gen A1 = 500 MW @ $20 / MW

Gen A2 = 1,000 MW @ $35 / MW

Grid B

Gen B1 = 500 MW @ $30 / MW

Gen B2 = 1,000 MW @ $50 / MW

Price is set by cost of marginal generator scheduled for reserves

For linked markets, the price is set assuming the marginal cross-border generation offers at $5 / MW below the cost of the marginal domestic generator

The resulting illustrative price and costs of reserves provision for each model are shown below:

- **No integration**: Each grid relies on local resources to meet their respective reserve standard, priced at the cost of their marginal reserve provider (A1 for Grid A and B2 for Grid B).
- **Common standards**: Synchronised grids force Grid A to raise its reserves requirement, and call on generator A2 for reserves, while Grid B is able to reduce the volume of reserves procured from higher-priced generator B2.
- **Reserves sharing**: Each grid is able to lower their volume of required local reserves, although the price is still set by each grid's higher cost generator (A2 and B2).

- **Linked markets**: Generator A2 is able to offer reserves to Grid B (at a mark-up), displacing the highest cost generator, B2.
- **Integrated markets**: With a reduced volume of reserves procured under a common pool, generator A2 sets the marginal price for both markets.

Figure 11 Reserves pricing and costs by illustrative model

	Grid A	Grid B	Total
No integration	A1 = 500 MW Price = $20 / MW Cost = $10,000	B1 = 500 MW B2 = 1,000 MW Price = $50 / MW Cost = $75,000	$85,000
Common standards	A1 = 500 MW A2 = 250 MW Price = $35 / MW Cost = $26,250	B1 = 500 MW B2 = 625 MW Price = $50 / MW Cost = $56,250	$82,500
Reserves sharing	A1 = 500 MW A2 = 100 MW Price = $35 / MW Cost = $21,000	B1 = 500 MW B2 = 400 MW Price = $50 / MW Cost = $45,000	$66,000
Linked markets	A1 = 500 MW Price = $20 / MW Cost = $10,000	B1 = 500 MW A2 = 1,000 MW Price = $45 / MW Cost = $67,500	$77,500
Integrated markets	A1 = 500 MW A2 = 100 MW Price = $35 / MW Cost = $21,000	B1 = 500 MW A2 = 400 MW Price = $45 / MW Cost = $31,500	$52,500

Annex B Status of ancillary services markets and cross-border trading in ASEAN

The following tables provide a summary of the current arrangements for ancillary services procurement and cross-border ancillary service provision in the AMS. This forms the basis of the review of the status quo in Section 4.1 and the proposed recommendations on which models are most suitable for which AMS which follow.

The tables are organised around the following aspects:

- **Physical and market trading environment**

  Overview of the domestic electricity market model, the generation and capacity mix, and existing interconnection arrangements.

- **Ancillary services provision**

  Overview of the current approach to provide ancillary services domestically. This includes identifying whether ancillary services are formally defined or managed implicitly, how ancillary services can be produced both in the long-term and short-term, whether the system operator is able to reserve capacity, and how flexibility can be provided.

- **Cross-border ancillary services provision**

  Overview of current arrangements, if any, for the cross-border provision of ancillary services.

Table 4 Current market status in ASEAN countries (Part 1)

	Brunei Darussalam	Cambodia	Indonesia	Lao PDR	Malaysia (Peninsular)	Malaysia (Sabah/Sarawak)
Overview of power system and market						
Electricity market model	Single buyer with vertically-integrated utilities	Single buyer with vertically-integrated utility	Single buyer with vertically-integrated utility	Single buyer with vertically-integrated utility	Hybrid. Predominately single buyer with vertically-integrated utility, but some limited direct trading through the corporate power purchase agreement (CPPA) programmes	Single buyer with vertically-integrated utilities
Key actors	Department of Electrical Services (DES) and Berakas Power Company (BPC), serving distinct areas, serve as the single	Electricité du Cambodge (EDC), operating transmission, distribution, and a portion of generation assets,	Perusahaan Listrik Negara (PLN), operating transmission, distribution, and, through its subsidiaries, a	Électricité du Laos (EDL), operating distribution, and some generation assets acts as the single buyer	Tenaga Nasional Berhad (TNB) operates transmission, distribution, and, through its subsidiaries, a	Sabah Electricity (SESB) operates transmission, distribution, and, through a ring-fenced entity, acts as the single buyer

	buyer and system operators	acts as the single buyer and system operator IPPs provide generation to EDC through long-term PPAs	number of generation assets, acts as the single buyer and system operator IPPs provide generation to PLN through long-term PPAs	IPPs provide generation to EDL through long-term PPAs EDL-T operates the transmission network under a concession IPPs also operate generation assets dedicate for export	number of generation assets. Through its ring-fenced business entities it operates the single buyer and system operator	and system operator. IPPs supply significant generation in Sabah, alongside SESB's own generation. Sarawak Energy acts as the vertically-integrated utility in Sarawak, with very limited IPP participation
Generation and capacity mix	Dominated by gas generation, with very limited solar generation	Mix of hydro and coal, and growing amount of solar Hydro is subject to seasonality, with imports from neighbouring countries during the dry season	Dominated by coal generation, with a small share of gas, hydro, and geothermal, as well as a very small but increasing amount of solar	Hydro-dominant, including significant export-orientated hydro generation High is subject to significant seasonality, with excess generation in the wet season and a shortage in	Dominated by thermal generation (coal and gas), though increasing share of solar.	Hydro dominant in Sarawak, with some thermal generation. Gas dominant in Sabah. Growing share of solar in both Sabah and Sarawak.

				the dry season which is covered through imports from neighbouring countries		
Existing interconnections and trade arrangements	No interconnections to other systems at present	Interconnections with Lao PDR, Thailand and Viet Nam Cross-border exchange generally managed bilaterally by EDC	Note the Indonesian system is split into different systems, reflecting the archipelagic nature of the country. The main systems are Java-Madura-Bali; Sumatra; Sulawesi; Kalimantan; and Nusa Tenggara, Maluku, Papua, while there are many further smaller islands. The systems are generally not interconnected and even within	Interconnections with Cambodia, China, Myanmar, Thailand, and Viet Nam Combination of bilateral agreements, as well as the multilateral Lao-Thailand-Malaysia-Singapore Power Integration Project (LTMS-PIP) agreement. Several interconnectors (primarily to Thailand) are	Interconnection with Thailand and Singapore Exchange is managed to bilateral utility agreements	Sabah and Sarawak interconnected with each other since 2025. Sarawak also interconnected with Indonesia (West Kalimantan) Exchange is managed to bilateral utility agreements

			systems there are islanded operations and significant transmission constraints. Only cross-border connection is between West Kalimantan and Malaysia (Sarawak), with exchange managed bilaterally by PLN	dedicated to the export of hydro generation from specific IPP hydro assets		
Ancillary service provision						
Overview of ancillary service provision	Not formally defined and managed implicitly by the utilities	Ancillary service products and obligations are set out in the Grid Code, but no formal process for their procurement	Grid Code mentions frequency and reserve requirements, but not formally defined as ancillary services	Not formally defined and managed implicitly by the utility New Grid Code currently under development, which may define some key terms	Defined in grid code Provision is managed implicitly by the system operator and through obligations in PPAs	Defined in Sabah Grid Code Information not available for Sarawak Provision managed implicitly by single buyer

		Provision managed implicitly by EDC's control centre	Provision of ancillary services managed implicitly by PLN			and system operator
Long-term ancillary service procurement arrangements	Not existent	Some obligations built into licence conditions and long-term PPAs	Not formally defined, but reserve obligations can be bundled implicitly in long-term PPAs	Not existent	Managed by Single Buyer through terms in long-term PPAs and defined operating reserve requirements	Sarawak: Not existent Sabah: Managed by Single Buyer through terms in long-term PPAs and defined operating reserve requirements
Short-term ancillary service procurement arrangements (eg. day-ahead)	Not existent	Not existent	Not existent	Not existent	Not existent	Not existent
Is the system operator able to reserve capacity with generators	Not formally established and managed within	Not formally. Grid Code required EDC to secure sufficient reserve	Not formally. Managed through PPA dispatch	Not formally.	Managed through PPA terms	Managed through PPA terms or within vertically-integrated utility

	vertically-integrated utility	capacity, but this is managed through planning and EDC's Control Centre	terms and PLN's planning			
Cross-border ancillary services provision						
Current provision of cross-border ancillary services	Not existent. No cross-border interconnections	Not existent. Cross-border trade focused on energy trade.	Not existent.	Not existent, though can be implicitly provided through large hydro fleet.	Not existent.	Not existent.
How can interconnector capacity be reserved for ancillary services and remunerated	Not applicable.	No defined mechanism.	No defined mechanism.	No defined mechanism.	No defined mechanism.	No defined mechanism.

Table 5 Current market status in ASEAN countries (Part 2)

	Myanmar	Philippines	Singapore	Thailand	Timor-Leste	Viet Nam
Overview of power system and market						
Electricity market model	Single buyer with several government-owned entities and government departments managing difference aspects of the supply chain	Liberalised generation competition, with wholesale electricity spot market (WESM) and retail competition for large customers	Liberalised market, with generation competition, a wholesale spot market, and retail competition	Single buyer system	Vertically-integrated utility	Unbundled single buyer system, in transition towards a market-based system. Currently a competitive generation market and a wholesale electricity market, which allows distribution entities to purchase electricity in a spot market which sits alongside the existing long-term bilateral contract. Retail competition is currently under development.

Key actors	Electricity Power Generation Enterprise (EPGE) acts as the single buyer The Department of Electric Power Transmission and System Control acts as the system operator Distribution is managed through regional supply corporations IPPs provide limited generation to EPGE through long-term PPAs	Generation fully liberalised with many private generators TransCo acts as owner of transmission system, which is operated under long-term concession by the National Grid Corporation of the Philippine (NGCP)	Generation fully liberalised with many private generators Market administered by the Energy Market Company, while transmission and distribution are provided by SP Group	Electricity Generating Authority of Thailand (EGAT) acts as the single buyer, while also operating the transmission system, and operating its own generators IPPs also provide electricity under long-term PPAs with EGAT Distribution is managed by the Metropolitan Electricity Authority (MEA) in greater Bangkok and the Provincial Electricity Authority (PEA) elsewhere	Electricidade de Timor-Leste (EDTL) provides all generation, transmission, and distribution	Vietnam Electricity (EVN) has been unbundled since 2009, though most of its subsidiaries remain under state-control. This includes the National Power Transmission Corporation. The National System & Market Operator is now an independent entity owned directly by the ministry. IPPs provide generation to PLN both through long-term contracts and the market.

Generation and capacity mix	Dominated by gas and hydro generation, with a small amount of coal and solar	Dominated by coal, with a smaller amount of gas generation. Significant hydro and geothermal generation, and expanding amount of solar and wind.	Dominated by gas generation, with limited solar generation (constrained by land availability).	Dominated by natural gas, with the balance made up of coal, domestic hydro, imported hydro, and solar	Dominated by diesel generation, with limited but increasing solar generation	Dominated by coal, with significant hydro generation and a rapidly increasing share of solar generation, alongside some wind generation.
Existing interconnections and trade arrangements	Interconnections with China, Lao PDR, and Thailand but very limited flows	No interconnections to other systems at present	Interconnection with Malaysia (Peninsular) Exchange managed bilaterality with the Malaysian utility, as well as the multilateral Lao-Thailand-Malaysia-Singapore Power Integration Project (LTMS-PIP) agreement.	Interconnection with Cambodia, Lao PDR, and Malaysia (Peninsular)	No interconnections to other systems at present	Interconnection with Cambodia, China, and Lao PDR Exchange managed by system operators

Ancillary service provision						
Overview of ancillary service provision	Not formally defined and managed implicitly through the utilities	Competitive market for ancillary services became operational in 2024 Prior to that bilateral contracts were agreed between the system operator and ancillary-service provided	Primary and contingency reserve are defined products which are co-optimised and traded competitively Further AS products (eg black start) are defined and procured separately	Not yet formally defined Managed implicitly by EGAT in its system operation	Not formally defined	Ancillary services defined in grid code and included in some PPAs Provision managed through system operator
Long-term ancillary service procurement arrangements	Not existent	NGCP signs multi-year Ancillary Services Procurement Agreements (ASPAs)	Black-start services are procured annually under contracts	Managed through obligations in PPAs	Not existent	Not existent
Short-term ancillary service procurement arrangements (eg. day-ahead)	Not existent	AS/reserve market offers potential for short-term trades	Reserve provision co-optimised in the half-hourly market	Not existent	Not existent	Not existent

Is the system operator able to reserve capacity with generators	Not formally established.	Yes, through firm bilateral ASPAs and the competitive reserve market	Yes	Not formally established and managed through PPA terms and on an ad-hoc basis during dispatch		Yes, managed through PPA terms and grid code obligations and technical rules
Cross-border ancillary services provision						
Current provision of cross-border ancillary services	Not existent.	Not existent.	The current ancillary service market makes no provision for cross-border exchanges	Not existent.	Not existent.	Not existent.
How can interconnector capacity be reserved for ancillary services and remunerated	No defined mechanism.	Not applicable.	Not defined.	Not defined.	Not applicable.	Not defined.

Annex C Overview of current and proposed interconnectors in ASEAN

Table 6 Status of existing and proposed APG interconnections (grid-to-grid only)

ID	Connection	Existing (MW)	Future (MW)	AIMS III 2040 projection (2040)
1	Malaysia (Peninsular) – Singapore	1,050 HVAC	TBC (up to 3,000)	1,050
2	Thailand – Malaysia (Peninsular)	80 HVAC + 300 HVDC	300-600	1,043
3	Malaysia (Sarawak) – Malaysia (Peninsular)	-	TBC	695
4	Indonesia (Sumatra) – Malaysia (Peninsular)	-	1,400-2,000	2,130
5	Indonesia (Sumatra) – Singapore	-	TBC	1,133
6	Malaysia (Sarawak) – Indonesia (Kalimantan)	230 HVAC	TBC	777
7	Malaysia (Sabah) – Philippines	-	200 HVDC	196
8a	Malaysia (Sarawak) – Brunei Darussalam	-	TBC HVAC	TBC
8b	Malaysia (Sarawak) – Malaysia (Sabah)	50 HVAC	Unchanged	177
9	Thailand – Lao PDR	955 HVAC	TBC	700

10	Lao PDR – Viet Nam	-	TBC	625
11	Thailand – Myanmar	-	TBC	1,262
12	Viet Nam – Cambodia	250 HVAC	400	1,353
13	Lao PDR – Cambodia	745 HVAC	TBC	625
14	Thailand – Cambodia	250 HVAC	TBC	1,315
15	Malaysia (Sabah) – Indonesia (Kalimantan)	-	TBC	174
16	Included with 5	-	-	
17	Lao PDR – Myanmar	30 HVAC	130-630 HVAC	624
18a	Indonesia (Sumatra) – Indonesia (Java)	-	2,600 HVDC	10,000
18b	Indonesia (Kalimantan) – Indonesia (Java)	-	TBC	435
n/s	Viet Nam – Singapore	-	1,200 HVDC	
n/s	Cambodia – Singapore	-	1,000 HVDC	

Notes: ID refers to Figure 5 (n/s = not shown)
Sources: ACE. 2024. ASEAN Power Grid Interconnections Project Profiles | ACE. 2025. ASEAN Power Grid Updates 2025 | Comments from HAPUA participations during consultation

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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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