Establishing Multilateral Power Trade in ASEAN

International Energy Agency

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Abstract

The ASEAN member states have a long-standing goal to establish multilateral power trading in the region. To date, regional power trading has been limited to a series of uncoordinated bilateral cross-border arrangements. Multilateral power trading can bring multiple benefits, including reduced system costs, increased energy security and an ability to integrate higher shares of variable renewable energy. An examination of international experiences shows that it is possible to establish multilateral trading while allowing for stepwise and voluntary development and respecting local sovereignty. At the same time, increased cross-border integration and power trade does require increased co-ordination and regulatory harmonisation.

This report identifies a set of minimum political, technical and institutional requirements that the ASEAN member states will need to meet in order to establish multilateral power trading in the region. Some of these minimum requirements can be met by building upon existing efforts in the region. The report also proposes a set of trading arrangements of increasing levels of ambition which, taken together, will enable ASEAN to establish multilateral power trading in a manner that is consistent with maximising national sovereignty and the equitable sharing of benefits. These recommendations include a summary of potential roles for regional institutions and an example transaction to show how trading might potentially work in practice.

Foreword

As the world's leading energy authority, and in line with our "open doors" policy to engage more deeply with emerging economies, the International Energy Agency (IEA) is proud to be a key partner of the Association of Southeast Asian Nations (ASEAN) and its member states in their efforts to enhance the security, affordability and sustainability of energy in Southeast Asia.

At the 36th ASEAN Ministers on Energy Meeting, held in Singapore in October 2018, ministers called for "stronger institutional ties" with the IEA to help the region meet its energy priorities. The IEA has answered this call with an extensive work programme with ASEAN member states over the past year, covering a range of critically important areas.

As the role of electricity in the economies and societies of Southeast Asia is growing rapidly, a key aspect of the collaboration has focused on power markets, including through this report. Increasing electricity trade across borders is critically important and rightly has a central place in Southeast Asia's energy co-operation plans. Regional power system integration can enhance electricity security, improve the affordability of electricity and scale up the deployment of the region's abundant renewable energy resources.

Based on extensive analysis and a review of international experiences and best practices, this report sets out a comprehensive roadmap by which Southeast Asia can achieve those objectives through greater power trade. The report outlines the preconditions that are needed – such as institutional development, grid code harmonisation and information sharing – and how these can be put in place. It then provides guidance on different operational models for multilateral power trade that the region could pursue.

I am confident that this report will provide invaluable and concrete assistance to policy makers in Southeast Asia as they continue to pursue ever-greater power system integration. I would also like to thank the leaders of ASEAN member states for their strong collaboration with the IEA over the past year.

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Executive Director

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Executive summary

The Association of Southeast Asian Nations (ASEAN) member states (AMS) have a long-standing goal of integrating their power systems via a common ASEAN Power Grid (APG). To date, development of the APG has primarily focused on cross-border infrastructure and bilateral trading. The AMS have also long recognised, however, that to fully unlock the benefits of the APG they will need to establish some form of multilateral trading in the region. The intent of this study is to provide the AMS with a set of concrete recommendations for how to establish multilateral power trading in the region. These recommendations are guided by international best practices, but also by recognition of ASEAN's unique context. This context includes a set of core principles that multilateral power trading must respect, including stepwise and voluntary development and maintaining national sovereignty.

Many models of multilateral power trade

Multilateral power trade can be categorised across many different dimensions. Limited models may involve relatively small amounts of trading relative to domestic consumption, and could even be unidirectional in nature, while complete models of trade involve the integration of domestic systems in a single common regional market. There is also a temporal element to trade, with some forms of trade occurring over long time horizons (such as long-term power purchase agreements) and others occurring close to real time (for instance, the intraday or day-ahead time frame).

Multilateral power trading can also be considered in terms of how it fits into national system operations. "Primary" models of trade are ones where regional, multilateral power trading is the default mode. "Secondary" models are ones where regional trading takes place as an additional option on top of domestic market or system operation arrangements. In an ASEAN context, as in other parts of the world, multilateral trading is in a nascent stage, where most or all existing trading is bilateral in nature, but there is a clear desire to implement multilateral trading of one form or another.

To put the ASEAN region in appropriate context, and to better understand international best practices, a set of international case studies was developed to support this study. Eight case studies were developed in total, including two in North America, one in Europe, two in South Asia, one in southern Africa, one in Central America and one in the Persian Gulf region.

Minimum requirements

There are certain minimum requirements to establish multilateral power trading in the ASEAN region. These requirements fall into three categories: political, technical and institutional.

Political requirements include broad areas such as intergovernmental agreements, and narrow ones, such as an agreement on a common working language. They also include the presence of a difficult-to-define but nevertheless critical element – political will.

There are numerous **technical** requirements for establishing multilateral trade. These include harmonised grid codes, a harmonised wheeling charge methodology, provisions for third-party access to domestic grids, agreements on data and information sharing, and a dispute resolution mechanism.

Finally, **institutional** requirements include additional responsibilities for existing institutions, which may in turn require additional capacity building, and the establishment of new institutions that can take on responsibility for new functions, such as market organisation.

Once these minimum requirements are in place, the AMS will be able to develop multilateral power trading in the region.

Proposed trade models for ASEAN

This report proposes three trade models for the ASEAN region. These models are of increasing levels of ambition, and are intended to be compatible with ASEAN's core principles, in particular stepwise and voluntary development.

First, it is recommended that the AMS develop a **harmonised bilateral** trade model. This would involve three key elements: a set of standardised bilateral contract templates, a standard wheeling charge methodology and a "regional co-ordinator" institution. Taken together, this would allow for any individual AMS to enter into bilateral trading agreements with any other AMS, regardless of whether they share a border. While this does not fulfil the broader goal of establishing multilateral power trading, it would improve the efficiency of bilateral trading in the region while also laying the groundwork for more formal multilateral trading.

Second, ASEAN should develop a **secondary trading** model. As defined above, a secondary model involves the development of a regional market that exists separately from national markets and system operations. This would build upon some elements established in the harmonised bilateral model, such as harmonised wheeling charges, and introduce new elements, such as a regional market operator and a central clearing party.

Finally, a more future-oriented **primary trading** model is proposed. Under this option, AMS could choose to replace their national markets with a fully integrated regional market. This would bring additional benefits to participating countries, but would also require more changes at the national level, including market restructuring.

Taken together, these options allow the AMS to make rapid progress on power system integration via the APG, while also enabling each country to make its own decisions as to when and how it chooses to participate in regional multilateral trading.

Findings and recommendations

Highlights

- With increasing shares of variable renewable energy in ASEAN, multilateral power trade can benefit the ASEAN Member States in terms of both increased system security and economic efficiency due to resource sharing.
- Multilateral power trade can be categorised across multiple dimensions, including from limited to complete, and from long-term to short-term trading. More complete and short-term models require more regional co-ordination.
- International experiences show that it is possible to develop multilateral power trading while respecting national autonomy. Establishing multilateral trading in an ASEAN context, however, requires an understanding of the region's unique circumstances and country-specific priorities.
- A number of political, technical and institutional minimum requirements must be met in order to establish multilateral trading in ASEAN. There are, however, no fundamental obstacles to meeting these requirements.
- A number of existing efforts in ASEAN – in particular the Lao PDR–Thailand–Malaysia–Singapore Power Integration Project and the Greater Mekong Subregion – can serve as starting points for work in ASEAN.
- Three trade models are proposed for ASEAN. First, a **harmonised bilateral model** should be established to improve the efficiency of bilateral trading in the region and to lay the groundwork for multilateral trading. Next, a **secondary trading model** should be introduced, creating a regional market for countries to use in addition to existing domestic markets or operations. Finally, for countries that wish to do so, a **primary trading model** could be introduced which would replace domestic markets with a unified regional market.

Overview of study

The Association of Southeast Asian Nations (ASEAN) member states (AMS) have a long-standing goal of integrating their power systems via the ASEAN Power Grid (APG). Development of the APG has, to date, been limited primarily to the development of cross-border transmission lines on a bilateral basis. Power trade has similarly been organised bilaterally, including through cross-border power purchase agreements (PPAs) and bilateral trading without financial compensation. The bilateral power trades that are currently organised are a great first start, but in the future with more variable renewable energy in the ASEAN region, more structured market set-ups with shorter time frames may be needed.

To realise the full potential of the APG, though, the AMS will need to establish multilateral power trading. Doing so would allow the AMS to tap into the potential benefits of an integrated ASEAN power system, including reduced costs and an increased ability to integrate variable renewable energy (VRE) resources.

Multilateral power trade will allow the AMS to take advantage of the resource diversity of the region, as well as create an additional source of flexibility, which will allow them to integrate higher shares of renewables. Multilateral power trade is therefore a framework to increase system security and increase economic efficiency, and an enabler of meeting renewable goals in line with the decarbonisation agenda.

At the same time, any multilateral power trading arrangement established in ASEAN will need to be compatible with certain core principles, including voluntary participation, stepwise development and respect for national autonomy.

Categories of multilateral power trade

Cross-border power trade exists across a spectrum of integration, ranging from limited efforts such as bilateral, unidirectional trades, to multilateral trading models that allow for trading among various jurisdictions, to fully unified models that include market participants from multiple states or countries. Nearly all trading in ASEAN can be described as bilateral between neighbouring countries. For example, Thailand currently imports electricity from the Lao People's Democratic Republic (Lao PDR) under various long-term PPAs.

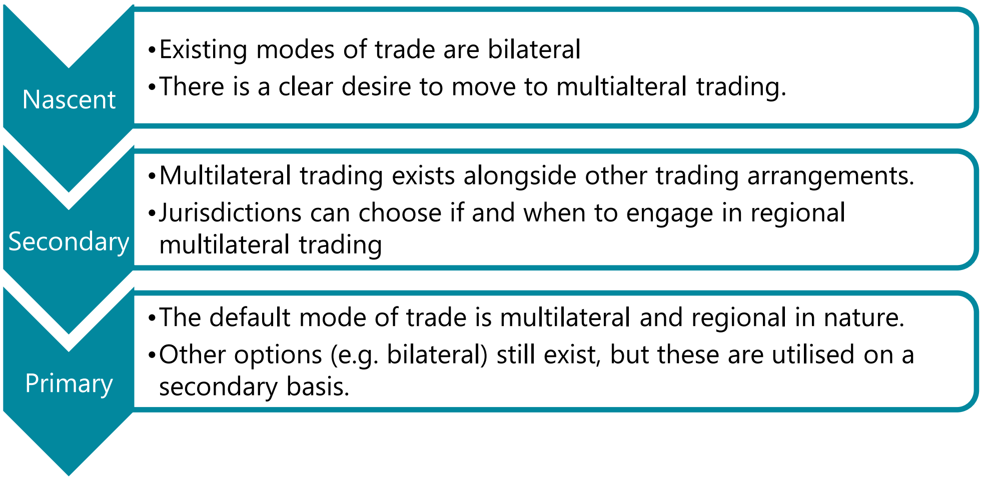
The only example of multilateral power trading in the region is among Lao PDR, Thailand and Malaysia. Here, Malaysia purchases power from Lao PDR under a predefined set of terms regarding price and quantity, and Thailand acts as the transit, or wheeling, country. This example, however, is multilateral only in the sense that it involves an agreement among more than two countries. The trade and associated power flow is unidirectional, and there is no generalised framework for allowing trades between any combination of the participating countries – something that would be necessary for it to be considered a true multilateral, multidirectional trading environment.

Cross-border trading also has temporal attributes. As noted above, most cross-border trading in ASEAN is done under long-term contracts. Trading can also be done closer to the time of delivery, for example in the day-ahead time frame. It is even possible to have real-time trading, such as balancing services. In the context of this study, multilateral trading primarily refers to day-ahead trading, though other types of trading may also be referred to if and when relevant.

Finally, there is a third way to group multilateral trading efforts: by the level of development and the relative role of regional trading as compared with local (i.e. within jurisdiction) alternatives. Multilateral trading arrangements fall into three categories: nascent, secondary and primary (Figure 1).

Nascent arrangements are ones where existing modes of trade are bilateral, but there is a clear desire among the respective jurisdictions to move to multilateral trading. Secondary arrangements are ones where regional multilateral trading exists alongside, and therefore in addition to, other trading arrangements. Jurisdictions are therefore able to choose if and when to participate in regional multilateral trading. Finally, in primary arrangements, the default mode of trade is multilateral in nature. Other options of trade (in particular, bilateral) can and usually do still exist, but typically they are utilised on a secondary basis compared with multilateral trading.

Figure 1. Categories of multilateral power trade



Source: IEA 2019.

International experiences in multilateral power trading

ASEAN is hardly the first region to seek to establish multilateral power trading. Examining efforts in other regions can provide some lessons that may be useful in an ASEAN context.

To get a broad range of experiences, eight regions were examined for this study. These were divided into the three categories of nascent, secondary and primary trading arrangements (Table 1).

Table 1. International case studies examined in this report

Primary	PJM
	ISO New England
	Nord Pool
	India
Secondary	Southern African Power Pool
	SIEPAC (Central America)
Nascent	Gulf Cooperation Council Interconnection Authority
	South Asia Regional Initiative for Energy Integration

Note: SIEPAC = Sistema de Interconexión Eléctrica de los Países de América Central (Central American Electrical Interconnection System).

Four of the case studies are **primary** arrangements. PJM and ISO New England are both regional power markets covering multiple states within the United States. Nord Pool is a regional wholesale market covering multiple countries in northern Europe. Finally, India has, over a number of years, managed to fully integrate its domestic power system into a single market covering the entire country.

Two of the case studies fall into the category of **secondary** trading arrangements. The Southern African Power Pool (SAPP) allows for multilateral trading among multiple countries in southern Africa, while SIEPAC does the same (albeit in a structurally different fashion) for six countries in Central America. Both exist as separate market arrangements that sit above (or separately from) local, in-country power market arrangements.

Finally, two **nascent** efforts were analysed: the Gulf Cooperation Council Interconnection Authority (GCC IA), and the South Asia Regional Initiative for Energy Integration (SARI/EI).

Though these examples are all quite different, a number of lessons relevant to an ASEAN context emerged from the analysis.

First, in all cases integration supported by multilateral trading was found to bring both economic and security benefits. Economic benefits derive, for example, from the more optimal utilisation of local and regional resources. This can lower operating costs, and can also support the development of larger (and therefore more economically efficient) power plants. Energy security benefits come in part from increased system diversity (in particular supply diversity, though demand diversity also brings benefits), and in part from increased visibility into other, interconnected systems. Physical integration among multiple jurisdictions without the presence of trading arrangements increases exposure to external influences while limiting the ability for local system operators to respond to those influences.

Second, each case demonstrated that it is possible to participate in multilateral trading arrangements while maintaining local sovereignty. It is also possible to develop trading arrangements that ensure an equitable sharing of benefits. All of the various international examples analysed in the context of this study respected the ASEAN principles for multilateral power trading. However, it is also clear that increased integration requires increased levels of cross-border collaboration and harmonisation.

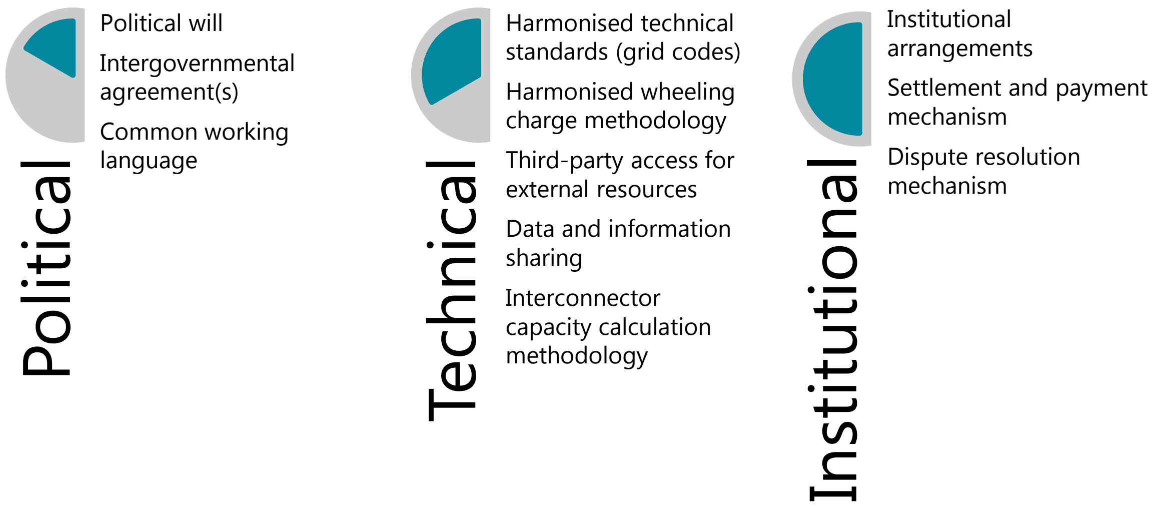
Finally, in each of the regions studied, integration and the establishment of multilateral trading was supported by the presence of various regional institutions. The exact roles and responsibilities of these institutions varied across regions, but in each case the institutions had critical roles to play.

Minimum requirements for establishing multilateral power trading

Reviewing international experiences also brought to light a set of common elements that could be considered "minimum requirements" for establishing multilateral trading in a region. In an ASEAN context in particular, these requirements would need to be met first before it would be possible to establish a full multilateral, multidirectional trading framework.

These minimum requirements can be grouped into three categories: political, technical and institutional.

Figure 2. Minimum requirements for establishing multilateral power trade



Political requirements

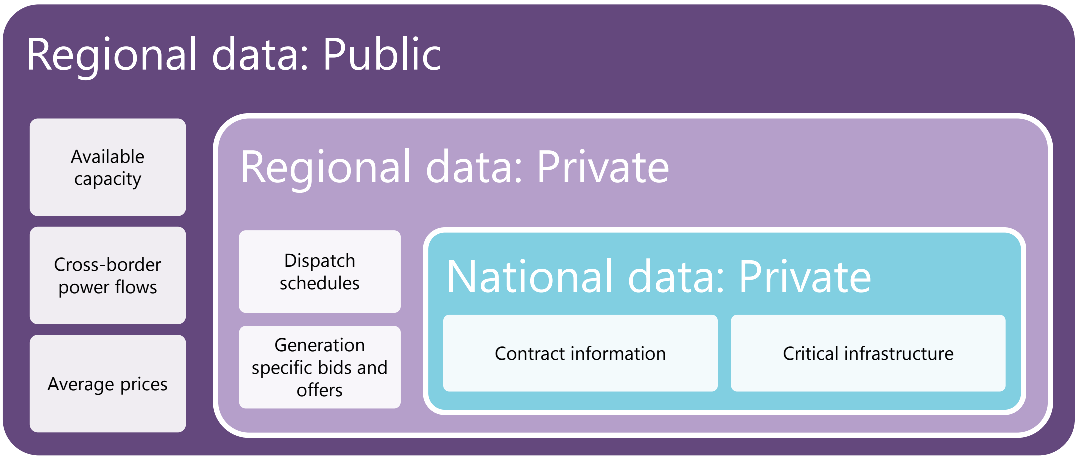
Political requirements include relevant intergovernmental agreements, and agreement on certain fundamental, but non-technical, issues such as a common working language. Analysis of or recommendations related to specific intergovernmental agreements is beyond the scope of this study, but for example, agreements may be needed to establish and/or designate specific authorities to relevant regional institutions. Another key political requirement is political will. Though difficult to define precisely, political will to support integration is nevertheless a crucial element, as it is one of the elements that differentiate cross-border integration from power system development within a single jurisdiction. Without political support across the relevant jurisdictions, no amount of technical work will be sufficient for integration to fully succeed.

Technical requirements

Technical requirements cover a broad range of topics, but in essence this category refers to the rules and procedures required to ensure that cross-border trade can function in a secure and efficient manner. For example, harmonised grid codes help to ensure that power system operations across interconnected systems are not in conflict with one another. Similarly, a harmonised wheeling charge methodology is necessary to allow trading between any combinations of AMS regardless of whether they share a border.

Data- and information-sharing agreements are even more fundamentally important, as without a clear agreement on which data to share and which data should be kept private, trading is not possible. In practice, data and information will fall into different categories of sensitivity. Information about existing contracts or critical infrastructure can and should remain private at the national or jurisdictional level. Some data, such as dispatch schedules and generator-specific bids and offers, will need to be shared regionally, but access to that data can be limited to regional market participants only. There are clear benefits, however, to making some data publicly available on a regional basis, including, for example, available transmission and generating capacity, historical information on cross-border power flows, and average clearing prices for regional trades.

Figure 3. Data and information sharing: Private versus public



Source: IEA 2019.

Institutional requirements

Finally, as noted above, international experiences show that multilateral trading and regional integration more broadly are best supported by regional institutions. In an ASEAN context in particular, additional institutional arrangements will be necessary to establish full multilateral trading in the region. This will include both additional capacity building at existing institutions, and potentially the development of new institutions. Some of these new institutional arrangements will go to support functions such as a settlement and payment mechanism and a dispute resolution mechanism.

Building upon existing efforts

Though there is much work to be done to establish full multilateral trading among the AMS, ASEAN is hardly starting from scratch. Two subregional efforts in particular are worth highlighting: the Lao PDR–Thailand–Malaysia–Singapore Power Integration Project (LTMS–PIP) and the integration effort in the Greater Mekong Subregion (GMS).

LTMS–PIP

The LTMS–PIP is a "pathfinder" project that is meant to demonstrate that multilateral power trading is possible in an ASEAN context. As it stands today, the LTMS–PIP involves the sale of electricity from Lao PDR to Malaysia, with Thailand acting as a transit, or wheeling, country.

The LTMS–PIP has demonstrated that power trading among multiple AMS is possible. What remains to be seen is whether it can be expanded to include more than three countries, and generalised to allow for multidirectional trading among any set of participants. Nevertheless, much of the work done under LTMS–PIP is relevant for establishing a general framework for multilateral trading in the region. For example, the LTMS–PIP includes a wheeling charge methodology that could become the basis for a harmonised regional model.

The process of developing the LTMS–PIP has also been instructive. It involved the establishment of separate working groups that gave each of the stakeholders a role in developing the power trade, even if, in the end, they chose not to participate. This sharing of responsibilities is one way to encourage all of the AMS to participate in the development of full multilateral trading, even if they do not expect to see an immediate benefit from it. Finally, the LTMS–PIP development process included the establishment of a detailed timeline for development with concrete deliverables and milestones. Having this in place gave all stakeholders a clear view of their respective roles, and made it easier to judge overall progress.

GMS

The GMS includes six countries. Five are AMS, while the sixth is the People's Republic of China (specifically, southern China). Efforts to integrate the power systems of these six countries have been ongoing since the early 1990s, and the GMS effort as a whole has existed in parallel to the development of the APG.

Establishing multilateral power trading in the GMS is one of the outstanding goals of the region. As with the APG effort, however, progress to date has been limited mainly to the establishment of various bilateral trading arrangements. Notable progress has been made, however, in a variety of technical and procedural areas, all of which offer lessons for efforts to establish multilateral trading among the AMS.

In terms of technical requirements, for example, the GMS effort has led to the development of draft harmonised grid codes and a draft wheeling methodology. While these have not been formally implemented, the development process did include five of the ten AMS, suggesting that these could provide a good starting point to developing a more general set of harmonised grid codes for the region as a whole.

The process of developing the GMS also has a number of positive lessons for the APG. In particular, progress has been made in a GMS context in large part because of the regular sharing of relevant information among the participating countries, such as grid plans.

At the same time, some of the challenges the GMS effort has faced offer lessons for ASEAN as well. For example, the GMS effort includes a proposal to develop a regional control centre. This effort has stalled, however, in no small part due to disagreements over where the institution should be located. The GMS effort also demonstrates the challenges, but also potential benefits, of including non-AMS in the process.

Proposed trade models for ASEAN

Once the minimum requirements are met, it will be possible to establish multilateral power trading in ASEAN. To do so, three trade models are proposed. These are meant to enable the development of multilateral trading while respecting ASEAN principles such as stepwise and voluntary development.

There is no requirement that each individual AMS participate in all of the various trade models, if and when they are developed.

These models are also designed to be compatible with one another, so that it will be possible for more than one model to exist simultaneously.

The proposed models are as follows. As a near-term step, it is recommended that ASEAN establish a framework to support **harmonised bilateral trading**. Then, as a medium-term step, the AMS should establish a **secondary trading model**. This would enable true multilateral, multidirectional power trading for the first time in the region. Finally, as a longer-term step, ASEAN should consider establishing a **primary trading model**, which would enable deeper integration and power trade among the participating countries.

Here is how these models would work in practice.

Harmonised bilateral trading

In the harmonised bilateral trading model, the AMS would develop a common framework for entering into and managing cross-border bilateral contracts. In essence, this model builds upon existing bilateral arrangements in such a way as to improve the efficiency of the process, and to allow any two interconnected AMS to trade with each other, regardless of whether they share a border.

To do this, the harmonised bilateral model introduces three key elements.

First, the AMS would develop a set of standardised bilateral contract templates. These would be relatively flexible contract templates that would provide a common starting point for any two countries (or market participants) to enter into a bilateral agreement. Second, the AMS would introduce guidelines for wheeling methodologies, as described above. This would allow any two AMS to trade with each other by ensuring that "transit" countries are compensated for the use of their grid.

Finally, this model would introduce the option for a "regional co-ordinator" institution, which would act as an enabler of bilateral trading. The regional co-ordinator would, in essence, only collect and share information, such as available transmission capacity, willingness among participants to trade and relevant information on signed bilateral contracts. It would not be directly involved in the transactions themselves.

While harmonised bilateral trading is not equivalent to full multilateral trading, with these elements in place it would be possible for the AMS to enter into a more flexible and diverse set of bilateral trading arrangements. At the same time, having the key elements of the harmonised bilateral trading model in place would set the stage for more formal multilateral arrangements.

Secondary trading model

A secondary trading model is, at its core, a regional power market that individual AMS (and other relevant market participants) can use in addition to domestic system operations or markets. Under the proposed model, only excess generation or supply gaps would be traded. Domestic markets or power systems would clear first, and the secondary market would be used only if and when doing so adds value to participating AMS.

Establishing a secondary trading model would enable full multilateral, multidirectional power trading among the AMS, while remaining fully compatible with harmonised bilateral trading. This would require the introduction of a number of new elements, some of which build upon the harmonised bilateral model, and some of which are unique to this model.

As a starting point, some of the core elements required to establish harmonised bilateral trading are relevant in a secondary trading model context as well. In particular, the wheeling model introduced as part of the harmonised bilateral model would also enable wheeling in the secondary model.

One new element that would need to be introduced in the secondary model is a regional market operator. The market operator would collect information on excess supply and demand, match potential trades, and provide relevant information to the AMS. It could also, potentially, aid in wheeling charge calculations. As some of these functions are similar to the recommendation for a regional co-ordinator role in the harmonised bilateral model, one option would be for the recommended regional co-ordinator institution to take on the market operator responsibilities as well.

Because trading in a secondary model is potentially more complicated than under a harmonised bilateral model, it would also be necessary to introduce an organisation that can function as a central clearing party (CCP). The CCP would simply collect and distribute money associated with any cleared trades. The proposed market operator could take on the CCP function as well, or that could be established in a separate institution.

Primary trading model

Establishing a secondary trading model would fully meet ASEAN's goal of enabling multilateral power trading among the AMS. It is, however, worth considering a more ambitious, future-oriented option that would bring more benefits to participating countries – albeit with more work required of them.

Under a primary trading model, regional multilateral trading would become the primary mode of trade. All generation in the participating countries would clear in the regional market. This allows for full reserve and capacity sharing, and enables increased optimisation of generation resources across the integrated markets.

Doing so, however, requires that domestic markets be fully restructured. Moreover, under the primary model, there are no national or local markets, but instead only a regional market among the participating countries. Harmonised bilateral trading is still possible under this model, but for the countries involved it would be a replacement for a secondary model.

Functionally, this model is not dramatically different from the secondary model. The role of the regional institutions remains essentially the same, though their overall responsibilities would increase significantly. It would be possible, though, for the same market operator in the secondary model to organise the primary market as well.

In all likelihood, many or perhaps even most of the AMS will choose not to implement a primary model, at least in the near term. This is therefore included as a more future-oriented option, one that could be implemented after the secondary model is established. It is important to note, however, that secondary and primary models are compatible with each other, in the sense that trading is possible between them. In addition, it is still possible for the AMS to utilise the harmonised bilateral trading model.

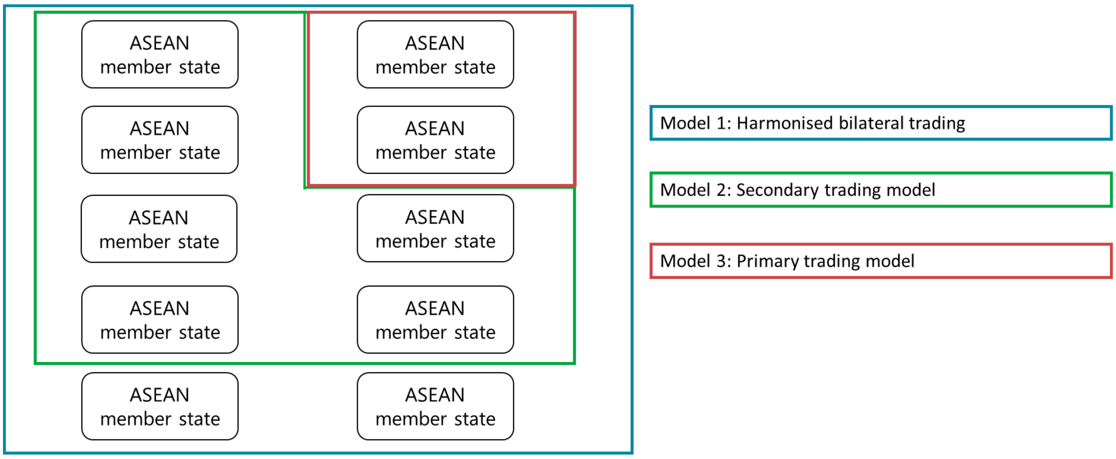
Conclusion

ASEAN has made significant progress on the development of the APG. Most of this progress, however, has been limited to the bilateral development of transmission infrastructure and trade. Though the ASEAN region is in many respects unique, lessons from international experiences show that it is possible to develop multilateral trading while respecting the local context. Moreover, pilot projects such as the LTMS–PIP demonstrate that it is very possible to establish multilateral trading within ASEAN.

Development of multilateral trading in ASEAN can and should be done in a stepwise and voluntary fashion. It is therefore possible, as demonstrated in Figure 4, that different AMS will choose to participate in different trading models. The proposed trading models allow for that kind of flexibility. Harmonised bilateral trading can benefit all AMS, so long as they are interconnected, by providing a framework and institutional structure to make it more efficient. It may be that a subset of AMS choose to limit themselves to bilateral trading only, while others choose to participate in a secondary model. It may also be that some AMS choose to create a primary trading model among themselves.

Regardless of the path each AMS chooses to take, there are clear benefits to be gained by ASEAN as a whole in moving forward with the establishment of multilateral power trade.

Figure 4. A possible future for power trade in ASEAN

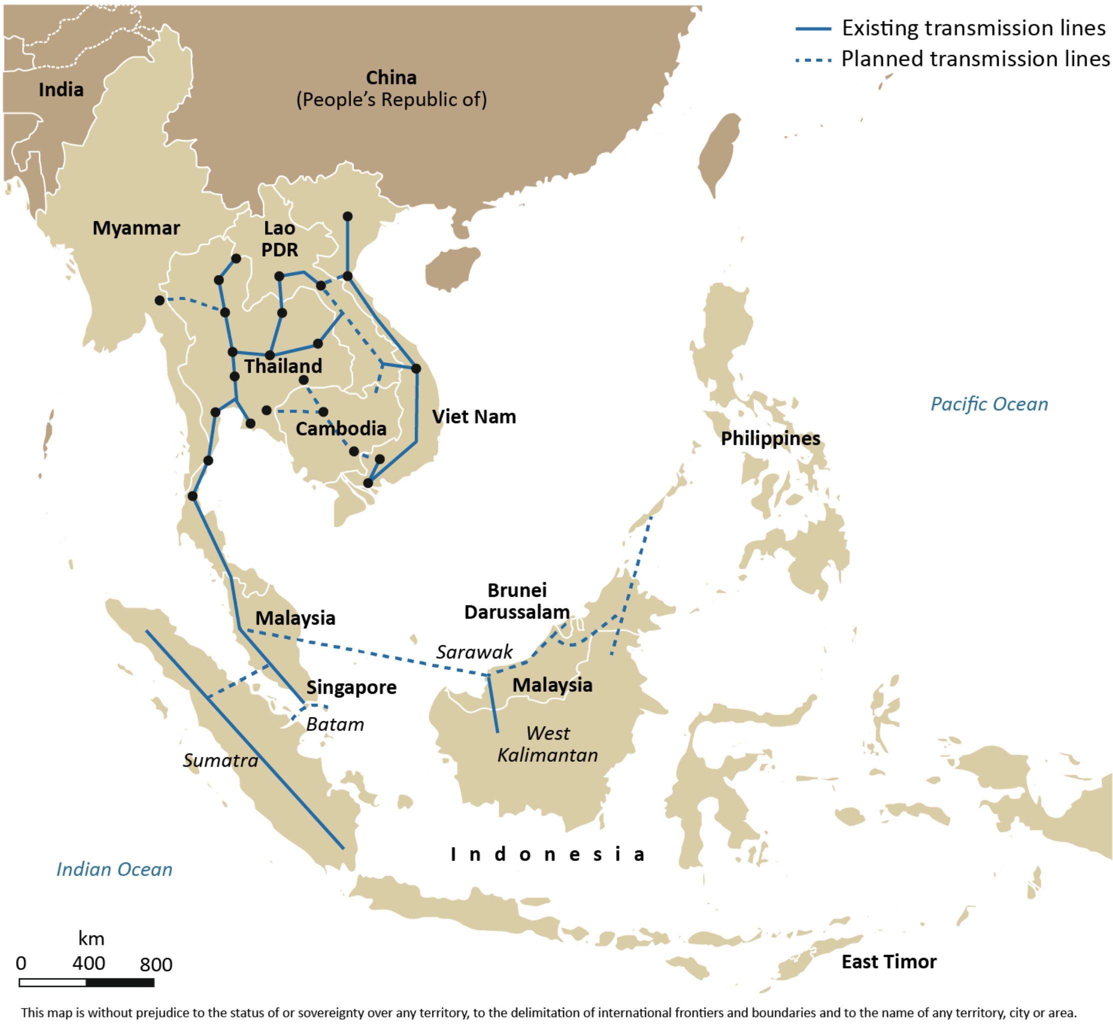


Source: IEA 2019.

1. Introduction

The ASEAN member states (AMS) have had a long-standing goal of integrating their power systems. The overarching aim is to develop the ASEAN Power Grid (APG). The APG is composed of a series of cross-border alternating current (AC) and direct current (DC) interconnectors. Power trade across the APG lines that currently exist is primarily bilateral, and organised under a wide range of different trading arrangements.

Figure 5. The APG



Note: Lao PDR = Lao People's Democratic Republic.

The APG, when fully developed, will interconnect the power grids of all of the AMS.

More recently, the AMS have expanded efforts to develop the APG to include the establishment of multilateral power trading. At present, multilateral power trading is limited to a single pilot project among Lao PDR, Thailand, Malaysia and Singapore. The aim of this feasibility study is to provide guidance to the AMS on how to establish multilateral power trading, considering both international best practices and ASEAN's unique circumstances.

Models of cross-border power trade

Cross-border power system integration efforts involve the tying together of two or more distinct power systems. Integration must therefore potentially contend with technical differences (e.g. different frequencies, different grid codes) and different power market structures (e.g. liberalised versus vertically integrated). There is no single path to cross-border integration, and integration is not a binary choice between all in or not at all. Rather, integration efforts exist across a spectrum ranging from limited to complete, with different choices across that spectrum bringing different sets of potential benefits, but also different sets of compromises and challenges.

Figure 6 lays out a hierarchy of power system integration models. These vary from ones that are very limited (e.g. the simplest model, unidirectional power trading) to ones that can be considered "complete", or fully integrated (e.g. the PJM system in the United States, which organises markets, supports transmission planning and manages generator dispatch across a wide geographic area that includes multiple jurisdictions).

Figure 6. Degrees of cross-border power system integration: From limited to complete

Bilateral, unidirectional power trade	• Thailand imports from Lao PDR
Bilateral, bidirectional power trade	• Malaysia–Singapore (non-financial)
Multilateral, multidirectional trade among differentiated markets	• Southern African Power Pool (SAPP)
Mulitilateral, multidirectional trade among harmonised markets	• European Union Internal Energy Market
Unified (pooled) market structure, differentiated operations	• Nord Pool
Unified market and operations	• PJM

Moving from "limited" models such as bilateral trade to more "complete" models such as multilateral or unified requires increased cross-border collaboration, including the sharing of resources.[1]

[1] Under unified models, resources are optimised across jurisdictional (e.g. national) borders, which means a high level of integration and a lack of local markets that are distinct from the regional market.

Among ASEAN countries, cross-border integration already occurs among many countries on a bilateral basis. Nearly all of the existing ASEAN cross-border integration efforts fit into the first two categories: unidirectional power trades and bidirectional power trades.

The Lao PDR–Thailand–Malaysia–Singapore (LTMS) power trade (also called the LTMS–PIP) is an interesting exception. The LTMS power trade involves the sale of 100 megawatts (MW) of electricity from Lao PDR to Malaysia, with Thailand acting as the transit, or wheeling, country.[2] Three countries are involved in the trade, and so by definition it is "multilateral" in nature. However, it is important to separate the trade of electricity from the physical flow of the delivered power. The power flow is, in this case, multilateral: power is exported from Lao PDR and imported into Thailand, then exported from Thailand and imported into Malaysia.

The last four models highlighted in Figure 6 are all more formal multilateral arrangements, each with differing degrees of integration: multilateral power trading among differentiated markets; multilateral power trading among harmonised markets; unified market structure but differentiated operations; and unified market and operations.

The SAPP model falls into the first category. It involves multiple countries of differing levels of development, market structure and resource base, trading power with one another through a common market framework. SAPP is a "secondary" power market in that it is differentiated from national power systems, with national utilities and other participants choosing whether and how much of their resource base to trade regionally. Another example is the SIEPAC market in Central America.

The European Union (EU) as a whole falls into the next category of multilateral trade. Composed of a range of member countries that vary widely in terms of level of development and resource base, the structure of EU member (and even some neighbouring non-member) power markets are nevertheless well-harmonised. EU member countries retain full control over domestic power system operations and planning, but are able to trade with one another utilising different, but functionally identical, power market platforms (the so-called power exchanges).

Individual power exchanges within Europe can function either within a single country or across multiple countries. Nord Pool is Europe's oldest example of a common market covering multiple countries. As in the rest of Europe, each country retains full control over system operations and transmission planning. Therefore, though there is a single market for the region, the national transmission system operators (TSOs) remain fully distinct from one another. It therefore falls into the "unified market, differentiated operations" category.

The last model of cross-border integration is the deepest of all: unified power market and system operations. PJM in the United States is responsible for organising electricity markets and for co-ordinating dispatch across all generators within its service territory, which extends across multiple states.

Another dimension of cross-border power system integration is worth emphasising: time. While the result of cross-border power trading is the physical delivery of electricity from one jurisdiction to another in real time, from a market perspective the trade could occur very close to the time of delivery (e.g. in the hour or day ahead) or months or years ahead of

[2] The LTMS power trade described here refers to Phase 1 of the project. Phase 2 is planned to expand to include Singapore and will potentially move to multidirectional power trade. This is described in more detail in Section 3.

delivery (Figure 7). There are many examples of each of these types of trades in the markets discussed above and in other markets as well, and different markets may trade different sets of various power "products".

Figure 7. Degrees of cross-border power system integration: From long-term to short-term

Cross-border power system integration can function across multiple time dimensions simultaneously.

This study focuses primarily on long-term and day-ahead trading, though it will also refer to other types of trading when appropriate. The reason for focusing on the day-ahead market is that it is internationally recognised as a cornerstone of power market design. The day-ahead market typically creates a reference price that can be used in other markets such as forward markets and balancing markets, which are typically developed after a day-ahead market has been established. Developing regional day-ahead trading could have specific implications for countries that already have domestic wholesale markets in place. How such trading would interact with specific national markets in an ASEAN context is out of scope for this study, but AMS are encouraged to investigate this on a national level.

ASEAN principles for developing multilateral power trade

In April 2017, the ASEAN Power Grid Consultative Committee (APGCC) agreed to a set of principles that should underpin increased power system integration in the region. These principles were reaffirmed at a follow-on workshop organised under the auspices of this study, held in September 2018. As any effort to establish multilateral power trading among AMS should align with these principles, it is important to present them and discuss their implications.

The six principles are:

1. Efforts to establish multilateral power trading should be **stepwise and voluntary**.
2. Power trade should focus on **gaps and excesses** and not require the full participation of all domestic generation in a regional power market. In particular, multilateral power trading should not interfere with the operation of national power systems.
3. National regulations should be **complemented by regional co-ordination**. While some regulatory alignment may be necessary to support trade, multilateral power trading should not require complete regulatory harmonisation among the participating countries.
4. Multilateral power trading should be supported by the **expansion of regional (cross-border) power system infrastructure**. A master regional infrastructure plan should be developed with multilateral power trading in mind.
5. True multilateral power trading will require the development of a **regional wheeling price model**.

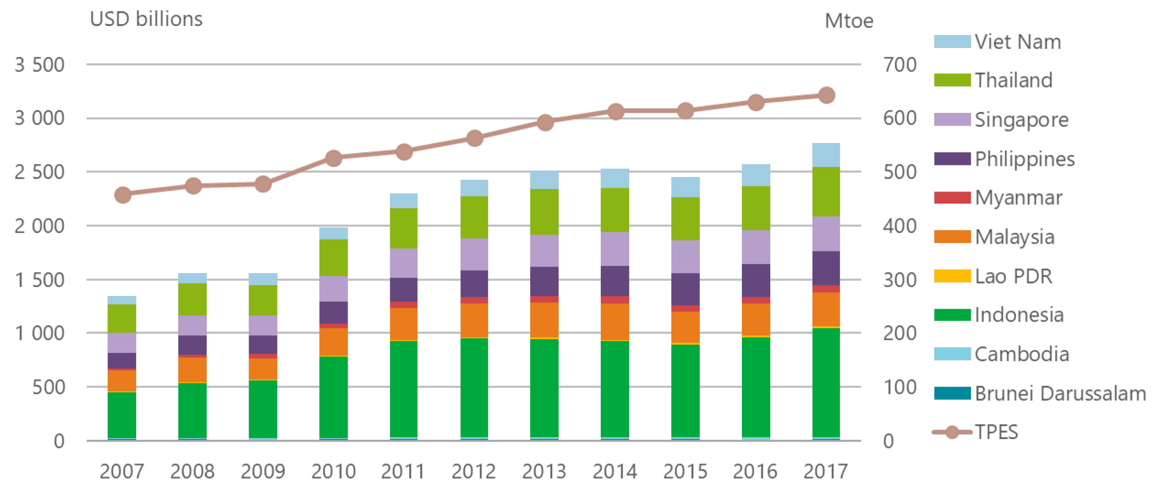
6. Multilateral power trade should **support the development of sustainable power systems**. For example, it should help to increase the deployment of variable renewables such as wind and solar photovoltaic (PV), and should help enable increased electricity access.

Taken together, these principles are broad enough to accommodate a potentially wide range of power trading models, but well enough defined to set some clear boundaries on the scope of the solutions put forward. With these principles in mind, the study now turns more specifically to the ASEAN context.

Overview of ASEAN's energy sector

Taken together, the ten countries that make up the ASEAN Economic Community are the sixth-largest economy in the world (ASEAN, 2016). This economy is home to approximately 634 million people and, between 2007 and 2017, real gross domestic product (GDP) in the region more than doubled – from USD 1.34 trillion to USD 2.76 trillion. Both energy demand and supply have also increased significantly over this period, with total primary energy supply (TPES) rising around 40% from 458 million tonnes of oil equivalent (Mtoe) in 2007 to 643 Mtoe in 2016.

Figure 8. GDP (current price) by AMS and overall TPES for ASEAN



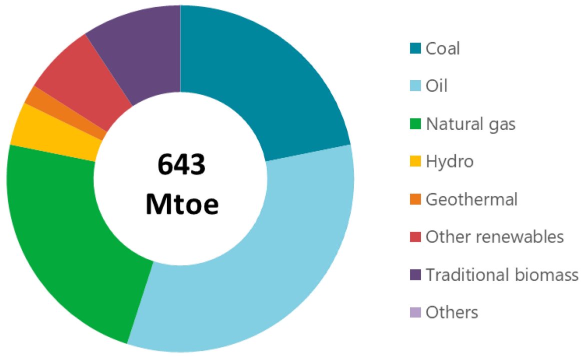
Source: ASEAN Centre for Energy.

The AMS range significantly in terms of size and level of development.

Energy is predominantly supplied by oil, followed by natural gas and coal (Figure 9). In 2017, renewable energy represented 20% of the total in ASEAN's TPES.

Under the ASEAN Economic Community Blueprint 2025, ASEAN committed to actively support "green development" by promoting a sustainable growth agenda that enables the use of clean energy, including renewable energy. Against this backdrop, the 32nd ASEAN Ministers on Energy Meeting (AMEM), held on 23 September 2014 in Vientiane, Lao PDR, endorsed the ASEAN Plan of Action for Energy Cooperation (APAEC) 2016-2025, which included seven programme areas. Renewable energy is the focus of programme area number 5, which sets an aspirational target of 23% renewable energy in the TPES by 2025 across the region.

Figure 9. ASEAN TPES by fuel type, 2017



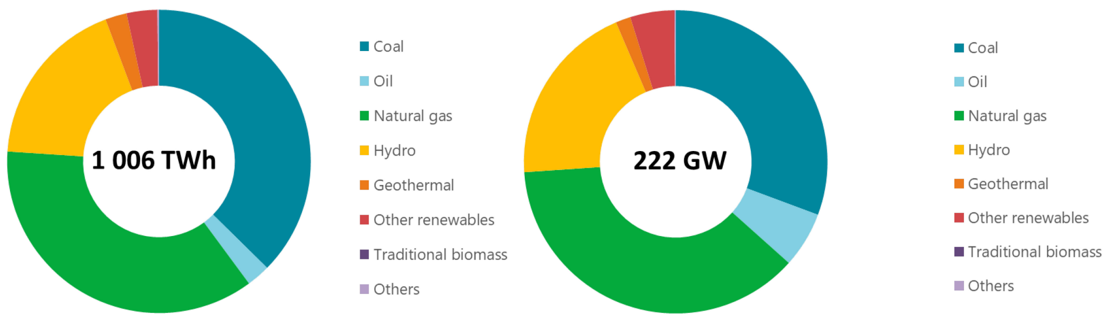
Source: ASEAN Centre for Energy.

Fossil sources make up the largest share of ASEAN's primary energy consumption.

ASEAN generated 1 006 terawatt-hours (TWh) of electricity in 2017 from more than 220 gigawatts (GW) of total installed capacity. Among generation sources, natural gas- and coal-fired power plants make up around three-quarters of the total. ASEAN is also rich in hydroelectric production, with hydropower making up about 20% of total generation. Other renewables and geothermal total only 5% each, with the rest composed primarily of diesel generation (see Figure 10, left side).

From 2010 to 2017, ASEAN member states built significant amounts of new coal-fired capacity. As a result, coal made up 37% of the generation capacity in 2017 while gas made up 36%, hydropower 22%, oil 3%, other renewables 3% and geothermal 2%.

Figure 10. ASEAN power generation (left) and installed capacity (right) by type, 2017

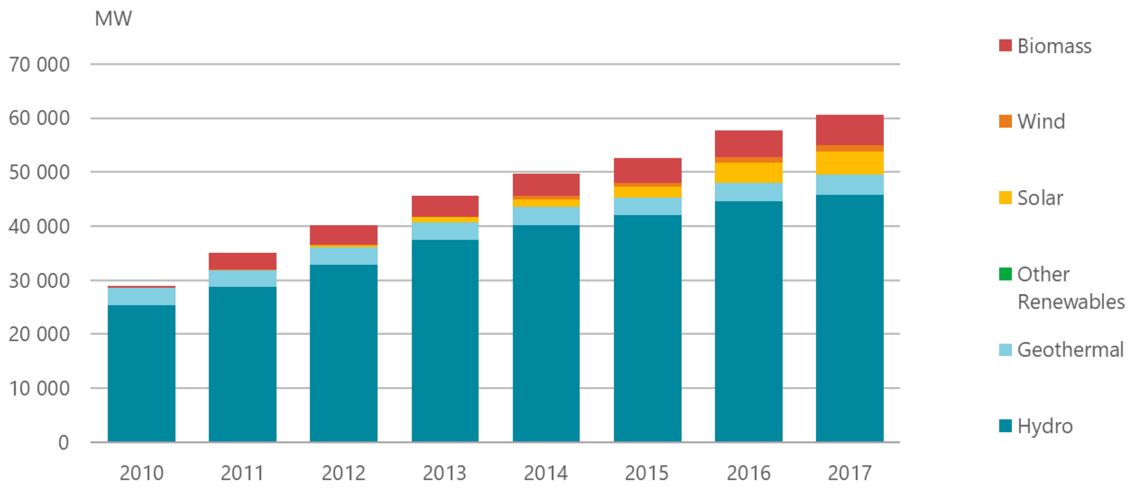


Source: ASEAN Centre for Energy.

ASEAN's power generation is primarily made up of fossil fuels.

Total installed renewable energy capacity (including large hydro) amounted to 60 GW, double what it was in 2010. As shown in Figure 11, hydropower makes up the highest share of installed renewables capacity in ASEAN at 76%, followed by biomass (9%), solar PV (7%), geothermal (6%) and wind (2%).

Figure 11. Installed renewable energy capacity in ASEAN by type, 2010-17



Source: ASEAN Centre for Energy.

Since 2010, hydro has grown the most in absolute terms, but solar PV and wind are the fastest-growing renewable resources.

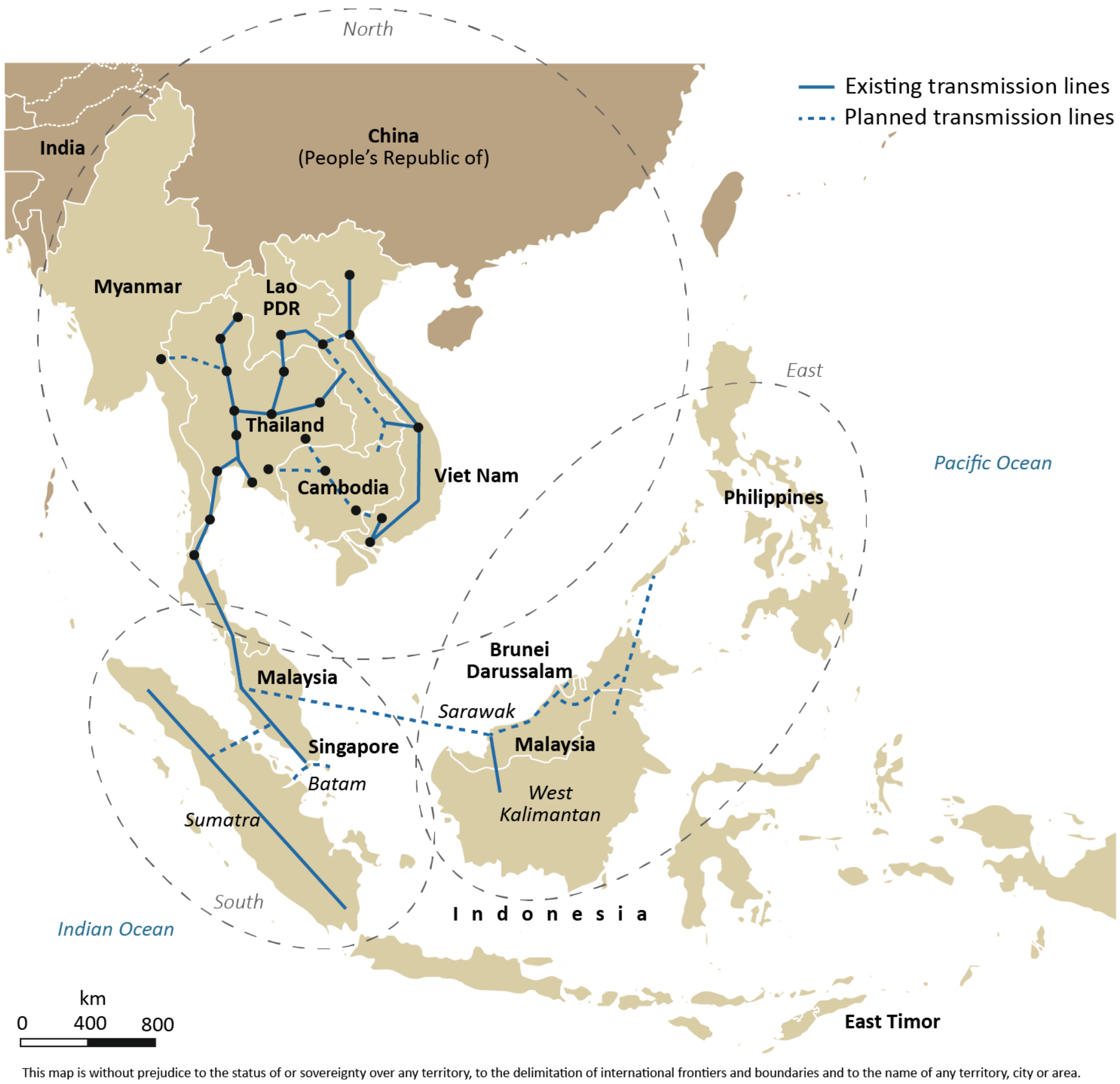
References

ASEAN (2016), *ASEAN Fact Sheet 2016*, https://asean.org/storage/2012/05/11a.-April-2016-Fact-Sheet-of-ASEAN-Community.pdf.

2. AMS perspectives

The following sections describe the power systems and market structures for each of the ten AMS. Countries are grouped by their APG region: North, South and East (Figure 12).

Figure 12. The three APG regions



Note: Lao PDR = Lao People's Democratic Republic.

The APG is divided into three subregions: North, South and East.

The North region (APG North) includes the largest number of AMS: Cambodia, Lao PDR, Myanmar, Thailand and Viet Nam. The South region (APG South) includes one whole country (Singapore) and parts of two others: Peninsular Malaysia and Sumatra Indonesia. Finally, the

East region (APG East) includes all of the Philippines and Brunei Darussalam, and the eastern portions of Malaysia (Sarawak and Sabah) and Indonesia (specifically West Kalimantan).

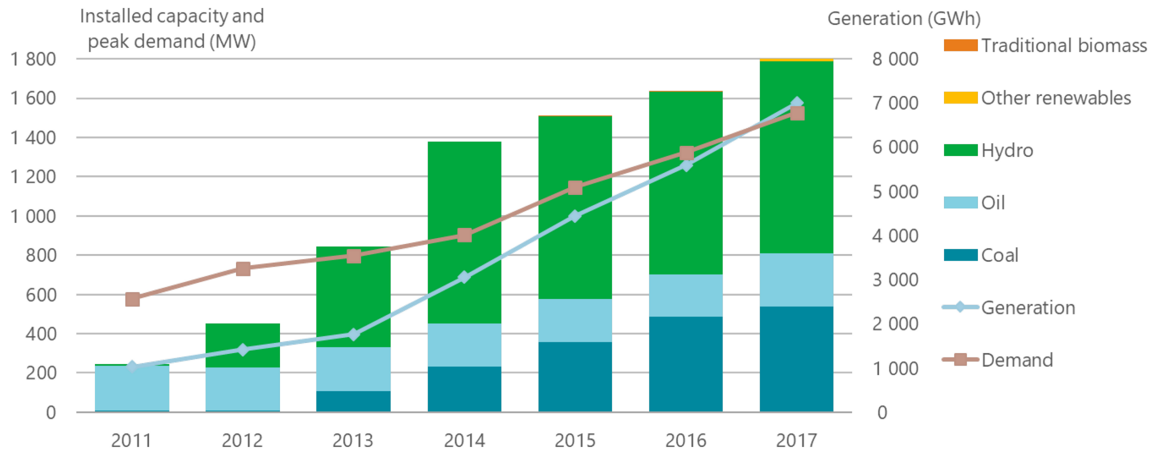
APG region: North

Cambodia

From 2011 to 2018, installed generating capacity in Cambodia increased by eight times. Total installed capacity is 2 208 MW, 57% of which is hydropower, followed by coal with 24%. In 2017, Cambodia installed 10 MW of solar capacity after a revision of its solar regulation. This may lead to more solar investments in the future.

In 2017, Cambodia generated 6 633 gigawatt-hours (GWh) of electricity, of which 2 711 GWh came from hydroelectric power, 3 569 GWh from coal and 259 GWh from oil (Figure 13). Imports supplied an additional 1 439 GWh, or nearly 19% of total demand.

Figure 13. Generation mix, total generation and peak demand in Cambodia, 2011-17



Source: ASEAN Centre for Energy.

Coal generation in Cambodia is growing relatively quickly, though hydro remains the dominant power source.

Cambodia's electricity market is vertically integrated, with a single utility, Electricite du Cambodge (EdC), responsible for the transmission sector and part of the distribution sector. EdC is responsible for distribution in the capital region and in some of the provinces, with the rest of the country managed by the Rural Energy Enterprises (REE). EdC owns generation, purchases power from independent power producers (IPPs) and imports power from neighbouring countries. IPPs are also able to sell to REE or, in some cases, directly to rural consumers. The Electricity Authority of Cambodia is responsible for regulating the power sector.

Cambodia has several existing interconnections with neighbouring countries, including Lao PDR, Thailand and Viet Nam. A total of 28 cross-border interconnectors have been commissioned since 2007, ranging in voltage from 22 kilovolts (kV) to 230 kV (Table 2).

Table 2. Cambodia's interconnections with its neighbours (as of 2017)

Country	Voltage
Lao PDR	22 kV, 115 kV
Thailand	22 kV, 115 kV
Viet Nam	22 kV, 35 kV, 230 kV

Source: ASEAN Centre for Energy.

Planned development, including cross-border integration

Cambodia's most recent power development plan (PDP) covers the period 2014 to 2030. It includes two scenarios: 1) a coal- and hydro-based scenario; and 2) a scenario where Cambodia also starts using natural gas by 2023. Under either scenario, new generation would be developed domestically, entirely offsetting imports, and in fact potentially turning Cambodia into a net exporter of electricity. Notably, neither scenario assumes new non-hydro renewable energy development (Electricity Du Cambodge and Chugo Epco,2015).

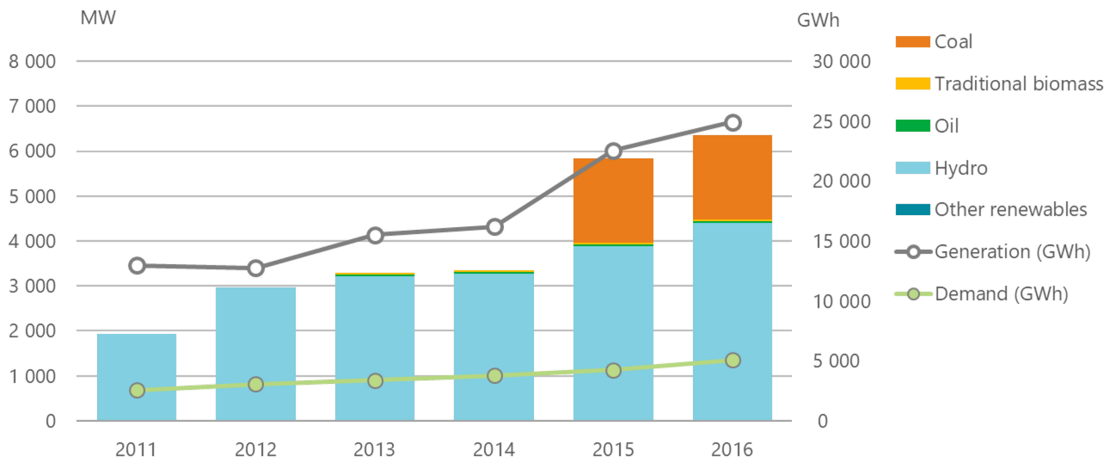
Under either scenario, Cambodia would have surplus hydro capacity during rainy seasons. The expectation is that this excess could be used to offset any loss of domestic generating capacity due to maintenance or other outages, or it could be exported to neighbours.

However, during the rainy season, neighbouring countries will also likely experience a surplus of hydropower (in particular, Lao PDR). Demand in nearby thermal-dominated power systems (e.g. Thailand and Malaysia) may be high enough to support imports from multiple countries, but this would require increased regional co-ordination, including of power trading.

Lao PDR

In 2017, Lao PDR had approximately 6 900 MW of installed generating capacity, up from only 1 936 MW of installed capacity in 2011. In 2015, Lao PDR commissioned 1 878 MW of coal capacity, most of which is sold on an export basis to Thailand. Prior to that, the installed capacity base was almost 100% hydropower.

Figure 14. Power mix, total generation and demand in Lao PDR, 2011-16



Source: ASEAN Centre for Energy.

Lao PDR is a significant net exporter of electricity, primarily from its large hydro resources.

Because domestic demand is low relative to domestic supply, Lao PDR uses only a fifth of its power generation for domestic consumption. The rest of is exported to neighbouring countries, in particular Cambodia, Myanmar and Thailand (among ASEAN countries) and southern China (in particular, Yunnan province via a 115 kV transmission line).

Lao PDR is vertically integrated, with state-owned Electricite du Lao (EdL) generating, transmitting and distributing electricity to end users. The power sector is regulated by the Department of Electricity Policy and Planning, which develops national energy policies (including tariff policy), monitors the energy sector to ensure compliance with applicable policies and regulations, and develops strategic plans for generation, transmission, distribution, rural electrification, renewable energy and energy exports.

However, on the generation side, domestic independent power producers (DIPP) and expanding independent power producers (EIPP) also play a role. As the names suggest, DIPPs sell power to domestic consumers via EdL, while EIPPs primarily export power to neighbouring countries such as Thailand and Viet Nam (though a small fraction of their production is also consumed locally). Cross-border electricity trading occurs at both the transmission and distribution levels.

Lao PDR has developed a number of interconnectors with its neighbours, in particular Thailand, which has been importing electricity from Lao PDR since 1993. As of 2017, total transfer capacity between Lao PDR and Thailand amounted to 3 564 MW over 17 interconnectors.

Table 3. Lao PDR's interconnections with its neighbours

Country	Number of interconnections			
	22 kV/35 kV	115 kV	230 kV	500 kV
Cambodia	1	1		
China (southern grid)	3	1		
Myanmar	1			
Thailand	7	5	2	3
Viet Nam	7		2	

Source: ASEAN Centre for Energy.

Planned development, including cross-border integration

Lao PDR possesses large hydroelectric potential, in particular relative to the region as a whole. Total hydropower capacity under development, concession agreements and power development agreements amounts to 10.5 GW. Of this, 3.6 GW will be installed in northern Lao PDR, 2.6 GW in the south and 4.4 GW in the central regions. In addition, there is a plan to develop a 600 MW wind project development in Sekong province, Phase 1 of which will be 250 MW.

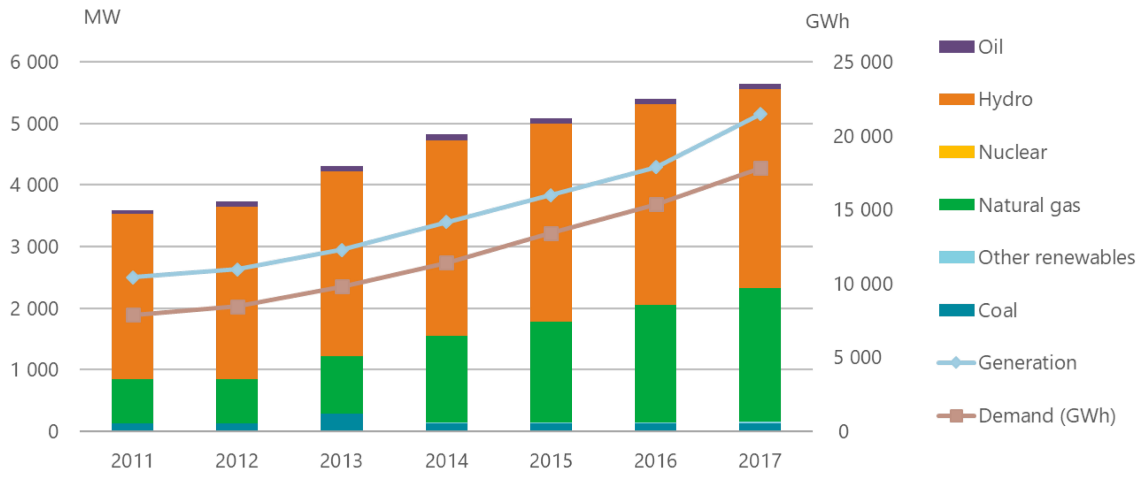
In total, Lao PDR has signed several agreements to exportelectricity to its neighbours. This includes between 7 GW and 9 GW to Thailand, 1 GW and 5 GW to Viet Nam, and 1 GW and 3 GW to China, plus 300 MW to Myanmar.

In addition to these bilateral exports, many of the transmission lines proposed for development would put Lao PDR in the role of transit country. In particular, there are proposals to develop 1 000 MW to 3 000 MW of high-voltage direct current (HVDC) transmission capacity connecting China to Viet Nam, and another 1 000 MW to 3 000 MW HVDC transmission capacity connecting China to Thailand.

Myanmar

Rich in hydropower potential, over the past ten years Myanmar has seen notable investment in new generation from both the private sector and the government itself. As of 2017, nearly 60% of total generation capacity was hydropower, while another third came from natural gas. The remaining portion came from coal and oil.

Figure 15. Myanmar's generation mix, 2011-17



Source: ASEAN Centre for Energy.

Myanmar's power system is primarily hydropower based, though natural gas-fired generation makes up a growing share.

Myanmar's power market is organised as a single buyer, with state-owned Myanmar Electric Power Enterprise (MEPE) responsible for both the transmission grid and procuring generation. Generation is owned by MEPE, the Hydropower Generation Enterprise and various IPPs. There are two distribution companies: Energy Supply Enterprise (ESE) and Yangon Electricity Supply Corporation (YESC). As the name suggests, YESC covers Yangon, while ESE is responsible for distribution in the rest of the country. The power sector is regulated by the Ministry of Electricity and Energy.

Planned development, including cross-border integration

Myanmar's electricity demand tends to be highest during the dry season. Looking forward, therefore, it is possible that Myanmar would be a net importer during these periods, and a potential net exporter during the rainy season. This depends significantly, however, on how Myanmar's domestic power system develops over the coming years.

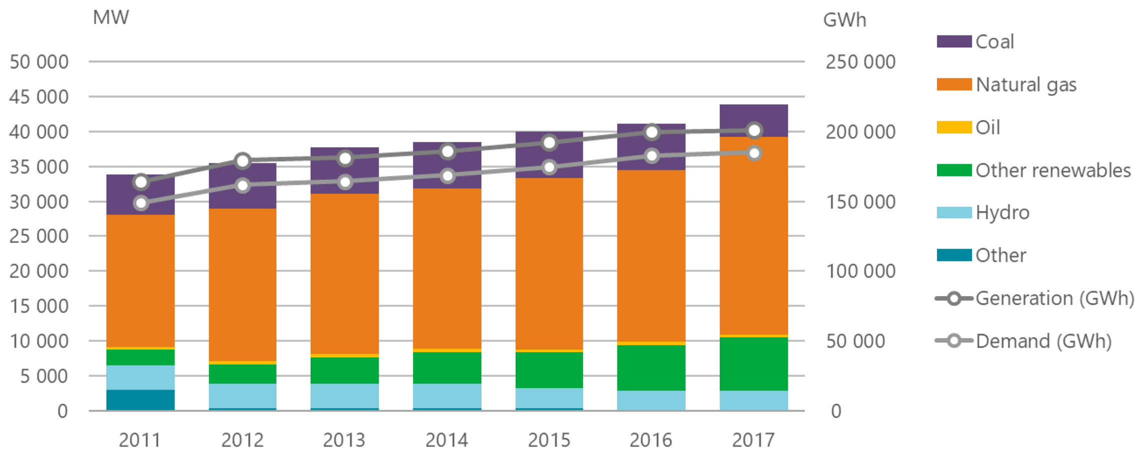
Under Myanmar's plan, hydropower would be exported to China, Thailand or both, though it will be necessary to develop interconnectors to support these exports. Under current plans, however, those interconnections will not be integrated into Myanmar's power grid. China and Thailand would construct their own transmission lines, which would be used exclusively for export.

In addition, in its PDP's final draft, Myanmar also notes an interest in interconnections with other GMS countries, including Cambodia, Lao PDR and Viet Nam (National Energy Management Committee, 2015).

Thailand

Thailand is the largest economy of the five northern APG countries, making up approximately 57% of total GDP in the region. It represents approximately half of peak demand in the region, and has 45% of the total installed capacity. Thailand's power mix is dominated by natural gas, which accounts for over 60% of the capacity and generation. Solar and wind have grown strongly and in 2017 accounted for 7.6 GW of capacity. Hydro accounts for another 3 GW. Thailand also has small but notable amounts of coal capacity. Electricity demand has been steadily increasing, rising from 148 TWh in 2011 to 185 TWh in 2017. Thailand's reserve margin is 16 GW, or 25%.

Figure 16. Generation mix, total generation and demand in Thailand, 2011-17



Source: ASEAN Centre for Energy.

Thailand's power mix is dominated by natural gas. The share of renewables, though small, is growing.

Thailand is notable for being the largest importer of electricity in ASEAN. In 2011, Thailand imported 10.7 TWh of electricity, or 6.5% of domestic demand. These imports came primarily from hydro plants and some lignite coal generation in Lao PDR and Myanmar. By 2017, total imports in absolute terms had more than doubled to 24.4 TWh, or 12.1%.

Thailand's power system is organised under a so-called "enhanced single buyer" (ESB) model. Under the ESB model, the state-owned Electricity Generating Authority of Thailand (EGAT) owns and operates the transmission system and a portion of generation. In addition, Thailand has a notable share of IPPs classified into three categories: large and medium IPPs; small IPPs (SPPs); and very small IPPs (VSPPs). On the distribution side the Provincial Electricity Authority (PEA) serves the metropolitan Bangkok region, and the Metropolitan Electricity Authority (MEA) serves the rest of Thailand. In addition, however, SPPs and EGAT are allowed to sell directly to the large (typically industrial) customers. VSPPs, on the other hand, can sell only directly to consumers or to PEA and MEA – EGAT is not involved in those transactions.

Since 2007, regulatory responsibilities have been the domain of the Energy Regulatory Commission (ERC), which was established as part of the Energy Industry Act, B.E. 2550 (2007). The ERC regulates both the electricity and natural gas sector. A state agency, the Office of the Energy Regulatory Commission was also established under the act to function as the secretariat, supporting the work of the ERC.

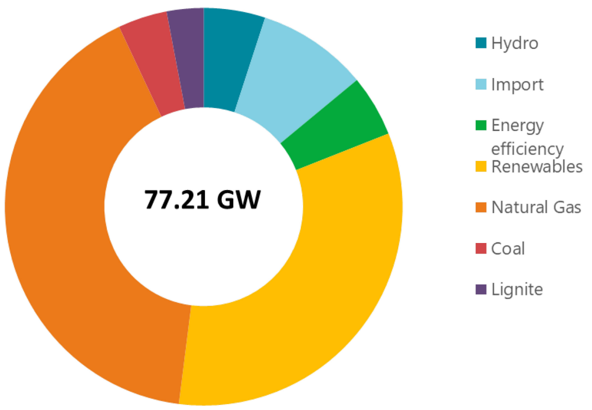
Thailand has cross-border interconnections with all of its neighbours except Myanmar. All of the interconnectors are used to import electricity, excluding the 300 kV HVDC interconnection with Malaysia, which is primarily used to export electricity (including as part of the LTMS–PIP).

Planned development, including cross-border integration

Under Thailand's PDP 2018-2037 (PDP2018), 56 431 MW of new generating capacity will be built from 2018-37. Over this same period, 25 310 MW of capacity is expected to retire. On net, therefore, Thailand's total installed capacity in 2037 would be 77 211 MW.

The PDP also includes an explicit portion of imported energy, which is expected to make up 12% of total supply in 2037. These imports would come from Lao PDR, Myanmar and Cambodia. The plan also assumes more renewables will be developed, particularly PV. The PDP also includes some nuclear development at the end of the planning horizon.

Figure 17. Thailand's power mix in 2037



Source: Energy Policy and Planning Office (2019), *Thailand Power Development Plan 2018-2037 (PDP2018).*

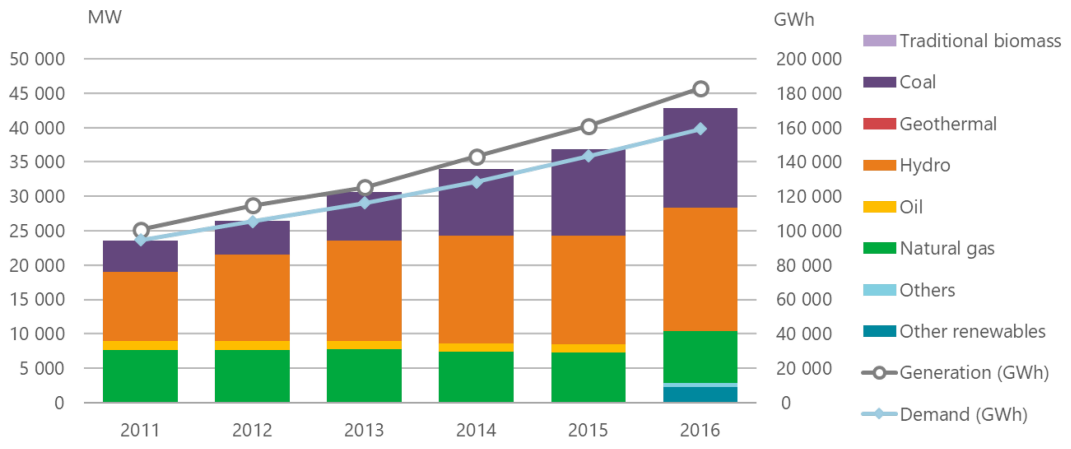
Imports are expected to make up a significant portion of the Thai energy mix in 2036 along with natural gas.

PDP2018 emphasises improved power system reliability covering generation, transmission and distribution at the regional level. Key features include enhancing grid flexibility, promoting cost-effective generation options, reducing the environmental impacts and boosting energy efficiency. This would primarily be met by reducing dependence on natural gas-fired generation and increasing the amount of renewables generation capacity and imported power. Renewables capacity would increase from 13% in 2018 to 33% in 2037. Solar PV in particular is expected to reach around 15 GW or 20% in 2037. Imported power would increase from around 7% in 2014 to 12% by 2037. Much of this increase will go to meet expected increases in demand. Several memoranda of understanding have been signed between Thailand and Lao PDR, and between Thailand and Myanmar, to help meet this anticipated need.

Viet Nam

Over the past six years, electricity demand in Viet Nam has almost doubled. Some of this increase in demand has been met by new hydropower, which as of 2016 made up approximately 42% of Viet Nam's installed capacity, or approximately 30% of generation (Figure 18). The rest of the increase has primarily been met by coal capacity (which, between new and existing capacity, now makes up about a third of total generation), followed by natural gas and other sources (primarily renewables, which contribute 4% of total generation).

Figure 18. Viet Nam's generation mix, total generation and total demand, 2011-16



Source: ASEAN Centre for Energy.

Viet Nam had significant investments in hydropower from 2011 to 2016. The share of fossil fuels is still relatively high.

Viet Nam's electricity market is structured with a single buyer, with the state-owned Vietnam Electricity (EVN) responsible for transmission, distribution and a large portion of generation (with the rest provided by IPPs). Viet Nam is unique among northern APG countries in one key respect: all generation participates in a cost-based pool, whereby all generating companies offer price-quantity pairs for the supply of electricity based on predetermined variable costs. The generation sector is regulated by the Electricity Regulatory Authority of Vietnam, which is a regulatory body under the Ministry of Industry and Trade. Viet Nam has also established a number of cross-border interconnections for trading electricity with neighbouring countries such as China, Cambodia and Lao PDR. The details of the interconnections are listed in Table 4.

Table 4. Viet Nam's interconnections with its neighbours (as of 2017)

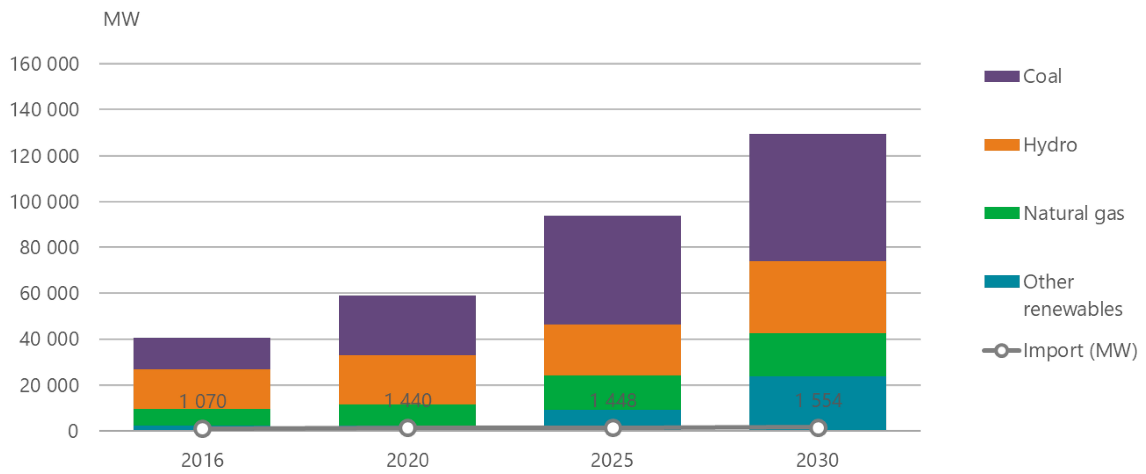
Country	Voltage (capacity)	Type
Cambodia		
Chao Doc – Takeo	220 kV (200 MW)	AC
China		
Tân Kiều – Lào Cai	220 kV	AC
Láo Cai – Xinqiao	220 kV	AC
Ha Giang – Maguan	220 kV	AC
Malutang – Hà Giang	220 kV	AC
Tinh Quang Ninh – Fangchenggang	110 kV	AC
Ha Giang – Maomaotiao	110 kV	AC
Láo Cai – Hekou	110 kV	AC
Lao PDR		
Xekaman 1 (Lao PDR) – Pleiku 2 (Viet Nam)	220 kV (290 MW)	AC
Xekaman 3 (Lao PDR) – Thanh My (Viet Nam)	220 kV (248 MW)	AC

Source: ASEAN Centre for Energy.

Planned development, including cross-border integration

Viet Nam's most recent PDP (Revision VII) moves planned nuclear development further out into the future. In the near term, increased demand will be met from new renewable energy and coal-fired generation, with coal making up 43% of its domestic capacity by 2030, followed by hydropower and limited amounts of natural gas-fired generation.

Figure 19. Viet Nam's power mix 2016-30



Source: ASEAN Centre for Energy.

Viet Nam expects a large growth in coal-fired power plants to cover the increased domestic demand by 2030.

In the coming years, Cambodia plans to reduce its reliance on imports, including those from Viet Nam, potentially freeing up generation in Viet Nam for domestic use or exports to other countries. However, Viet Nam also expects to import more electricity from Lao PDR, with the two countries having signed a memorandum of understanding (MoU) for the joint development of power projects in Lao PDR, and new interconnectors and imports into Viet Nam are as follows:

- Up to 2020: development of 29 hydropower plants with a total capacity of 1 350 MW, with about 1 000 MW allocated for export to Viet Nam.
- From 2021 to 2025: development of an additional 29 hydropower plants (58 in total) with an overall installed capacity of 3 925 MW, of which around 3 000 MW would be for export to Viet Nam.
- From 2026 to 2030: further hydropower development leading to total export capacity (to Viet Nam) of about 5 000 MW.

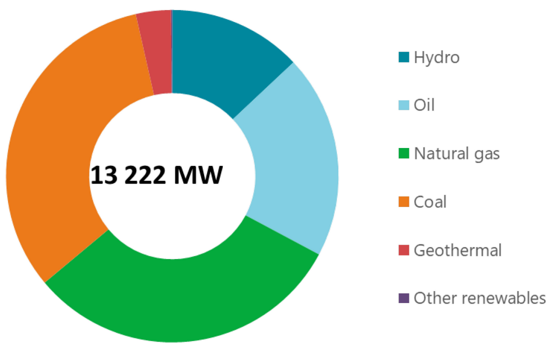
APG region: South

Indonesia (Sumatra)

Indonesia is the largest of the ten AMS in terms of geography, population and electricity demand. As an archipelagic country, however, demand and supply characteristics vary widely. One of the big five islands – Sumatra – is close to peninsular Malaysia. Home to 12 million customers, Sumatra is also Indonesia's second-largest source of electricity demand.

Sumatra's power system has about 13 GW of installed capacity, which includes a mix of fossil fuels, hydropower and geothermal. A third of the total capacity is coal-based, and natural gas supplies another third. Diesel generation is also widespread, with oil capacity making up a fifth of the total. Geothermal makes up 3% of total power capacity and hydropower 13%.

Figure 20. Indonesia (Sumatra) power mix, 2017



Source: ASEAN Centre for Energy.

Fossil fuels make up the largest part of the power mix, with coal and gas accounting for almost a third each.

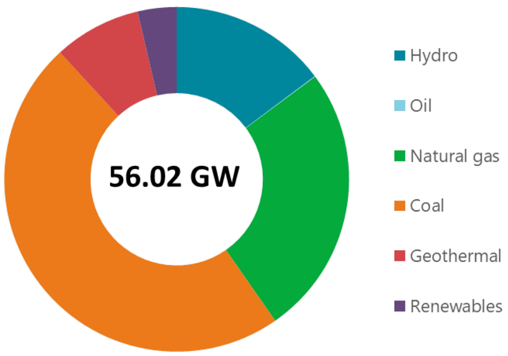
Indonesia's power market structure is a conventional monopolistic market with PLN (or National Power Utility) as the single buyer as well as the retailer. PLN develops, owns and operates the transmission and distribution system. On the generation side, PLN has PT PJB (Java–Bali Power Utility) and Indonesia Power as subsidiary companies that are responsible for generating electricity for the country. In addition, various IPPs and leased power producers also participate in the power system. Indonesia's electricity system is a highly regulated market, where PLN determines the price and retails the electricity to the consumers in industry, residential, commercial and other sectors.

In terms of international interconnectors, a 600 MW HVDC transmission line connecting Sumatra and Peninsular Malaysia was to be commissioned by 2015. However, Indonesia has postponed the project in order to focus on domestic priorities.

Planned development, including cross-border integration

Indonesia's PDP – the Electricity Supply Business Plan, with the Indonesian abbreviated RUPTL – is updated on an annual basis. Under the most recent RUPTL (2018-27), more than a third of new capacity will be coal generation (26.8 GW), while a quarter of total installed capacity will come from natural gas- and oil-fired generation. In addition, Indonesia plans to develop renewable energy sources, in particular hydro (15%) and geothermal (8%). Only a small fraction of new capacity will come in the form of wind and solar PV (PT PLN, 2017).

Figure 21. Capacity additions in Indonesia, 2018-27, based on RUPTL



Source: ASEAN Centre for Energy.

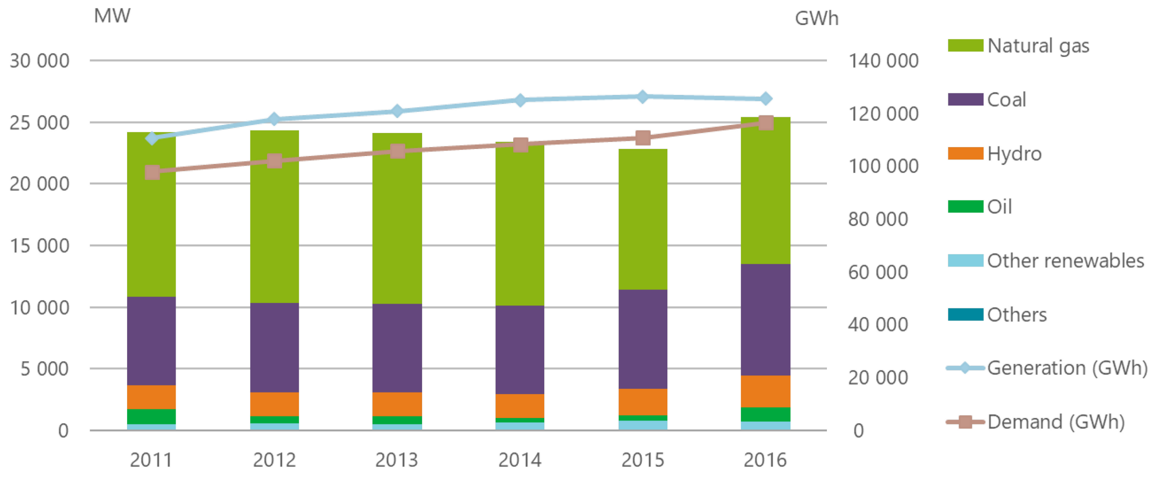
Most of the capacity addition will come from fossil fuels, though Indonesia also has plans to build hydro capacity.

Interconnection targets are explicitly included in the RUPTL, including, for example, a 500 kV, 600 MW HVDC submarine interconnection connecting Sumatra to Peninsular Malaysia. This interconnection, if developed, would take advantage of the two regions' different demand patterns, with Indonesia expected to be a net exporter. However, at present Indonesia is focusing on developing domestic generation (in particular, its 35 GW target) and interconnector development is not a priority.

Malaysia (Peninsular)

Peninsular Malaysia is the centre of the country's economy, making up about 80% of Malaysia's total power demand. Demand is also growing rapidly, having increased 20 TWh in only six years, to 116.5 TWh in 2016. This demand is met by 25.4 GW of generating capacity, primarily based on natural gas.

Figure 22. Power mix total generation and demand in Peninsular Malaysia, 2011-16



Source: ASEAN Centre for Energy.

Fossil fuels make up the majority of Peninsular Malaysia's power generation, which serves a rapidly growing power demand.

Coal is the second-largest source of generation. In addition, a feed-in tariff for solar PV has encouraged investment in a growing portion of renewables, in particular solar PV, which reached around 264 MW (Figure 22).

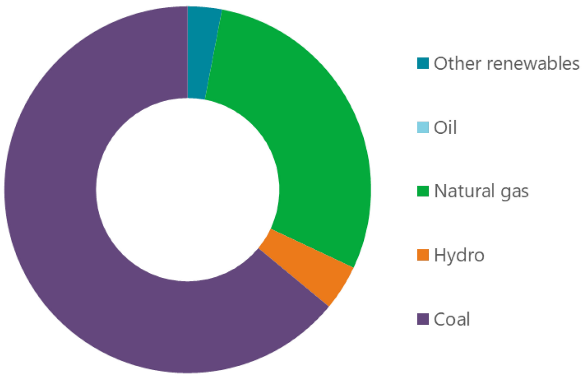
The electricity supply industry in Peninsular Malaysia is served by a single vertically integrated utility, Tenaga Nasional Berhad (TNB), which is regulated by Suruhanjaya Tenaga (ST) or Energy Commission (EC). IPPs also take part in Malaysia's electricity market structure, and their quantity is roughly 50% of electricity generation. TNB is also the main distributor for Peninsular Malaysia, but the government also issues licences to local distributors in certain designated areas (i.e. hill resorts, shopping complexes, industrial parks).

There are existing interconnections between Peninsular Malaysia and its neighbours, Thailand (the 300 MW Khlong Ngae–Gurun interconnection, commissioned in 2002) and Singapore (a 250 megavolt ampere [MVA], 230 kV high-voltage alternating current [HVAC] line commissioned in 1985). These are primarily used for imports. On 24 January 2018, Malaysia imported power for the first time from Lao PDR, via Thailand.

Planned development, including cross-border integration

Power development plans are mandated under the 11th Malaysia Plan. The most recent plan was developed by the EC for a 2026 planning horizon, and approved by the Committee on Planning and Implementation of Electricity Supply and Tariff (JPPPET). The proposed generation mix is detailed in Figure 23.

Figure 23. Planned generation mix for Peninsular Malaysia in 2026



Source: Energy Commission Malaysia (2015), *11th Malaysia Development Plan*.

The primary capacity addition to Peninsular Malaysia in 2020 will be from fossil fuels, primarily coal but also some natural gas.

Malaysia plans to strengthen its interconnection with Singapore (Plentong–Woodland) through the addition of a 600 MW HVDC line after 2020. Thailand and Malaysia are considering developing two new interconnections: a 300 MW, 300 kV HVDC line and a 100 MW, 132/115 kV HVAC line. The new 300 kV is an additional part of the existing Khlong Ngae–Gurun interconnection which capacity is 300 MW and already backed up Thailand and Peninsular system since 2002. Finally, a proposed 600 MW interconnection with Indonesia (to Pekan Baru, Sumatra) is expected to be commissioned after 2021, though this remains unconfirmed.

Singapore

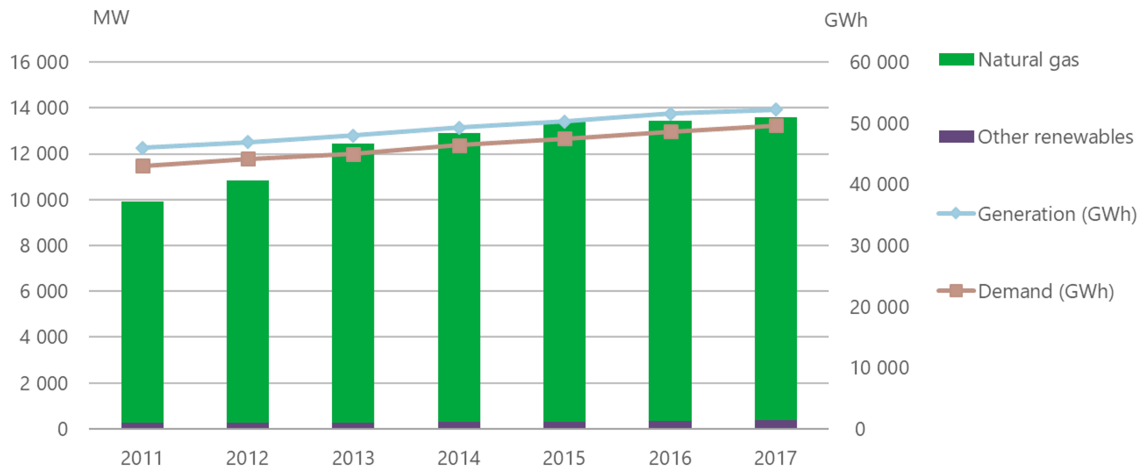
As of the first quarter of 2018, total power capacity in Singapore was 13 614 MW, a notable increase over the 9 918 MW of installed capacity in 2011. Over the past few decades, Singapore's electricity generation industry moved away from oil-fired steam turbine plants by building new combined-cycle gas turbine (CCGT) plants, or repowering existing plants and investing in new units. From 2014 to today, the share of natural gas-fired generation has risen to 95%. The remaining 5% of generation is based on other sources which include refuse/biomass, coal syngas, fuel oil, diesel and solar.

As of 2018, CCGT plants, including co-gen and tri-gen, made up 77.2% (or 10 508.2 MW) of total capacity and steam turbines 18.8% (or 2 554.6 MW). Open-cycle gas turbines made up 1.3% (or 180.0 MW), waste-to-energy plants 1.9% (or 256.8 MW) and solar PV 0.8% (or 114.8 MW).

Relative to other ASEAN countries, the electricity market structure in Singapore is more advanced, as competition has been introduced not only on the generation side, but also in the retail (customer facing) sector. Singapore Power is the national utility responsible for developing and maintaining the transmission and distribution systems.

Since 1985, Malaysia and Singapore have been interconnected via a 2 x 230 kV AC interconnection (Plentong–Woodlands) with a rated capacity of 500 MVA. This line consists of an AC overhead line (10 kilometres [km]) and submarine cables (2 km). This line provides a source of power supply during system emergencies for both interconnected power systems, and is managed jointly by TNB and SP PowerGrid.

Figure 24. Power mix – total generation and demand in Singapore, 2011-17



Source: ASEAN Centre for Energy.

The primary resource for power generation in Singapore is gas.

Planned development, including cross-border integration

As Singapore is a fully liberalised power market, there is no central PDP focusing on generation. Instead, the market decides what to build and when. If a potential investor decides to build a new generator, so long as the investor has met the necessary prerequisites for its new plant (e.g. access to land and fuel, and a connection to the grid), the Energy Market Authority will generally grant the necessary generation licence.

Malaysia (Sarawak and Sabah)

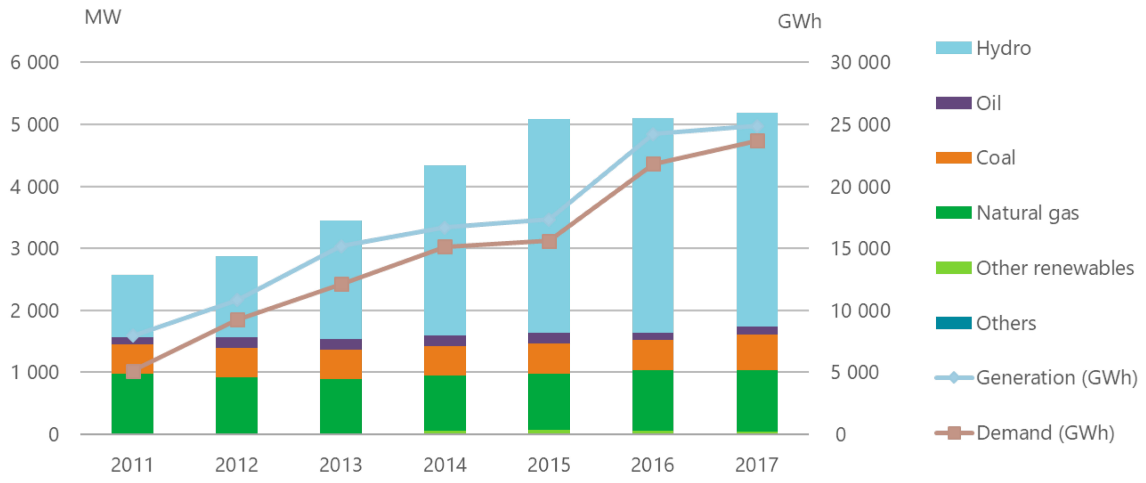
There are three vertically integrated utilities in Malaysia, two of which operate on the island of Borneo. In Sabah, Sabah Electricity Sdn Bhd (SESB) operates the electricity system and market, and in Sarawak, they are operated by Sarawak Electricity Supply Company (SESCO). SESB is regulated by EC, while SESCO is regulated by the state government of Sarawak.

Abundant in hydropower resources, Sarawak has a mainly hydro-based power capacity, though natural gas and coal are also utilised. In 2011, the quantity of installed hydroelectric capacity was approximately equal at about 1 GW each. Since then, however, there has been significant investment in hydropower. As of 2017, hydropower made up two-thirds of the power system. Total generation in 2017 was 25 TWh, while total demand was 21 TWh.

Sarawak has an interconnection to West Kalimantan, Indonesia, which is utilised for both economic and power security purposes (see section on Indonesia [West Kalimantan] below).

SESCO has plans to develop the transmission network further to Baleh and Murum, which are regions with significant hydropower potential. This expansion would also potentially open the possibility for power trade with Indonesia (via Batang Ai Point), and to Brunei Darussalam (via Sungai Tujuh Tudan Point). Under the current plan, this line should be developed by 2020. In addition, new transmission lines from Limbang, Lawas, Trusan, Tutoh and the Tinjar river basin would also be connected via Tungku–Kuala Belait in Brunei, then go back to Malaysia via Sungai Tujuh Tudan.

Figure 25. Power mix – total generation and demand in Sarawak (Malaysia), 2011-17



Source: ASEAN Centre for Energy.

The main power generator is hydro based in Sarawak, while gas and coal also contribute.

On 20 January 2016, Malaysia for the first time exported 50 MW of electricity to West Kalimantan. In total it took four years to develop this interconnection, starting with the power exchange agreement signed on 5 September 2012.

Planned development, including cross-border integration

SESCO develops generation and transmission capacity expansion plans under a number of different scenarios:

- High-load growth in Sarawak, particularly the Kuching area.
- Aggressive development of energy-intensive industries in Sarawak.
- Peninsular Malaysia imports power from Sarawak.
- Power export to the Brunei Darussalam–Indonesia–Malaysia–Philippines East ASEAN Growth Area (BIMP–EAGA countries), in line with the ASEAN agenda.

Scenarios 3 and 4 include the cross-border interconnections under discussion as part of the BIMP–EAGA project. While Scenario 4 considers the plan of BIMP–EAGA listed in the APG programme under APAEC 2016-2025, Scenario 3 assumes exports of 2 000 MW of hydropower electricity from Sarawak to Peninsular Malaysia via an HVDC transmission line.

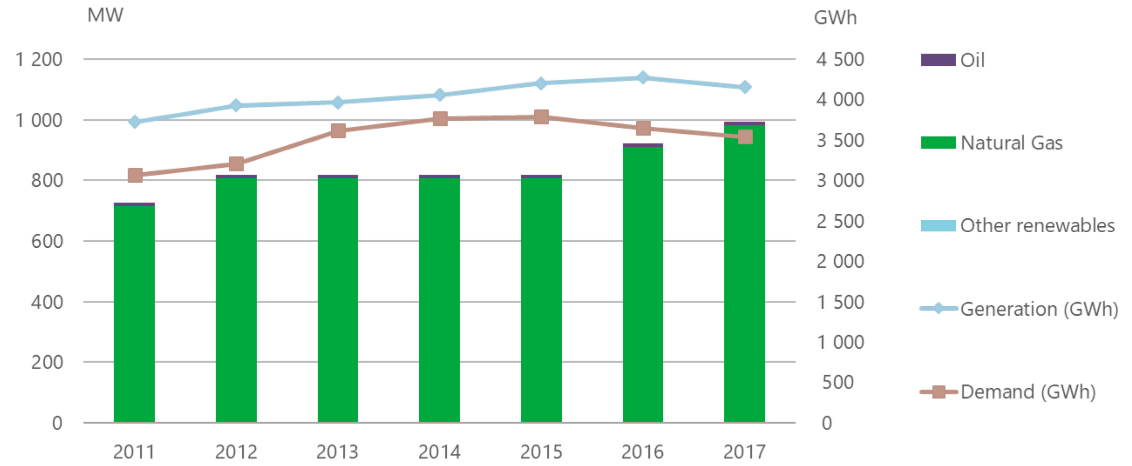
In terms of cross-border transmission lines, a proposed Sipitang interconnection would connect Sabah to Brunei Darussalam, and a proposed 275 kV Kalabakan interconnection would increase the linkages between Malaysia and West Kalimantan. Interconnections to the Philippines are also under consideration, in particular connecting to Mindanao (Dam Road interconnection) and Palawan (Kudat interconnection).

APG region: East

Brunei Darussalam

Brunei Darussalam is a significant producer of oil and gas, and nearly all of its generating fleet is based on those two fuels. In addition there is a small amount of renewable generation, specifically solar PV. Total installed capacity has increased in total over the last seven years, though there were no new plants commissioned between 2012 and 2015. As of 2017, about 12% of Brunei Darussalam's power generation comes from auto-producers. Lower oil prices over the last three years have reduced the country's economic output and, therefore, electricity demand as well.

Figure 26. Power mix – total generation and demand in Brunei Darussalam, 2011-17



Source: ASEAN Centre for Energy.

The primary fuel used in Brunei Darussalam's power mix is natural gas.

Brunei Darussalam is unusual for a small country in that it has two power utilities, namely the Department of Electrical Services (DES) and the Berakas Power Management Company (BPMC). Both DES and BPMC are responsible for generating, transmitting and distributing power to consumers. DES, which is under the authority of the Minister of Energy, serves 60% of power demand in the country, including electricity demand from the oil and gas sectors.

The power system is regulated by the Autoriti Elektrik Brunei Darussalam (AEBD), or the Electricity Authority (EA). The EA is responsible for enforcing Electricity Order 2017, which aims to regulate the generation, transmission and distribution sectors and to ensure the safe use of electricity in the country. The EA issues licences and regulates electrical appliances and consumer products.

Brunei Darussalam's AC transmission grid is made up of 66 kV lines. In 2015, Brunei Darussalam delivered 4.2 GWh of electricity to nearly 100% of its inhabitants.[3] Brunei is not interconnected with neighbouring Malaysia, and so currently relies on domestic generation to meet all of its needs.

[3] The rate of electricity access is 99.9%.

The country has set a renewable energy target of 10% by 2035. Given its limited geographical landscape and renewable energy resource potential, interconnections with Malaysia and Indonesia could potentially offer significant benefits.

Planned development, including cross-border integration

Brunei Darussalam has no specific PDP. However, a Sarawak-Brunei Darussalam interconnection was included in the 2010 ASEAN Interconnection Masterplan Study (AIMS) II. Should this interconnection be developed, Brunei would most likely be a net importer of electricity.

In addition, the Asian Development Bank has proposed a Sarawak–Brunei–Sabah interconnection. If developed, Sarawak Malaysia would be able to sell power to Sabah Malaysia by wheeling power through Brunei's power network. This would avoid the need to invest in dedicated transmission lines linking the two Malaysian states. For such a transaction to function, a wheeling charge arrangement would need to be developed.

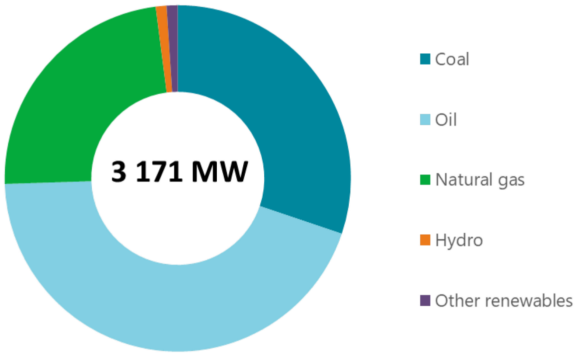
Indonesia (West Kalimantan)

Indonesia's Kalimantan region is abundant in coal and natural gas reserves. As such, it relies on coal generation for a third of its electricity needs, and natural gas for approximately a quarter. The single largest fuel source, however, is oil-based generation, which makes up almost half of power capacity and which primarily serves remote communities.

As in the rest of Indonesia, responsibility for developing and maintaining the power system on Kalimantan rests with PLN (see Sumatra section above for more detail). PLN is organised as three separate entities in Kalimantan: PLN West Kalimantan, PLN South and Central Kalimantan, and PLN East and North Kalimantan. Each is responsible for transmission, substation, distribution, load and customer management as well as the small power generators (from IPPs). Constructing interconnections among Kalimantan's three subsystems is a priority for PLN.

Bengkayang in West Kalimantan is interconnected with Malaysia (specifically, Mambong in Sarawak) via a 275 kV line that was commissioned on 31 December 2015. The 128 km line has a maximum transfer capacity of 230 MW, and is used primarily to enhance reliability and to serve critical load. The line is widely regarded as beneficial to both parties, and is also seen as having improved economic conditions in West Kalimantan. This interconnection also displaced between 50 MW and 130 MW of diesel power in West Kalimantan with electricity from Sarawak, which is 75% from hydroelectricity. This translates into cost savings as well as lower carbon emissions for PLN.

Figure 27. Indonesia (West Kalimantan) power mix, 2018



Source: ASEAN Centre for Energy.

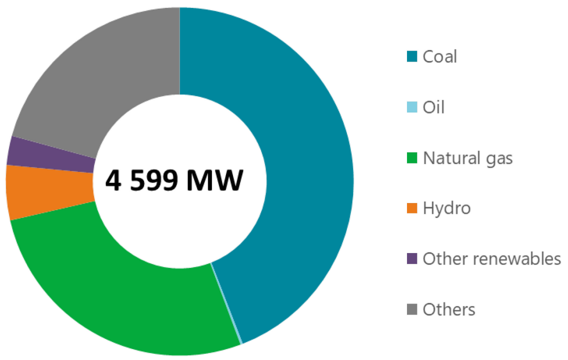
The primary source of generation is fossil fuels, with oil generating 44% of the total power generation.

Planned development, including cross-border integration

PLN developed the RUPTL, which is summarised in the section on Indonesia (Sumatra) above. Figure 28 shows the contribution to the PDP for Kalimantan.

In the same PDP, the existing cross-border interconnection with Sarawak is expanded to an extra-high voltage line that will continue on to Sabah. At that point, all of Kalimantan's system would be interconnected in a so-called Grid Borneo. Should interconnectors be developed, Indonesia's Kalimantan system is likely to be a net importer of electricity.

Figure 28. Capacity additions in Kalimantan, 2018-27



Source: ASEAN Centre for Energy.

Fossil fuels make up the majority of the planned generation additions in Kalimantan.

The Philippines

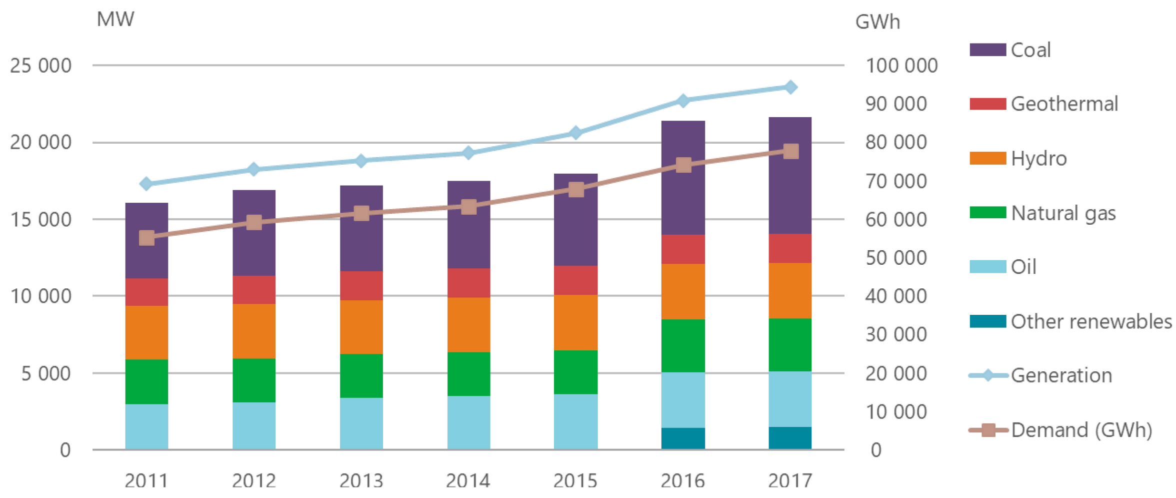
In the Philippines, the demand and supply for electricity has been steadily increasing as shown in Figure 29 below. Furthermore, the margin between supply and demand is kept constant year-by-year (about 15 GW). The total installed capacity in 2017 was approximately 21.6 GW. Coal is the largest source of generation, followed by hydro, natural gas, oil and geothermal.

Renewable energy capacity increased significantly between 2015 and 2016, due to the introduction of the feed-in tariff regulation.

In generation terms, coal is the largest single source of power, followed by natural gas. Geothermal is also abundant in this archipelagic country, and so it is used widely, producing more power than hydropower or oil.

The Philippines is one of two ASEAN countries that currently have restructured (competitive) wholesale markets. The market in the Philippines was opened as part of the Electric Power Industry Reform Act, passed in 2001 and effective from 13 March 2002, with a more recent reform passed in 2018.

Figure 29. Power mix – total generation and demand in the Philippines, 2011-17



Source: ASEAN Centre for Energy.

The main source of fuel for power generation is fossil fuels; however, renewables have seen increases since 2015. The difference between demand and generation is due to losses.

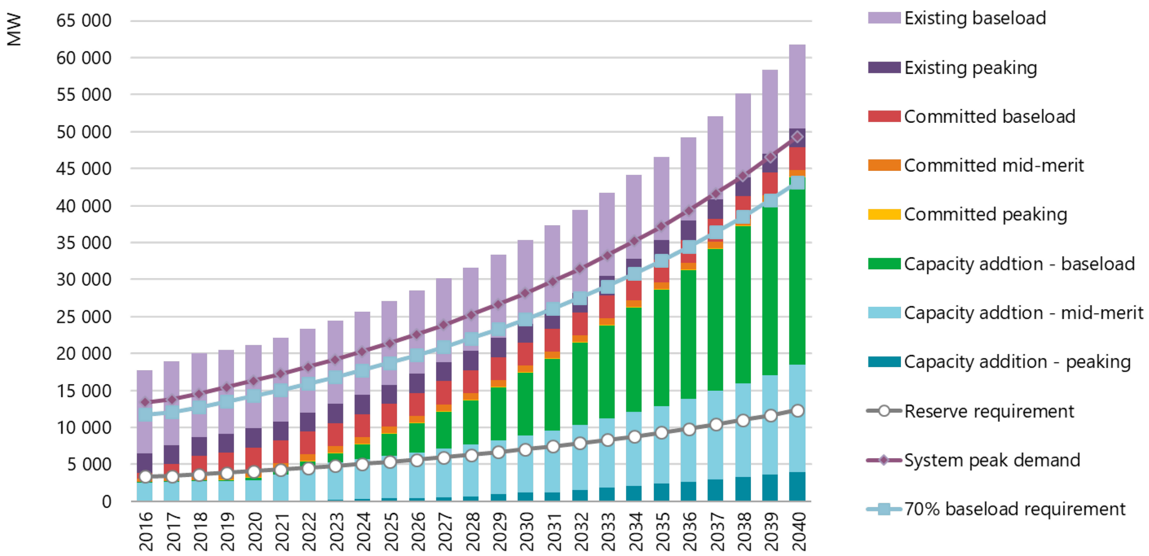
As a competitive market, power trading is managed via the Whole Electricity Spot Market (WESM). WESM's rules of operations and its price determination methodology are subject to Department of Energy and ERC approval. All the distribution retailers are regulated under the ERC, and the electric co-operatives are supervised by the National Electrification Administration.

There are currently no interconnections between the Philippines and neighbouring countries.

Planned development, including cross-border integration

According to the Philippines' most recent PDP (covering the years 2016 to 2040), total capacity additions are expected to be 43.7 GW. The PDP does not break this total down into specific technologies, but does categorise them according to the role they would play in the generation mix. In particular, the PDP indicates that baseload generation will make up more than half of the total (25.6 GW), followed by mid-merit plants (14.5 GW) and peaking plants (4 GW) (Figure 30).

Figure 30. Evolution of the Philippines' power mix, 2016-40



Source: Department of Energy, Philippines (2016), *Power Development Plan (2016-2040).*

The primary evolution in the Philippines power mix will be in baseload generation, whereas the secondary evolution will be in mid-merit generation.

The PDP does not include any cross-border transmission development. However, the Philippines is part of the BIMP–EAGA initiative, which includes an interconnection component.

Similarly, noted in AIMS II is the possibility to develop interconnections with Malaysia via HVDC cables connecting from Sabah to Palawan. According to another more recent study, there is also the possibility of connecting Sabah and Mindanao (Philippines). If such interconnectors were developed, the Philippines would likely be a net importer.

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3. Regional perspectives

This section examines existing efforts to establish multilateral power trade among AMS and the potential for expanded regional integration beyond AMS.

The first subsection begins with a brief overview of the APG, the largest and oldest effort to develop a regional power system among AMS, and also the one that underpins the effort to develop multilateral power trading among ASEAN countries. It then discusses two subregional efforts among AMS: the LTMS–PIP, which has been functioning since the beginning of 2018, and the more nascent BIMP–EAGA interconnection project, an ambitious effort that, if completed, would connect the Philippines to the rest of ASEAN for the first time. Finally, this section ends with a focus on the ADB-led effort to develop a regional power market among the GMS countries, which includes five ASEAN countries plus southern China.

Existing regional integration efforts among AMS

The APG

It would be impossible to discuss existing efforts at regional integration within ASEAN without first detailing the largest and oldest effort, the APG.

The proposal to connect the power grids all of the various AMS was first established at the Second ASEAN Informal Summit, held in Kuala Lumpur in December 1997. The APG was one of the key components of the ASEAN Vision 2020, which included a resolution to establish interconnected grids for electricity (the APG), natural gas (the Trans-ASEAN Gas Pipeline) and water within ASEAN.

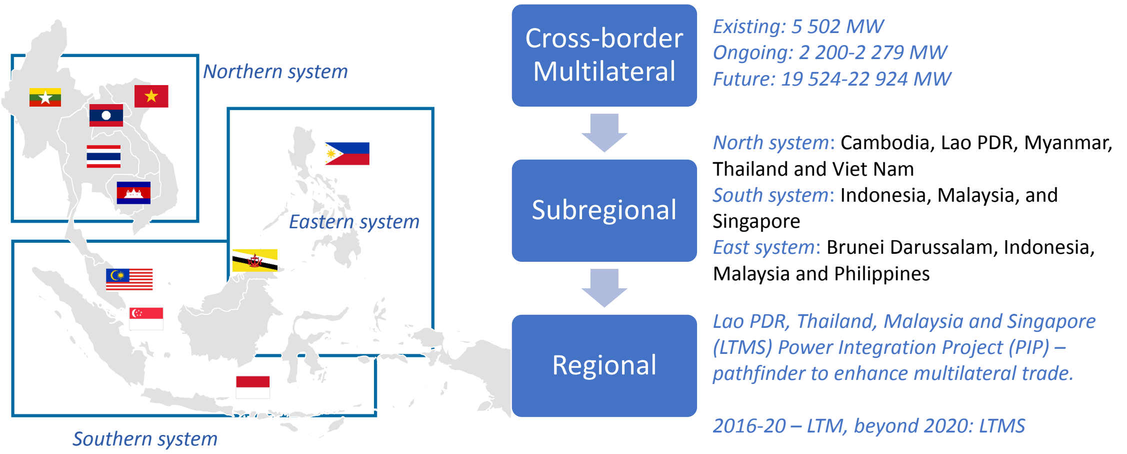
The main objectives in establishing the APG were to:

- Promote more efficient, economic and secure operation of power systems through harmonious development of national electricity networks in ASEAN by region-wide interconnections.
- Optimise the use of energy resources in the region by sharing the benefits.
- Reduce capital required for generation capacity expansion.
- Share experiences among member countries.
- Provide close power co-operation in the region.

Development of the APG so far has progressed only on a bilateral basis between neighbouring countries. The expectation has always been, however, to move from bilateral interconnections to subregional power systems (focusing primarily on three subregions: North, South and East, and finally to a fully integrated regional system.

The Heads of ASEAN Power Utilities/Authorities (HAPUA) have been tasked as ASEAN's official specialised energy body under the APAEC. One of its primary roles is to ensure regional energy security by promoting the efficient utilisation and sharing of resources. Under this mandate, HAPUA has performed various studies, including, for example, regional planning and development studies, the so-called AIMS.

Figure 31. Pathway to establishing regional (multilateral) power trading



Note:This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.
Source: ASEAN Centre for Energy.

The pathway to regional (multilateral) power trading has different steps, where most progress has been made in bilateral cross-border trading.

AIMS put forward a comprehensive plan for a regional transmission network to link the various ASEAN power systems. The first study (AIMS I) was completed in 2003 and the second study (AIMS II) was completed in 2010. According to AIMS II, a more interconnected ASEAN would offset about 2 013 MW of investments by 2025.

As of November 2017, 5 502 MW of APG interconnectors had been developed, up from 3 489 MW as reported in 2015. The majority of these interconnections were constructed between Lao PDR and Thailand, amounting to 3 584 MW.

Table 5. Status of the APG in MW by project as of January 2019

	Interconnections	Existing	Ongoing (up to 2011)	Future	Total
	North system	**4 442**	**2 179**	**15 219-18 369**	**21 840-24 990**
9	Thailand–Lao PDR	3 584	1 879	1 310	6 773
10	Lao PDR–Viet Nam	538	-	TBC	538
11	Thailand–Myanmar	-	-	11 709-14 859	11 709-14 859
12	Viet Nam–Cambodia	200	-	TBC	200
13	Lao PDR–Cambodia	-	300	-	300
14	Thailand–Cambodia	120	-	2 200	2 320

	Interconnections	Existing	Ongoing (up to 2011)	Future	Total
	South system	**450**		**1 200**	**1 650**
1	Peninsular Malaysia–Singapore	450	-	600	1 050
4	Peninsular Malaysia–Sumatra	-	-	600	600
5	Batram–Singapore	-	-	TBC	-
16	Singapore–Sumatra	-	-	TBC	-
	East system	**230**	**30-100**	**550-800**	**810-1 130**
6	Sarawak–West Kalimantan	230	-	-	230
7	Philippines–Sabah	-	-	500	500
8	Sarawak–Sabah–Brunei	-	30-100	50-300	80-400
15	East Sabah–East Kalimantan	-	-	TBC	-
	North-South system	**380**	**-**	**400**	**780**
2	Thailand–Peninsular Malaysia	380	-	400	780
	South-East system	**-**	**-**	**1 600**	**1 600**
3	Sarawak–Peninsular Malaysia	-	-	1 600	1 600

Note: TBC = to be confirmed.

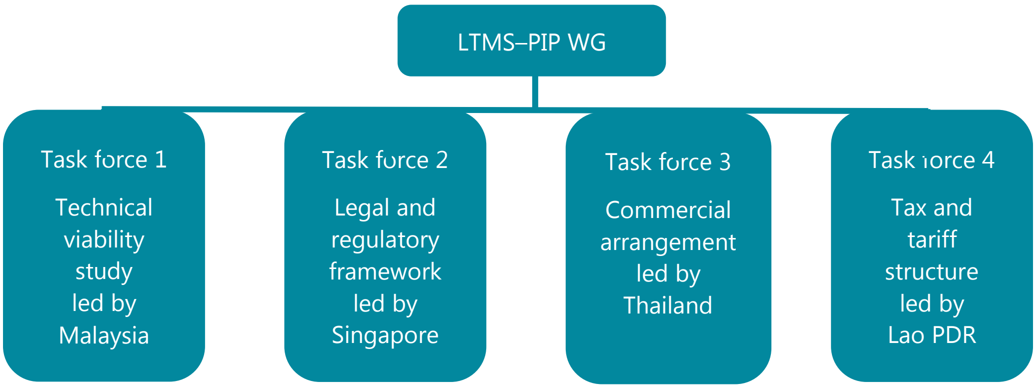
The majority of APG interconnectors developed in the last few years have been between Thailand and Lao PDR.

Development of the full APG is critical for the establishment of full multilateral power trading among ASEAN countries, as trading cannot occur without sufficient supportive infrastructure. To date, the APG effort has focused primarily on infrastructure development, with market arrangements also being organised only on a bilateral basis.

LTMS–PIP

In December 2013, the idea to transfer up to 100 MW of electricity from Lao PDR to Singapore via Malaysia's and Thailand's transmission grid networks was mooted during a special Senior Officials Meeting on Energy (SOME) in Manado, Indonesia. This LTMS–PIP would serve as a pathfinder to complement existing efforts towards realising the APG and the ASEAN Economic Community by creating opportunities for electricity trading beyond neighbouring borders. As a pilot project, the focus is primarily on identifying and resolving issues that could affect cross-border electricity trading among the AMS more broadly.

Figure 32. Structure of the LTMS–PIP working group and technical task force



Source: ASEAN Centre for Energy.

Each of the countries of the LTMS–PIP leads a work stream that is required for realising the project.

To implement this project, a LTMS–PIP Working Group (WG) was formed with four technical task forces looking into technical, commercial, legal and tariff aspects of the project (Figure 32).

As a first step, each country developed a grid study to confirm that it would be technically possible to transfer 100 MW of electricity from Lao PDR to Singapore using existing transmission facilities in each participating country

Based on the recommendation of a technical task study (2016), the LTMS–PIP was divided into two phases:

- Phase 1, 2018-19: power trade between Lao PDR and Malaysia via Thailand only utilising existing network and interconnections
- Phase 2, 2020 or beyond: possible expansion to include Singapore.

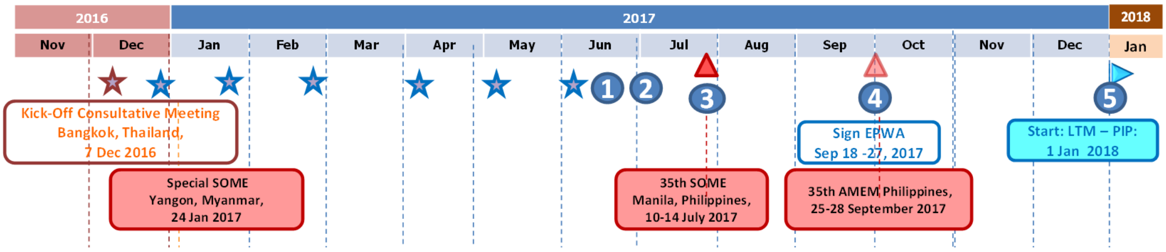
A consideration to the inclusion of Singapore is the fact that Singapore has a fully liberalised power market. Under the current proposal, in order to support power trade, the exporting country will need to establish a local subsidiary to sell electricity directly into Singapore's market.

In the first phase, the LTMS governments signed an MoU on 21 Sept 2016 at the 34th AMEM held in Myanmar for implementation of Phase 1. The MoU is valid for five years.

After the MoU was signed, a wheeling mechanism was developed. The Energy Purchase and Wheeling Agreement was signed by EDL, EGAT and TNB at the 35th AMEM held in Manila for implementation of Phase 1. The timeline of project finalisation on the LTMS–PIP is illustrated in Figure 33 below.

Trade under the LTMS–PIP commenced in January 2018. As of March 2019, 24.97 GWh has been traded under this scheme.

Figure 33. Timeline of Phase 1 of the LTMS–PIP



Note: Singapore did not participate in the power trade in Phase 2 of the LTMS–PIP.
Source: ASEAN Centre for Energy.

The first LTMS–PIP power trade took place on 1 January 2018.

ASEAN sees the LTMS–PIP as a "pathfinder" project for developing multilateral trade in the region. The success of this project in meeting both its timeline and its overall goals suggests there are no fundamental obstacles to developing multilateral power trade across the region as a whole.

The LTMS–PIP is a multilateral trading arrangement insofar as it includes more than two countries. However, it is also a unidirectional trade, and so it is more limited than multilateral trading as defined by this study. However, certain key elements of the LTMS–PIP are very relevant to the broader goals of the APG. Two stand out in particular: the development of the wheeling charge and the underlying process for developing the LTMS–PIP in the first place.

To establish multilateral power trading in the region, it will be necessary to develop a common wheeling methodology. The LTMS–PIP wheeling methodology could be an appropriate start. The LTMS–PIP wheeling charge is based on the following elements: the distance of the trade (megawatts per mile); a loss charge (charged per megawatt hour); a balancing charge (also per megawatt hour); and a fixed administrative charge. To generalise this methodology to ASEAN as a whole, the LTMS partner countries will need to share additional details on how each of these components are calculated. It should be emphasised, however, that this can be done without sharing the actual wheeling charge applied to the LTMS–PIP trade, should this information be considered too sensitive to share publicly.

The underlying process used to develop this project is also very relevant to the ASEAN-wide discussion. In particular, work on the project was divided across four working groups, which looked at 1) tax and tariff structure; 2) commercial arrangement; 3) technical viability study; and 4) regulatory and legal arrangements, each of which was led by a different country (Figure 32). There are two key lessons from this arrangement. First, dividing work across the participating countries is a good way of giving everyone a stake in, and a sense of ownership over, the underlying process and therefore the project as a whole. Second, it is possible for a particular AMS to be actively involved in the development process even if it does not take part in the trading arrangement itself. This is an important lesson for ASEAN as a whole, as it is certain to be the case that some AMS will participate in multilateral power trade early on while others will wait.

One last relevant point on process is the timeline for development. The LTMS–PIP process included setting a specific timeline for project development (Figure 33). By setting a schedule with concrete deliverables and milestones, the LTMS–PIP partner countries could allocate resources as appropriate, and they had reference points for measuring both their own work and progress on the project as a whole.

As to whether the LTMS–PIP can be a good starting point for developing multilateral trade across ASEAN as a whole, it should be emphasised again that the LTMS–PIP, as it currently stands, is not a full multilateral, multidirectional trading arrangement. However, it has some key elements in place. It would not be difficult to turn it into a multilateral trading arrangement among the three countries already involved. The wheeling charge methodology would still need to apply only to Thailand, and so this would primarily require two changes. The three countries would need to agree on some generalised terms of trade (perhaps initially through development of a standardised contract template that all three countries could use, and eventually through the development of a trading platform). Relatedly, Malaysia and Thailand would need to agree on a method for paying the wheeling charge.

Generalising beyond the three countries, though, would require additional work. As already noted, the wheeling charge would need to be generalised to ASEAN as whole. In addition, it would be necessary to develop a generalised framework for buying and selling power. Under the LTMS–PIP, Thailand is responsible for collecting trade information. So long as Thailand is the only wheeling country, this is potentially fine. For multilateral trading to work across any set of AMS, though, there will need to be some way for all countries to indicate when and how much they would like to trade. One option would be for Thailand to open up this service to all AMS. However, this would mean it would be involved in all trading in the region, even if no power flows through Thailand's grid. A better solution would be to have some regional institution host this capability.

In summary, the LTMS–PIP offers key lessons for the AMS as a whole. More importantly, the effort could serve as a starting-off point for developing multilateral power trade across ASEAN as a whole. However, a significant amount of work would still need to be done.

BIMP–EAGA interconnectivity project

The BIMP–EAGA began as an agenda item at the high-level talks of the Philippines with its counterpart heads of states from Brunei Darussalam, Indonesia and Malaysia in 1992. The endorsements and confirmations of those three countries paved the way for the BIMP–EAGA Inaugural Senior Officials' Meeting and Ministers' Meeting in Davao City, Philippines, on 24-26 March 1994.

BIMP–EAGA covers the entire sultanate of Brunei Darussalam and various underdeveloped and geographically remote areas in the other three member countries: nine provinces in Kalimantan, Sulawesi, the island chain of Maluku and Papua (Indonesia); the federal states of Sabah and Sarawak, and the federal territory of Labuan (Malaysia); and Mindanao (26 provinces) and the province of Palawan (Philippines). The end goal is a narrowing the development gaps among its member states.

The BIMP–EAGA economic co-operation focuses on four strategic pillars: enhanced connectivity, food basket strategy, tourism development and environment. Included in the category "enhanced connectivity" is a portion of the APG, specifically the East system. The power interconnection project among the BIMP countries is also included in the BIMP–EAGA Vision 2025 rolling pipeline 1 (2017-19) project and priority infrastructure projects.

From Malaysia's perspective, Sarawak is both central to the BIMP–EAGA project and a gateway to the western ASEAN regions. This region is also rich in energy resources, in particular hydropower. In total, the 11 river basins have a power capacity potential of around 20 000 MW and a production potential of around 87 TWh. Tapping into these resources would potentially help both Indonesia's West Kalimantan and Brunei Darussalam reduce their dependency on fossil generation. This would depend, however, on development of both additional supportive transmission infrastructure and a mechanism for trading power

GMS

Established in 1992, the GMS involves six countries: five AMS (Cambodia, Lao PDR, Myanmar, Thailand and Viet Nam) and China. A subregional Electric Power Forum was established in April 1995. In 2002, the Regional Power Trade Coordination Committee (RPTCC) was established to co-ordinate the implementation of regional power trade. The first meeting of RPTCC was held in 2004, and (to date) 24 meetings have been held in total.

The GMS countries are already interconnected and trading power, albeit to varying degrees and (as with the APG) only on a bilateral basis. Cambodia has been importing from Lao PDR since 2010, Thailand since 2009 and Viet Nam since 2008. Lao PDR has been importing from Thailand since the late 1990s and Yunnan province, China, since 2009. Thailand has been importing from the Lao PDR (hydropower) since 1971. Viet Nam has been importing from Yunnan province since 2004. Yunnan province has been importing from Myanmar (hydropower) since 2008.

The GMS roadmap has four stages:

- Stage 1: Bilateral power transactions where the PPAs of bilateral trading between neighbouring countries without synchronisation.
- Stage 2: Partial regional transmission network and trade among any pair of GMS countries but limited based on available capacity of lines linked to PPAs. The power trading possible between any pair of GMS countries by third-party access (TPA) with surplus capacity.
- Stage 3: Third parties other than utilities are allowed to trade.
- Stage 4: Establishment of a fully competitive regional competitive market within the GMS.

Building off existing efforts: The GMS grid codes

As part of the GMS project, the GMS countries have developed a set of draft grid codes.[4] These GMS grid codes are relevant to ASEAN as a whole, as the proposed minimum requirements in this report are largely aligned with the draft GMS codes and policies.

The focus of this feasibility study is not on the details of the grid codes themselves, and so they will not be summarised here. Instead, the purpose of this section is to determine whether and to what degree the work done as part of the GMS could provide a starting point for the AMS as a whole.

Some discussion and recommendations made in the context of the GMS process are directly relevant to this study. In particular:

- Establishment of a proposed Regional Power Coordinating Centre (RPCC). In a GMS context, the RPCC is proposed to be an advisory body on regulatory issues, and not a regional regulator per se.

[4] As of February 2019, the GMS grid codes have been produced but are waiting for a last round of comments before being finalised. This section is based on materials publicly available from the RPTCC meetings (Greater Mekong Subregion, 2019a; 2019b).

- Creating a "high-level" template for bilateral trades, which could be tailored to national contexts as appropriate.
- Discussion of market restructuring and TPA.
- Gradual implementation of a methodology for estimating wheeling charges based on megawatt-kilometre distance and load-flow based methods.
- Drafting "harmonised" grid codes.

Each of these items relates in some way to the discussion in this study. For example, the RPCC points to the role of regional institutions, as discussed later in this section. In particular, the RPCC would be a platform for national regulators to share knowledge and agree on regional issues, something that would be relevant in a broad ASEAN context as well.

However, one important lesson from the GMS efforts comes from debates over the placement of the RPCC. In practice, it has been difficult for the GMS countries to agree on a host country for the RPCC. This is not an uncommon problem, but it can be a difficult one to overcome. One option is to create multiple regional institutions that have different roles and to locate those institutions in different countries. This and other relevant issues are discussed in the subsection below on the role of institutions.

The recommendation to create "high-level" bilateral trade templates raises an important point for the AMS as a whole. "Multilateral" trade is often taken to mean organising some kind of regional market. Moreover, the ultimate intention of this study is to show how such a regional market might be developed in an ASEAN context.

Creating high-level templates for bilateral trading would allow for a more generalised model of trade among the AMS. With a generalised wheeling methodology in place as well, it would also allow for a form of multilateral trade. However, the GMS recommendations must be considered in detail. In particular, it would be more beneficial if it was not necessary to tailor the harmonised templates to national laws, as this might limit the scalability of such a harmonised bilateral trading model. It is also important to note that such a harmonised bilateral model may be a good first step, but it is not a replacement for a more generalised framework for multilateral trading.

The GMS process has led to a set of strong recommendations on market restructuring and TPA. While there may be many reasons to restructure a power market, it is not a requirement for establishing multilateral trading, and so is not relevant in the context of this feasibility study. Allowing TPA is more relevant. However, as discussed below, TPA means something quite different in the context of regional power trade than the complete opening of domestic power systems to third-party participation.

The GMS grid codes have not been publicly released, and so they have not been reviewed as part of this study. However, detailed analysis of the GMS grid codes is out of the scope of this study. Regardless of what is contained within the grid codes, five of the GMS countries are also APG countries. This suggests that, at a minimum, these grid codes are already acceptable to five out of the ten AMS.

The fact that the other five APG countries were not included in the development of the GMS grid codes, though, poses a challenge, as without their input it is not possible to say whether the GMS grid codes are generalisable to the full APG context. At a minimum, however, it would be difficult or even impossible for the AMS that are part of both the GMS and the APG to follow two different sets of grid codes. Therefore it would be useful to determine whether there is still flexibility in the definition of the GMS grid codes, either so they may be changed to be more appropriate for all of the AMS, or so that their implementation can be tailored as necessary to APG subregions.

The AMS as a whole can also learn from some of the difficulties that arose during the development of the GMS grid codes, including:

- significant concerns about data sharing
- delay in establishment of the RPCC
- discussions regarding the need for a planning code.

Within the GMS effort, most of the countries have expressed concerns about data sharing. This is not a problem isolated to the GMS or ASEAN context. In most of the world, grid data have some degree of national or jurisdictional security status, making them difficult or even illegal to share.

In the context of multilateral power trading, though, it is important to note that the data that need to be shared are unlikely to have this level of sensitivity. More often than not, it is the data related to grid planning and harmonised/integrated capacity calculation methodologies that have the highest sensitivity. While the AMS may well benefit from sharing sensitive data with one another, it is not a minimum requirement to establish multilateral trading. As a result, lack of detailed data sharing on more sensitive topics should not delay efforts to develop multilateral trading in an ASEAN context. Relevant data issues may instead be addressed through parallel processes, or at some later point.

Another GMS discussion with split opinions is on the need for a regional planning code. Similar to the discussion on the sharing of sensitive data, while a regional planning code for the ASEAN region may have benefits, it is not a minimum requirement for multilateral trading. Co-ordinated regional planning is important, but it can also be done in parallel to the development of multilateral power trading or at some later stage in the process. It is also not necessary for AMS to participate in regional planning exercises. Instead, regional planning could be organised by APG region (North, South and East), or perhaps even among smaller subsets of AMS.

In summation, the GMS effort offers many important learning points for the APG. Most importantly, it offers a starting point for the AMS to work from, which could be beneficial in terms of accelerating the work within the ASEAN region.

References

Greater Mekong Subregion (2019a), *Conference Proceedings*, (webpage), greatermekong.org, https://greatermekong.org/conference-proceedings?page=1.

Greater Mekong Subregion (2019b), *24th Meeting of the Regional Power Trade Coordination Committee*, (webpage), greatermekong.org, https://greatermekong.org/24th-meeting-regional-power-trade-coordination-committee-rptcc-24-0.

4. International case studies

The ASEAN region is hardly alone in its efforts to increase cross-border power system integration. It is possible to find examples from across the globe of countries and subnational jurisdictions expanding power infrastructure, and in many cases, power market frameworks, across borders.

The following sections briefly highlight eight multilateral trading arrangements in six regions:[5]

- two in North America (PJM and ISO New England)
- one in Europe (Nord Pool)
- two in south Asia (India and the South Asia Regional Initiative on Energy Integration [SARI/EI])
- one in southern Africa (the SAPP)
- one in Central America (SIEPAC)
- one in the Gulf region (the Gulf Cooperating Council Interconnection Authority [GCC IA]).

Some of the efforts are relatively mature while others are nascent. All involve different design choices that reflect local circumstances, including differing regulatory and governance arrangements and market structures.

None of these examples is a one-to-one match for the ASEAN context. In fact, such an example would be impossible to find, as ASEAN is as unique an arrangement of countries and jurisdictions as each of the examples discussed below. However, in examining these models closely, it is possible to identify a set of lessons and key insights directly relevant to the ASEAN region.

The rest of this section divides these case studies into three groups of trading regimes: primary, secondary and nascent.

Primary trading arrangements are ones where the default form of trade is multilateral in nature. In other words, while it is still possible to enter into bilateral arrangements, the primary mode for organising power trade is one that connects multiple buyers and multiple sellers, generally through some kind of a power exchange.

Secondary arrangements are ones where multilateral trading exists as a separate option for local utilities to utilise as they work to match supply and demand. In these environments, it is entirely possible for participants to ignore the multilateral trading option entirely.

Another way to contrast these efforts is in terms of the volumes of trade that occur within and outside of the market. In a primary trading environment, most or all power trading utilises the multilateral market platform. In a secondary trading environment, most supply-demand matching is done outside of the market.

[5] The case studies presented are excerpts of longer case studies that have been presented to the AMS. The full case studies may be published separately at a later date.

Finally, **nascent** efforts are ones where the details of the multilateral trading regime are still under development. ASEAN would fall into this category, but there are many initiatives in other regions that can provide useful lessons.

Primary power trading arrangements

Four of the case studies in this section are **primary** power trading arrangements: PJM and ISO New England in the United States, Nord Pool in Europe, and India (which has a fully unified domestic power system).

PJM

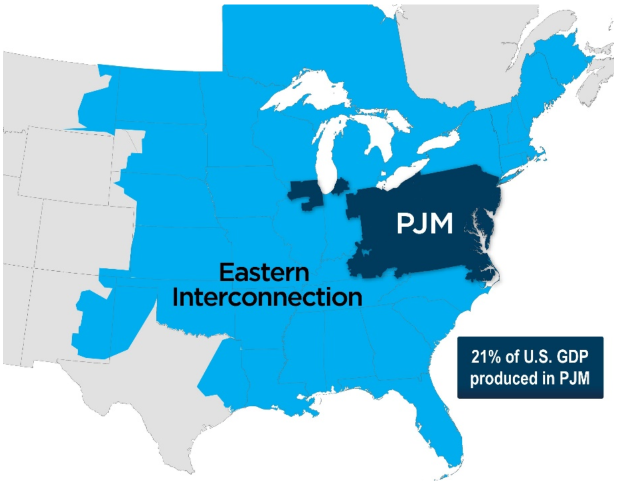
Today, the PJM Interconnection in the United States (US) co-ordinates the movement of electricity in all or parts of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia) and the District of Columbia, serving 65 million customers with 178 564 MW of generating capacity. A brief summary of key statistics on the portion of the US bulk electric grid under PJM operating control is depicted inTable 6.

Table 6. Statistical information about PJM

Population (number of customers served)	65 million
Number of states served	13 + District of Columbia
Electricity consumption	773.5 TWh (2017)
Peak load	165.5 GW
Installed capacity	180 GW
Length of transmission network	135 252 km
Number of generation sources	1 379
Geographic area	630 447 sq. km

Source: PJM, (2018a), *2018 PJM Annual Report*.

Figure 34. PJM's service territory within the Eastern Interconnection



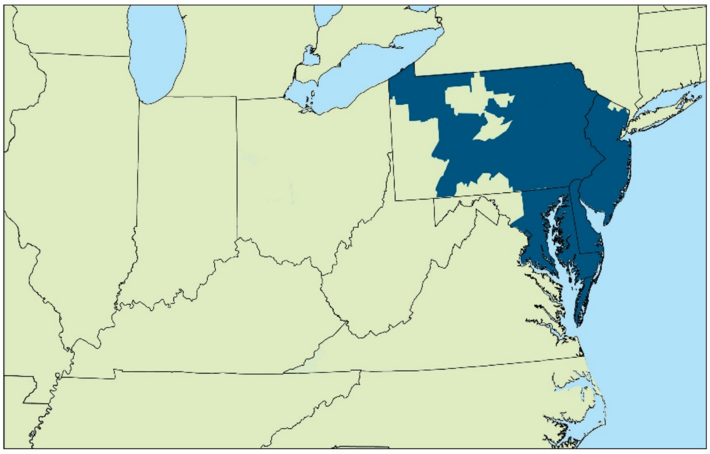
Note:This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.
Source: PJM.

PJM is the largest regional transmission organisation in the United States in terms of load served.

Power pooling in PJM's eastern territory

The concept of forming a power pool was originally centred on the benefits of optimising the dispatch of a shared hydroelectric plant located in the original PJM footprint. That hydroelectric plant had more capacity than was needed by any one owner. As a result, an agreement was reached among the co-owners of the hydro facility to share generation reserves from the plant as well as jointly plan and build transmission lines in order to maximise utilisation of the facility among the three co-owners.

Figure 35. PJM's eastern territory



Note:This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.
Source: PJM.

PJM's earliest members were all located in its eastern territory.

From these early initiatives, the concept of neighbouring utilities operating through a "power pool" was born. In addition to sharing the costs of such large infrastructure investments, the pool also took advantage of differences in load profiles and weather conditions to realise the advantages of diversity of demand over a larger footprint. However, this structure minimised competition as it was closed to any IPPs.

The pool operated successfully as an agreement among its utility members from 1927 to the mid-1990s. Although there was limited access to move power through the PJM transmission grid through negotiated wheeling contracts, it was not until Congressional passage of the Energy Policy Act of 1992 that new merchant entities got access to both to the transmission grid and to the pool itself, where they were able to buy and sell power.

In essence, the move toward competition in the United States in the mid-1990s drove the transformation of the "closed" power pool into a regional non-discriminatory market for energy, capacity and ancillary services.

The measurable value of markets in the PJM region

The value of markets in the PJM region has led to the following empirical savings to customers.[6]

- USD 2.3 billion per year is saved resulting from dispatching power plants based on their individual economic bids over a very large footprint and the ability of customers to obtain power from that wider pool of resources.
- Over 32 000 MW of new cleaner generation replaced an equivalent amount of older generation that retired because of new environmental requirements. This transition was accomplished with cost savings to customers as the risks of retirement as well as new installations were borne entirely by private investors rather than customers.
- Due to the competition drivers that forced the retirement of older, more inefficient generating units, annual emissions within the PJM footprint have declined by 30% over the last decade.
- Local economic development has been enhanced as the ability to monetise investment in a generating plant through the market attracts new builds, which enhances local jobs and local economic development. Just in the PJM states of Pennsylvania and Ohio alone, there has been over USD 17 billion in investment in the local economies through the development of new, cleaner generation and demand response resources.
- The ability to demonstrate and monetise the cost of new investments has led to the PJM region serving as a test bed for innovative new technologies. PJM became the test bed for one of the world's largest battery installations at Laurel Mountain, West Virginia, and continues to work with developers on using innovative technologies such as electric vehicles and electric water heaters to provide valuable services to the grid such as frequency regulation and demand response.

ISO New England

The ISO New England electricity market has evolved organically since the six New England states formed the New England Power Pool in 1971 to co-ordinate regional dispatch. Today, the market is among the most advanced in the world, with active trading by hundreds of participants within New England as well as substantial trading with an external US market (New York Independent System Operator) and several Canadian provinces.

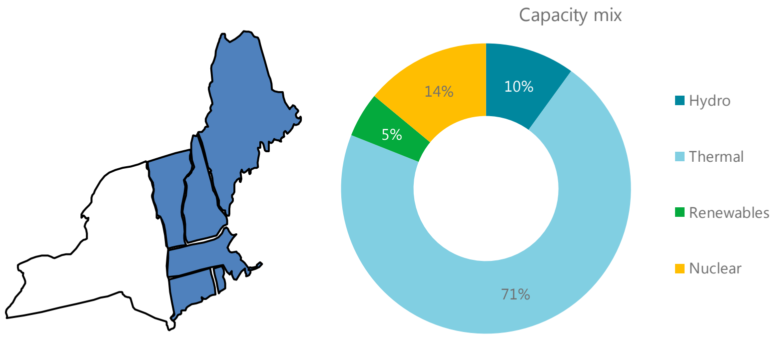
Market overview

New England, in the northeast of the United States, is made up of six states: Maine, New Hampshire, Vermont, Massachusetts, Rhode Island and Connecticut, which were among the earliest English colonies in the country. New England is bounded on the west by New York state, which was originally settled by the Dutch; by Canadian provinces on the northwest (Quebec, a former French colony) and northeast (New Brunswick, a former English colony); and on the east by the Atlantic Ocean.

The power mix is dominated by gas-fired generation, with some coal and oil (together 71%), followed by nuclear power (14%), hydropower (10%) and non-hydro renewables (5%).

[6] This section was based on PJM (2018b).

Figure 36. New England overview and context



Indicator	Value
Population millions	15
GDP/capita USD 000s	69
# States, core market	6
Electrification rate	100%
Peak demand MW	28 817
Installed capacity MW	34 000

Note:This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.
Source: U.S. Census Bureau (2018), *2018 National and State Population Estimates*; Bureau of Economic Analysis (2018), *GDP by State*; ISO New England (2017), *2017-2026 Forecast Report of Capacity, Energy Loads and Transmission*.

New England has a regional electricity market covering six states in the northeastern United States. Most of its generating capacity is thermal, primarily fuelled by natural gas.

ISO New England is part of the Northeast Power Coordinating Council (NPCC) region of the North American Electric Reliability Corporation (NERC). NERC establishes grid codes and performs reliability assessments for Canadian and US power systems, as well as for a portion of northern Baja California, Mexico.

Market structure

Energy policy, planning and regulation for the New England power market are the responsibility of multiple layers of federal, state and regional entities. For example, in terms of policy, there are tax incentives for renewable generating technologies under federal law, and states may have renewable portfolio standards that mandate that specific proportions of demand be supplied by renewable technologies.

The New England Power Pool (NEPOOL), which is the predecessor organisation to ISO New England,[7] is now the industry association of members in ISO New England, and in this capacity acts as a kind of regulatory institution for ISO New England, addressing areas not regulated by the Federal Energy Regulatory Commission (FERC) (in particular related to market rules) and providing legal and technical oversight to ensure compliance with FERC requirements.

Public utility commissions provide state-level regulation of utilities (other than in relation to FERC-approved transmission tariffs).

NEPOOL and ISO New England are responsible for planning for New England, with ISO New England playing the lead role.[8] NERC also plays a role in planning, in particular by setting reliability standards and setting resource adequacy targets for the region. ISO New England is also the market and system operator.

[7] When ISO New England was formed, NEPOOL employees became employees of ISO New England.
[8] The main ISO New England planning documents are the annual *Regional System Plans* (in PDF) and *Forecast Report of Capacity, Energy, Loads, and Transmission* (CELT reports) (in Excel) (ISO New England, 2017). An example of NPCC's planning work is its *Northeast Power Coordinating Council 2017 Long Range Adequacy Overview*, 5 December 2017.

Market participants range across the entire length of the power sector value chain, from generators to retailers (Table 7). As of September 2018, there were 514 active participants in ISO New England.[9]

Table 7. Institutions and market participants

Area of focus	Relevant institutions
Energy policy	Federal and state governments
Regulation	Federal: FERC States: Public utility commissions Regional NEPOOL (for market rules)
Planning	Federal: NERC Regional: NEPOOL, ISO New England
Market and system operations	ISO New England
Market participants	Generators, traders, importers/exporters, transmission owners, distribution companies and retailers
Customers	Served by retailers, except in Vermont

Nord Pool

The Nordic power market is widely viewed as one of the most successful power markets in the world. Today it exists as part of the integrated European market coupling effort.

Table 8. Statistical information about the Nordic region, 2018

Population	27 million
Electricity consumption	393 TWh
Traded volumes (Nord Pool, Nordics only)	367 TWh

Source: Nordic Council of Ministers (2018), *Nordic Energy Statistics 2018*; Nord Pool (2018), *2018 Annual Report*.

Nord Pool is one of several exchanges currently active in the European market coupling. As a result, in total Nord Pool has approximately 380 members from 20 countries. Membership is varied, including large utilities, municipalities, end consumers, producers, retailers, brokers, start-ups and small businesses.

Nord Pool's buy-side volume for the Nordic markets only was 367 TWh in 2018, which means that the market share in the Nordic area, compared with consumption, was approximately 90% in 2018. The rest of the trading is done bilaterally outside Nord Pool. The day-ahead market is the most liquid, with approximately 500 TWh traded. The day-ahead market is complemented by a financial forward market in the Nordics which is run by Nasdaq OMX Commodities. Consumers and producers use the financial market for risk mitigation if they do not wish to be exposed to the day-ahead price volatility.

[9] A handful of these participants are involved only in regulatory and management aspects, such as state public utility commissions. To give a sense of the number of external participants in the market, 39 are Canadian, including entities such as Hydro Quebec, Brookfield, Emera and numerous Ontario-based companies. The membership list is available at www.iso-ne.com/participate/participant-asset-listings/directory.

Governing agreements and regulation

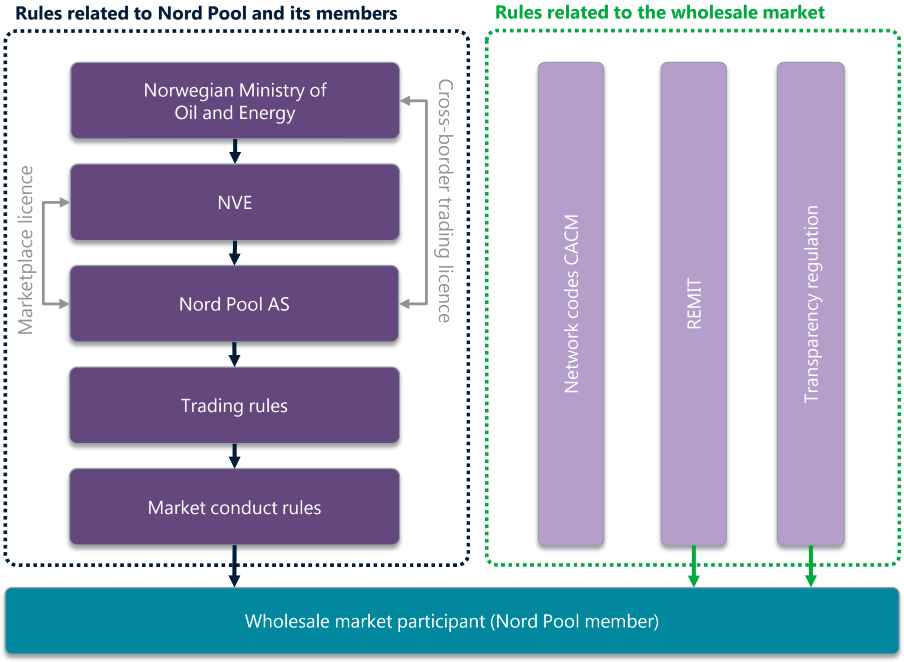
One reason the Nord Pool market has succeeded in organising a single market across a number of (often quite varied) countries is because it is regulated based on principles, not detailed rules. The Nord Pool market licence is just five pages and lists only a set of principal requirements and framework for the operation. Detailed rules do, of course, exist, but under a principles-based approach, market rules may be adjusted to reflect changing circumstances or new ideas, so long as those adjustments are consistent with the governing principles.

For example, one key requirement in the Nord Pool exchange rules is that every market participant at Nord Pool post collaterals to be allowed to trade. This protects both the power exchange and the market participants from counterparty risk in the markets. The size of the required collateral, however, is determined by the market participants' trading behaviour, and thus it changes over time.

Nord Pool has been granted a cross-border trading licence from the Norges Vassdrags – og Energidirektorat (NVE), the Norwegian Water Resources and Energy Directorate. In addition, each of the Nord Pool countries (as with all other EU countries) mandates TPA (that is, all market participants are granted equal access to the grid so long as they comply with the appropriate set of rules and technical requirements). Practically speaking, this means that the TSOs cannot block market participants from connecting to the grid, and therefore must allow them to participate in cross-border power trading.

The European network codes play a central role in the rules governing power trading. The network codes set requirements for nearly all aspects of the European power system, and as such act as the target model for the European power markets. This includes regulations that directly impact cross-border power trade, such as capacity allocation and congestion management (CACM) and rules on transparency (Figure 37).

Figure 37. Nord Pool rules and regulations related to power trading



Note: REMIT= Regulation on wholesale Energy Market Integrity and Transparency; CACM = Capacity Allocation and Congestion Management
Source: Nord Pool.

The network codes have higher legal status than Nord Pool's market rules and must therefore be adapted accordingly.

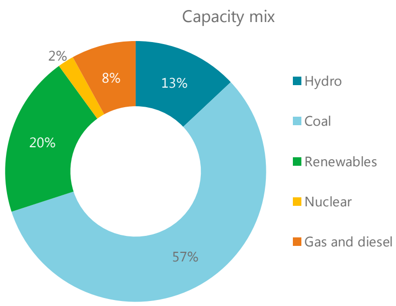
One important category of market participant is the balancing responsible party (BRP). A BRP is financially responsible for any imbalances created. Within Europe there are different requirements for BRPs. Some countries require BRPs to be balanced and others do not. According to the general principles set by the balancing market rules, all legal entities owning generation or consumption units connected to the grid above a threshold (set by the TSO and approved by the national regulator), are obliged to become a BRP or have their assets connected to another BRP. The TSO sets the terms and conditions for each BRP on a case-by-case basis, and they are regulated via an agreement between the BRP and the TSO.

India

Market overview

India is the second-most-populous country in the world, with an estimated 1.34 billion citizens in 2017. It is also the third-largest economy in the world, though low GDP per capita puts the country in the World Bank's Lower Middle Income category.

Figure 38. Overview of India, including key statistics



Indicator	Value
Population millions	1 340
GDP/capita USD 000s	1 980
# States, core market	36
Electrification rate	85%
Peak demand MW	164 000
Installed capacity MW	344 000

Note:This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.
Source: Charts and tables prepared by Delphos International. Data: Indian Ministry of Power (2018), *Power Sector at a Glance*;World Bank (2019a), *Population, Total*; World Bank (2019b), *GDP per Capita (current LCU)*; Economist Intelligence Unit (2018), *EIU India Fact Sheet.*

India has a large power system dominated by coal generation and growing shares of renewables.

The Indian power grid is fully interconnected and synchronised across all states. India's nationwide household electrification rate was 85% as of March 2018. The current government has implemented a USD 2.5 billion programme aiming to electrify every rural household by 2019; however, as of September 2018, 45% of rural villages were still undergoing the electrification process, with some states in the North and Northeast regions remaining well below the national electrification rate.

Market structure

India's power market is fully unbundled, with separate generation, transmission and distribution entities. The market is open access for licensed entities, allowing licensed parties to compete for the ability to sell electricity into the system, and since 2008, power exchanges have allowed for exchange-based trading of electricity via the Indian Energy Exchange (IEX).

Policy and regulation

The Indian power sector has governing bodies at two levels: central (or federal) and state. The central-level power market is divided into five regions: Northern, Western, Southern, Eastern, and Northeastern (Central Electricity Authority of India, 2019). The Ministry of Power is the highest central governing body and is responsible for policy, planning, and project development and implementation. It shares the policy and planning responsibility with the Central Electricity Authority and state governments.

Regulation is handled by the Central Electricity Regulatory Commission (CERC), which regulates tariffs of centrally owned generating companies and other generating companies that sell electricity in more than one state as well as regulating and determining the tariffs for interstate transmission, and by State Electricity Regulatory Commissions, which handle electricity generated by individual states and electricity that is sold within a single state (Ministry of Law and Justice, 2003). The Central Advisory Committee (CAC) is in place to advise CERC on policy questions, compliance of power market licensees and standards of performance by utilities; however, CAC has no direct policy or regulatory control.

Secondary power trading arrangements

Two of the case studies in this section can be characterised as **secondary** power trading arrangements: SAPP and SIEPAC. These are detailed in the following sections.

SAPP

SAPP was created on 28 August 1995, with the primary aim of providing reliable and economical electricity supply to consumers in each of the SAPP member countries, consistent with reasonable utilisation of natural resources and minimised negative impact on the environment. SAPP consists of 12 countries totalling a population of approximately 300 million people. As of 2018, SAPP had 16 members active in cross-border power trade. The approximate consumption in the SAPP area is 400 TWh, though traded volumes are significantly lower at only 1 TWh (Table 9).

Table 9. Statistical information about SAPP

Population	277 million
Electricity consumption	Approx. 400 TWh (2017)
Traded volumes (SAPP)	1 TWh (2017)

Source: Southern African Power Pool (2017), *SAPP Annual Report 2017*.

One important lesson from the development of SAPP is that the national markets have not been deregulated. In each of the participating countries, national incumbent power companies act as single buyers (and sellers) of electricity. However, this has not hindered the development of a market model to support the better utilisation of power resources on a regional basis. In some of the countries, IPPs have been allowed to participate directly in SAPP.

Another key difference from the primary models discussed above is that, under the SAPP market framework, only excess generation is traded. In other words, member states first ensure that they are able to cover their own demand before offering generation capacity to the SAPP regional market. In addition, power can also be traded through SAPP on an emergency basis, to help meet unexpected shortfalls.

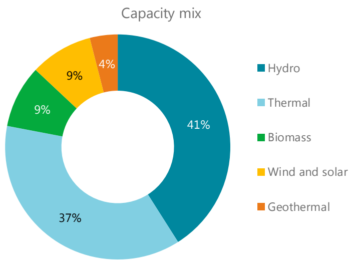
SIEPAC

Focused efforts began in the late 1980s to create a regional electricity market spanning the six Spanish-speaking Central American countries of Guatemala, Honduras, El Salvador, Nicaragua, Costa Rica and Panama, though initial regional market integration steps began 30 years earlier.[10] SIEPAC, the organised regional market that eventually emerged in the early 2000s is the purpose-built 230 kV transmission line and associated infrastructure to support the regional market, the Regional Electricity Market (Mercado Eléctrico Regional [MER]).[11] The two terms – SIEPAC and MER – are used interchangeably in this case study to refer to the regional market, unless otherwise clear from context. [12]

Market overview

The MER is sometimes referred to as the "seventh market", operating on top of the six national markets. That is, all six of the member countries have their own national markets – several of them advanced markets in their own right – and there is significant structural variation across these markets. Participation in the MER at the national level depends on national-level laws and regulations. Thus, Honduras and Costa Rica participate in the MER through their vertically integrated national utilities, while generators, marketers, distributors and large customers from the remaining four countries participate directly in the MER.

Figure 39. SIEPAC (MER) overview and context



Indicator	Value
Population millions	47
GDP/capita USD 000s	5
# States, core market	6
Electrification rate	91%
Peak demand MW	8 900
Installed capacity MW	15 000

Note:This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.
Source: World Bank (2019a), *Population, Total*; World Bank (2019b), *GDP per Capita (current LCU)*; IDB (2017), *Central American Electrical Integration: Genesis, Benefits and Prospects of the SIEPAC Project*; EOR (2016), *Operational Planning for Central America 2016-2017*.

SIEPAC is made up of a diverse set of countries from Central America.

[10] The seventh Central American country, Belize, is English-speaking, with a population more than ten times smaller than that of Panama, the country with the next-smallest population in Central America. Belize's transmission system is not interconnected with any other Central American transmission system; its only international interconnection is with Mexico.
[11] SIEPAC is often referred to as Proyecto SIEPAC, or the SIEPAC Project.
[12] The following report provides a useful history and details in English of the financing of the SIEPAC line: IEA (2016), *Large-Scale Electricity Interconnection: Technology and Prospects for Cross-Regional Networks*. More detail, in Spanish, can be found in IDB (2017), *Integración Eléctrica Centroamericana: Génesis, Beneficios y Prospectiva del Proyecto SIEPAC* [Central American Electrical Integration: Genesis, Benefits and Prospects of the SIEPAC Project].

Trading in the MER is short term (mainly real-time), though progress is being made towards firm transactions of up to one year.[13] Figure 39 shows a brief statistical overview of the SIEPAC region.

Nascent power trading arrangements

The final two case studies presented in this section – the GCC IA and the SARI/EI – are both nascent. That is, they are both at the early stages of their development (though, as in ASEAN, in both cases there are already cross-border interconnectors and power trading arrangements in place).

GCC IA

The Gulf Cooperation Council (GCC) is an intergovernmental/regional organisation focusing on economic and political collaboration and co-ordination. GCC covers six Gulf states (Bahrain, Kuwait, Oman, Qatar, Saudi Arabia and the United Arab Emirates) with a total population of around 54 million people, and was established in 1981. A GCC power market is being developed. When completed, this market will support Gulf State co-operation on power trade and, in particular, co-ordination of the 400 kV GCC interconnector that spans the region.

The responsible organisation is the GCC IA, which is the regional TSO created by all the member states to build and manage the interconnection. The GCC IA is also the facility responsible for the development of the regional power market. The grid/interconnection is currently operational, so GCC IA is now focusing on the development of a regional power market to optimise the usage of the transmission infrastructure.

The GCC power market is currently in the development stage. The Nordic power market is the blueprint for market developments in the Gulf region, though as in other regions where the Nordic market has been used as an example, the final design will certainly be reflective of the specific circumstances of the Gulf countries.

Table 10. Statistical information about the GCC region and GCC IA

Population	58 million
Electricity consumption	527 TWh
Traded volumes (GCC IA)	1.3 TWh (2016)

Source: GCC IA 2016), *2016 Annual Report*.

[13] As discussed later in this case study, there are two categories of markets within the MER: an "opportunity" or spot market and a contracts market. Most trade is in the opportunity market, which is settled based on real-time conditions. Most trade in the contracts market is relatively short term as well: under a year in nearly all cases and mostly running weeks to months.

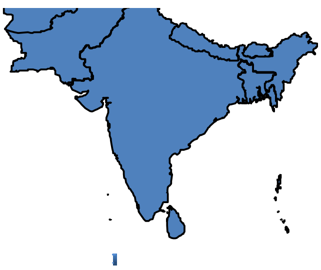
Figure 40. GCC interconnection

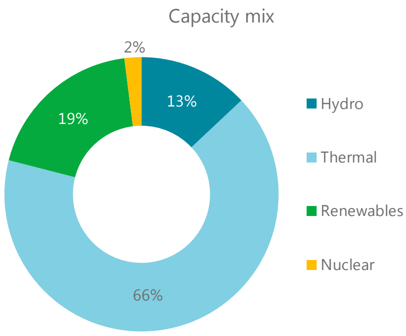
Source: GCC IA (2017), *2017 Annual Report*.

SARI/EI

Countries in South Asia have engaged in cross-border power trading through bilateral interconnections since the 1970s, when India began importing energy from Bhutan. Until recently, further development of cross-border power trading had been limited. In 2000, the South Asia Regional Initiative for Energy programme was launched with support of the US Agency for International Development with the goal of regional energy security and energy development. The programme is in its fourth phase, called SARI/EI, and encompasses eight countries: Afghanistan, Bangladesh, Bhutan, India, Maldives, Nepal, Pakistan and Sri Lanka. This case study focuses on the five core South Asian countries (SACs) where most of the activity to develop cross-border trade has taken place: India, Bangladesh, Bhutan, Nepal and Sri Lanka.

Figure 41. Overview of South Asia region





Indicator	Value
Population millions	1 500
GDP/capita USD 000s	2 961
# States, core market	5
Electrification rate	82%
Peak demand MW	176 000
Installed capacity MW	364 000

Note:This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.
Source: Delphos International, Data: World Bank (2019a), Population, Total; World Bank (2019b), GDP per Capita (current LCU); Economist Intelligence Unit (2018), EIU India Fact Sheet.

The South Asia region has 66% thermal energy

Market overview

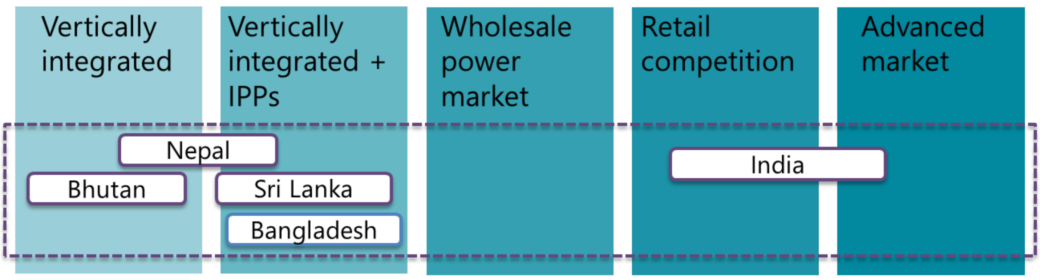
The SAC region covers more than 1.5 billion people, over one-fifth of the world's population (Worldometers, 2018). The region has experienced high economic growth, averaging more than 7% annual GDP growth over the last decade (World Bank, 2018). These impressive figures naturally give way to challenges, one of which is trying to efficiently meet growing demand for electricity.

There is significant diversity across the SACs on a range of factors. Power sectors across the SACs are at different stages of development (described in the next section). Additionally, per capita consumption is highest in Bhutan, at 3 219 kWh, and lowest in Afghanistan, at 133 kWh. The SACs utilise both common law and mixed legal systems, which incorporate aspects of common law as well as religious or localised legal systems, and span a breadth of official languages. This diversity is further reflected in the resource endowments of each nation, such as the vast but underutilised hydro resources in Nepal, or thermal capacity in Bangladesh. Despite the low electricity consumption, almost all the SACs still experience outages due to capacity shortages and seasonal limitations.

Market structure

The power sectors of the SACs are at different phases of development by country. India has unbundled its power sector while also moving towards an active market-based power trade. Other nations in the region operate a bundled utility structure or partially bundled structure characterised by vertical integration. Figure 42 provides an overview of the power sector structures in the region.

Figure 42. Market structures of the SACs



Source: Delphos International.

Key findings: Lessons for ASEAN

It is impossible for any set of case studies[14] to capture the full breadth and depth of experiences in cross-border, multilateral power trade. Examples of cross-border market integration from multi-country regions such as South America or other parts of Africa, or examples of intra-country integration such as the development of the Australian Energy Market or the establishment of the Organization for Cross-Regional Coordination of Transmission Operators (OCCTO) in Japan, would also have lessons for the ASEAN community of countries.

[14] This section has been written based on a more in-depth review of the international case studies, which for editorial purposes has been left out of the publication.

The case studies presented in the sections above, therefore, are not meant to be exhaustive. However, taken together they offer a number of key insights and lessons learned that could help guide the development of multilateral power trading in the ASEAN region.

Drivers and benefits

In all cases, a primary driver of integration has been the desire to better utilise both local and regional resources. In many cases, the resources in question are hydroelectric, such as in the first iteration of PJM, in southern Africa and in Central America. Interest in sharing hydro resources is a driver of regional integration in ASEAN as well.

The focus on hydroelectric power also points to a benefit of regional integration with regard to renewables more broadly, namely the integration of variable renewables such as wind and solar PV. In both cases, the benefit comes in part from being able to plan better around weather-dependent resources. For hydro, the issues tend to be seasonal, while for wind and solar the variability occurs over much shorter time frames.

Notably, the markets discussed above were not designed explicitly around the issue of renewables integration. As the penetration of renewables in the various regions has increased, however, the benefits of both increased interconnection and regional market frameworks have become increasingly apparent. This has led, in addition, to some design choices, such as increased interest in the trading of electricity products closer to real time.

The security benefits of regional integration have also already been noted. These derive in particular from the fact that regional integration increases the diversity of available resources, and decreases the amount of resources necessary to meet the total needs of the power system.

Power trading across borders is the mechanism that allows jurisdictions to take advantage of regional resources. Therefore, implementing multilateral power trading also brings security benefits. One way to think of it is to recognise that trading arrangements provide information to the relevant participants on key issues such as what resources are available, and whether and when a particular resource will be dispatched. Physical integration without power trading arrangements in place brings additional security risks by exposing the interconnected countries to external factors without giving them any visibility into those factors.

Design options and minimum requirements

The case studies above were grouped into different categories based on the relative stage of development and the relative role the regional power trading arrangement played at the national or local level. The main point is to emphasise the fact that regional integration exists across a spectrum. It is therefore entirely possible to find a model for ASEAN that will enable multilateral power trading while also meeting the specific requirements of the various AMS.

However, regional integration does bring about a set of requirements that are necessary even in the loosest of options. These minimum requirements include (but are not necessarily limited to):

- Harmonised grid codes, in particular those that relate to transmission capacity allocation and the secure operation of the grid.
- A commonly agreed upon method for developing wheeling charges.
- A common working language.
- A common (and secure) method for data and information sharing.

- A mechanism for settling transactions, including an agreement on which currency (or currencies) to use and minimum financial requirements for participation.
- A dispute resolution mechanism and procedures for handling events such as defaults.

Other market design elements are also common across the case studies. For example, each of the markets in question uses short-term auction-based mechanisms for determining the price of electricity and establishing the required flows of electricity. In addition, the markets all act as central clearinghouses, helping to lower counterparty risk. Finally, in all the cases market rules are defined via transparent, inclusive processes, and are made public.

The need for enabling institutions

Another commonality across the case studies is the presence of one or more regional institutions. The nature and role of these institutions differ, but in all cases, they support increased regional integration and co-ordination.

In each of the examples of primary power trading arrangements, there are also regional institutions with specific, and significant, authorities. PJM and ISO New England, for example, are both regulated by FERC, and both follow reliability standards set by NERC. Similarly, in India there is also a federal government structure with a national regulator, CERC. Nord Pool member countries must obey the market rules set down by the European Commission, the regional regulator, the Agency for the Cooperation of Energy Regulators (ACER) (though ACER's role is much more limited compared with FERC's), and the European Network of Transmission System Operators for Electricity (ENTSO-E).

In each of the examples of secondary trading arrangements, there are also regional institutions. SAPP, for example, reports to the Southern African Development Community's Division of Infrastructure Services, creating an efficient link between the energy ministers and the utility executives. SIEPAC has three regional institutions: the regulator Regional Electricity Interconnection Commission (Comisión Regional de Interconexión Eléctrica [CRIE]); the Regional Operating Entity (Ente Operador Regional [EOR]; and the transmission line owner, the Network Owner Company (Empresa Propietaria de la Red [EPR]). Dividing the various responsibilities into three different entities recognises the fact that these responsibilities are not fundamentally overlapping, but also allows for a more equitable distribution of responsibilities across the participating countries.

Notably, in some examples the institutions – and even the infrastructure – predated the development of the market. In the GCC, for example, there is the GCC IA and the associated regional transmission line. Within South Asia there is ongoing cross-border power trade on a bilateral basis (similar to ASEAN). These existing institutions and arrangements can become the foundation of regional, multilateral power trading.

In this way, therefore, moving from bilateral to multilateral power trading can be seen as having both bottom-up components, driven by the experiences and needs of the respective countries, and top-down components, driven by the presence of enabling institutions.

Financial implications of regional institutions

As noted above, each of the eight case studies involves one or more regional institutions. These institutions come with associated costs, and therefore also require a revenue source to cover these costs. These costs and revenues are very system-specific, depending on the size and scope of the institutions in question and their relative place in overall power trading. However, as ASEAN will likely need to augment existing institutions or create new ones, it is helpful to summarise a few key figures to at least put these prospective costs in their proper context.

Total costs and revenues are summarised in Table 11. More detailed information and data for additional years (when available) are summarised in the respective case study sections.

Table 11. Costs and revenues for case study markets (USD million)

Market	Total cost	Total revenues
PJM	285	308
ISO New England	184	184
Nord Pool	33.6	39.3
IEX	19.2	35.7
SAPP	3.6	5.3
SIEPAC	7.6	--

The range of costs is wide, from USD 3.6 million for SAPP to USD 285 million for PJM. However, these costs are directly proportional to the relative size and role of the regional institution in question. PJM and ISO New England, for example, are both relatively large organisations that in addition to organising the regional power market are also responsible for dispatch. Therefore, a significant portion of the cost for those markets relates to the technical aspects of real-time system operations. The costs associated with Nord Pool and IEX – both primary institutions that organise only the regional market – are significantly lower, at USD 33.6 million for Nord Pool and USD 19.2 million for IEX.

Not surprisingly, therefore, the associated costs with the two secondary markets discussed – SAPP and SIEPAC – are an order of magnitude smaller. The cost of operating SAPP in 2017 was USD 3.6 million, while the cost of SEIPAC was USD 7.6 million.

Revenues for these markets are, for the most part, in line with costs. A more critical question is how these costs are recovered. For markets where detailed revenue information is available, the models for cost recovery break down into two main groups. In some cases, revenues are collected via a fee per transaction. PJM, for example, recovers its costs via a per-MWh charge, which in 2017 amounted to USD 0.36/MWh.

In other cases, costs are recovered via a combination of fixed and transaction-dependent fees. For example, in 2017 Nord Pool collected USD 3.7 million in fixed fees and USD 25.5 million in volume-dependent fees. SAPP recovers its costs in a similar fashion, earning USD 2.1 million in 2017 from market trading platform fees. A significant portion of its costs, though, are also covered via grants from development agencies and other sources. For nascent organisations in developing parts of the world, utilisation of such development funding can make sense, as it helps to kick-start development without putting an undue burden on relatively cash-strapped governments. In the long run, however, it is important that costs be recovered in a sustainable fashion through some combination of transaction and participation fees.

It is also important to note that the costs summarised in the table above are not exhaustive. In particular, this analysis focuses only on the cost to operate power exchanges or, in the case of PJM and ISO New England, for both market organisation and system operation functions.

Other instructions are also relevant – for example, regional regulatory bodies such as FERC and ACER – and these institutions also have their own costs and related revenue requirements.

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5. Establishing multilateral power trade in an ASEAN context

The previous sections summarised the reasons to establish multilateral power trading across ASEAN, the existing situation within the various AMS and the region as a whole, and a set of international examples. This section will seek to lay out a foundation for establishing multilateral power trade in the ASEAN region. It will discuss minimum requirements, the role of regional institutions and the potential to build off existing efforts. Using this as a starting point, the next section will suggest a specific set of steps for establishing multilateral power trade among the AMS.

Minimum requirements for establishing multilateral power trade

As briefly summarised in Section 4 on international case studies, there are certain minimum requirements necessary for the establishment of secure, transparent and efficient multilateral trading. These minimum requirements span multiple areas, including technical and operational standards, regulations and laws, and financial and commercial terms.

As a first initial step towards greater regional co-operation, though, it is important to establish political support for regional integration. To this end, the relevant countries should consider developing and entering into relevant intergovernmental agreements. It is beyond the scope of this study to provide specific recommendations for which agreements may be necessary, if any. At a minimum, however, there may be a benefit in an agreement that states the ambition to establish multilateral trading in a voluntary and stepwise manner. This agreement would provide the national utilities and other relevant stakeholders the authority to move forward with any necessary developments. Without this political driver, it may be difficult to undertake some of the needed changes, which may require exemptions or changes to existing laws and regulations.

From a technical and operational standards perspective, there is a need for some harmonisation among interconnected countries to ensure co-ordinated and secure operations. In addition, it will also be important to agree on a common working language and to develop a secure method for data and information sharing. The level of needed technical and operational harmonisation and data sharing will depend on the level of system co-operation and co-ordination requested by the involved member countries.

To support the commercial trading of electricity across multiple countries, it is important that the AMS develop a transparent wheeling methodology and loss compensation regime to compensate grid owners for their transmission services. This should ideally be developed and defined on an ASEAN level, ensuring transparency and providing a common transmission pricing methodology for the region as a whole. However, as a first step it is possible to develop a methodology that involves only a subset of AMS.

Related, it will be important that participating countries allow TPA to their domestic transmission grids, so that all relevant external (i.e. non-domestic) stakeholders are subject to equal rules and treatment. Another important point is an agreement on how to measure available transmission capacity (ATC). The ideal solution is to establish a common calculation methodology for the AMS, but this would not be a minimum requirement. Rather, the first step may be to agree on sharing domestic ATC calculations, and having a common agreement in place for how to deal with mismatched measurements.

Depending on the future design of the regional market setup for ASEAN, it may also be important to eventually agree on minimum requirements around settlements, payments and transactions resulting from the multilateral trading. However, this should not be considered a minimum requirement to initiate trading. Rather, it is a potential way to make trading more efficient and financially secure. Similarly, in regional power pooling arrangements, a common trading currency is often used to make the trading and transactions more efficient. As an initial step, it may be fine for countries to agree on which local currencies would be acceptable when settling trades.

The following sections will present these minimum requirements in more detail.[15]

Harmonised technical standards (grid codes)

The primary reason for establishing harmonised technical standards and operational procedures (collectively referred to as "grid codes") is to ensure that all members of an interconnected system maintain a minimum set of technical, design and operational criteria to ensure secure and reliable supply. In interviews and in various forums, AMS representatives interested in establishing multilateral power trade have expressed a concern that increased cross-border power trading may create security risks, such as exposure to external system shocks such as sudden outages or increased reliance on external resources to meet domestic system needs. These concerns are not uncommon, but they can be addressed through the proper implementation of harmonised grid codes and standards.

The minimum harmonised regional grid codes should apply to all portions of the power system that may affect the overall security and reliability of the interconnected system. There is no need to fully harmonise national grid codes across all of the AMS. Rather, it would be sufficient to have a common regional operational agreement that focuses on interconnectors, in order ensure co-ordinated cross-border system operations.

Summary of minimum level of grid code harmonisation

As noted above, the minimum level of grid code harmonisation should focus on cross-border interconnections. At the start, therefore, the need to revise national-level grid codes will, in many cases, be limited. This is not to discount the possibility, however, that national regulations may constitute a barrier in some AMS. It will be important for future work to identify and address potential national barriers to regional power trade.

[15] The minimum requirements discussed below have been aligned with another project, led by the Economic Research Institute for ASEAN and East Asia, which focuses on the potential establishment of an ASEAN Power Grid Transmission System Operator (ATSO) institution. That project has, among other things, researched and summarised the basic requirements and content of a possible future APG grid code aimed at establishing co-ordinated system operations run from a central co-ordination centre. However, the possible steps forward and overall recommendations contained in this section and throughout the remainder of the study are entirely the responsibility of the authors of this report.

To initiate basic regional trading, the topics listed below require consideration. It is important to emphasise, however, that the development of harmonised grid codes, though beneficial for establishing full multilateral power trade among the AMS in the long-term, is not a necessary first step. Many TSOs can agree upon minimum requirements on a border-to-border basis. Of course, this should not prevent groups of AMS from choosing to harmonise with one another as a first step, and ideally, all ten AMS should at least participate in discussions on harmonisation methodologies.

The nature of interconnections will also matter, as countries with synchronised power grids face different issues than countries with asynchronous (DC-based) interconnections.

As a start, it is first necessary to establish a governance process to manage the development of relevant codes and standards. The AMS already has many of the necessary pieces in place to support this process, including relevant institutions as discussed below. Nevertheless, further evolution of these institutions and a more formal recognition of their roles by the various AMS may be necessary.

The governance process, once in place, is the general framework that will allow the AMS to address the key topics required to establish secure interconnections. These topics are listed below. This list could also grow or shrink as the actual work of harmonisation begins. More importantly, the nature and level of harmonisation needed for each topic will vary depending on the level of system co-operation and co-ordination requested by the involved member countries.

Connection policies:

- demand connection policies
- connection requirements for synchronously connected generators
- HVDC connections
- connection requirements for asynchronously (DC) connected generators.

Operational policies/codes:

- operational security
- operational planning and scheduling
- load frequency control and reserves
- emergency response and restoration.

Market policies/codes (operational aspects):

- capacity allocation and congestion management
- electricity balancing
- forward capacity allocation
- metering policy
- operator training policy.

This general list covers elements that are the key minimum technical and operational requirements for establishing multilateral power trade among the AMS. Even here, however, the level of detail required for each topic will vary depending on the level of system operational co-ordination. As a starting point, with only basic regional trading, many of these topics could be agreed upon between relevant TSOs on a border-to-border basis. Given the technical nature of these topics, full harmonisation across multiple countries may require the intervention of an ASEAN-wide institution or perhaps subregional institutions.

The list below outlines in more detail technical elements required in different categories.

- principles and harmonised technical standards
- operating voltage range per voltage level
- correction time for frequency deviations
- speed governing systems
- handling of reactive power levels
- operational procedures
- control area and control block co-ordination
- frequency control standards
- voltage control
- monitoring of interconnection flows and data
- AMS system security and defence plan
- co-ordinated system restoration plan
- black start capability
- cybersecurity
- network for information sharing
- data exchange standards
- data sharing between TSOs and ASEAN co-ordination centre/market operator (if and when they are established).

Building off existing efforts: The GMS grid codes

As discussed in Section 3, for a number of years the countries of the GMS have been working together to more formally integrate their power systems across borders.[16] As part of this process, the GMS countries have developed a set of draft grid codes.[17] These GMS grid codes are relevant to ASEAN as a whole, as the proposed minimum requirements in this report are largely aligned with the draft GMS codes and policies.

The focus of this feasibility study is not on the details of the grid codes themselves, and so they will not be summarised here. Instead, the purpose of this section is to determine whether and to what degree the work done as part of the GMS could provide a starting point for the AMS as a whole.

Some discussion and recommendations made in the context of the GMS process are directly relevant to this study. In particular:

- Establishment of a proposed RPCC. In a GMS context, the RPCC is proposed to be an advisory body on regulatory issues, and not a regional regulator per se.

[16] The GMS countries include five AMS (Cambodia, Lao PDR, Myanmar, Thailand and Viet Nam) and southern China.
[17] As of February 2019, the GMS grid codes have been produced but are waiting for a last round of comments before being finalised. This section is based on materials publicly available from the RPTCC meetings (Greater Mekong Subregion, 2019a; 2019b).

- Creating a high-level template for bilateral trades, which could be tailored to national contexts as appropriate.
- Discussion of market restructuring and TPA.
- Gradual implementation of a methodology for estimating wheeling charges based on megawatt-kilometre distance and load-flow based methods.
- Drafting harmonised grid codes.

Each of these items relates in some way to the discussion in this study. For example, the RPCC points to the role of regional institutions, as discussed later in this section. In particular, the RPCC would be a platform for national regulators to share knowledge and agree on regional issues, something that would be relevant in a broad ASEAN context as well.

However, one important lesson from the GMS efforts comes from debates over the placement of the RPCC. In practice, it has been difficult for the GMS countries to agree on a host country for the RPCC. This is not an uncommon problem, but it can be a difficult one to overcome. One option is to create multiple regional institutions that have different roles and to locate those institutions in different countries. This and other relevant issues are discussed in the section below on the role of institutions.

The recommendation to create high-level bilateral trade templates raises an important point for the AMS as a whole. "Multilateral" trade is often taken to mean organising some kind of regional market. Moreover, the ultimate intention of this study is to show how such a regional market might be developed in an ASEAN context. However, bilateral trading can also take on multilateral qualities. For example, the LTMS–PIP (described in Section 3) is a bilateral trade that nevertheless involves three countries: Lao PDR, Thailand and Malaysia. In that sense, therefore, the trading arrangement is multilateral in nature.

Creating high-level templates for bilateral trading would allow for a more generalised model of trade among the AMS. With a generalised wheeling methodology in place as well, it would also allow for a form of multilateral trade. However, the GMS recommendations must be considered in detail. In particular, it would be more beneficial if it was not necessary to tailor the harmonised templates to national laws, as this might limit the scalability of such a harmonised bilateral trading model. It is also important to note that such a harmonised bilateral model may be a good first step, but it is not a replacement for a more generalised framework for multilateral trading.

The GMS process has led to a set of strong recommendations on market restructuring and TPA. While there may be many reasons to restructure a power market, it is not a requirement for establishing multilateral trading, and so is not relevant in the context of this feasibility study. Allowing TPA is more relevant. However, as discussed below, TPA means something quite different in the context of regional power trade than the complete opening of domestic power systems to third-party participation.

The GMS grid codes have not been publicly released, and so they have not been reviewed as part of this study. However, detailed analysis of the GMS grid codes is out of scope for this study. Regardless of what is contained within the grid codes, five of the GMS countries are also APG countries. This suggests that at a minimum, these grid codes are already acceptable to five out of the ten AMS.

The fact that the other five APG countries were not included in the development of the GMS grid codes, though, poses a challenge, as without their input it is not possible to say whether the GMS grid codes are generalisable to the full APG context. At a minimum, it would be difficult or even impossible for the AMS that are part of both the GMS and the APG to follow two different sets of grid codes. Therefore it would be useful to determine whether there is still flexibility in the definition of the GMS grid codes, either so they may be changed to be more appropriate for all of the AMS, or so that their implementation can be tailored as necessar y to APG subregions.

The AMS as a whole can also learn from some of the difficulties that arose during the development of the GMS grid codes, including significant concerns about data sharing, delay in establishment of the RPCC, and discussions regarding the need for a planning code.

Within the GMS effort, most of the countries have expressed concerns about data sharing. This is not a problem isolated to the GMS or ASEAN context. In most of the world, grid data have some degree of national or jurisdictional security status, making them difficult or even illegal to share.

In the context of multilateral power trading, though, it is important to note that the data that need to be shared are unlikely to have this level of sensitivity. More often than not, it is the data related to grid planning and harmonised/integrated capacity calculation methodologies that have the highest sensitivity. While the AMS may well benefit from sharing sensitive data with one another, it is not a minimum requirement to establish multilateral trading. As a result, lack of detailed data sharing on more sensitive topics should not delay efforts to develop multilateral trading in an ASEAN context. Relevant data issues may instead be addressed through parallel processes, or at some later point.

Another GMS discussion with split opinions is the need for a regional planning code. Similar to the discussion on the sharing of sensitive data, while a regional planning code for the ASEAN region may have benefits, it is not a minimum requirement for multilateral trading. Co-ordinated regional planning is important, but it can also be done in parallel to the development of multilateral power trading or at some later stage in the process. It is also not necessary for AMS to participate in regional planning exercises. Instead, regional planning could be organised by APG region (North, South and East), or perhaps even among smaller subsets of AMS.

In summation, the GMS effort offers many important learning points for the APG. Most importantly, it offers a starting point for the AMS to work from, which could be beneficial in terms of accelerating the work within the ASEAN region.

External (third-party) access to domestic grids

Unlike, for example, the SIEPAC and GCC interconnection discussed in the international case studies section, the APG is not made up of jointly owned "backbone" transmission infrastructure connecting the AMS. Instead, the existing transmission infrastructure is primarily owned and operated at the national level. This makes the development of multilateral power trade among the AMS somewhat more complicated, as *a priori*, it is not necessarily obvious who should be allowed to trade power across borders and, in particular, how a relevant external stakeholder should be granted the right to access and utilise a local (domestic) transmission grid.

It is also worth considering the possibility of the development of privately owned cross-border transmission lines. In some cases, these lines may already exist, such as those originally built for dedicated export arrangements. It is possible (though by no means a requirement) that these interconnectors could become part of a wider national or even international transmission network. For example, one option is to transfer ownership of these lines (after appropriate compensation) to a transmission company, which then operates the interconnector as part of the grid system to ensure that all relevant access and non-discrimination principles are honoured for both current and future market participants. This transmission owner could even be a regional entity such as SIEPAC's EPR, thus creating a "backbone" grid for at least part of the APG.

Regardless, the critical question is how to avoid discrimination and issues related to market power abuse when it comes to cross-border power trading. To establish efficient multilateral trading, the transmission infrastructure that makes up the APG must be made available for all relevant parties under transparent and non-discriminatory principles. It is therefore necessary to establish agreements or guidelines on how future interconnector capacity should be shared, as well as the terms of interconnection. This can be referred to generally as TPA.

However, it is important to distinguish TPA in a regional context (where multiple jurisdictions are involved) from TPA in a domestic or local context. Regional TPA means granting access to external market participants. These may be, for example, vertically integrated utilities or privately owned IPPs. Domestic TPA means opening access to the domestic grid to third-party domestic resources. Many AMS have already done this to some degree, either by allowing IPPs or, in the cases of the Philippines and Singapore, fully restructuring their domestic markets. It should be emphasised, though, that domestic TPA is not a requirement for regional multilateral power trade.

Establishing a general framework for multilateral, multidirectional power trade will require agreements related to TPA among all participating countries. In the ideal case, a package of agreements would be developed covering all relevant topics and including all ten AMS. At the start, however, the signers of the relevant agreements could be limited to subsets of AMS. Even in such a case, however, this package of agreements should be developed in an open, inclusive manner that allows AMS stakeholders (including, for example, national utilities and system operators, transmission owners, and IPPs) to contribute even if they do not initially sign on or are not initially allowed to participate.

A high-level overview of the basic agreements required is provided in Table 12.

Table 12. Basic agreement package for establishing cross-border TPA

Agreement	Topics covered
Transmission licence	This agreement sets out the TPA provision for the transmission infrastructure owner and, if a different entity, the TSO of the grid. It states that these stakeholders needs to provide TPA based on certain principles to allowed parties when they request access to and use of the grid.
Connection and usage agreement	This agreement covers the requirements for generators and, if appropriate, large consumers to be allowed to connect to and use the transmission grid. This requires, among other things, compliance with both national and regional grid codes, and that generators obey with the operational minimum requirements.
Potential additional licences required for generators to operate	Minimum contractual requirements to operate as an independently owned and operated generator (IPP). This licence may differ among countries, and some countries may choose not to allow IPPs to participate directly in cross-border power trade. In essence, however, a generation licence and an export/import licence would be necessary.

The agreements could cover a potentially extensive range of topics, as they should define each participant's rights, as well as the obligations that come with these rights, to participate in cross-border trading and operations. These obligations may include, for example, performance requirements such as grid codes applied to generation (including but not limited to IPPs), and other area- or technology-specific requirements that govern how certain units should operate when connected to the grid. Transmission operators, on the other hand, are obligated to operate the transmission grid in a secure and reliable manner and need to make sure the voltage levels and frequencies are within the ranges of determined safe operation. They also must guarantee access to their grid to any external participant that has been granted the right to buy and sell electricity across borders.

The involved parties and their respective rights and obligations can be summarised as follows:

IPPs:

- rights: connect to the transmission grid, stay connected based on criteria from the national grid code and send power through the grid
- obligations: obey operational requirements and rules of the grid.

National utilities and transmission operators:

- rights: access to regional transmission grids to deliver power when required
- obligations: operate the transmission grid in a secure and reliable manner, grant grid access to allowed producers and consumers, allow for transfer of power through the national grid.

Other owners of transmission infrastructure:

- rights: ability to interconnect and transmit power when properly licensed to do so
- obligations: allow market participants (IPPs and others) to connect to and use its grid infrastructure; ensure the operation of the transmission assets is in line with grid requirements and standards.

There are different approaches to how to structure a third-party agreement package. For example, in SAPP's case the operating guidelines contain provisions relating to wheeling, and obligate the members' utilities to make their networks available for wheeling purposes. When an IPP, for example, becomes a member of SAPP, it has a right through the SAPP agreement structure to sell power to any other SAPP member – which means, in turn, that all relevant TSOs have the obligation to wheel that power to the appropriate border.

In this case, therefore, TPA is granted only to members of the SAPP. Individual SAPP member countries are at different stages of electricity sector restructuring, and so the legal and regulatory arrangements permitting access to national networks vary between countries. This approach might be appropriate for the ASEAN region as well, given the fact that member countries differ in terms of market structure.

Wheeling charge methodology

As discussed above, AMS that choose to participate in multilateral power trading must agree on legal terms for accessing each other's transmission grids. In addition, it is also necessary to agree upon the commercial terms for transmission services performed by wheeling (or transit) countries.

Wheeling charges should be paid by the transmission system user to the transmission owner providing the wheeling service. For example, in the LTMS–PIP, the wheeling charge is paid by

Lao PDR (the generator) to Malaysia (the wheeling country). Lao PDR recovers this wheeling charge from Malaysia under the terms of the bilateral PPA.

The wheeling charges paid should reflect the full costs (fixed and variable) to the transmission owner of providing the necessary transmission infrastructure and services. This could potentially include capital cost, asset depreciation, operational and maintenance cost, and any associated losses.

There are multiple ways of structuring wheeling charges, but regardless of the chosen method, local AMS circumstances must be considered. For example, it is important that this transmission charge methodology promote an optimal usage of the relevant transmission infrastructure. In some cases, the internal grid of the relevant ASEAN country may not be sufficiently developed to support large quantities of wheeled power. In such a case, it is in everyone's interest to ensure that the country in question is compensated in such a way as to incentivise further infrastructure development. Transmission owners should also be provided a reasonable return for the increased utilisation of existing assets. At the same time, the methodology should take into account the varying capabilities of the respective AMS TSOs, in particular technical capabilities and available human resources.

A wheeling arrangement needs to consider both the physical and commercial aspects of transmission of power. Some of the key aspects that need to be considered in a basic arrangement can be summarised as follows:

- amount of wheeling capacity
- time duration of the transmission
- grid or country entry and exit points
- metering of actual flows
- agreed balancing procedures (to be used if a counterparty fails or is unable to honour the agreed transaction volumes)
- how to handle transmission losses
- an agreement on handling taxation of cross-border trades.

It is possible for this methodology to cover both long-term bilateral trading agreements and short-term trading.

Some of basic wheeling charge design parameters that may be appropriate for ASEAN are listed in Table 13.

Table 13. Design parameters for developing an ASEAN-appropriate wheeling methodology

Complexity level	As a starting point, the methodology should be simple to use and agreed upon (e.g. one with a minimum level of required harmonisation and implementation effort). It is possible to develop more detailed/advanced methods at a future stage.
Reflective of the cost of grid use	The wheeling charges could follow general rules that approximately reflect actual grid costs, or they could reflect the actual effect each trade has on the relevant parts of the transmission system's infrastructure. The latter methodology is more accurate from a system perspective, but also more complex to implement.

Cost recovery	As a general rule, wheeling charges should seek to cover the fixed and variable costs of providing the transmission services, including a reasonable rate of return for the transmission owners.
Wheeling price certainty	Price stability is important from the perspective of investors and other stakeholders seeking to develop generation or transmission projects. However, this should not preclude changes to the wheeling methodology over time.
Transparency	A transparent methodology should be favoured, as this builds trust among relevant stakeholders. Transparent in this context refers both to the development of the methodology itself (including any future changes), which should be done in an open, inclusive manner, and to the determination of the wheeling charges themselves.
Loss handling	Each trade wheeled through a transmission system will see losses. Only losses directly related to the wheeled power should generally be covered by the methodology. It may be worth developing a methodology that incentivises TSOs to minimise their losses, but this is not necessary as a first step.
Non-discriminatory practices	All involved parties should have the same rights and obligations in the regional market. This is partly covered by the third-party agreements package but it is worth reviewing for the wheeling charges, too.
Decentralised versus centralised management of charge collection and distribution	As a starting point, market participants should pay the wheeling charge directly to the relevant transmission owner (that is, in a decentralised manner). In the future, collection and distribution of these charges could be managed by a centralised institution.
Possibility for a methodology applicable to both international and domestic transmission services	It is possible for a wheeling charge methodology to also be used to determine domestic transmission charges. This is not a requirement, but some countries may find it beneficial, and so it should at least be discussed at an early stage.

The overall stability of wheeling charges is worth emphasising. In general, the wheeling charge methodology and the resulting price for transmission services should be stable, to provide predictable costs to potential investors in new generation and transmission.

That said, the wheeling charge methodology developed by AMS could, and likely should, evolve over time. For example, in more modern wheeling methodologies the actual effect of a trade on the system directly impacts the wheeling service charge. Load flow calculations can be done to determine the extent of actual impact each trade has on the infrastructure and its associated costs. This methodology, though, is relatively complex, and it is most likely not an appropriate starting point for ASEAN.

In fact, in the near term, harmonisation of wheeling charge methodologies across the AMS could be minimal. Regional approaches simplify the development of multilateral trading and so is the preferred approach, but it is not a requirement to initiate trading. It is more important that the methodology be transparent – both in how it is developed and in its application.

An alternative approach, therefore, is to allow for varying wheeling methodologies for different sections/stretches of the APG (for example, by APG region). So long as countries are aware of which wheeling charge methodology applies in which country or region, the calculated wheeling charge could be paid directly to the relevant national TSOs. Should a relevant regional institution be established, it could take on the task of calculating the appropriate wheeling charges, and potentially even the collection and distribution of the fees. Again, however, this is not a necessary first step.

From international experience, wheeling charges tend to evolve over time. Wheeling methodologies are an effective tool to ensure that transmission owners provide capacity for multilateral trading, since the value of providing the capacity is known in advance for the transmission owners. Wheeling charges can evolve to become more sophisticated or harmonised over time. When market models change it may also be appropriate to change the way transmission owners are compensated. In highly integrated markets such as in the primary model, proposed in later sections, wheeling charges may change to congestion rents. Congestion rents offer the transmission owner compensation based on the short-term value of the grid, and is as such not known in advance; this coupled with connection tariffs is typically the way highly integrated markets compensate the utilisation of transmission grids. Since the ASEAN region is in the early stages of creating multilateral power trading, wheeling charges are an important tool in succeeding with establishing multilateral power trading.

Data and information sharing requirements

Multilateral trading requires some level of data and information sharing. This is another area where the presence of a central, responsible organisation can be extremely helpful, as it can take on responsibility for receiving and distributing information to and from relevant ASEAN stakeholders using a central IT and communications platform. For example, such an institution would be able to receive transmission system data from the transmission owners, and it could in turn send back information on traded volumes.

The sharing of power system operations and planning information will inevitably raise concerns over data confidentiality.[18] It is not unusual for data to be considered too sensitive to share, or there may even be legislative or regulatory obstacles to data sharing. It is possible, therefore, that some AMS will need to change relevant national legislation or add specific exceptions to existing regulations in order to allow these data to be shared with a regional co-ordination body.

As a starting point, though, it is worth bearing in mind that the initial data sharing requirements may be minimal. For example, before the development of a regional institution, data will need to be shared on a bilateral or multilateral basis among limited groups of AMS. These countries could decide among themselves what data requirements are necessary, and how to share these data in a secure manner.

Ideally, however, data sharing methods and requirements should be harmonised as early as possible. Over time the data sharing requirements will certainly change, in particular as multilateral trading in ASEAN develops into a more organised regional market. At a minimum, therefore, any agreements defining data requirements should be easy to amend and update.

Information that will need to be exchanged will primarily be focused on items that directly relate to cross-border power trade. A high-level list of future potential market information-sharing requirements includes:

- aggregate and/or calculate ATC

[18] This section draws on work done as part of the ATSO institution study, which is currently not publicly available.

- collect and distribute operational information, in particular cross-border power flows
- collect and distribute system-planning information.

In the future, a regional market operator could also maintain central databases and computational processes to help manage power system optimisation, metering data acquisition and processing, trade settlement calculations, and website feeds, among other items.

Dispute resolution mechanism

When establishing multilateral trading, it is important to have a dispute resolution mechanism; however, it may be appropriate for ASEAN to have several dispute resolution mechanisms depending on the origin and nature of the dispute. There are two different kinds of disputes that would require different approaches to dispute resolution.

The first type of dispute is one that occurs during or as a result of the actual trade itself (in this case, of electricity). The dispute may be the result of a failure to deliver; of unintended cross-border exchanges; or a failure of, or disagreement related to, payment, among other things.

The second type of dispute is related to the process of establishing multilateral power trade in the first place. This type is much more critical for ensuring the development process has sufficient momentum to succeed.

It is up to the AMS to decide what is appropriate in the ASEAN context in terms of handling the two types of disputes. The establishment of dispute resolution mechanisms (and, if necessary, the relevant institution) should be high on the priority list, since it can help move forward other processes that might otherwise become stuck.

When the dispute resolution mechanism for development of methodologies is established, it is important that all AMS recognise its authority. This may therefore be one area where an intergovernmental agreement is required. If the AMS do not recognise the authority of the dispute resolution mechanism, it will not be able to effectively resolve disputes, potentially impacting the development of multilateral power trading in the ASEAN region. The agreed-upon mechanism should be valid for both the entire ASEAN region and within any subregions. This will help to ensure that issues brought to the dispute resolution mechanism are solved in similar ways and thus be a tool to ensure the cohesion of the methodologies in the ASEAN region as a whole.

Other minimum requirements

Two additional minimum requirements are worth highlighting. Both may be obvious on their face, but both are also critical to the proper functioning of multilateral power trade.

First, it will be important for the AMS to agree on a common language, or set of languages, to use for communication. This is true both in the development process, and also for the trading arrangements themselves when they are established. Many ASEAN meetings already function using a common language (typically English), and so it should not be difficult for the AMS to agree on a common language for power trade as well.

At the same time, provisions will need to be made to translate relevant materials to local languages. This is because, while regional collaboration can function with a commonly agreed-upon language, domestic work will almost certainly be performed using the domestic language. It will be important that everyone understand the processes and tools developed to support multilateral power trading, as much of the implementation work will occur domestically. Therefore, each country should prepare for regular translation of written materials.

Second, multilateral power trade requires infrastructure. Put another way, it is impossible for two countries to trade electricity if they are not physically interconnected via transmission lines. This perhaps obvious point is worth emphasising because when it comes to regional power trade, infrastructure and market development can often face a "chicken and egg" problem. There is no way to trade without infrastructure in place, but the infrastructure itself would make no sense without the potential for trade. Establishing multilateral power trade can itself be a driver of interconnection development, in particular by offering opportunities to trade across borders that would not exist otherwise. At the same time, the lack of market frameworks should not be seen as an obstacle to infrastructure development in the short term. Cross-border transmission lines can take years to develop. Putting them in place sooner rather than later means they will be available when multilateral power trading is established in the region.

Funding implications of stepwise implementation

Following the principle of stepwise development means that, in an ASEAN context, the various AMS will likely choose to participate in multilateral trading at different speeds and to differing degrees. This means that some AMS may be first movers when it comes to the development of relevant regional institutions (as discussed in the next section) and associated systems (such as those discussed above).

With careful consideration, there is no reason why staggered development should be an obstacle to the long-term participation of any or all AMS. However, the potential that some AMS may not actively participate early on does raise an issue related to funding.

At some stage, it will be necessary for the AMS to develop relevant institutions and systems, a process that will require agreements on how to fund this work. Ideally, the AMS should agree at as early a stage as possible on when and how initially non-participating countries will contribute to costs. Without such an agreement in place, there is a risk of free-riding or potential delays in development. If the AMS that move first are clear on how other AMS, when they join, will pay for their share of development costs, then the incentive to delay development is reduced and free-riding is eliminated.

There is no one right way to allocate costs and to ensure proper funding long term, and so the exact arrangements for joining an established market should be left up to the AMS. Some general principles, though, do apply. The arrangement should be fair to both existing and potential participants, and it should be transparent both in terms of how it is developed and how costs are allocated. This will limit the potential for mistrust, disputes or incentives to develop parallel (and therefore unnecessarily duplicative) systems.

The arrangements could also explicitly indicate which costs may be reallocated under any possible future arrangement, and the extent to which cost allocations will reflect the ability of participants to pay. On this latter point, it is reasonable that larger participants might pay a larger share of the costs. On the other hand, this could lead to those who contribute more having a higher degree of influence on the allocation of resources. There may therefore be merit to sharing costs equally across all participants.

Another potential issue is the extent to which the cost of requests from a single AMS should be socialised. Here, setting out clear rules for cost allocation is important. A blanket socialisation of all costs could result in a single country imposing costs on the rest for functionality that is specific to its needs. At the same time, if none of these costs are socialised, countries may be unwilling to request new features out of a concern that they will be unfairly bearing the costs of developments that benefit multiple participants.

In an ideal world, all necessary provisions would be settled up front. This, however, could put such a burden on the process that nothing moves forward at all. Therefore, it may be better to agree on high-level principles first, before development starts, and to implement a decision-making process that is flexible and fair enough to respond to future needs.

Role of institutions

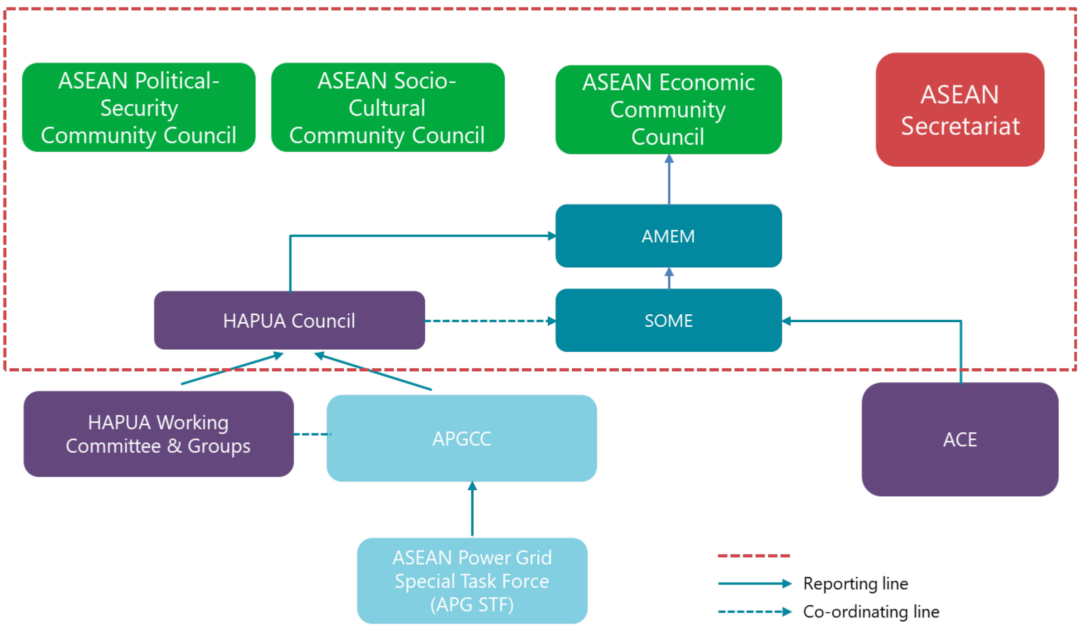
Many of the roles and responsibilities necessary to support multilateral power trading may be managed more efficiently through a central, regional institution, or a set of institutions. Some of the functions discussed above could potentially be managed by institutions that already exist in ASEAN, while in other cases new institutions may need to be created. This is another area that will almost certainly evolve over time.

As a starting point, it is worth reviewing the existing institutions already present in ASEAN. Then, this section will discuss some of the functions that a regional institution could or should manage.

Overview of existing ASEAN regional institutions

There are already a number of institutions in ASEAN that are relevant to the establishment of multilateral power trade in the region. Some, such as the ASEAN Secretariat, have primarily political roles, while others have technical roles, such as HAPUA and the ASEAN Centre for Energy (ACE). The full range of ASEAN institutions and their relationships to each other are shown in Figure 43.

Figure 43. Select regional institutions in ASEAN and their relationships



Source: Based on information provided by ASEAN Centre for Energy, IEA (2019).

At the highest level, the ASEAN Secretariat plays an overall co-ordination and organisational role. AMEM and SOME are the critical meeting points for the relevant political and staff-level representatives from each of the ten AMS. Reporting up to AMEM and SOME are various relevant technical bodies such as HAPUA and ACE. In addition, there are other technical committees and working bodies under HAPUA not included in the chart. These are described in more detail in the following sections.

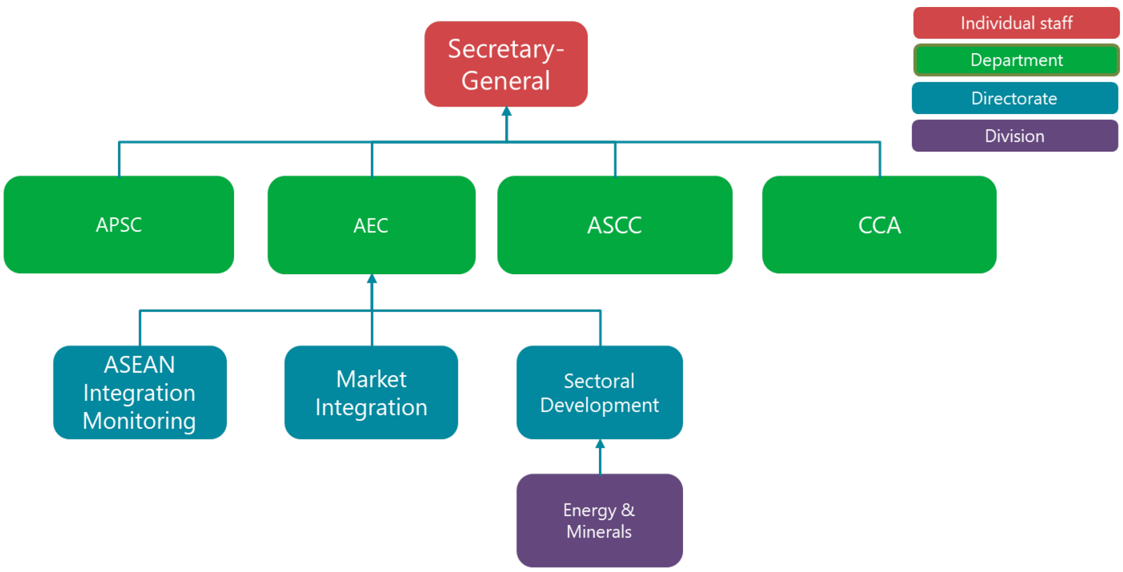
ASEAN Secretariat

Established in February 1976 by the foreign ministers of ASEAN, the ASEAN Secretariat is based in Jakarta. The ASEAN Secretariat's primary mission is "to initiate, facilitate and co-ordinate ASEAN stakeholder collaboration in realising the purposes and principles of ASEAN as reflected in the ASEAN Charter" (ASEAN Secretariat, 2019). This is done primarily through the promotion of collaboration among the AMS, in particular to support the effective implementation of various ASEAN projects and activities. A number of these activities relate to energy topics in general and electricity in particular, though the overall scope of the ASEAN Secretariat expands well beyond these two areas.

The structure of the ASEAN Secretariat is shown in Figure 44. The most relevant section is the Energy and Minerals Division, which sits under the Sectoral Development Directorate. The Sectoral Development Directorate reports in turn to the ASEAN Economic Community Department, which reports directly to the Secretary-General.

The Energy and Minerals Division also acts as the secretariat to a number of relevant regional bodies and forums, including the ASEAN Energy Regulators Network (AERN), described in more detail below.

Figure 44. Select portions of the ASEAN Secretariat organisational structure



Source: Based on ASEAN Secretariat (2016).

HAPUA

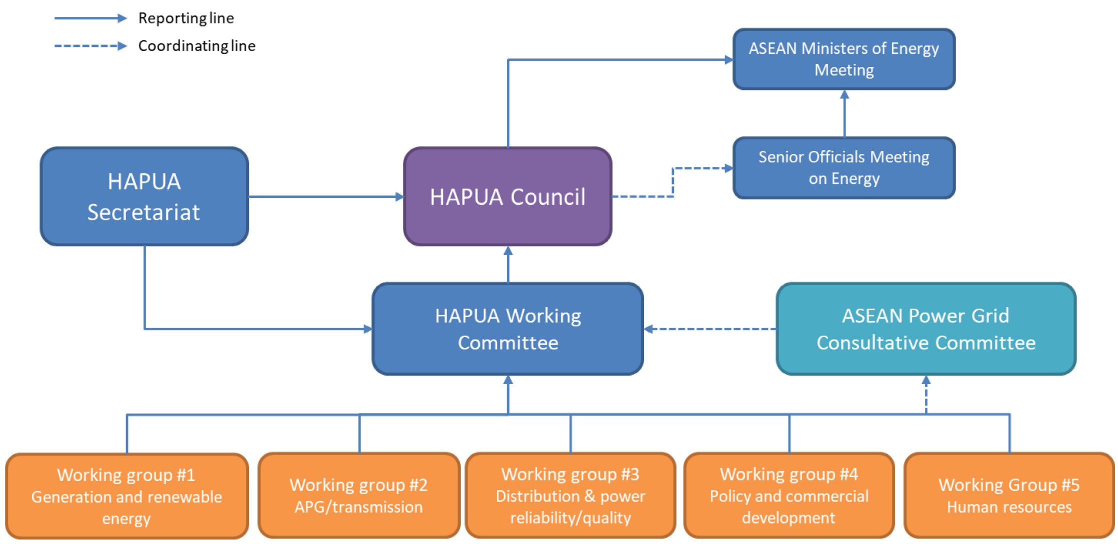
HAPUA is a Specialised Energy Body established in 1981 with the mission to "promote cooperation among its members to strengthen regional energy security through interconnection development, enhancing private sector participation, encouraging standardisation of equipment, promoting joint project development, cooperation in human resources, research & development, and to enhance quality & reliability of electricity supply system" (HAPUA, 2019a). HAPUA has a number of roles and responsibilities directly relevant to the establishment of multilateral power trade in ASEAN, including supporting the development of cross-border interconnectors, enhancing the participation of private-sector market participants, encouraging equipment standardisation, promoting the joint development of energy-related infrastructure projects, supporting research and development efforts, and enhancing the quality and reliability of ASEAN power systems.

Since its establishment, HAPUA has gone through several organisation restructurings. The most recent was finalised at the 28th HAPUA Council Meeting in June 2012, where the following HAPUA Working Group (WG) structure was formally adopted:[19]

- HAPUA WG No. 1 – Generation & Renewable Energy
- HAPUA WG No. 2 – APG/Transmission
- HAPUA WG No. 3 – Distribution and Power Reliability & Quality
- HAPUA WG No. 4 – Policy & Commercial Development
- HAPUA WG No. 5 – Human Resources.

The relationship among HAPUA, its working groups, and the SOME and AMEM is presented in Figure 45.

Figure 45. The structure of HAPUA and relationship to ASEAN collaborative meetings



Source: Based on HAPUA (2019b), *HAPUA Coordination Line*.

[19] This feasibility study project is an input into HAPUA WG 2.

HAPUA plays a critical role in supporting energy market integration in ASEAN. In particular, HAPUA is responsible for development and implementation of the APG. To support this effort, HAPUA and the AMS have created two relevant working groups: the APGCC and the APG STF.

AERN

The AERN is a relatively new organisation in ASEAN, having only been established in 2012. Unlike HAPUA and the ASEAN Secretariat, the AERN does not have a permanent home. Instead, chairmanship of the AERN rotates among the AMS every two years.[20] However, recently the Energy & Minerals Division of the ASEAN Secretariat has taken on the responsibility of being the AERN's secretariat.

As the name suggests, the AERN's primary mission is to focus on regional regulatory issues, in particular ones related to power and gas. In particular, the AERN has been tasked with the following functions:

- Collaborate on regulatory issues related to ASEAN flagship integrated energy projects such as the APG and the Trans ASEAN Gas Pipeline.
- Promote consistency in energy regulation in the region through information exchange and dialogue.
- Develop a channel for communications among ASEAN energy regulators to promote mutual understanding and mutual benefit to energy regulation and regional economic development.
- Promote knowledge sharing and capacity building among ASEAN energy regulators on regulatory issues and best practices.

To support this work, the AERN has established two working groups: one on technical and regulatory harmonisation, and another focused on establishing a database of relevant legal and regulatory documents.

ACE

ACE was established in 1999 as a specialised organisation under the governance of the SOME leaders and an *ex officio* representative from the ASEAN Secretariat. It supports the broad range of AMS interests in the energy sector. ACE has three main functions (ACE, 2019):

- Act as a think tank for the AMS by identifying and disseminating innovative policy, legal, regulatory and technical solutions for ASEAN's energy challenges.
- Act as a catalyst to unify and strengthen ASEAN energy co-operation and integration through relevant capacity-building programmes and projects.
- Act as the energy data centre and knowledge hub for the AMS.

ACE also performs a number of relevant studies, including the upcoming AIMS III, which will evaluate the potential benefits of increased interconnection among the AMS.

Functions that would require regional co-ordination

Regional co-ordination to achieve multilateral trading in ASEAN naturally requires some level of harmonisation of different functions that are currently performed by domestic institutions in

[20] At the time of writing, the chair of the AERN was Cambodia.

each AMS. As a starting point, it is necessary to identify the different functions that would require, or significantly benefit from, increased regional co-operation. These are illustrated in Figure 46 below.

The goal of co-ordination in the context of multilateral power trade is to ensure that overall system security, stability and reliability are maintained. This will require the sharing of system operation information and planning data, which in turn means regional co-ordination and/or development of relevant IT and communications systems. The ASEAN transmission owners and utilities have a wide range of IT systems and communication protocols, making it a challenging but manageable task to develop a common communication policy. Co-ordination will be necessary to define and develop relevant IT standards and to implement specific (perhaps regionally managed) IT systems. It will also be necessary to introduce new information policies and protocols that support regional collaboration while maintaining the highest possible levels of data security.

Figure 46. Functions requiring or benefiting from regional co-operation

Note: IT = information technology.
Source: ASEAN Centre for Energy.

Regional co-ordination should support both short-term and long-term trading. This may in part require active support of the relevant AMS utilities in areas related to the development and harmonisation of market rules and power trading practices. As will be discussed in Section 6, it is possible to differentiate regional trading from domestic system operations. However, the progressive harmonisation of domestic electricity market rules and power trading practices would foster the future function of ASEAN multilateral trading.

Later in the process, this regional regulatory co-ordination process could also include tasks such as compliance monitoring (including market monitoring and compliance with regional standards and regulations), as well as continuous review of the effectiveness of the standards and procedures as implemented. It will also be important that some authority ensures that transmission and distribution owners review relevant terms and procedures (for example, for grid connection and access), to ensure there are no discriminatory practices. This authority could lie entirely with the national regulators. Some regional authority, however, may be necessary to settle disputes related to the connection and/or access to and operation of the APG.

Topics related to TPA will involve many stakeholders such as generator owners (including IPPs), transmission owners and TSOs, as well as national regulators and ministries. This topic will therefore also require close co-ordination and facilitation. This includes commercial arrangements such as the wheeling charge methodology.

Finally, some degree of training and capacity building will be required across the AMS. This will also require co-ordination, both to ensure capacities are aligned throughout the region and to reduce any existing knowledge gaps.

Mechanism for settling transactions

When establishing multilateral power trade, a key focus will need to be on ensuring the efficient and secure handling of the financial aspects of trading. Most of the markets in existence have a CCP, also called central clearinghouse, that plays an intermediary role in these transactions in order to reduce overall counterparty risk in the market.

Any future multilateral trading among the AMS will need to consider the financial elements of wheeling and loss settlements, settlement of traded volumes through organised markets, and other trading and currency-related monetary flows. To reduce market risk further, it is also common to require collateral be posted by the market participants before they are allowed to participate in regional trading. Collateral calculations and related operations are also often handled by a central clearinghouse.

Minimum requirements with regard to settlement and clearing functions should be agreed upon at the start between all relevant parties. This type of financial operation may involve a larger volume of transactions that require timely (i.e. rapid) settlement, so it may also be necessary to establish minimum requirements for any banks involved in the settlement process.

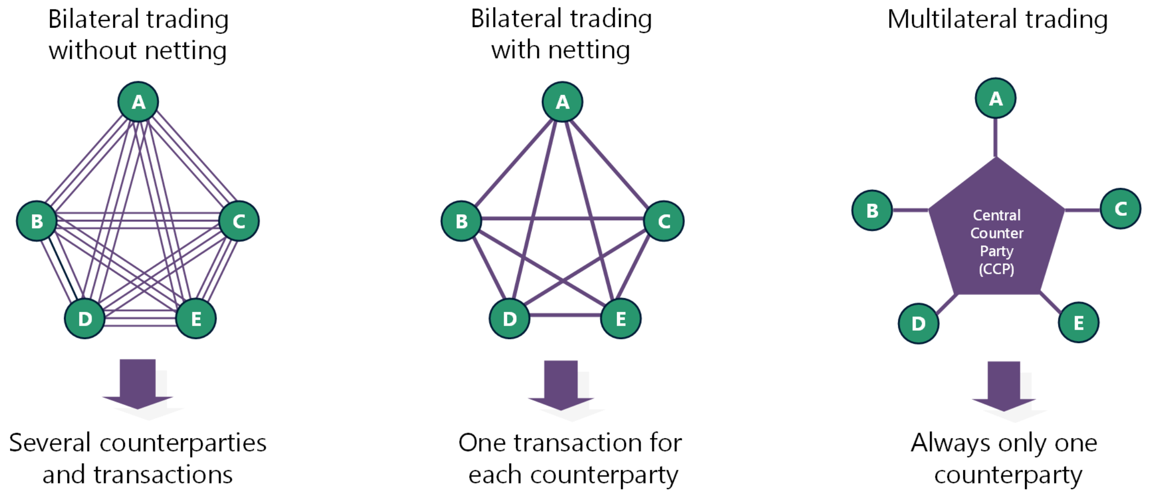
Potential role of a CCP

There are a number of relevant functions that could or should be centralised to ensure that multilateral trading is efficient and financially secure. The main roles of a CCP should include at least the following:

- responsibility for all clearing-related operations for electricity wholesale markets
- interface to the market participants
- interface to the market operator settlement team (if separate entity)
- internal data provider for financial reporting services
- partial owner of the operational procedures for wholesale electricity markets clearing (with ownership shared with the relevant transmission owners, which provide relevant data and retain ownership of that data).

The aim of a CCP is to establish a transparent and efficient flow of funds while overseeing the financial settlement and clearing of all trades in the organised market(s). In addition, a CCP can reduce counterparty risk. For example, if one market participant fails to settle its obligations, the CCP will step in to honour the obligations and cover any monetary shortfall. An overview of markets with and without a CCP is provided in Figure 47.

Figure 47. Overview of a CCP function



Source: Nord Pool.

Optional requirement: Trading currency or currencies

Multilateral power trade among the AMS is complicated to some degree by the fact that each AMS maintains its own currency. To manage this, two main options are possible. First, the AMS could agree on a single common currency to use for all regional trades. Second, regional trading can allow for settlement in local currencies. In fact, many of the international case examples presented in Section 4 use a common currency – typically USD, though the European Union uses the euro. The SAPP uses USD as the main currency, but it also allows for settlement in South African rand.

There are pros and cons to multicurrency trading. From market participants' point of view, it may be easier, more economical and more secure to trade in the local currency. However, from a regional perspective, this increases operational complexity and exposes counterparties to potential currency risk. One key aspect when considering this design parameter is whether the local currency trading is required under the laws and regulations of the respective AMS, or if it is a term set specifically in trading agreements. This can be managed by, for example, the organisation that hosts the regional market or by a CCP (if there is one).

Potential options for regional institutions in ASEAN

As noted above, there are already a number of relevant institutions in ASEAN. Depending on how multilateral power trade develops in the region, the roles of these institutions may need to change. In addition, it may be necessary to develop new institutions.

Therefore, the AMS should take a two-pronged approach to institution development. First, leverage to the greatest extent possible existing institutions. Second, in areas where existing institutions are insufficient, develop new ones.

Some of the functions discussed above will naturally fall under the purview of existing institutions. Take, for example, the development of harmonised grid codes. HAPUA already includes all of the relevant ASEAN utilities. As these utilities will need to be involved in grid code harmonisation, it makes sense to leverage HAPUA as a first choice, instead of building a new institution to perform a similar function.

At the same time, the AMS regulators will also need to be involved in the grid code development and harmonisation process. Here, the AERN is a logical choice for an existing institution to utilise. However, in contrast to HAPUA, the AERN does not have permanent staff or the necessary infrastructure to do this work. Therefore, the AERN could and should be further built up so that it can perform the necessary work.

In addition, ASEAN will almost certainly need to build new institutions to manage functions that do not have an obvious existing home, such as market organisation. Structurally, in doing so the AMS will need to find an appropriate balance between centralisation and distribution of responsibilities.

Generally, as the level of integration increases, the role of regional institutions becomes more crucial. Unnecessary duplication of functions can lead to inefficiencies and the potential for conflicting or divergent pathways to the development of multilateral power trade across the region. Therefore, it may make sense to develop single central institutions to take on certain key roles.

However, given the principles of stepwise development and voluntary participation, it is possible that some AMS will develop deeper forms of multilateral power trading faster than others do. It may therefore make sense to develop multiple institutions that can manage the differing needs of the various AMS.

Institutional flexibility will be important. Given ASEAN's principles of stepwise development and voluntary participation, it is likely that some AMS will choose to participate in multilateral trading early on, while others will choose to wait. It may even be that over the long term, multiple different markets emerge in an ASEAN context.

As will be discussed in Section 6, it is possible to develop market frameworks that allow for differing levels of participation among the AMS. Institutions can either help or hinder this, depending on how they are designed.

Market operation, for example, is a central function. If there is more than one market in ASEAN, then there may need to be more than one market operator. In practice, it will likely be necessary to develop new institutions to organise and operate the relevant market or markets.

As noted above, parallel development of market operation functions would be less efficient than centralisation in a single ASEAN-wide institution. However, a single institution may find it difficult to manage any potential subregional markets, especially if those markets are serving very different needs or if they have different designs.

The ownership structure of the regional market operators also matters, as it to some degree determines how easy it is to share knowledge across regions. If the market operator is structured as a private company, many of the best practices might be considered proprietary knowledge, and thus not be shared between subregions. It may therefore make more sense to have state ownership of the institutions, or to structure the institutions as a non-profit. A detailed analysis of the appropriate ownership structure for the AMS is out of scope for this study. It is important, however, that this issue be settled early on in the institutional development process.

Regardless of the path or paths the AMS take to develop multilateral power trade in the region, the role of regulators will be critical. Some issues that they face, such as the impact of increased cross-border power flows, will be the same regardless of the model of trade developed. Therefore, there is a significant benefit to the development of a single ASEAN-wide regulatory institution of some kind, even if multiple markets develop. Here again, the further development of the AERN probably makes more sense than developing an entirely new institution. At the same time, this would not prevent the development of subregional collaborative bodies among subsets of AMS. For example, in Europe there is the Council of European Energy Regulators, which is a regulatory network similar in many ways to the AERN, and NordREG, which includes only regulators from the Nordic region.

There are a number of functions that are only indirectly relevant to the establishment of multilateral power trade in ASEAN. High among these is regional collaboration on transmission planning. Power trade is not possible without transmission infrastructure in place. At the same time, the activity of transmission planning is not directly related to the practice of multilateral power trade.

Given that transmission planning is needed across ASEAN, here again it probably makes the most sense for a single central institution to take on this responsibility. It may be that an existing institution such as HAPUA should take on this role. It is notable, however, that the AIMS III study is being managed by ACE. This arrangement may make sense over the long term as well, or it may make more sense to further develop HAPUA's capabilities. Alternatively, a formal regional transmission operator institution could be developed, as per the recommendations of the ATSO study discussed previously. Regardless, here an ASEAN-wide institution most likely makes the most sense. At the same time, the existence of such an institution should not prevent groups of AMS from developing their own collaborative grid studies. This is the case in Europe, where ENTSO-E develops a Europe-wide grid study, but where groups of countries also collaborate to develop deeper and more fully integrated assessments on, for example, resource adequacy.

Finally, it is worth emphasising why there is value in at least some division of responsibilities. One of the lessons of efforts such as the GMS or regional integration in other parts of the world is that it can be difficult to decide which country should host a new institution. If all aspects related to regional integration are placed in a single organisation, it will be difficult or even impossible to decide who will host. Dividing functions across multiple institutions, and creating multiple institutions with some parallel or even overlapping functions, may lead to some inefficiencies, but it will also allow multiple AMS to more actively participate, and therefore feel some ownership over, the process of establishing multilateral power trade in the region.

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6. Models for establishing multilateral power trade in ASEAN

Overview of proposed models

Section 5 set out a set of minimum requirements and potential institutional arrangements that are necessary, but not sufficient, to establish multilateral power trade in the region. Even with these elements in place, the AMS will also need to settle on a design for the multilateral trading arrangement or arrangements.

The design(s) chosen will also need to be consistent with the ASEAN principles for developing multilateral power trade, as summarised in Section 1. For example, the model will need to allow stepwise development and voluntary participation.

This section proposes three models of trade for the region:

- harmonised bilateral trade
- secondary trading model
- primary trading model.

The naming of these models intentionally does not follow a particular international best practice. Instead, generic names have been chosen to allow the AMS to determine a naming convention appropriate for the region.

It is also important to emphasise that these models should not be seen as a ladder that the AMS must climb. That is, while each model may represent a "step" in developing multilateral power trade, there is no fundamental requirement that all AMS move collectively in the participation of each step as they are developed. Instead, the proposed models show different options of integration between the AMS that they may choose to adopt at their own speed and preference. In addition, the models are not mutually exclusive, meaning that they can exist simultaneously if the individual AMS so choose.

The following sections include an overview of the model itself, any additional requirements beyond the minimum that will need to be met to develop the model and the potential role of regional institutions.

Establishing harmonised bilateral trade with wheeling

All current trade arrangements among the AMS are bilateral in nature. In addition, these bilateral trading arrangements vary by country or even by border. The first step toward establishing multilateral power trade in the region should have a low threshold for development, so it can be developed in a relatively rapid and straightforward manner. It should also ideally bring benefits to all AMS, even if they do not choose to participate in multilateral trading at the outset.

Therefore, as a first step, it is proposed that the AMS develop a harmonised bilateral trading model. Combined with a harmonised wheeling charge methodology, this would allow any two AMS to trade with each other in any direction and regardless of whether they share a border. Such a model would also have long-term benefits, as even with a full multilateral trading model in place, AMS stakeholders may wish to enter into long-term bilateral trade agreements.

Overview of trade model

The primary goal for this model is to initiate harmonised bilateral trading based on the utilisation of the excess transmission capacities that exist in the APG. This model has the following key components:

- a standardised bilateral contract template
- a harmonised wheeling charge methodology
- a platform for connecting potential buyers and sellers.

Trading under this model can be both long term and short term, and could support any configuration of AMS countries, so long as interconnections are in place connecting them all together. It will also be important that there is a common understanding of ATC on a per border basis. Therefore, any AMS that wish to participate in this trading model will need to have processes in place to calculate ATC, and there will need to be some way of sharing this information with other stakeholders, including market participants.

The definition of "market participants" in this context would depend on the structure and policies of the AMS themselves. For example, in countries with vertically integrated power systems, participation may be limited to the national utility, or individual IPPs and large consumers granted the relevant export and/or import licences.

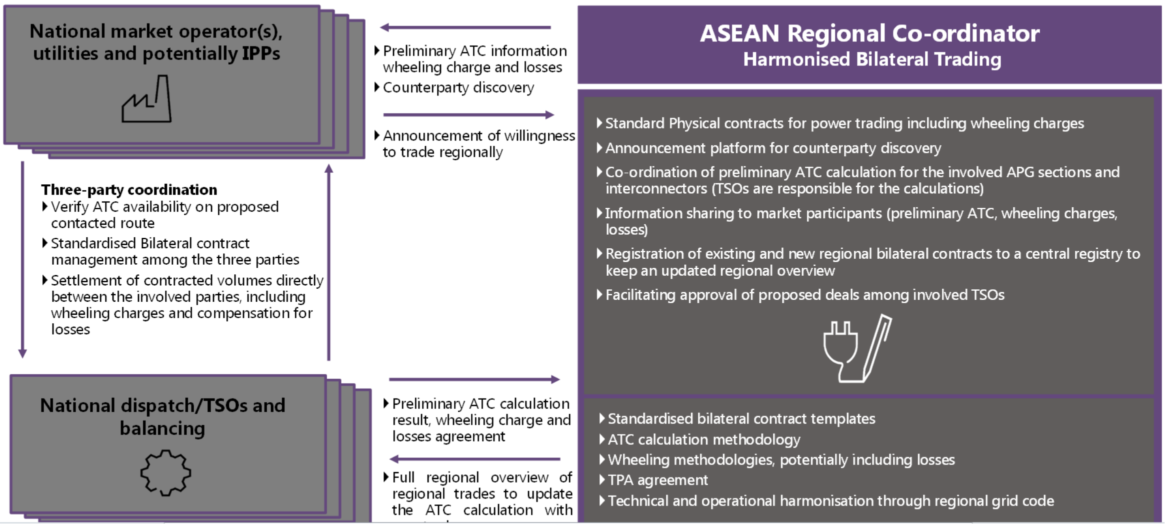
A harmonised bilateral trading model would be based on standardised contracts for the physical delivery of power. These contracts would be used only for regional trading, meaning that domestic bilateral contracts and markets would remain national.

The contracts themselves will be in the form of a multiparty agreement among the buyer, the seller, and the TSO or TSOs providing wheeling services. This contract should be as streamlined as possible so that it can be easily implemented across ASEAN, meaning it should contain only what is deemed minimally necessary to settle the terms of trade. This could include information on quantity and price, and the length of time the trade is valid for. On this last point, however, the AMS may wish to set limits on the maximum length for a trade, or ensure there are terms for cancelling trades. This is to ensure that bilateral contracts are as flexible a resource to the AMS as possible. The TSOs involved in the trades will also need to be able to provide a high degree of certainty regarding the availability and cost of the transmission services they provide.

To ensure that all AMS can fully benefit from a harmonised bilateral model, the AMS should establish some kind of regional co-ordinating organisation. This institution would facilitate and co-ordinate the implementation of the bilateral model, including hosting a platform that would help connect buyers and sellers and posting ATC information. This platform would allow potential buyers and/or sellers to post their desired trade, and allow for the matching of counterparties without a high degree of third-party intervention. Institutional roles and functions are described in more detail below.

The overall concept for the harmonised bilateral design is presented in Figure 48.

Figure 48. Harmonised bilateral trading



Source: Nord Pool.

Under a harmonised bilateral trading model, transactions are handled by the relevant trade participants, with a co-ordinating institution acting as a central facilitator of trade.

The harmonised trading model will involve several interactions among relevant parties. It is important, therefore, that there be a clear and agreed-upon process flow in order to ensure information is shared at the right time and to the right party or parties. This transaction flow is described in the "example transaction" section below.

Additional requirements and analytical gaps

Establishing a harmonised bilateral trading model will require additional building blocks beyond the minimum requirements described in Section 5. These are summarised in Table 14.

Table 14. Additional requirements – harmonised bilateral trade

1	Development of standardised bilateral contract templates
2	Identification or development of institutional options to enable stronger regional coordination of bilateral trades, including a "regional coordinator" or similar institution
3	Methodology for calculating and aligning preliminary ATC calculations per border
4	Agreement on what trade data are to be published
5	Processes and templates for stakeholders to provide information to the regional co-ordinator
6	Platform to connect potential buyers and sellers

The standardised bilateral contract templates should be developed by a WG that includes all relevant stakeholders from the AMS. What this means in practice may differ across the various AMS, but it should likely include representatives from utilities, regulators and/or energy ministries, IPPs or other generation owners, and large consumers. The template or templates should be as simple and generally applicable as possible, though the specific information necessary will also depend on progress on some of the minimum requirements discussed in Section 5. For example, if the wheeling methodology is in place across ASEAN, then it may not be necessary to include wheeling charge-related details in this template.

The WG will also need to decide if items such as the currency of the transaction should be defined in advance, or if that should be decided when the trade is negotiated. The parties involved in the trade should decide on information specific to the trade itself (price, volume, origin and destination, etc.). It is suggested, however, that there should be no volume-related trading fees within this model. The intention here is to encourage regional trading, though it is also justified by the fact that the operational costs of the regional market operator will be limited during this phase, so they could be recovered through annual membership fees.

Wheeling methodologies, as detailed in Section 5, will need to be in place as it will be necessary to calculate wheeling charges for any possible route. As a starting point, though, the national transmission operators may have varying wheeling methodologies. The wheeling charges themselves could be shared only with the parties involved in the trade itself. Ideally, however, they would also be shared with the regional co-ordinator, which can then in turn share the information with market participants. Without information on wheeling charges, market participants would find it more difficult to determine the full cost of entering into a bilateral contract.

Similarly, for the harmonised bilateral model to work as a generalised framework for trade across the region, market participants will need to have some visibility as to the amount of transmission capacity potentially available across the APG. The preliminary ATC calculation is therefore a key input. Another regional WG could be established to develop and agree on high-level principles for calculating preliminary ATCs. The specific methodology and responsibility for calculating ATC would remain national, and the process for aligning the value for a cross-border transmission line could be agreed upon on a per border basis. Factors such as grid maintenance, air temperature, included and excluded interconnections, and existing bilateral trade agreements (i.e. already booked capacity) will affect the availability of the individual grid sections.

It will be important that there be some way of sharing this information with all potential market participants. Therefore, there also needs to be some agreement on how to process and format the preliminary ATC data, and some institution in place to collect, host and disseminate the data. The calculation interval or update interval of the preliminary ATC will need defined. The initial proposal is to update every second week, with additional event-based updates if they are deemed necessary. The ATC calculations should be updated based on the trading activity so that the information is as accurate as possible.

The platform for sharing wheeling charges and ATC information should form the basis of a tool for connecting buyers and sellers. This simple "announcement platform" could function as a simple bulletin board, with information posted on a regular basis. This bulletin board could also allow potential buyers and sellers to indicate a willingness to trade. This system would require some investment in IT and communications systems, and it could potentially also retain information that would not necessarily be shared broadly, for example hosting a central registry for bilateral cross-border trades.

Meeting these additional requirements will require some degree of additional research and analysis. Addressing these analytical gaps in detail is beyond the scope of this study. Instead, they are summarised in Table 15.

Table 15. Analytical gaps – harmonised bilateral trade

1	Identification of national legislative and regulatory gaps
2	Development of appropriate enabling agreements
3	Identification or development of a regional co-ordinator
4	Capacity-building plan for market participants and other stakeholders

Four analytical gaps will need to be addressed. First, relevant legislation and regulations will need to be analysed across the AMS to ensure that the minimum requirements detailed in Section 5 have been met, and to address additional items such as requirements for import/export licences.

Second, even with an overall intergovernmental agreement in place, there will need to be operational agreements between the TSOs, and potentially non-disclosure agreements for information considered too sensitive to share publicly. For example, from an operational perspective, there may be occasions where the producer or consumer cannot meet its obligations under its bilateral agreements, resulting in metered imbalances. These situations will need to be addressed either through terms set down in the standardised bilateral contracts themselves, or under some general market rules that cover all ASEAN market participants. One solution for the imbalance problem is to designate a predetermined generator or utility as being responsible for imbalance adjustments for each grid section as needed. The generator or utility would then be compensated based on terms set out in the bilateral contracts or under a more general agreement.

With regard to data, some trade-related information may be considered confidential, and so may require confidentiality agreements between the involved parties. This could potentially be regulated under a blanket set of bilateral market trading rules that state the rights and obligations of all market participants and TSOs across ASEAN, as well as the recommended regional co-ordinator institution. Another option would be for the market participants and TSOs to use framework agreements (if the trading among these parties is frequent) which govern the general aspects of the bilateral trading, with trade-specific details defined in separate, relatively lightweight bilateral contracts.

Third, the AMS will need to agree on where to host the "announcement platform" – either in an existing institution or in some potential new institution. As the relevant institution could play a much larger role over the long term, the ideal choice is one that will allow for as much long-term flexibility as possible.

Finally, some degree of capacity building will almost certainly be necessary. Therefore, the AMS should identify capacity gaps related to bilateral trading and develop a plan for addressing them.

Potential role of institutions

As a start, it is worth emphasising that national institutions would have a strong role to play under the harmonised bilateral model. For example, regulators will need to be involved throughout the process, as they help determine what types of information should be public.

Regulators are also involved in the development and approval of national technical standards and related methodologies, for example on ATC calculations.

Developing a regional, harmonised bilateral model, though, will require increased collaboration across a range of stakeholders, including, but not limited to, regulators, utilities, policy makers and market participants. Therefore, some regional institutions and collaborative bodies will be necessary for the harmonised bilateral model to fully function.

That said, under the harmonised bilateral trading model, the regional institution would have a relatively limited role. In practice, the relevant organisations would primarily act as facilitators of information, providing relevant stakeholders with all of the information they need to support or participate in cross-border trading. Though the role is limited, it is nevertheless still vital for the functioning of the harmonised bilateral model, as trade can function properly only if market participants have access to timely and accurate data. Moreover, the presence of a regional institution bridges the gap between the existing bilateral modes of trade and the more concrete multilateral trading models described in the following sections.

Table 15 summarises the proposed main responsibilities that will need to be managed at a regional level.

Table 16. Main responsibilities of the regional institution(s) under harmonised bilateral trading

1	Facilitating the development of standardised bilateral contracts (buyer, seller and TSO[s])
2	Providing a simple announcement platform for bilateral trades
3	Collection of preliminary co-ordinated ATC calculations from involved TSOs
4	Keeping a central registry giving an overview of the trades
5	Information sharing among market participants (ATC, wheeling charges, losses and trades)
6	Enabling co-ordination between relevant national stakeholders

The depth of responsibilities for the regional institution or institutions would depend on the role in question. On issues related to regulation, for example, the primary need under the harmonised bilateral model will be increased co-ordination among AMS regulators, in particular to facilitate knowledge sharing. The AERN, with further development, could fill this role. It could also take the lead on certain issues that will or should be regional by nature, such as data publication.

Development of the standardised contract template(s) and wheeling methodologies would require deeper levels of collaboration and technical work. HAPUA already has a mandate to work on this issue. As such, it would be logical that the efforts to establish the contract template and the wheeling methodologies be led by HAPUA/APGCC. In addition, however, it is recommended that there is active involvement from the regional co-ordinating institution, if it is established or identified. Similarly, the process for delivering information to the recommended regional co-ordinator should be developed via a joint working group that involves HAPUA/APGCC and the regional co-ordinator itself.

The recommened regional co-ordinator could also register existing and new regional bilateral contracts. An accurate, up-to-date central registry would give all relevant stakeholders a regional overview on the contracted volumes and the directions of trade. This information could be of importance to the TSOs as they prepare their preliminary ATC calculations.

In general, the recommended regional co-ordinator could have an important information-sharing role, providing the market participants with the information they need in a standardised format. As part of this, the AMS will need to agree on what the regional co-ordinator can share. The national regulators should determine this with the support of the AERN. Ideally, all information on the price, volume and duration of trades should be shared publicly. This information provides transparency on the value of the trading, helps prevent market abuse and can encourage others to participate in the market.

Settlement of trades will be handled entirely by the trade participants themselves. Therefore, there is no need for a CCP under this model.

Example transaction

Under a harmonised bilateral trading model, the number of involved parties will depend on the physical path of the trade. There could be as few as two countries involved, in the case of a simple bilateral trade between neighbouring countries, or there could be multiple countries involved, in cases where there are one or more wheeling countries.

Each trade, though, would be unidirectional in nature. That is, the standardised bilateral contract would cover only a single seller trading power with a single buyer. Bidirectional trades would still be possible, but they would require two different bilateral contracts.

The following example describes a hypothetical transaction involving three countries: the seller, the wheeling country and the buyer. Table 16 summarises the full process.

Table 17. Example harmonised bilateral trade process

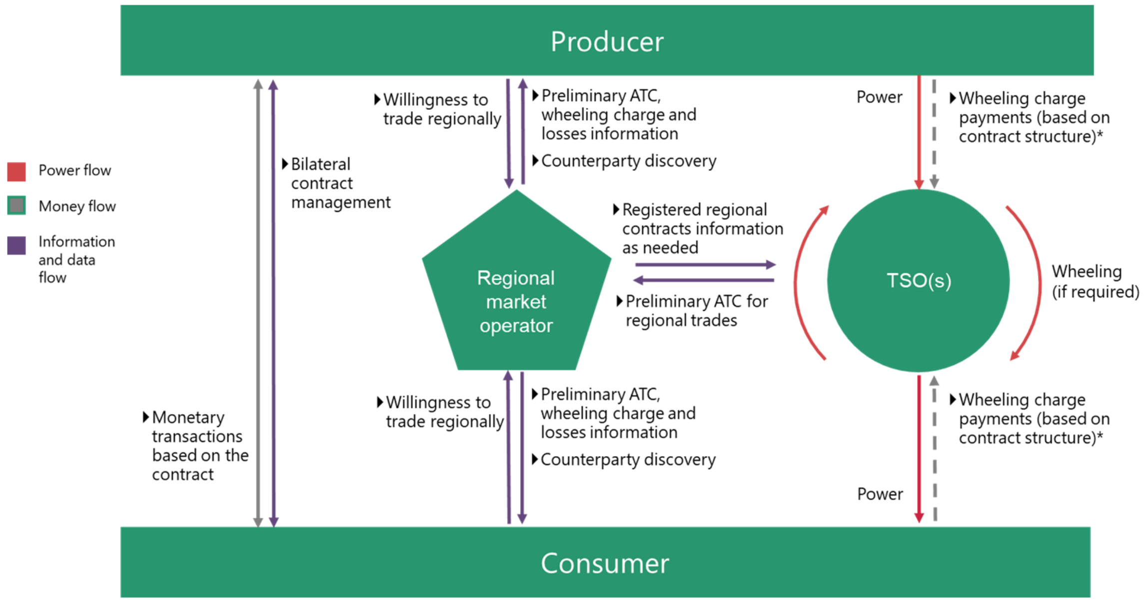
1	TSOs calculate the preliminary ATC; ATCs are aligned at each border based on the agreed-upon methodology
2	TSOs provide the preliminary ATC to the regional co-ordinator
3	Market participants, taking into account the preliminary ATC, announce their willingness to trade regionally by using the announcement platform
4	After counterparty discovery, parties are to verify that the final ATC is available on the proposed contracted route by consulting the involved TSOs directly
5	Standardised bilateral contract management and signing among the relevant parties (buyer, seller and TSO[s])
6	Registration of the accepted trade at the regional co-ordinator
7	Delivery of power between the two parties using wheeling services as relevant
8	Settlement of contracted volumes directly between the involved parties, including wheeling charges and compensation for losses and imbalances as agreed in the standardised contact

All transactions involve the flow of three key elements: information, electricity and money. Under the harmonised bilateral trade model, the flow of information is kept to a minimum, and the monetary flow is only between the parties involved in the trade. Figure 49 summarises the physical power flows, the monetary flow and the information flow for a hypothetical transaction. Note that in this case the counterparties are clearly labelled as producers (which sell power) and consumers (which purchase power). This is because all transactions under the harmonised bilateral model are unidirectional in nature.

Physical power flows are based on the bilateral contracts. The seller will inject the agreed amount of power into the grid at the agreed-upon time and for the agreed-upon duration, and the buyer will consume the same according to the contract. The TSOs in the seller, transit and buyer countries will be responsible for providing the transmission services, as governed by the ASEAN TPA agreement and any operational arrangements made by the involved TSOs.

Power flows naturally result in losses, which will need to be compensated for under terms set in the standardised bilateral contract. Each transmission operator will be responsible for keeping the grid operation within agreed technical and operational requirements, as per the harmonised grid codes. All power flow/operational issues are managed by the respective TSOs, and so under the harmonised bilateral model there is no need for the regional co-ordinator to play any role with regard to real-time operational co-ordination of the APG.

Figure 49. Harmonised bilateral trading example: Path of information, money and power flows



Note: *Wheeling charges are paid either buy producer or consumer of split between according to the contract structure
Source: Nord Pool.

The regional market operator is only a facilitator of information for trade to happen. The monetary flows stay between the parties of the trade (buyer, seller and TSO[s]).

Data and information flows have an important role in facilitating the regional trading in this model. The transmission operators provide the recommended regional co-ordinator with the preliminary ATC information on the grid sections they are responsible for. The recommended regional co-ordinator aggregates and publishes this information, giving market participants an overview of the amount of capacity available across the APG for facilitating regional trading. Market participants will then indicate a willingness to buy or sell power using the announcement platform, taking into account the amount of transmission capacity potentially available to deliver the power. When the participants find a counterparty, the contracting process is managed entirely bilaterally, i.e. without the intervention of the regional co-ordinator. However, the market participants would use the standardised contracts, while the regional co-ordinator would also potentially host. It should be noted that the exact information that will be published and stored by the regional co-ordinator is a design question. Thus the AMS, should discuss and agree on the appropriate level of facilitation and information sharing done by the regional co-ordinator in the future design phase, which is out of scope for this report.

Monetary flows are based on the terms of the bilateral contract and the settlement process between the buyer and seller. In addition, payments will need to be made to the relevant transmission operators for wheeling services and to compensate for any losses. There may also be an imbalance compensation mechanism that addresses imbalances arising from the delivery (or lack thereof) of the contracted power.

Establishing a secondary trading model

Though the harmonised bilateral model detailed above would be an improvement over the existing situation in ASEAN, as the name suggests, it is not a complete model of multilateral trade. It is therefore proposed that the AMS develop a secondary trading model, as defined in Section 4. That is, the AMS should establish a model where multilateral trading exists as a separate option for local utilities and market participants to utilise when they want to, in addition to the existing domestic market model.

Establishing a secondary model would enable multilateral trade among the AMS while remaining fully consistent with the ASEAN principles described in Section 1. In particular, participation in a secondary trading model would remain voluntary, and it would involve only the trading of gaps and excesses. Similarly, national regulations would be complemented by regional ones, with countries remaining fully in control of their national power systems. In other words, there is no need to restructure national power markets to support a secondary model.

If a secondary trading model were introduced, however, the responsibilities of the regional institutions would increase. In particular, regional co-ordination, as described in the harmonised bilateral model section above, would no longer be sufficient. Instead a regional market operator is needed.

Overview of trade model

In the secondary trading model, the role of the recommended regional co-ordinator will need to be enhanced to become a formal regional market operator. The tasks for this market operator in facilitating development and operation of the secondary market model are shown in Table 18.

Table 18. Additional responsibilities of the regional market operator in the secondary trading model

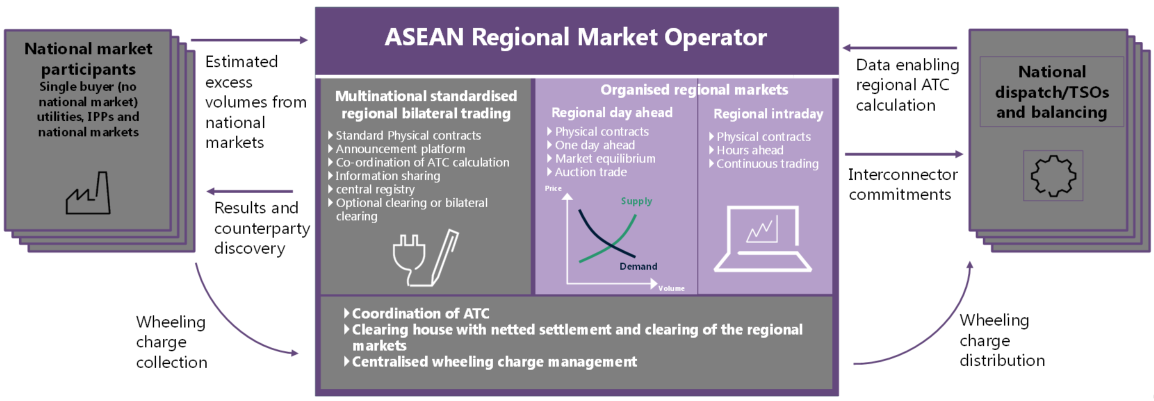
1	Organisation of day-ahead markets (DAMs) and eventually intraday markets (IDMs)
2	Organisation of implicit capacity allocation for interconnectors in the DAMs and IDMs
3	Responsibility for settlement between market parties
4	Potential CCP responsibilities
5	Nomination and co-ordination of traded volumes to the TSOs

As a first step, it is important to note that this secondary market model and the harmonised bilateral trading model are fully compatible with each other. That is, it is possible to keep harmonised bilateral trading even after the secondary market model is in place. The secondary trading model introduces short-term market segments that complement the harmonised bilateral trading.

Under the secondary trading model, the regional market operator will develop two markets for trading electricity: a DAM and, at a later point, an IDM. Usually the DAM is introduced first, and then the IDM follows a few years later. This stepwise implementation approach to developing the organised markets could also be applied in an ASEAN context. Once in place, these two market segments will allow for more flexible and efficient regional trading across the AMS. It should be emphasised, however, that in a secondary model, trading should be primarily regional by nature, and thus avoid local (national) order matching, which would potentially interfere with the functioning of national markets.

Figure 50 describes the secondary market at a high level. As noted above, the national market would remain untouched. Consequently, the ASEAN regional secondary markets would be operated based on the residual volumes remaining after the national markets have cleared. These residual volumes would be provided on a voluntary basis to the regional market operator by the relevant national market participant (for example, the national market operators or national stakeholders who have permission to trade regionally). The regional market operator will then organise an auction-based DAM and, eventually, a continuous IDM, based on these residual volumes.

Figure 50. Market model for secondary trading



Source: Nord Pool.

National and harmonised bilateral trading still exist alongside the new secondary market model.

The DAM would allow market participants to trade hourly products for the next delivery day. The objective of the market is to facilitate trading hour by hour to balance the participants' internal portfolio for production and consumption. The market results in a contract based on hourly physical delivery. The DAM is open for trade every hour for the whole year and is based on standardised products.

The DAM is often referred to as the cornerstone of the total market concept because its market price serves as a reference for other markets. This might include long-term markets (including, for example, long-term bilateral contracts), the IDM and potentially markets for future ancillary services products. A DAM is considered the most appropriate practice for achieving economic efficiency in the power sector through short-term trading, and is therefore the logical place for the AMS to begin when developing multilateral trading in the region.

The IDM functions in the intervening time between closure of the DAM and the physical delivery of power (typically one hour ahead of real-time operation, though some markets may close closer to real time). Market participants can, through the IDM, place purchase and sales orders continuously throughout the day. Trades are made whenever two orders match in price and quantity. In other words, each placed order can be matched independently whenever a suitable counter offer is found.

Because the IDM allows for trading close to the delivery period, it provides market participants a way to balance out their positions after the DAM results are published, and to trade any remaining residual volumes that did not clear in the DAM. In regions where the share of renewable generation is growing, the role of the IDM is increasing in importance. This is because variable generation such as wind and solar PV is harder to predict far ahead of real time, making it harder to trade in DAMs where participants need to commit to physical delivery schedules one day ahead. The IDM allows for rebalancing of positions as more accurate forecasts become available.

After the DAM results are published, it will be necessary to update the available interconnector capacity. This is done through an "implicit auction" process, whereby transmission capacity is allocated based on the implicit needs of the volumes that cleared in the DAM. This process can continue into the IDM, when it is in place, with interconnector capacity not allocated in the DAM made available for trades in the IDM.

Once trading is done, the regional market operator will, based on both bilateral deals and the short-term market results, inform the national transmission operators as to the committed regional volumes and expected power flows in the region. However, to ensure accurate information is provided (in particular in regions where there may be high volumes of activity), the national transmission owners and dispatchers will need to provide the regional market operator with ATCs on a daily basis. Harmonisation of the ATC calculation methodology and the process for sharing data is even more important in the secondary model than in the harmonised bilateral model, as the accuracy and timeliness of information can have more immediate impacts on regional trading.

It will also be important for ASEAN to have established a full wheeling model for the secondary market to function properly, as the possible paths for trades will be much more dynamic and hard to predict. It is possible to introduce a centralised wheeling charge collection and distribution function at the regional market operator, though this is optional.

Settlement and clearing of the DAM (and IDM), however, should be handled centrally. This is discussed in more detail in the section below discussing the potential role of institutions.

Additional requirements and analytical gaps

The secondary trading model requires some enabling key elements and functions. Thus, some additional analysis is necessary. Requirements need to be met beyond the minimum requirements described in Section 5 and, to some extent, the requirements of the harmonised bilateral trading model. The additional requirements for establishing a secondary trading model are listed in Table 19.

Table 19. Identified additional requirements – secondary trading model

1	Full market design for the DAM and, eventually, the IDM
2	Trading platforms and supporting IT infrastructure for DAM (and IDM)
3	Harmonised process for exchanging ATC information
4	Designation and design of the CCP function
5	Further building of regional market operator organisation

The first and perhaps the key additional requirement is the detailed market design for the DAM and, eventually, the IDM. While there are many international examples of both market types, an ASEAN secondary market must be designed to fit the ASEAN context. Areas that will require additional study cover essentially all of the design elements, including market timing (which should, for example, take into account the timing of national power systems), technical standards, and transaction-focused issues such as the allowed currency or currencies. The total level of financial, data and other information flows will be significantly higher than under the harmonised bilateral model. The full market design must therefore formalise these flows in such a way as to be clear to all market participants but also reflective of domestic capacities.

A second but equally critical requirement is the development of trading platforms and associated IT infrastructure to support DAM (and IDM) trading. The entity responsible for organising the markets will need to create specifications for the required software and hardware and acquire this from available vendors. It will also be important that any software solution take into account the announcement platform for bilateral trading. In particular, the announcement platform should be reviewed to determine whether and how it would need to change to reflect the existence of the secondary trading model.

Third, a secondary trading model will require increased harmonisation and co-ordination of ATC calculations. In particular, the transmission operators will need to provide updated information to the market operator on a more regular basis. There may also be a need for additional agreements on interconnector capacity allocation, as the transmission operators must honour the ATC they provide to the market, as well as be able to respond to updated information that comes from the implicit auction process.

Fourth, one of the major new elements in the secondary trading model is the introduction of a CCP for all trades conducted in the DAM (and IDM). This function could extend to the bilateral market as well, though this is not a fundamental requirement and so utilisation could be on a voluntary basis. To establish function, it will be necessary to perform a detailed design study that clearly defines the CPP's operational rules, market obligations and other relevant functions. As part of this, it will be necessary to establish a method for selecting banks that may participate in regional trading, as this will enable secure and efficient monetary flows between the CCP and market participants.

Finally, a fifth identified additional requirement is the development of the ASEAN regional market operator institution, which will play a significant role in both the development and operation of the regional market and related functions. These roles are described in more detail in the next section

Meeting these additional requirements will require further research. The relevant analytical gaps are summarised in Table 20.

Table 20. Identified analytical gaps – secondary trading model

1	Design requirements for the DAM (and IDM)
2	Harmonised process for exchanging ATC for the implicit auctions in the DAM (and IDM)
3	Detailed technical specification for trading platforms and associated IT solutions
4	Research on different service models for the operation of DAM (and IDM)
5	Detailed design for clearing and settlement of DAM (and IDM)
6	Capacity-building plan and related work for institution development

Potential role of institutions

As noted above, under the secondary trading model the regional institutions will take on a bigger role, evolving from regional co-ordinators to market operators. The market operator function in this model is to identify or match trades through a formal marketplace, and share necessary information with relevant market participants. The market operator will therefore need to be heavily involved in the market design process, initially for the DAM and eventually for the IDM as well.

Assuming responsibility for the design and organisation of the DAM (and eventually IDM) market segments will significantly increase the organisational needs of the market operator. This means the formation of new departments, as well as increased staffing and other resources. Some of this additional functionality could be developed with seed funding, provided by the AMS, outside funding organisations or a combination of the two. Eventually, however, these capacities will need to be funded independently, so any development plan should take this long-term goal into account. Related, the regional market operator organisation will require targeted capacity building to effectively take on these new roles and responsibilities. Similarly, this operational expansion will also require further development of research programmes, operational rules, and handbooks and guidelines for staff and outside contractors.

The market operator could also potentially take on the role of CCP. That is, it could facilitate the settlement of the trades conducted through the market platform.[21] It could also perform the same role for bilateral trades made under the harmonised bilateral model. In both cases, locating this function at the market operator is optional, but if done, it would also require additional capability building and training.

Regardless, the market operator and existing institutions such as HAPUA, the national energy regulators and the AERN will need to be heavily involved in the development of the CCP function. As the CCP centres on monetary flows and reducing the potential for systematic market risk in the case of default, financial regulators may also need to be involved, both in the design phase and to oversee operation.

[21] The CCP role is described in more detail in Section 5.

ATC calculations and alignment will require more frequent updates, and so the transmission operators will need to perform this function in a relatively efficient manner. This could call for increased harmonisation of calculations across borders, which means in turn that there could be a benefit to a regional institution facilitating harmonisation to the extent possible. In this case, HAPUA could be the logical choice to lead this process. However, the regional market operator will also need to be involved, to ensure that the calculation process is consistent with the method for reporting ATC values.

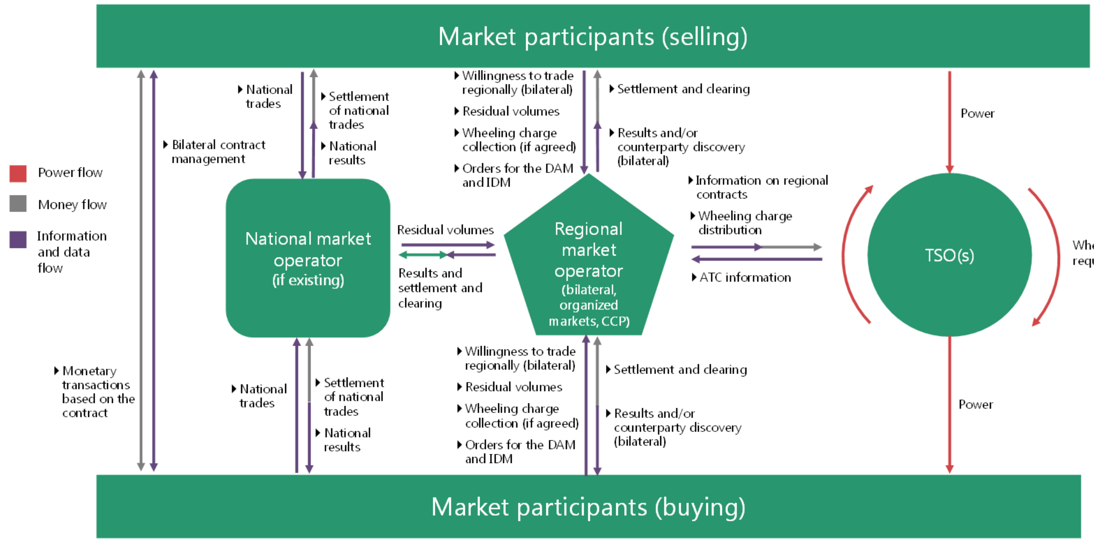
Finally, the AERN will have a large role to play in the establishment of the secondary trading model. In particular, though the methodologies developed within the secondary trading model may need national approval, the AERN would need to play a central role in ensuring regulatory alignment and knowledge sharing between national regulators. Some capacity building within the AERN will therefore also be necessary.

In general, the secondary trading model increases the need for co-ordination among national institutions. To the greatest extent possible, these co-ordination tasks should be placed in existing institutions, in particular HAPUA and the AERN, but also the APGCC. At the same time, it will be necessary to designate a regional market operator. It is not clear whether the existing institutions are well placed to play this role. Therefore, it probably makes more sense to develop a new institution to perform the relevant functions, one that would be separate from, but work closely with, HAPUA, the APGCC, the AERN and others.

Example transaction

The secondary trading model will introduce new regional markets (first the DAM, and eventually the IDM) and a CCP function. Taken together this increases the amount and complexity of information and data flows. The flows of physical power, monetary amounts, and the information and data are illustrated in Figure 51.

Figure 51. Secondary trading model – example of trade flows



Source: Nord Pool.

The national and harmonised bilateral trading still exist alongside the new secondary market model.

One key difference from the process outline in the harmonised bilateral model (Figure 49) is that the contractual parties are no longer clearly producer and consumer, but rather they are simply market participants. This is because the introduction of short-term markets allows for multilateral trading, and not only trades between the two parties in a bilateral deal. That is, it is possible that bids and offers could be met by multiple market participants.

Physical power flows will essentially follow the same scheme as in the harmonised bilateral trading model, with one important difference. Because it will now be possible for multiple parties to be involved in any given transaction, the physical power injected into the APG may come from more than one producer and may be transmitted by more than one TSO. Since trading in the secondary trading model is intended to be purely regional in nature (i.e. matching will be done only on a cross-border basis), the transmission of the power from injection point to the withdrawal point is expected to involve wheeling at least in the respective national grids and possibly through one or more transit grids.

Monetary flows under the secondary model are more complex compared with harmonised bilateral trading. The new short-term markets will require both centralised money collection and crediting to the market participants through the CCP function. Collection must be central because the number of counterparties will vary depending on how the market clears. Practically speaking this will mean that the CCP will first bill the appropriate amount (based on actual DAM and eventually IDM trades) from the buyers, and then credit appropriate amounts to the sellers. It is also possible that the CCP could manage the wheeling charge collection and distribution process as well, though this is optional. Settlement of bilateral trades could remain unchanged from the harmonised bilateral model, or the settlement function could move to the CCP as well. Again, this last step is optional.

Data and information flows, including contract management, will also become more complex. In particular, contracting under the organised markets framework will split into two pieces. First, the market participants will have contracts with their national market operator (if it exists in the respective AMS), which allows them to trade domestically. This might mean participating in a liberalised wholesale market as in the Philippines and Singapore, or it might mean being a licensed IPP. Second, the market participants (including the national market operators if relevant) need to enter into contracts with the regional market operator to allow them to participate in the regional market.

Trade information flow will follow a similar split. Market participants will submit domestic trades to the national market operator, while regional trades will be submitted to the regional market operator; however, under the principle of trading gaps and excesses, in practice this second step would involve the trading of residual volumes. The amounts available for trade, therefore, would depend on the results of the national system clearing processes.

The regional market operator will send data and information in three streams. First, information on clearing and settlement will be sent back to the national market operators. Second, market participants will receive information on any transactions and settlements that they are involved in. Third, the transmission operators will receive information on committed and expected regional physical power flows based on the market results.

Finally, under this model, information flows related to bilateral contracts would remain separate and therefore the responsibility of the market participants, as per the harmonised bilateral trading model. Ideally, though, the market operator should be responsible for recording bilateral trades as well as organisation of the secondary market

Establishing a primary trading model

The secondary model, when implemented, would fully meet the fundamental goal of establishing multilateral power trading among the AMS. However, there is value in considering a third, more deeply integrated model. Specifically, the AMS could decide to establish a primary trading model.

A primary trading model is one where regional, multilateral trading is the default option. It is important to note, however, two key caveats. First, this proposal is very future-oriented. That is, there is no reason for ASEAN to consider implementing a primary model until after a secondary model has been established and demonstrated to work. Second, even with a very long-term view, it is highly unlikely that it would make sense to develop a single primary market for ASEAN as a whole. Instead, it should be considered an option only for those AMS that decide a deeper level of integration would bring sufficient benefits to justify the necessary domestic changes and regional work.

The primary trading model requires a high level of co-operation among the participating AMS as well as a high level of technical, regulatory and policy harmonisation. Within the primary trading model, it is still possible to keep the harmonised bilateral trading. However, a secondary trading model might not be possible, at least not for the AMS that choose to participate.

Under a primary trading model, more volumes would be traded based on short-term market and system conditions. The fully integrated primary model therefore focuses on establishing the DAM as the key market segment. This can provide a more efficient utilisation of the generation resources and transmission infrastructure. It also brings particular benefits to renewables integration, and so therefore may be an option worth pursuing if and when the penetration of variable renewables rises above a certain share.

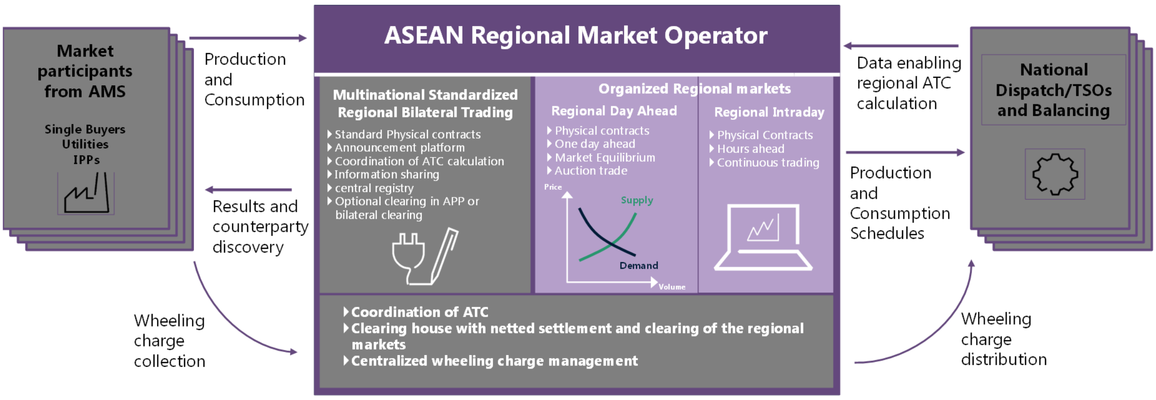
Another key element that should be highlighted is the fact that moving to a primary trading model would require market restructuring at a national level. This is because without full competition among generation, the market is unlikely to be sufficiently dynamic to ensure the development of efficient price signals. Successful electricity market liberalisation creates three sources of improved economic performance. First, it results in a better overall allocation of resources, lowering prices to reflect the marginal costs of production. Second, an open market and competitive environment encourage the efficient use of the generation capacity and innovations that lower production costs. Last, wholesale prices would better reflect underlying market conditions, which can lead to more efficient consumption patterns across consumers exposed to those prices.

Under the primary trading model, domestic generation resources are cleared in a unified, integrated manner. That is, all production and consumption is traded through the regional market operator. This means the primary market model does not follow the ASEAN principle of trading only gaps and excesses, as the optimisation of domestic resources is determined by regional system needs. However, responsibility for system operations and system planning would remain entirely domestic. For example, dispatch of generation would still be controlled by the national system operator. National sovereignty, therefore, is not sacrificed under the primary trading model.

Overview of trade model

The building blocks of the primary trading model, as detailed in Figure 52, largely follow the concept of the secondary trading model. The primary difference is on the left side of Figure 52, where the national markets and internal procurement processes have been removed. Instead, all national supply and demand is traded through the primary market trading platform hosted by the regional market operator.

Figure 52. Market model for primary trading



Source: Nord Pool.

Within the primary trading model, cross-border flows and national flows are optimised at the same time.

The primary market model is more complex than a secondary market model, and so implementing a primary model is not a simple task. Many design elements will need to be decided up front, and these design elements can have a significant impact on the development of the market or its overall impact on trade and investment. For example, for the AMS that choose to develop the primary market model, the regional market becomes the sole wholesale electricity price signal. It is therefore important that the nature of the pricing regime be defined up front. In particular, a primary trading model can utilise either zonal or nodal pricing. Nodal pricing, as used in PJM and ISO New England (Section 4) brings a number of potential benefits, but it also increases the complexity of the market design and can raise concerns over market power abuse. Nodal pricing also requires a higher degree of harmonisation than zonal pricing, which can make it more difficult to implement from a legal perspective. Zonal pricing, which is widely used in Europe, is simpler to implement but, unless the zones accurately reflect transmission constraints, can lead to less efficient operations and investment. An analysis of the pros and cons of zonal versus nodal pricing is not in the scope of this study but would be needed in a detailed design of a primary market model.

Certain other design elements should be employed to ensure that the primary market meets, to the highest degree possible, the ASEAN principles for multilateral power trade. For example, the market-clearing algorithm can allow each participating AMS to have an internal/national matching between supply and demand. This should be done through an implicit auction process, meaning that the calculated ATC will be one of the factors (together with the orders from the market participants) that sets the prices for each country while at the same time establishing the flows in and out of the different countries. Interconnector flows will automatically be scheduled from the low-price (surplus) areas towards the high-price (deficit) areas. Over time this should lead to an equalising of the major price differences between the participating AMS, assuming there is sufficient cross-border transmission capacity. Prices themselves should be based on the marginal cost of production, so that wholesale prices are optimised according to the principle of least cost. Taken together this should maximise the long-term benefits for consumers across the AMS.

The CCP function will remain as in the secondary trading model, but under the primary model, it would see a significant increase in traded volumes. Whether the same CCP should be used for both secondary and primary markets, or if separate CCPs would need to be developed, is a decision left to the AMS to decide.

Finally, it should be emphasised that under this model the national transmission operators will remain in charge of the operation of the national power systems. The regional market will determine schedules for dispatch, but real-time system operations will remain local. Additionally, this model allows for the development of more complex regional markets to handle items such as imbalances.

Additional requirements and analytical gaps

The primary trading model is a fully integrated market that would stretch across multiple AMS. It will therefore require some new key enabling elements and functions. These are listed in Table 21.

Table 21. Identified additional requirements – primary trading model

1	Major market reform package at the national level (design, organisational aspects, regulation, legislative changes, etc.) to allow integrated markets and institutions
2	Capacity-building programme tied to domestic market changes
3	Consolidation of national procurement processes and national market operators (if relevant) as these will be centralised at the regional market operator
4	Incentivised liquidity promotion measures to promote the organised pooled auction market segments
5	Option: Transposing long-term physical contracts to financial contracts, making the short-term (DAM/IDM/etc.) the key market for physical trading purposes
4	Option: Implementing a congestion rent model as an alternative to wheeling charges

The first requirement is a significant one. In order for a primary market to function properly, the participating AMS will need to have fully harmonised, restructured markets. This implies significant changes to national legislation and regulation, including unbundling of domestic generation and transmission. However, it should be emphasised that unbundling does not imply privatisation. The transmission operator could, for example, remain government-owned. Generation, however, should ideally be privatised to the largest degree possible, to ensure sufficient competition in that sector. It would also be possible, but not an absolute necessity, to introduce retail competition.

At a regional level, the market operator will need to be further developed so that it can manage its increased responsibilities and flow of data and funds. Capacity building will therefore be of key importance. This is true both at the national level and at the regional level, as this market concept will be a completely new way of thinking for many or most stakeholders.

It is important to note that these changes do not need to happen all at once. In fact, ideally these changes would be implemented under a stepwise, but certain and transparent, implementation plan. This would avoid giving the market participants too much uncertainty.

There will likely also need to be incentives for attracting liquidity into the DAM, as a liquid DAM is a cornerstone of the primary market model as presented. This could include the introduction of a financial contracts market, which could, among other things, allow for the transposing of bilateral contracts to financial contracts, and for long-term hedging.

Finally, the participating AMS will need to decide how to handle wheeling charges. It is possible to continue to use a harmonised wheeling methodology. Alternatively, the AMS could recoup the cost of their transmission system through congestion rents. Under this model producers receive the price in their home country (or zone), while consumers pay the price in their country (or zone). In the likely case that available transmission capacity is not unlimited, there will be times when the price paid is higher than the price received. This price difference is collected by the market operator and then paid to the transmission operator(s) as the fee for providing transmission services. How the revenues are shared among the relevant transmission operators will also need to be determined. This, however, could be handled between neighbouring transmission operators on a bilateral basis, potentially tied to the cost-sharing arrangements for cross-border transmission infrastructure.

One challenge with this model is if there is no price difference, then the transmission operators that provide the transmission services do not get paid. There are other ways for paying the TSOs for the transmission services, which will not be explored here. How to ensure payment of the provided transmission services is a design question when doing the major reform package that is needed to implement this model.

Establishing a primary model would require additional research. A set of analytical gaps that would need to be addressed are summarised in Table 22.

Table 22. Identified analytical gaps – primary trading model

1	Study the legal aspects of full regional integration and the changes required in national legislation and regulation
2	Identify potential liquidity promotion measures for attracting volumes to the DAM, including a possible financial contracts market
3	Develop a roadmap to fully integrate the market with the centralised market operator and institutions in a stepwise manner
4	Evaluate different remuneration options for transmission/wheeling services

Potential role of institutions

Institutions – both regional and national – will have a significant role to play in the development of a primary market model.

As a starting point, it is worth emphasising that the primary trading model depends on free and open competition among all possible resources. This means that national regulators will have a bigger role to play in monitoring market participants, as one of the major issues with competitive markets is the potential for market abuse. Regulators must develop monitoring functions and set strict market rules in order to identify market abuse and to punish offending market participants. Doing so will build trust among market participants, which in turn means that the market itself will function more efficiently and fairly. These market rules should also apply to transmission operators, which can affect prices significantly through the way they calculate transmission capacity. While much of the market monitoring and regulatory enforcement will need to be done at the national level, the AERN will also have a significant role to play, both in helping the national regulators perform their duties and in monitoring the regional market.

The role of the market operator increases significantly under the primary trading model. As a starting point, because all trading is now done through the centralised regional market, the volume of trades that the market operator must manage increases dramatically. Perhaps more importantly, because of the critical role the regional market operator plays in helping to manage the power systems of the participating AMS, security of operations must never be compromised. A robust security protocol and fallback procedure in the event of an outage will both be required in order to ensure that the market is never disrupted.

The CCP also holds an increasingly important role under the primary trading model if established, as it will be responsible for all the monetary flows that are created through the regional market. In addition to further developing its capacities, oversight of this institution – ideally by financial regulators – is vital. As financial regulation gains a more significant role under the primary model, it may be necessary to expand the AERN's remit to also focus on financial regulation, or identify an appropriate alternative institution to take on this role.

As competition increases on the generation side and potentially on the consumer side as well, organisations that represent their interests might become more active regionally. This might create the need for more cross-regional and stakeholder co-ordination and information sharing. Depending on the topic, this could be supported through the work of the AERN, HAPUA, the APGCC or perhaps the ASEAN Secretariat, as well as through additional organisations that the respective groups develop on their own.

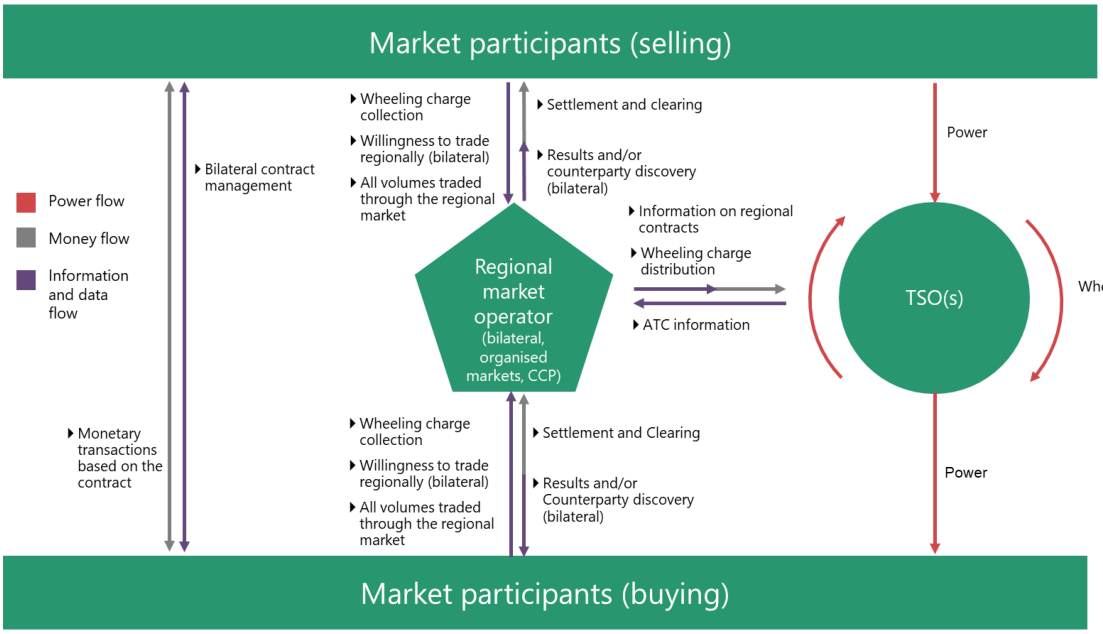
In summary, the primary market model will increase the need for and role of regional institutions across nearly every area. Much of the foundation for this, however, has already been laid through the existing regional institutions, or will have already been developed through the process of building the secondary market.

Example transaction

The information and data flow of the transactions under the primary trading model is very similar to that of the secondary trading model. However, some things that are optional in the secondary trading model would most likely become mandatory in the primary trading model. For example, the collection and distribution of wheeling charges would need to be centralised, as the increase in transaction volume would make it difficult or impossible for the transmission operators to manage on their own.

Another difference between the primary trading model and the secondary trading model is the role of the national market operator. In the primary trading model, all market participants on both the buying and selling sides would bid directly into the regional market. There would therefore no longer be a need for national market operators.

Figure 53. Primary trading model – example of trade flows



Source: Nord Pool.

Within the primary trading model, cross-border flows and national flows are optimised at the same time.

To illustrate an example trade, suppose that Malaysia, Singapore and Thailand have agreed to develop a primary trading model among themselves.[22] All participating countries have done their ATC calculation and per border alignment for the day-ahead time frame. In this example it is assumed that there is available cross-border capacity among the three AMS.

All buyers and sellers in the three AMS provide their bids and offers to the regional market co-ordinator within a predefined trading window for the day-ahead time frame. The market operator then runs its optimisation algorithm. The algorithm determines the least-cost dispatch given the conditions of the available transmission capacity among the three countries.

Assume in a particular hour it turns out that Thailand has the lowest cost generation in the region, while Singapore has the highest cost generation. This would mean that Thailand would export power to Malaysia and Malaysia would export in turn to Singapore. This process would continue until prices equalise or the available transmission capacity is fully utilised.

The settlement of **monetary flows** depends on how the wheeling charges are set up in this model. Assume that the three countries have decided to use congestion rents instead of wheeling charges.

The **information flow** would be as follows. The market operator informs the buyer, the seller and the relevant transmission operators about the production and consumption schedules, based on how the DAM cleared. This ensures that the buyer knows what they have bought and at what price, the seller knows what to produce and what price they get for it, and the transmission operators know what to transport.

[22] This example is only for illustration purposes, and should not be construed as a recommendation for a specific trade arrangement among any of the referenced parties.

7. Implications for ASEAN stakeholders

The implications for ASEAN stakeholders related to implementing multilateral power trading vary depending on the type of regional market model. As discussed in Section 6, however, the proposed trading models (harmonised bilateral, secondary trading and primary trading) can largely co-exist with one another. It is therefore up to each AMS to decide the speed and type of implementation it wishes to follow.

The principles of stepwise and voluntary implementation mean that a number of different futures are possible in an ASEAN context. Rather than discuss a hypothetical mix of options, to simplify the discussion this section assumes the implementation of a secondary regional trading model, while also noting how implications would change if other models of trade were implemented instead.

As a start, however, it is important to highlight key differences between the harmonised bilateral and secondary models, and the primary trading model. In both the harmonised bilateral trading and secondary regional market models, changes required at the national level in terms of regulation, policy and legislation are minimal. Under the primary market model, however, national markets are subsumed into a regional market, requiring a high degree of regional regulatory harmonisation across participating AMS. Simply put, the implications of the primary regional trading model are significantly wider-reaching than those of the secondary trading or harmonised bilateral trading models.

Many of the implications, for example on human/institutional capacity development and data collection and sharing, also depend on the existing market model and degree of market/institutional development in each country. As discussed in Section 2, with only two exceptions (the Philippines and Singapore), national power systems among the AMS remain vertically integrated. To keep the discussion relatively straightforward, the following sections assume vertically integrated national markets. Some implications for liberalised markets are discussed, however, when relevant.

The remainder of this section discusses implications of establishing multilateral power trade for the following stakeholder groups: utilities, regulators, investors and consumers.

Utilities

As detailed in Sections 5 and 6, the minimum requirements for implementation of a secondary trading model include a harmonised regional grid code, TPA, a wheeling charge methodology, data- and information-sharing requirements, formation of a regional market operator, and development of a market clearing and settlement platform. Meeting all of these requirements will require significant engagement by the region’s utilities on an ongoing basis. This in turn suggests implications for a wide range of utility activities, including planning and operations, as well as implications for utility costs and revenues.

Regional markets require significant data sharing to function, including data related to system planning (in particular, but not only, cross-border or other common-use infrastructure) and for ongoing operations, especially as they relate to ATC.

As discussed in Section 6, there are two main types of data/information that must be shared by all AMS that participate in a secondary market: ATC, and demand and supply offers (or bid/ask postings). ATC information allows all market participants (including national vertically integrated utilities, unbundled and privatised utilities, and IPPs and marketers) to identify potential trading opportunities, and so this information must be shared on a regular basis to ensure trades are feasible. Information on the underlying ATC calculation may also be beneficial to share. However, it should be left up to national regulators to determine how much transparency is required from the respective TSOs regarding their ATC calculations.

Demand and supply offers, including quantities, prices, duration and location within the regional market, must also be shared on a regular basis. These would be consolidated and matched by the regional market operator so that trades can be identified and cleared.

The data above are required to support short-term trading. Long-term planning, however, can also have an impact on multilateral power trading. It is therefore important to support the development of regional transmission plans, such as the various AIMS, and ideally, to perform such studies on a regular basis.

There are two main aspects of transmission system planning that must be addressed as part of regional market development and operation: 1) cross-border or common infrastructure for the regional market; and 2) national transmission systems. In relation to the first item, utilities should expect to be involved in all aspects of the planning, from participation in data collection and modelling efforts (most likely, supporting a third-party consulting effort) to contributing to high-level discussions about financing arrangements for new cross-border facilities.

These in turn require regional system dispatch simulations and impact assessments that model potential trade patterns and identify necessary or recommended new transmission infrastructure (cross-border or otherwise) and non-grid alternatives. Developing these regional modelling exercises will require data held by the utilities, including:

- locational hourly energy demand on the high-voltage grid
- forecast demand growth
- details on the existing transmission system infrastructure
- plans for and the status of internal and cross-border transmission projects under development.

Relevant technical details on power plantsAdditional information that would be helpful to regional modelling efforts include:

- historical unserved energy and loss of load probability, as well as national planning targets for these values
- characteristics of operational ancillary services available/required in each country.

The first item would help document how improved regional transmission infrastructure and integration would help support national system reliability, while the second item would help ensure accurate system impact modelling (and it might be necessary to share this information regardless to ensure compliance with the regional grid code).

It is important to note that while regional planning efforts can be helpful for multilateral trading, they are not a minimum requirement. While the data mentioned above are required for regional planning purposes, they are optional when it comes to developing multilateral power trading, including the secondary trading model.

National transmission system planning also would need to reflect expected international trading patterns. In this respect, bear in mind that under the secondary trading model, international trades would take place only in accordance with ATC. Since ATC calculations would reflect national pre-dispatch, participation in the regional market would not, by itself, result in a need for increased investment in national transmission systems. Put differently, regional trade will occur only to the extent it is feasible across national systems after those national systems attend to their own demand (other than the portion that might be met by imports). It is important to understand, however, that national utilities should still model international trade impacts on transmission under various scenarios, since there may be value in higher trading volumes that could be made possible through additional investments in the domestic grid. In order to document the value of any potential investments to the national government and other stakeholders, it would be important to be able to document the gains from increased trade.

National governments may have legitimate concerns about sharing the detailed data mentioned above, and laws may exist that identify some data as national security-related, criminalising public release of the information. The standard approach – and the approach recommended here – is to categorise data and information according to whom and how they would be released. An outline of such an arrangement is presented in Table 23, below.

Table 23. Overview of tiered access to data under a secondary trading model

Planning	Modelling team, including national utility representatives: all relevant data. Planning reports to be published: summary information about power systems, demand, expansion plans (power and transmission) and key findings.
System dispatch	Each country would retain control of its own power system and would dispatch its system to reflect scheduled trade. Information sharing would be among the regional market operator and national system operators, and would include data feeds on system conditions and scheduled flows. The regional market operator would require only a subset of national system information, mainly scheduled flows on all transmission paths considered to be within the market.
Market operations	All market participants require access to certain forward information, e.g. day-ahead dispatch schedules, buy/sell information and ATC. It is customary to provide limited public access to information as well, such as for regional clearing prices, demand levels and transmission flows.

Another critical area with implications for utilities is grid code development. National utilities will need to invest significant time participating in regional grid code harmonisation efforts, as well as making periodic adjustments to the regional grid code through ongoing activities.

There may be potential costs as well related to the regional grid codes themselves. For example, it is possible that some countries would need to commit to tightening the operating frequency band for their power systems, requiring investment in system controls and certain types of generating capacity. Alternatively, some countries may need to commit to DC-only interconnections to mitigate frequency control weakness at the national level. This in turn may lead to a relative increase in investment costs, depending on connection length and other factors.

Significant time also will be required for activities related to the establishment of the secondary market. This may include items such as development of the agreement for participation in the regional market, agreements for interconnections and trading, development of the ATC methodology, development of wheeling methodologies, and so on, as described in Section 5.

Before discussing the implications for national system operation, it is important to reiterate that national utilities would retain full control over domestic systems under the secondary market model. That is, all ordinary system dispatch activities would proceed as they already do, with adjustment at the margin to accommodate trades or wheeling. Trades would occur only to the extent they benefit both parties, and wheeling charges would compensate for usage of, and any losses on, national systems in multilateral trades.

As discussed in the Section 6, data and information sharing would be required to support regional trading. These data principally would comprise national balances and all planned and emergency grid actions, plus factors affecting ATC values. If ongoing updates to ATC calculations were handled by national utilities, then this would be an additional obligation at the national level.

Regional trading under the secondary model will have generally positive operational impacts. Each national system would have more flexibility in meeting domestic demand under both ordinary and emergency conditions since, on the one hand, there would be no obligation to export power (other than under pre-existing bilateral agreements) and, on the other hand, there would be increased options to import power. Under ordinary conditions, wholesale domestic energy prices would be driven down because imports would occur only if they lowered costs and exports would occur only using extra-marginal generating capacity (that is, capacity that would not have been dispatched otherwise). Under emergency conditions, by contrast, the ability to import could keep the national system from dropping load.

There are voltage and frequency control benefits to increased regional interconnections, since each AC interconnection of different national markets would make all other synchronised systems in the regional market more robust in the face of voltage and frequency deviations. HVDC interconnections would offer fewer frequency control benefits as well as less risk in extreme scenarios of system collapse propagating across international interfaces.

One important positive benefit of regional market integration is that each national system would be able to support more variable renewable energy (VRE) resources – mainly, wind and solar PV – because of the voltage and frequency control benefits mentioned above. VRE can have significant system impacts when it makes up a large portion of the capacity mix of a power system. Increased interconnections can bring technical benefits such as improved voltage and frequency control, increasing the amount of VRE that can be securely integrated into a system. This is because the aggregate generation uncertainty of VRE declines as more VRE units are added across geographically diverse areas. Put another way, larger power systems can integrate larger shares of VRE.

Apart from the environmental and macroeconomic benefits of VRE (from reduced emissions and from reduced import of fossil fuels), higher VRE penetration may result in lower wholesale generation costs, given how competitive wind and solar PV can be in the right settings. Utilities would benefit by having lower costs of operations, and by more easily meeting national renewable deployment targets, where they exist.

The positive benefits above would occur as a function of simply having a functioning regional market and would derive automatically from multilateral trading and the physics of grid interconnection. Certain international grid operating actions, however, could be handled on a bilateral basis through utility-to-utility support agreements. For instance, two utilities could agree to support the other in cases where one or the other is unable to perform its system balancing obligations in the regional market or needs other ancillary services support.

While the positive impacts of regional integration are expected to exceed the negative impacts, there are a few potential negative consequences to examine. There may be occasional system perturbations or even outages driven by events in external markets. These impacts would tend to impact smaller markets more than larger ones, all else equal, though the same smaller markets would also tend to see more significant positive operational benefits. This is because inter-connections of a given size would be larger in proportion to smaller markets than larger markets.

Another potential negative impact is that occasionally, penalties may be assessed on a national utility for failure to adhere to the regional grid code (primarily a concern with synchronised systems). On the other hand, failure in this respect may also reflect a failure in the first instance to reliably serve the national market, meaning that regional grid code penalties could be avoided by investing in better national-level outcomes.

Under both the harmonised bilateral and secondary models, revenues should increase and energy generation costs should decrease for all participating countries in comparison with scenarios with less trade. As discussed previously, national utilities would import only if doing so reduces domestic generation costs, and they would export only if domestic demand is already served and the export is economic.

Transmission costs could increase for some countries because of investments to implement cross-border trade, increased congestion on some transmission paths requiring incremental transmission investment (though there may be reduced congestion on other paths), and increased losses on some paths (though there may be reduced losses on other paths).

There are two types of trades and their impacts to examine in this context: exports from/imports to the country and wheeling trades (from the perspective of the wheeling country). In the first case, the costs/benefits of grid impacts from the trade should be valued by the country itself as part of its overall economic evaluation of the trade. There should be no incremental investment impact unless the country assesses that over the longer term, it would like to facilitate more trades. Wheeling, however, presents a different situation. Consider a case where Country A is used to wheel power from Country B on one side to Country C on the other side, and the trade pattern is persistent. In principle, wheeling charges should fully compensate Country A for its role in facilitating the trade, but if wheeling charges are not carefully set (and periodically adjusted), then trading patterns could impose net negative impacts. On the other hand, errors in setting wheeling charges could also overcompensate Country A for the wheeling service. It is therefore important to include a regular review of the wheeling charge methodology and its implications in the overall governance process.

Regulators

In a secondary regional market model, there are some implications, albeit limited, for national market regulatory bodies (regulators/ministries). National markets would continue to function independently of the regional market. Although a regional market operator would be created, this entity would act only in relation to the regional market, pursuant to regional market rules, and hence would not directly affect domestic regulatory structures.

The regional market would require a regional market operator. One of the first tasks of this entity would be to develop an agreement governing participation in regional trading by market participants. This agreement would likely cover execution of individual trades upon submission and acceptance of bid/offer forms. Alternatively, individual trades could be covered under stand-alone agreements.

Once the market is operating, ongoing functions of the regional market operator would include publishing buy/sell offers, allocating ATC to clear the market, managing settlements and reporting on market activity.

National market regulators would retain all existing responsibilities for their respective domestic markets and would have an additional responsibility: monitoring the behaviour of other national market participants in the regional market in order to advocate for their own national interest when the regional market is thought to be functioning improperly.

On the other hand, it would be necessary for national regulators to cede certain aspects of regulation to the relevant regional bodies in limited instances involving the failure of market participants from that market to abide by regional market rules. For instance, if a national utility has executed its participation agreement for the regional market and then fails to perform per that agreement, then the national regulator would be expected to not intervene in the regional market operator's actions pursuant to the participation agreement.

If permitted by national law, the national regulator would be expected to allow domestic generation companies and unregulated customers to participate in the regional market without interference.

In each of these cases, however, the national market's relevant authorities, including its regulators and utilities, would have participated in the drafting of the participation agreement for the market and all other market-governing rules, regulations and protocols, such that the only expectation would be for the national regulator to carry out its agreed obligations.

National regulators would be expected to participate in the initial drafting and ongoing adjustments to the regional grid code. They would also be expected to evaluate and approve any regional codes.

A related role for the regulator would be to regulate the domestic market in such a way as to avoid problems in the regional market. For instance, it might be necessary to develop and adjust the national grid code to facilitate compliance with the regional grid code.

Few or no changes would be required to national market design under the secondary market model. In some cases, minor changes might be required to allow for cross-border transactions and/or to pass through imports to regulated retail customers. Some markets might consider explicitly allowing purpose-built cross-border IPPs as an adjunct to regional market development efforts.

Even if few changes are required to the existing national market design, authorities might consider certain changes to the market design to capture additional benefits from trade. For instance, if national market rules permit the national utility to invest in transmission only for domestic use but building new transmission lines could facilitate exports that would benefit the domestic economy, then it might be worth considering allowing the utility to make the investment.

In terms of ongoing responsibilities, with respect to the regional market, national regulators would be focused on matters such as how to approach the export of energy-constrained resources, such as storage hydro; how fuel price subsidies affect outcomes for export of generation fired by domestic gas/liquid fuels; the appropriate balance of fixed and variable operations and maintenance costs to use for exports; and similar matters.

Investors

A regional market represents potential risks and rewards for investors in the national markets. This section focuses on IPP investors; since most regional markets are not libralised, there are few other opportunities for private investments in the region.

Although IPPs certainly would see increased opportunities for revenues related to exports in a regional market, IPPs may worry about being undercut by lower-cost imports in national dispatch. This could undermine financing, especially where the IPP is exposed to dispatch risk under its PPA. Even where a PPA does not involve dispatch risk, such as for take-or-pay arrangements, lenders will have an interest in the underlying economics of the project in the market, in case the PPA is terminated. Nonetheless, for most or all the ASEAN countries, it is not expected that anticipated participation in the regional market would significantly impede any project financings.

For the liberalised markets in the region, especially Singapore, the issues discussed above for IPPs would be joined by retailer concerns about seeing reduced IPP interest in the domestic market versus retailer hopes that they could procure more competitive supplies from imports.

Consumers

Implementation of a regional market should bring significant benefits to consumers: lower wholesale energy costs (tending to support reduced retail tariffs), improved reliability of service and potentially increased overall electrification, as discussed below.

Consumers could see downward pressure on tariffs associated with implementation of the regional market, driven by expected reduced wholesale energy prices. Any increased costs for transmission should be covered by wheeling fees and/or simply from gains from energy trade. In addition, the ability for regional utilities to count on potential imports should help avoid costly emergency generation projects that would ultimately need to be paid for by consumers. Of course, the extent of consumers' benefits depends on tariff design choices. There is also a possibility that national governments may use reduced power sector costs to attend to pressing needs in other areas, rather than reducing retail electricity tariffs.

In markets with retail choice (Singapore), consumers would be expected to benefit from retailers' increased access to potential supply of competitive power in the form of imports. There is also the possibility that some uncommitted generation in Singapore would seek higher margins in export markets rather than selling to domestic free customers, but the impact of this on prices should be negligible.

Currently unserved communities near borders could potentially benefit from cross-border supply in a regional market. Cross-border retail supply is already occurring in some parts of ASEAN; for instance, significant areas of Myanmar are served by Thailand. This is distribution-level "trade", more like an international extension of distribution company service territories than the wholesale trade envisioned for the regional market. However, some hard-to-reach areas in domestic markets might see significant benefits, for instance, southern Myanmar, which is not on the Myanmar national grid and where major load centres are too far from Thailand to be served economically at distribution voltage.

Retail service quality should improve somewhat from regional trade for reasons discussed above, that is, because overall system reliability would be positively impacted by cross-border transmission elements.

Finally, it should be reiterated that multilateral power trading could bring significant environmental benefits, in particular by enabling the integration of higher shares of VRE. Consumers would benefit from these environmental impacts, in particular improvement of air quality. They would also benefit from some of the long-term macroeconomic impacts, including reduced reliance on imported fossil fuels.

Acronyms and abbreviations

AC	Alternating current
ACE	ASEAN Centre for Energy
ACER	Agency for the Cooperation of Energy Regulators
AEBD	Autoriti Elektrik Brunei Darussalam
AERN	ASEAN Energy Regulators Network
AIMS	ASEAN Interconnection Masterplan Study
AMEM	ASEAN Ministers on Energy Meeting
AMS	ASEAN member states
APAEC	ASEAN Plan of Action for Energy Cooperation
APGCC	ASEAN Power Grid Consultative Committee
ATC	Available transmission capacity
ATSO	ASEAN Power Grid Transmission System Operator
BIMP-EAGA	Brunei Darussalam-Indonesia-Malaysia-Philippines East ASEAN Growth Area
BPMC	Berakas Power Management Company
BRP	Balancing responsible party
CAC	Central Advisory Committee
CACM	Capacity allocation and congestion management
CCGT	Combined-cycle gas turbine
CCP	Central clearing party
CDO	Communications and Digital Office
CERC	Central Electricity Regulatory Commission
DAM	Day-ahead markets
DES	Department of Electrical Services
DIPP	Domestic independent power producers
EA	Electricity Authority
EC	Energy Commission
EdC	Electricity of Cambodia
EdL	Electricity of Lao PDR
EGAT	Electricity Generating Authority of Thailand
EIPP	Expanding independent power producers
EOR	Ente Operador Regional
EPR	Empresa Propietaria de la Red
ERC	Energy Regulatory Commission
ESB	Enhanced single buyer

ESE	Energy Supply Enterprise
EU	European Union
EVN	Viet Nam Electricity
FERC	Federal Energy Regulatory Commission
GCC	Gulf Cooperation Council
GDP	Gross domestic product
GMS	Greater Mekong Subregion
HAPUA	Heads of ASEAN Power Utilities and Authorities
HVAC	High-voltage alternating current
HVDC	High-voltage direct current
IDM	Intraday markets
IEX	Indian Energy Exchange
IPP	Independent power producers
IT	Information technology
JPPPET	Committee on Planning and Implementation of Electricity Supply and Tariff
LTMS–PIP	Lao PDR–Thailand–Malaysia–Singapore Power Integration Project
MEA	Metropolitan Electricity Authority
MEPE	Myanmar Electric Power Enterprise
MER	Mercado Eléctrico Regional
MoU	Memorandum of understanding
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NVE	Norwegian Water Resources and Energy Directorate [*Norges Vassdrags – og Energidirektorat*]
OCCTO	Organization for Cross-Regional Coordination of Transmission Operators
PDP	Power development plan
PEA	Provincial Electricity Authority
PLN	National Power Utility
PPA	Power purchase agreements
PV	Photovoltaics
REE	Rural Energy Enterprises
REMIT	Regulation on wholesale Energy Market Integrity and Transparency
RPCC	Regional Power Coordinating Centre
RPTCC	Regional Power Trade Coordination Committee
RUPTL	Electricity Supply Business Plan [*Rencana Usaha Penyediaan Tenaga Listrik*]
SAC	South Asian countries
SAPP	Southern African Power Pool

SESB	Sabah Electricity Sdn Bhd
SESCO	Sarawak Electricity Supply Company
SIEPAC	Central American Electrical Interconnection System [*Sistema de Interconexión Eléctrica de los Países de América Central*]
SOME	Senior Officials Meeting on Energy
ST	Suruhanjaya Tenaga
TNB	Tenaga Nasional Berhad
TPA	Third-party access
TPES	Total primary energy supply
TSO	Transmission system operators
US	United States
VRE	Variable renewable energy
WESM	Whole Electricity Spot Market
WG	Working Group
YESC	Yangon Electricity Supply Corporation

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INTERNATIONAL ENERGY AGENCY

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