ERIA Research Project Report 2015, No. 16

Achieving an Integrated Electricity Market in Southeast Asia: Addressing the Economic, Technical, Institutional, and Geo-political Barriers

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December 2016

Economic Research Institute for ASEAN and East Asia

ERIA Research Project FY2015 No.16

Published in December 2016

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Executive Summary

The BIMP (Brunei, Indonesia, Malaysia, and the Philippines) region contains significant energy resources that could be developed to stimulate the economic growth and development of the region. These resources, however, are unevenly distributed. The current supply and demand imbalances create opportunities for trade and initiate power market integration at the sub-regional level. In the long-term, Malaysia's Sarawak and Indonesia's Kalimantan could emerge as major power exporters in Borneo. Full development of the energy resources of BIMP, however, can only be realised when its power market cluster is fully integrated in the much broader ASEAN power markets.

In the first chapter, the authors evaluate the benefits of expanding grid interconnection lines in ASEAN by carrying out a simulation with the Optimal Power Generation Planning Model and the Supply Reliability Evaluation Model on the basis of the current expansion plan of grid interconnection. Through the efficient use of hydropower resources in Borneo and the expansion of regional interconnection lines, it is possible to reduce fossil fuel consumption, CO_2 emissions, and costs of power source development. By expanding the interconnection lines within BIMP alone, these effects can be expected to a certain extent. But even more remarkable effects may be expected by further interconnecting with large energy-consuming areas like Peninsular Malaysia and Luzon. However, any significant cost reduction can only be achieved from a long-term point of view or within a period up to 2050. Thus, long-term plans by the government of host country as well as international financial institutions and their steady implementation are indispensable.

The second chapter contributes a road map to resolve the regulatory, institutional, and technical barriers specific to the electricity market integration in BIMP, where it can be initiated despite the disparity of electricity industry structures and regulatory frameworks between trading countries. Among the approaches for market integration, the coordination of power system operators rather than the consolidation of the power market and power system operators is the most practical and appropriate for the BIMP power market cluster.

Given the power industry structures and regulatory environment of the BIMP countries, the coordination models that could be applied include: i) unidirectional trade, ii) bidirectional power transactions, iii) power purchase from IPP, iv) third-party access, and v) multi-buyer multi-seller market. The interconnection projects and planned power exchanges identified under APG for the BIMP market cluster could be characterised according to these coordination arrangements.

To fully realise economic benefits from developing the region's energy resources for power generation, the paper outlines a road map for power market integration in BIMP that serves as recommendation to governments in the region on how to proceed with regional power interconnections. The road map is divided into four stages of development.

- Stage 1. Incremental development of regional transmission backbone infrastructure;
- Stage 2. Incremental intra-Borneo power trade based on projects with mutual benefits;

- Stage 3. Incremental inter-Borneo trade arrangements; and
- Stage 4. Establishment of a multi-buyer, multi-seller regional power market.

Following the road map requires individual country investment commitments. Stage 1 investments would be by each of the countries in their territories. Investments in stage 2 and stage 3 would be carried out by trading parties. Stage 4 requires cooperation commitments from BIMP countries since the establishment of a multi-buyer, multi-seller market requires multilateral financing and the transfer of some of the functions of the national system operators to the cross-border market operator.

Chapter 3 aims to develop a business model for pan-ASEAN integrated electricity market. For this, it is necessary to understand the success formula of currently operating integrated electricity markets and identify key factors involved such as principles, frameworks, practicalities, and conditions. At present, the European electricity market represents the world's most extensive cross-jurisdiction reform of the electricity sector involving integration across distinct states and national electricity markets. As such, Europe is selected as study model to understand the market principles, framework, and practicalities for the integration of regional electricity market.

To design a business model for integrated electricity market for Southeast Asian region, the most significant aspects should include market coupling arrangements and algorithms, congestion management and capacity auction methods, coordination mechanism and relevant network code among transmission system operators (TSOs) for grid balancing, and auxiliary services and compensation for such services. This chapter touches upon these issues by referring to the Nordic and European experiences. Major standing problems and challenges of the European electricity market model are also briefly discussed.

Chapter 4 aims to investigate the barriers, especially institutional and political barriers, to electricity market integration in ASEAN. It also discusses practical policy options to accelerate market integration in the ASEAN power sector.

Besides emphasising political will as necessary in accelerating the development of APG and market integration, several policy recommendations are provided. The first is to strengthen and build institutional capacity. The second is to improve collaboration in national capacity building and coordination in power sector reforms among ASEAN countries. The third is to adopt a stepwise approach toward the promotion of power trade and market integration. The fourth is to build public–private partnership to give the private sector a more active role in market integration, especially with regards to investment in power infrastructure. This can also be extended to international institutions such as the World Bank and the Asian Development Bank. The fifth recommendation is to promote cleaner and abundant renewable energies. Penetration of renewable energy into the power sector calls for power grid interconnection and market integration. It should be noted, however, that higher share of renewable energy also raises challenges to the robustness of ASEAN countries' power grid.

Introduction

Yanfei Li and Shigeru Kimura

1. Background and Objectives

Background

Driven by economic and industrial development, population growth, and higher standards of living, electricity demand in the member states of the Association of Southeast Asian Nations (ASEAN) is projected to more than triple between 2013 and 2035 (ERIA, 2015), a growth rate higher than any other region in the world.

Plans to secure energy supplies in the region require evaluation of the geographic scope of desirable and feasible integration. For example, the ASEAN Plan of Action for Energy Cooperation 2010–2015 has a number of objectives that include the establishment of an ASEAN Power Grid (APG), increased penetration of renewable energy, and further development of an ASEAN gas network. APG, a flagship programme of 16 interconnection projects, is expected to expand from a bilateral to a subregional basis and, ultimately, achieve a totally integrated system. Smaller regional integration potential also exists between the countries of the Greater Mekong Subregion (GMS) and BIMP (Brunei, Indonesia, Malaysia, and the Philippines).

Despite the promising objectives of the ASEAN APG plan and the potential of the GMS and BIMP grids, their implementation to date has largely been problematic owing to, besides economic feasibility and political factors, market structure, harmonisation of technical standards, operational procedures, and regulatory frameworks. A coordination body called the Heads of ASEAN Power Utilities/Authorities (HAPUA) has been formed under the ASEAN mechanism. However, as with the experience of other regions, such as the Nordic and European countries, the formation of an interconnected and integrated electricity market requires further authorisation to this organisation to formulate legitimate plans, regulations, and requirements for relevant parties' actions in coordinated manner among countries in the region.

Much research has been done on the economic and technical viability of electricity integration in ASEAN (Kimura and Phoumin, 2014; Kutani and Li, 2014; Wu et al., 2012), as well as on the financial viability of power infrastructure investment (see Li and Chang, 2014). For example, Li and Chang (2014) point to three main barriers to grid interconnection in the ASEAN+2 (China and India) region:

- First, investment in transmission lines is very capital-intensive, usually costing from millions to billions of (US) dollars, and requires both public and private sector investment;

- Second, cross-border electricity trade is complicated by political, social, and environmental considerations, enough for such projects to be considered high risk; and
- Third, the profitability of each transmission line is dependent on the evolution of the pattern of cross-border electricity trade in the region, which in turn is dynamic and difficult to predict.

In many respects, the first challenge (cost) can be overcome if greater understanding and certainty is achieved in relation to the second (non-economic factors) and third (regional trade patterns) challenges. The emphasis of this project is therefore on understanding the non-economic factors and the regional trade patterns within the region.

To that end, and building on the work that has already been done in relation to integrated electricity systems in ASEAN, this project examines what the potential benefits from increased energy market integration are in the ASEAN region, why progress has been slow so far, and how the obstacles to greater regional energy and electricity integration in the Asia-Pacific can be overcome. It is, therefore, of direct and critical importance to all countries in ASEAN and East Asia.

The market design for power trading in the region should be carefully studied, following existing regional trading models such as the Nordic system, the continental regional systems in Europe, and the PJM (Pennsylvania-New Jersey-Maryland) system in the US. An appropriate market design is the key to mobilising the massive investment needed, especially from the private sector, to conduct power grid interconnection projects as well as other power infrastructure, and then profiting from their operation.

Market design is a broad concept that includes (1) allocation of costs, revenue, and rights to use cross-border transmission lines; (2) the mechanism to determine transmission (both cross-border and domestic) tariff, the resolution in case of congestion in the interconnected grid system, and the prices of grid balancing and ancillary services if market-based approaches are used for issue (1); (3) the algorithms for the prices of electricity in cross-border trade that clears the market and, correspondingly, the rules for dispatching; (4) special treatment or regulations on the electricity generated from intermittent renewable energy sources (e.g. obligations to balance the grid); (5) coordination and harmonisation among participating countries in the trading licenses, import tariff, tax structure, and system gate closure time.

The market design should be able to give correct price signals to incentivise investment in both power generation capacities and cross-border transmission infrastructure. It should also give enough incentive with clear rules to balance the interconnected grid and therefore maintain its stability and reliability. In this way, power grid interconnection in the region will not only deliver cheaper and cleaner power supply but also enhance energy security in the power sector of the region.

Objectives of the Research

This ambitious, timely project has three overarching objectives:

- To assess the economic, technical, institutional, and geopolitical feasibility and desirability of electricity market integration among ASEAN countries;
- To identify existing economic, technical, institutional, and geopolitical barriers to electricity market integration;
- To identify governance and institutional arrangements that can support integrated energy and electricity markets in the Asia-Pacific that contribute to energy security, prosperity, sustainability, and stability in the region in the 21st century; and
- To present a feasible market design and business model for the pan-ASEAN electricity pool by identifying principles, frameworks, practicalities, and conditions.

These objectives feed into the key policy recommendations listed in Section 4.

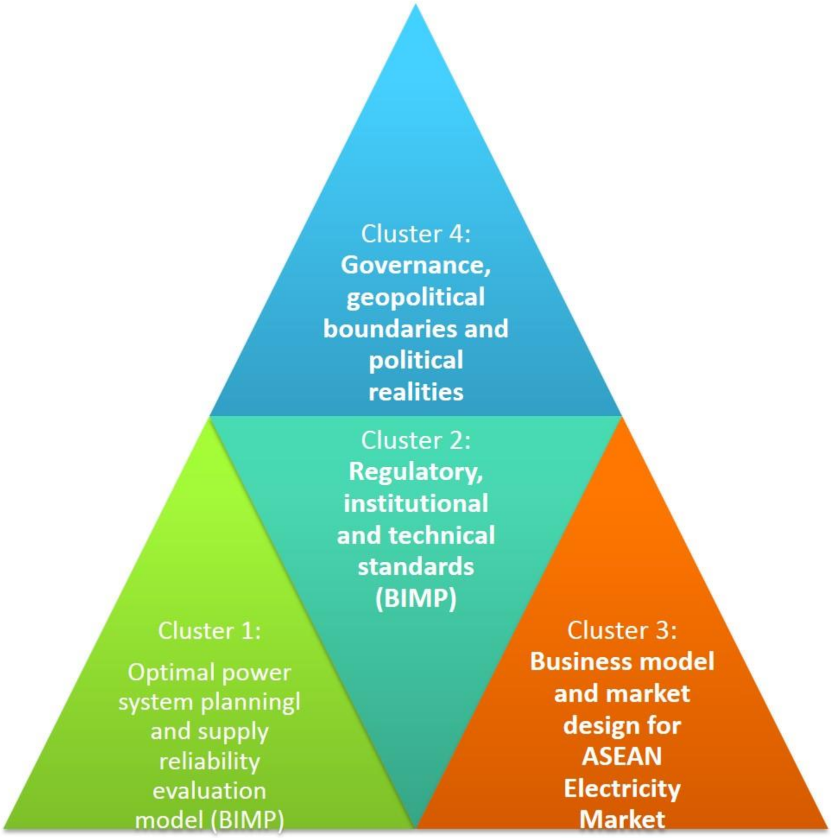
2. Study Method

The research is divided into four interdependent research clusters, with each cluster conducted by one partner research institute and drawing either on quantitative or qualitative research methods. Figure 1 sets out the structure of the project as well as the topic of each research cluster.

Cluster 1 and 2 apply case studies on the BIMP countries using different methods. Cluster 1, led by the Institute of Energy Economics, Japan, conducts dynamic linear programming model to simulate the development of power infrastructure, interconnection, and exchange of power in this sub-region of ASEAN. It emphasises the economic rationale and feasibility of electricity market integration in the region. Cluster 2, led by the Brunei National Energy Research Institute, focuses on the regulatory, institutional, and technical barriers that stand in BIMP. It also develops a roadmap toward the solutions of these issues. This study thus gives some insight regarding regional specific barriers or issues for other regions based on an established understanding of the common issues in principle from previous studies.

Cluster 3 is conducted jointly by the Economic Research Institute for ASEAN and East Asia (ERIA) and the Energy Research Institute at Nanyang Technological University. The study mainly refers to the Nordic and European cases of electricity market integration and analyses both their business models and overall market design for grid interconnection and cross-border trading of electricity. In doing so, the study eventually tries to deliver implications on the possible business model and market design for ASEAN.

Figure 1. Structure of the Research Project



Source: ERIA Working Group.

The Cluster 4 study, carried out by one researcher from the University of Western Australia, discusses political and institutional barriers to the formation of an integrated ASEAN electricity market and derives several practical strategies in addressing such barriers as the policy implications.

3. Key Research Findings

This is an ambitious project that is intentionally multidisciplinary, with researchers coming from backgrounds of economics, engineering, and political science. Each of the four clusters provides specific policy recommendations to enable and support deeper regional electricity market integration. In general, the following achievements have been made through this project:

- Identifying and articulating the benefits and limitations of integrated electricity markets in the region and thus allowing for the emergence of new technologies especially in the BIMP countries (Clusters 1 and 2).

- Quantifying the opportunities and benefits of greater penetration of renewable energy with and without grid interconnection (Clusters 1 and 2).
- Identifying an 'order of priority' for transmission line interconnections based on the economic and non-economic factors examined (Clusters 1 and 2).
- Articulating the history of electricity market integration process in other regions and drawing lessons for ASEAN countries (Clusters 3 and 4).
- Providing insights into a working business model and market design for electricity market integration, comprehensively reviewing key components such as market coupling arrangements and algorithms, congestion management and capacity auction methods, coordination mechanism and relevant network code among TSOs for grid balancing, and auxiliary services and compensation (Cluster 3).
- Recommending flexible organisational, institutional, and regulatory arrangements/road map to implement and manage the operation of interconnected grids in the region (Clusters 2 and 4).

With these findings, this project constitutes one of ERIA's efforts in its third stage of research in electricity market integration: addressing the institutional, regulatory, and technical barriers or challenges in ASEAN and proposing feasible high-level business model and market design for all stakeholders of the market integration. This stage of research remains largely uncharted waters. Thus, although these findings are unique contributions to the literature on this subject, continuous research efforts are required to achieve systematic solution to the future integration of electricity market in ASEAN.

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Chapter 1

Integrated, Trans-boundary Energy and Electricity Markets in the BIMP Region – A Quantitative Assessment

Yuhji Matsuo

Miyuki Tsunoda

The demand for electricity is projected to expand rapidly in most countries of the Association of Southeast Asian Nations (ASEAN). In Borneo, however, current power development plans could not be regarded as efficient as far as improvement of fossil fuel-fired power-generation efficiencies and effective use of domestic hydropower resources are concerned, due mainly to its poor grid systems. In this regard, grid expansion is considered an effective way to improve the economic performance of the island's future power supply systems.

In this chapter, the authors evaluate the benefits of expanding grid interconnection lines in Borneo by carrying out simulation with the Optimal Power Generation Planning Model and the Supply Reliability Evaluation Model. Through efficient use of hydropower resources and expansion of regional interconnection lines, it is possible to reduce fossil fuel consumption, CO_2 emissions, and costs of power source development in Borneo. These can be expected to a certain extent by expanding the interconnection lines within the BIMP region alone. But even more remarkable effects may be achieved by interconnecting with large energy-consuming areas like Peninsular Malaysia and Luzon in the Philippines. However, only from a long-term perspective can such a significant cost reduction be achieved or within a time frame up to 2050. Thus, long-term plans and their steady implementation by the government as well as international financial institutions are indispensable.

1. Introduction

1.1 Study Objective

With rapid economic growth comes a continuous sharp increase in energy demand in ASEAN countries, with power demand showing a remarkable increase. The power demand in 10 ASEAN countries increased from 11.2 million tonnes of oil equivalent in 1990 to 59.2 million tonnes of oil equivalent in 2012, and is expected to increase further by 3.3 times through 2035 in the 'business as usual' case (Kimura et al, 2015). How to meet the increasing power demand has become a major issue for ASEAN countries.

The important point concerning power supply in this area is that the countries and regions with large power demand are different from those with large energy resources. For this reason, by merging these regions with international connection grid lines, it is expected that efficiency in utilising resources will be enhanced and the related cost will be reduced, thus contributing to the improvement of energy security in the entire area. Kutani et al. (2014) calculated the economic effect from transmitting electricity from the hydropower resources of Southern China, North Eastern India, Lao PDR, etc. to the large-demand regions of Thailand, Malaysia, Singapore, Indonesia, etc. through model calculation that targeted the major ASEAN countries and surrounding areas. However, since the model was calculating by country, particularly separated regions in each country were not sufficiently evaluated. Specifically, because the territories of Malaysia, Indonesia, and the Philippines are divided by water, the regions with large power demand and those with large resources differ, with no interconnection for power systems. As with international connection grids, connecting independent domestic power systems could be of great significance.

This study conducts model calculations for the island of Borneo, including the territories of Indonesia, Malaysia, and Brunei Darussalam, that have large hydropower resources or the so-called BIMP region (Brunei, Indonesia, Malaysia, and the Philippines, although it is actually often referred to as the region containing Mindanao in addition to Borneo) as well as the surrounding regions with large energy demand, and evaluates the effects of connecting their power systems.

1.2 Geographical Coverage and an Overview of Regions

1.2.1 Geographical coverage

Borneo is made up of the territories of Indonesia, Malaysia, and Brunei Darussalam. It is divided into eight regions: Sarawak and Sabah for Malaysia; West, Central, South, East, and North Kalimantan for Indonesia; and Brunei as one region.

Table 1-1 shows the regions and their respective codes used in this study.

1.2.2 Population and gross regional domestic product

The most populated region of Borneo is West Kalimantan (Kalbar), but the region with the largest gross regional domestic product (GRDP) is East Kalimantan (Kaltim).

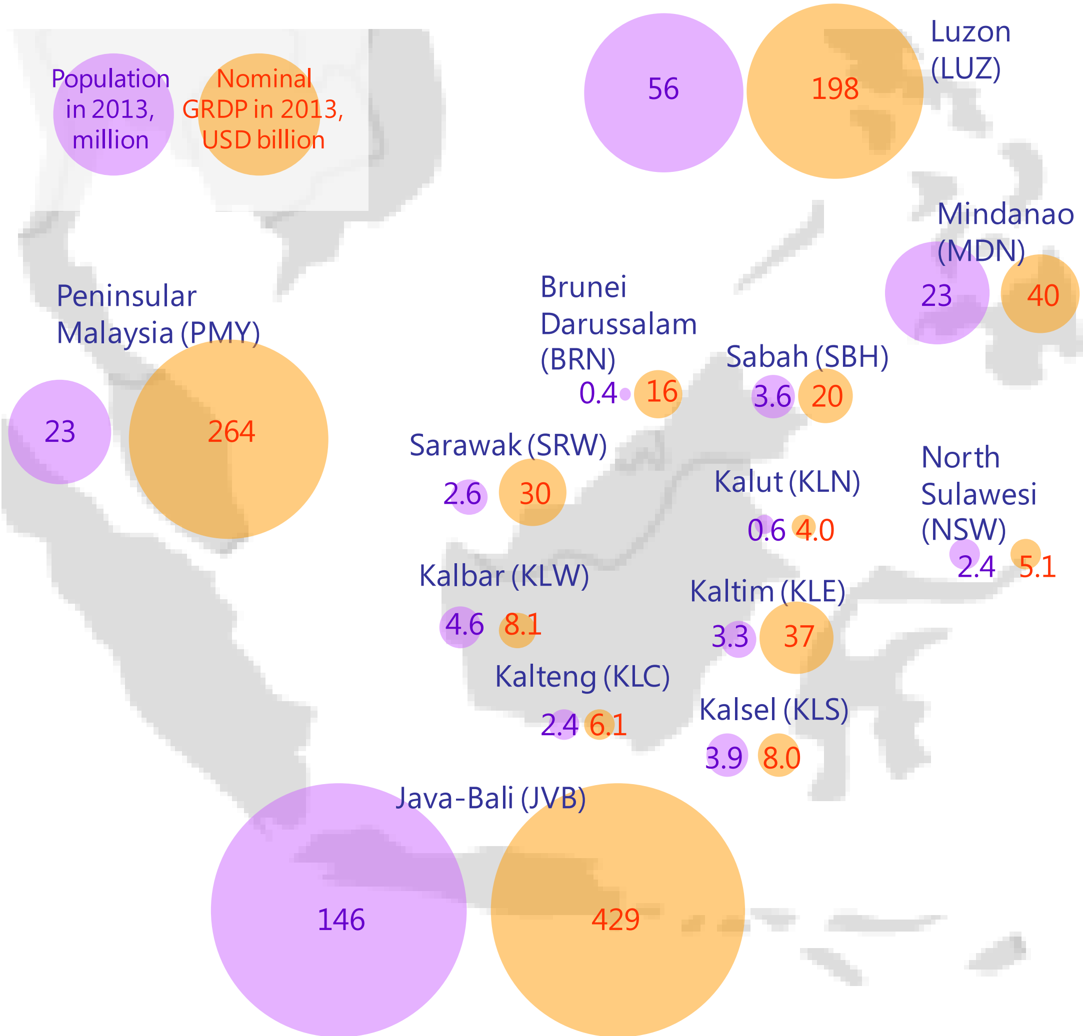
This study also covers adjacent regions with possible interconnections with Borneo: from Sarawak to the Peninsula Malaysia, from East Kalimantan to North Sulawesi, and from Sabah to Mindanao and Luzon (refer to Figure 1.2-4 for details).These regions are more populated and have larger GRDPs than Borneo.

Table 1.1-1. Classification and Codes of Borneo's Regions and Neighbour Regions

Country	Borneo Region	Code
Brunei Darussalam		BRN
Malaysia	Sarawak	SRW
	Sabah	SBH
Indonesia	West Kalimantan (Kalbar)	KLW
	Central Kalimantan (Kalteng)	KLC
	South Kalimantan (Kalsel)	KLS
	East Kalimantan (Kaltim)	KLM
	North Kalimantan (Kalut)	KLN

Country	Neighbour Region	Code
Malaysia	Peninsular Malaysia	PMY
Indonesia	Java and Bali	JVB
	North Sulawesi	NSW
Philippines	Luzon	LUZ
	Mindanao	MDN

Figure 1.1-1. Gross Regional Domestic Products and Populations of Borneo's Regions and Neighbouring Regions

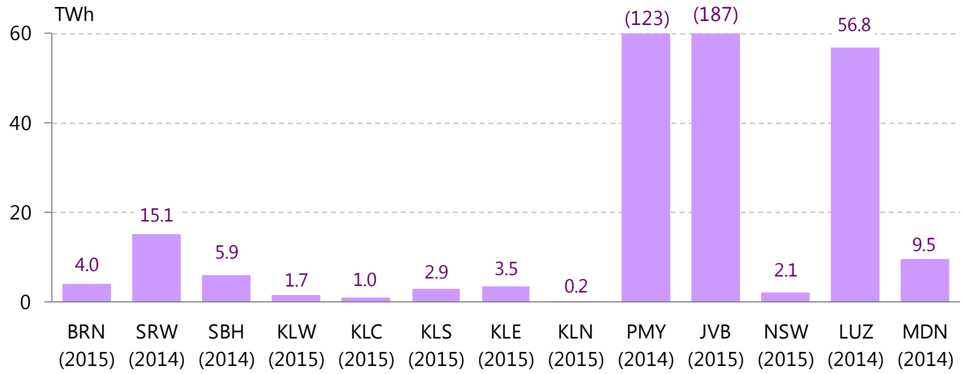


Sources: World Bank, Badan Pusat Statistik, Ministry of Energy and Mineral Resources, Department of Statistics Malaysia, Philippine Statistics Authority.

1.2.3 Power demand and the power generation mix

Power demand is linked with GRDP, demand being larger in metropolitan areas with larger GRDPs such as the Peninsular Malaysia, Java, and Luzon. Within Borneo, the combined power demand of the five states of Indonesia is not larger than that of Sabah's of Malaysia. However, compared with those of metropolitan areas, the combined power demand of the whole of Borneo is small.

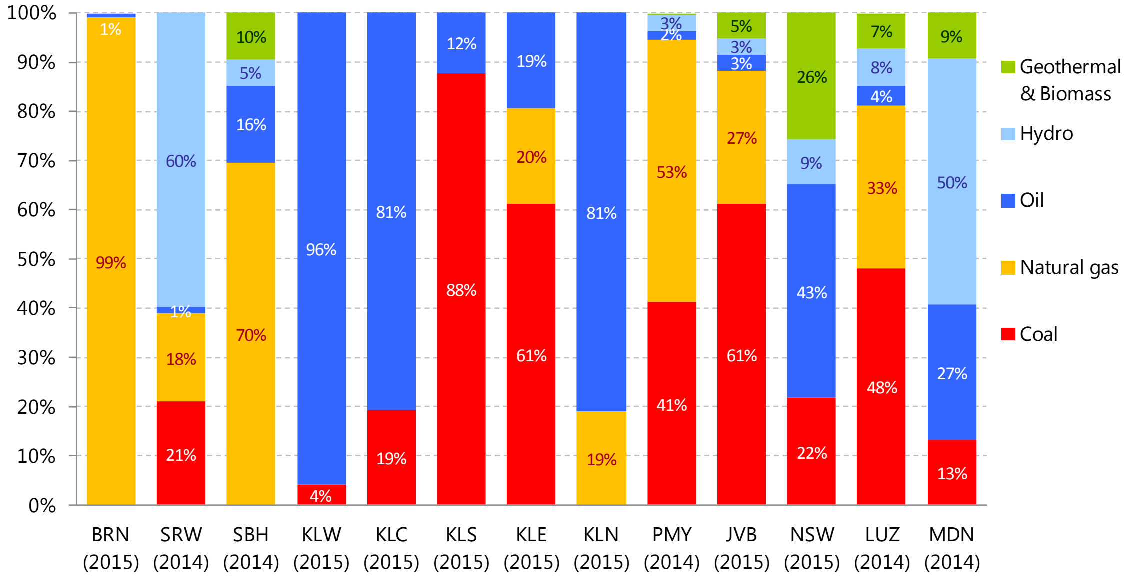
Figure 1.1-2. Power Demand of Borneo's Regions and Neighbour Regions



BRN = Brunei Darussalam, JVB = Java–Bali, KLC = Kalteng, KLE = Kaltim, KLN = Kalut, KLW = Kalbar, KLS = Kalsel, LUZ = Luzon, MDN = Mindanao, NSW = North Sulawesi, PMY = Peninsular Malaysia, SBH = Sabah, SRW = Sarawak.

Sources: Estimates from various sources.

Figure 1.1-3. Power Generation Mix of Borneo's Regions and Neighbour Regions



BRN = Brunei Darussalam, JVB = Java-Bali, KLC = Kalteng, KLE = Kaltim, KLN = Kalut, KLW = Kalbar, KLS = Kalsel, LUZ = Luzon, MDN = Mindanao, NSW = North Sulawesi, PMY = Peninsular Malaysia, SBH = Sabah, SRW = Sarawak.

Sources: Indonesia: PLN, Ministry of Energy and Mineral Resources; Malaysia: Energy Commission; Philippines: Department of Energy.

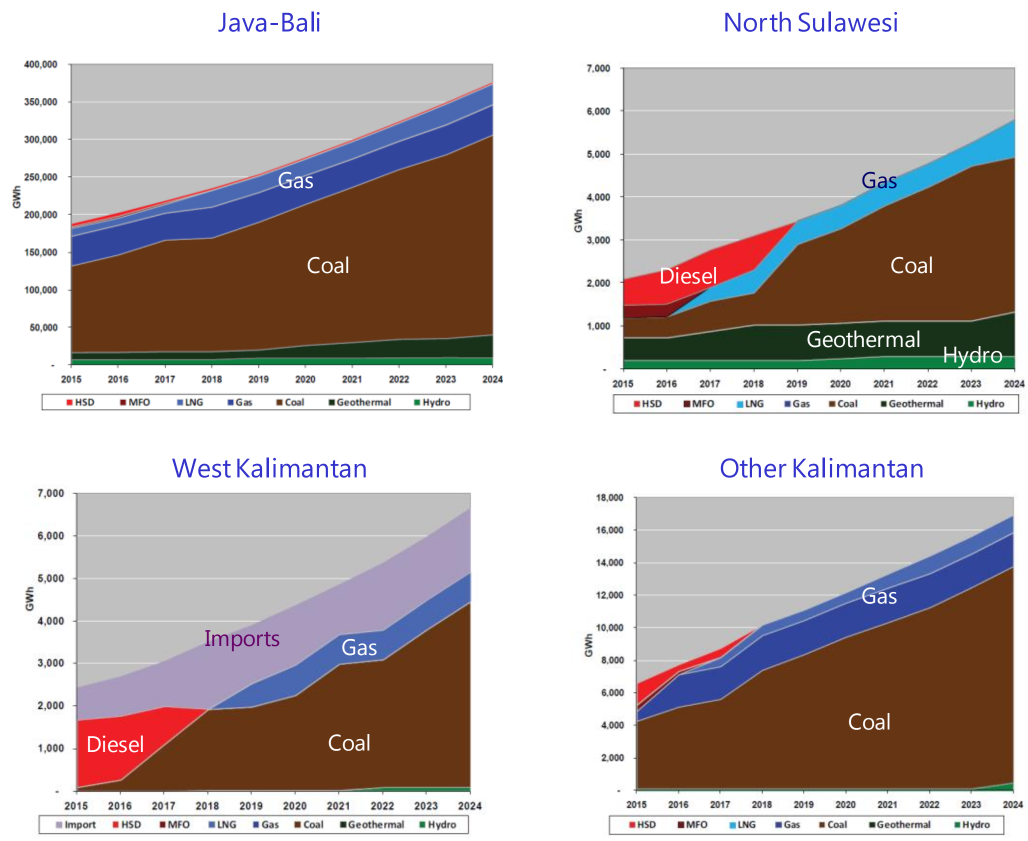
Brunei depends on natural gas for 99 percent of its power generation mix. Similarly, natural gas accounts for a large proportion of the power supply of Sabah. In Kalimantan, dependence on oil and coal is significant. In contrast to these regions that depend on fossil fuels, Sarawak and Mindanao, where energy supply is mainly based on renewable energies including geothermal and biomass, depend on hydropower for more than half of their power mix.

1.2.4 Power supply plan of each country

(a) Indonesia

The share of oil-fired thermal power is expected to decline in all states of Indonesia, which would result in higher dependence on coal-fired thermal. Dependence on fossil fuels is therefore expected to continue. The future plan by the power utility Perusahaan Listrik Negara (PLN) also assumes power import from Sarawak to West Kalimantan.

Figure 1.1-4. Power Supply Plan of Indonesia



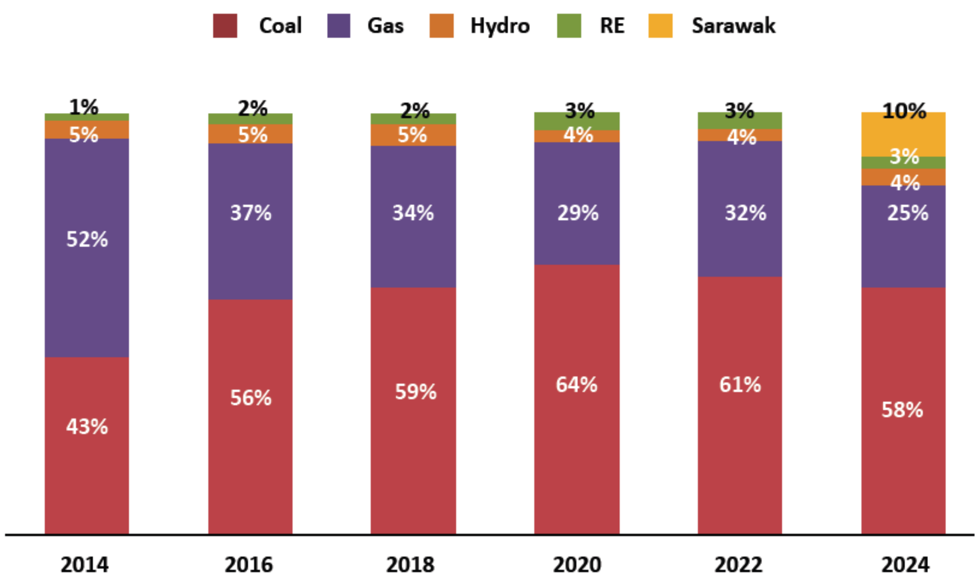
GWh = gigawatt hour, HSD = high speed diesel, LNG = liquefied natural gas, MFO = marine fuel oil.
Source: Perusahaan Listrik Negara.

(b) Malaysia

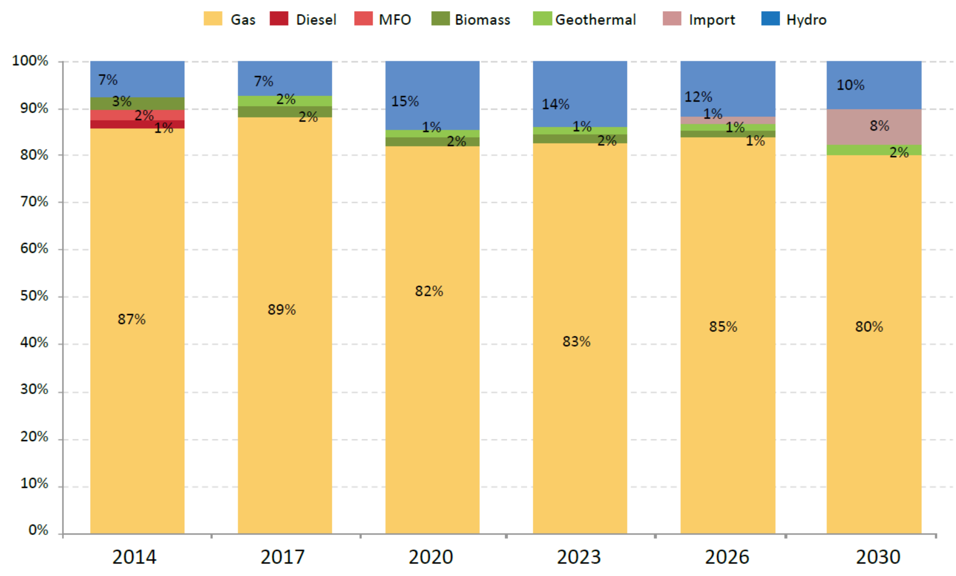
The Energy Commission of Malaysia has been announcing its long-term power development plan for Peninsular Malaysia and Sabah. As of 2014, coal-fired and liquefied natural gas (LNG)-fired thermal power accounted for 90 percent of the power mix in Peninsular Malaysia. Future power trade from Sarawak to Peninsular Malaysia is slated to start in 2024, when the share of LNG-fired thermal power would have declined whereas dependence on coal-fired thermal power would have continued. In contrast, Sabah does not use coal-fired thermal power but depends on LNG-fired thermal power. Although power trade is to be initiated from Sarawak to Sabah in 2026, dependence on LNG-fired thermal power is forecast to remain high.

Figure 1.1-5. Power Supply Plan of Malaysia

Peninsular Malaysia



Sabah

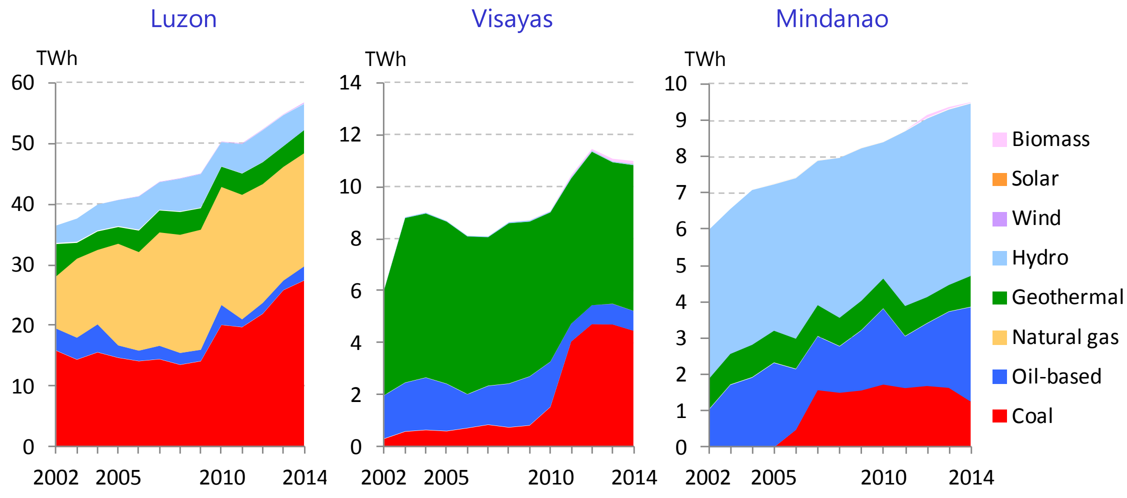


RE = renewable energy, MFO = marine fuel oil.
Source: Suruhanjaya Tenaga (Energy Commission).

(c) The Philippines

In terms of power supply, the Philippines has three large regions: Luzon, the Visayas, and Mindanao. Luzon is highly dependent on fossil fuels such as coal and LNG, while the Visayas and Mindanao are highly dependent on renewable energy sources such as geothermal and hydropower.

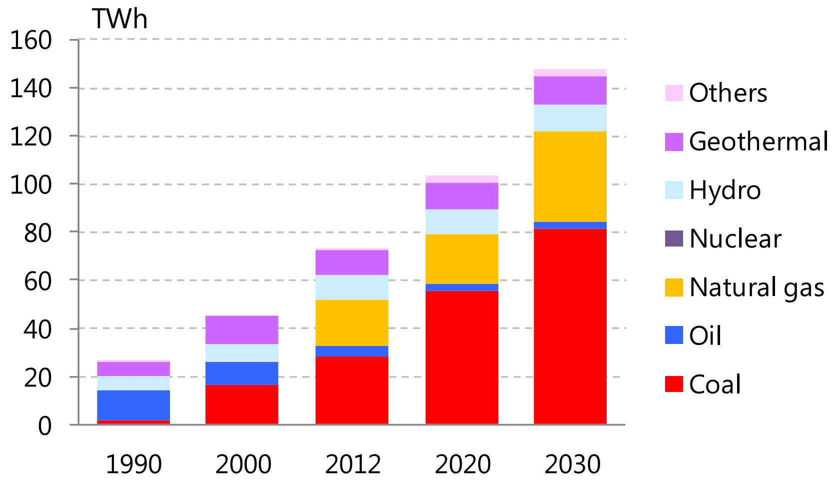
Figure 1.1-6. Trend of Power Supply in the Philippines



TWh = terawatt-hour.
Source: Department of Energy (Philippines).

As the Philippine government has not released any power development plan by source, the assumptions for this study are based on the ERIA outlook (Kimura et al., 2015) where it is assumed that the country's power demand increase in the future will be met mainly by coal and LNG-fired power generation (Figure 1.1-7).

Figure 1.1-7. Power Supply Outlook of the Philippines



TWh = terawatt.
Source: ERIA.

2. Methodology and Major Assumptions

2.1. Overview of the Model

This study uses two models similar to those used by Kutani et al. (2014).

(1) Optimal Power Generation Planning Model

The model is designed to determine an optimal electricity mix to satisfy a given electricity demand level at a minimal cost in a country or region. To assess the effects of international power grid interconnection, the model can set specific grid interconnection capacities between countries and regions and design electricity supply to meet the demand at any time.

(2) Supply Reliability Evaluation Model

An international power grid connection can be expected to improve reliability of electricity supply by allowing a country to receive electricity supply from other countries to avoid blackouts when its domestic supply is short. This means that an international power grid interconnection can allow any country in the interconnection to achieve the same loss of load expectation even at a lower supply reserve margin than in the case without such interconnection and save reserve power generation capacity. To assess this effect, this study has developed a supply reliability evaluation model using the Monte Carlo method.

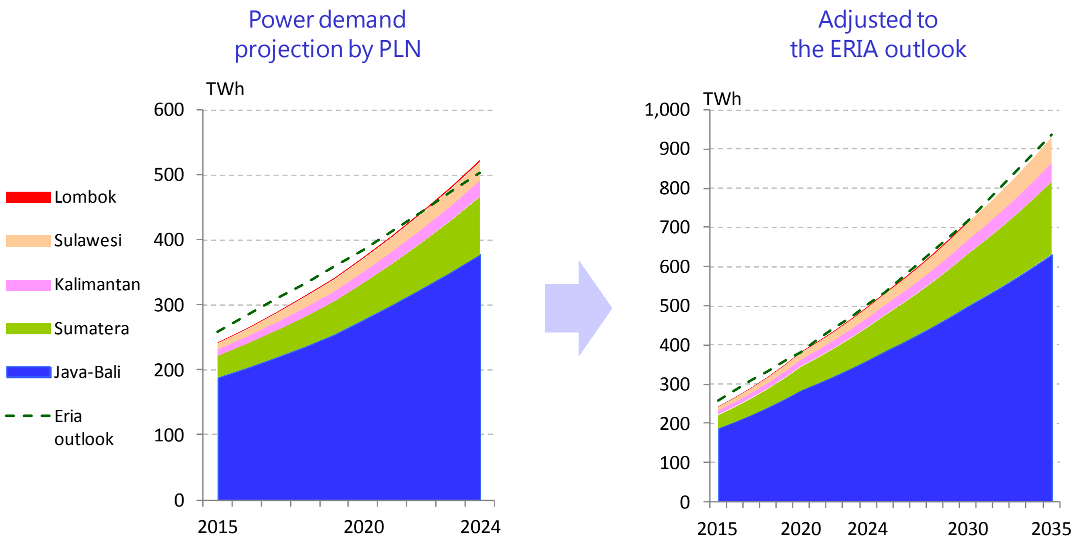
2.2 Outlook for power demand

This study refers to the ERIA outlook for the prospect of increasing power demand in Indonesia, Malaysia, Brunei, and the Philippines. As regards the projection in each region of these countries, the outlook for each country was adjusted so that the growth of the entire power demand will match that of the ERIA outlook. The details for each country are shown below.

Although the PLN's plan and the ERIA outlook both expect a future power demand increase in Indonesia, they present different growth rates: while an increase of 8.9 percent (2015–2024) is assumed in PLN's plan, the ERIA outlook presents a more modest increase of 7.5 percent (2015–2025).

In this study, the regional outlook by PLN through 2024 was corrected so that it would match that of ERIA's in terms of the demand in the entire country. The regional outlook from 2025 to 2035 was worked out by extrapolating the growth rate up to 2024.

Figure 1.2-1. Power Demand in Regions of Indonesia

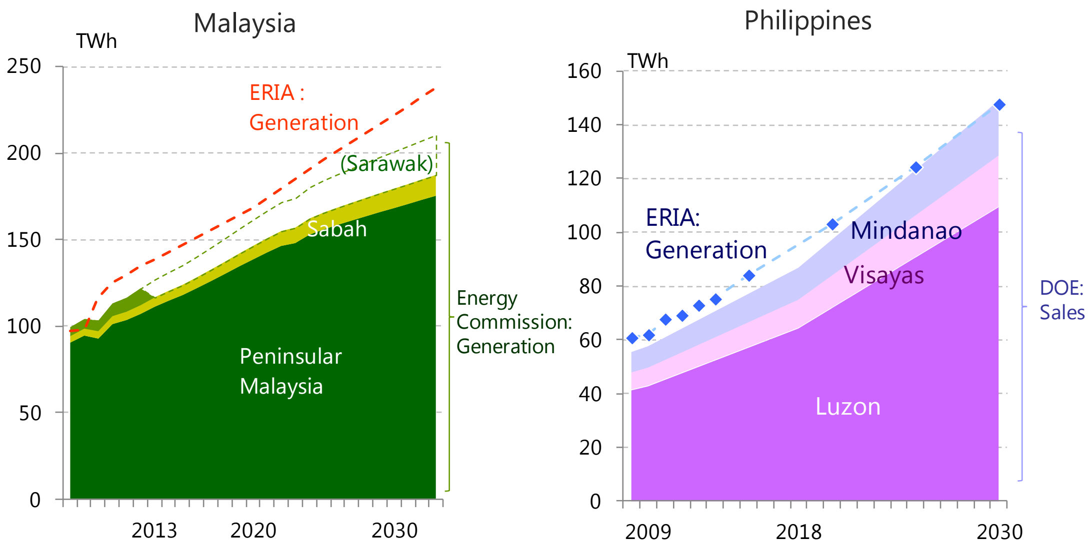


ERIA = Economic Research Institute for ASEAN and East Asia, PLN = Perusahaan Listrik Negara, TWh= terawatt-hour.
Source: Perusahaan Listrik Negara.

The growth rate of power demand in the ERIA outlook is higher in the case of Malaysia than that assumed by the Malaysian government. It is lower than that of the government's in the case of the Philippines. Figure 1.2-2 shows comparison of national projections with the ERIA outlook, where power generation for Sarawak, shown in green dotted lines, is extrapolated using power generation projections for the other two regions and the historical growth rates, as the Energy Commission publishes projections only for Sabah and Peninsular Malaysia.

In this study, corrections were made so that the growth rate of the entire nation would match that shown in the ERIA outlook for Malaysia and the Philippines. As for Brunei, the numerical values of the ERIA outlook were used.

Figure 1.2-2. Power Generation Assumptions in Malaysia and the Philippines



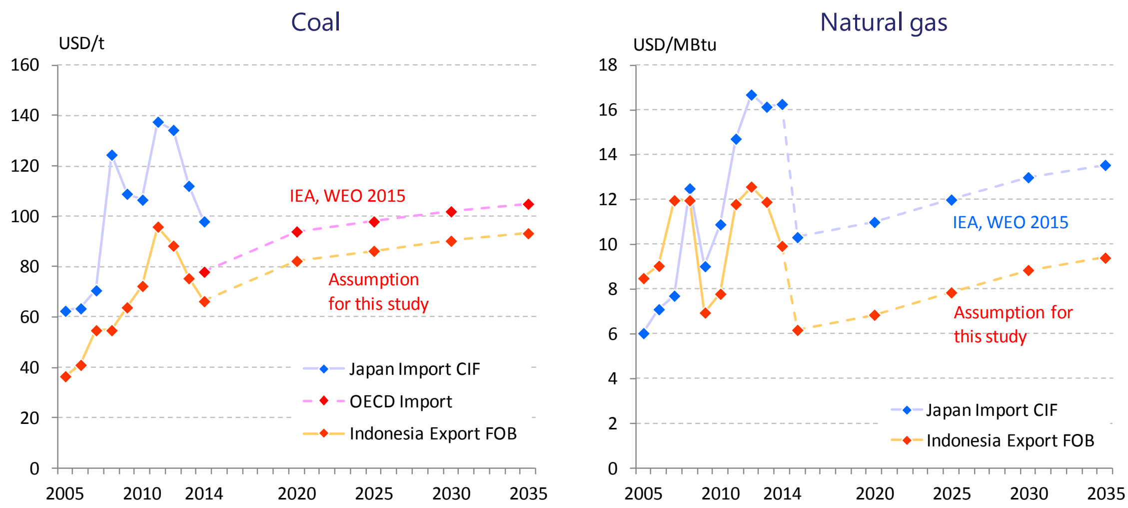
DOE = Department of Energy, ERIA = Economic Research Institute for ASEAN and East Asia. TWh = terawatt-hour.
Sources: Energy Commission, Department of Energy.

2.3 Outlook for Primary Energy Prices

If the share of hydropower increases in ASEAN countries rich in resources, domestic consumption of fossil fuels can be reduced and surplus will be available for export. From this point of view, this study uses the free-on-board export price of fossil fuels as the energy price.

The assumptions on prices were set based on the New Policies Scenario of the International Energy Agency's 'World Energy Outlook'. The export price of coal is assumed to rise from US$66/t in 2015 to US$93/t in 2035. The price of natural gas is assumed to rise from US$6.2/MMBTU in 2015 to US$9.4/MMBTU by 2035.

Figure 1.2-3. Outlook for the Prices of Coal and Natural Gas



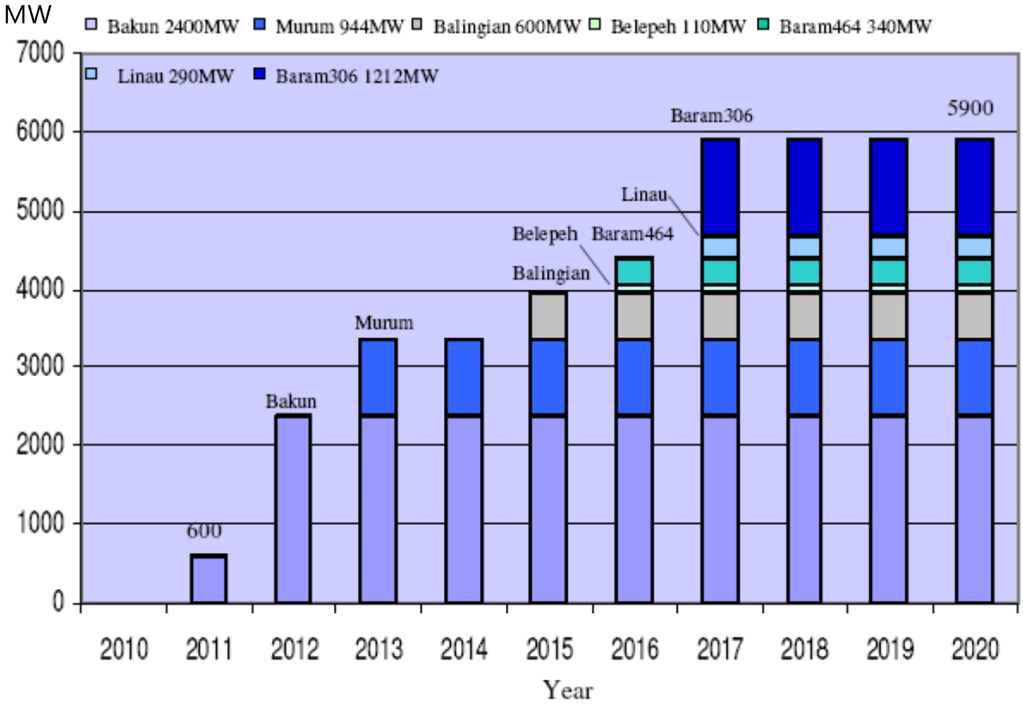
CIF = cost, insurance, and freight, FOB = free on board, IEA = International Energy Agency, MBtu = one million British thermal unit, WEO = World Energy Outlook.
Sources: Ministry of Energy and Mineral Resources, The Institute of Energy Economics Japan, International Energy Agency.

2.4 Renewable Energy Potentials

(a) Sarawak

The potential for hydropower generation in Sarawak is estimated to be 20,000 MW. In the past, only the 104-MW Batang Ai dam (started in 1985) had been used. Recent large-scale developments include the 2,400-MW Bakun dam (started in 2011) and the 904-MW Murum dam (started in 2014). At present, the 1,200-MW Baram dam is under construction and is scheduled to start operation in 2017.

Figure 1.2-4. Power Source Development Plan of Sarawak



MW = megawatt.
Source: Asian Development Bank.

(b) Sabah

The potential for 1,900 MW of hydropower and 500 MW of biomass power generation has been estimated.

(c) North Kalimantan

It has the potential for hydropower, especially along the Sesayap River, where the potential for 5,572 MW is estimated.

2.5 Expansion Plan of Regional Interconnection Lines

The expansion of regional interconnection lines is planned not only for Borneo but also in in adjacent regions not currently interconnected, except for Sarawak and West Kalimantan that have been interconnected very recently. As shown in Figure 1.2-5 and Table 1.2-1, future construction plan of interconnection lines assumes that the whole of Borneo will be interconnected by 2030. The plans also include interconnections from Borneo to Peninsula Malaysia, Java, North Sulawesi, and Luzon. The advantages of interconnection may be the following points:

(1) Effective use of the energy resources in Borneo

Large potential for hydropower exists in Borneo, especially in Sarawak and North Kalimantan, but compared with this potential, the power demand of these regions is not so large and the potential cannot be fully utilised. By interconnecting with grids out of the regions, the resources could be effectively utilised.

(2) Stabilisation of power systems

As power interchange can be achieved with other regions in an emergency, interconnection will contribute to the stabilisation of power systems. From an economic viewpoint, stabilisation of power systems will lead to a reduction in power capacity margin and equipment investment.

(3) More efficient power generation equipment

From the viewpoint of the reliability of power supply, the scale of coal-fired thermal power plants in each region is limited to within 10 percent of the entire power system. However, the power-generation efficiency of coal-fired thermal power generation plants differs in different scales, and generally, the larger the scale, the more efficient thermal efficiency will be. For this reason, by enlarging the scale through interconnection, higher efficiency technology options can be introduced.

Figure 1.2-5. Construction Plan of Inter-Borneo Interconnections

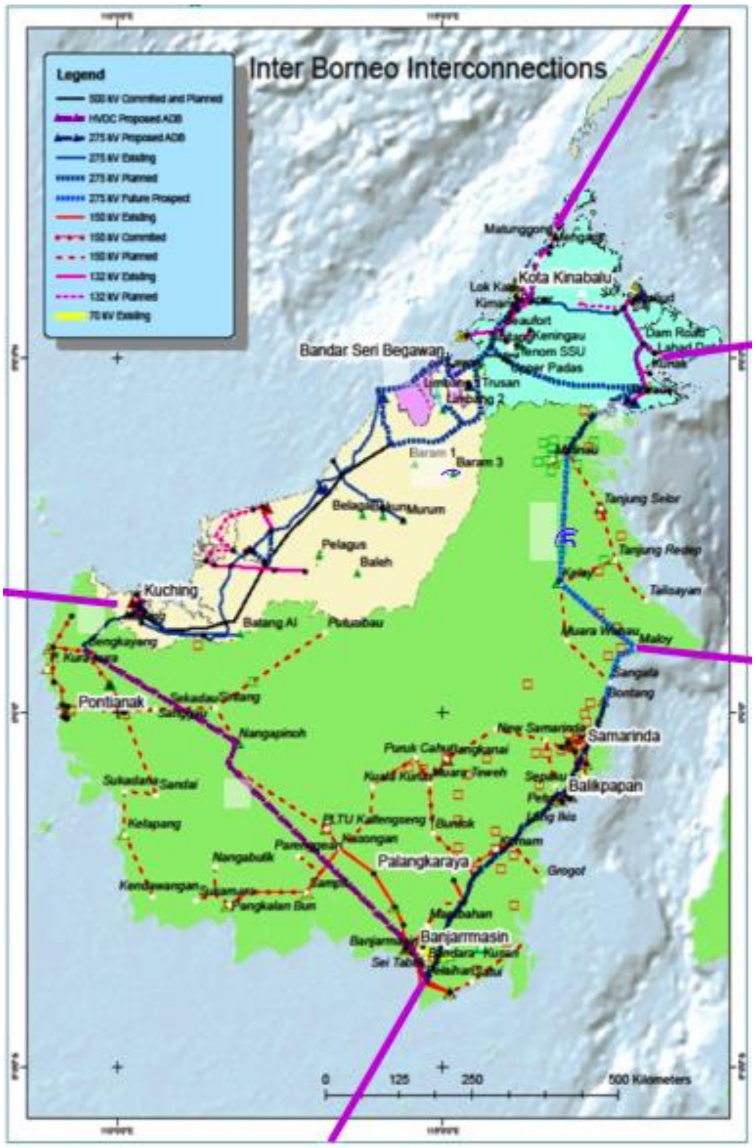


Table 1.2-1. Details of Interconnection Plans

		Year	Capacity (MW)	Length (km)	Total cost ($/kW)
(1)	Sarawak–Kalbar	2015	300	83	209
(2)	Sarawak–Brunei–Sabah	2016	300	265	363
(3)	Kalbar–Kalteng	2018	300	860	830
(4)	Kaltim–Kalut	2018	600	550	454
(5)	Kalut–Sabah	2020	600	150	132
(6)	Sarawak–P. Malaysia	2020	2,000	1,200	1,129
(7)	Kalsel–N. Sulawesi	2025	300	235	875
(8)	Sabah–Mindanao	2025	600	412	899
(9)	Kalsel–Java	2025	2,000	470	520
(10)	Sarawak–Sabah	2025	300	300	626
(11)	Sabah–Luzon	2030	2,000	950	521

km = kilometre, kW = kilowatt, MW = megawatt.

Source: Asian Development Bank.

2.6 Setting the Cases for Calculation

Using the Optimal Power Generation Planning Model and the Supply Reliability Evaluation Model, the optimal power generation mix and power exchange through 2035 were calculated. Calculations were done up to 2050 to avoid boundary effects, extrapolating the assumptions properly. However, as the introduction of renewable energies, except hydropower and nuclear power, depends mainly on policies, the introduced amount of these power sources was fixed on the basis of the values presented by ERIA and only thermal power generation (coal, natural gas, and oil) and hydropower were used as the object of analysis. Of these, the introduced amount of hydropower in Case 0 and Case 1 was fixed at the amount indicated by ERIA, while in other cases, the introduction potential was used as the potential for additional hydropower.

When the Optimal Power Generation Planning Model was used, the time interval was set at five years, with the values for 2010 as the latest historical values, and those for 2015 and subsequent years as predicted values. The discount rate was set uniformly at 5 percent so that the result of the calculation would roughly match the values presented by ERIA.

Most ASEAN countries assume large power capacity margins in power source development plans to keep to a low level the probability of blackouts. For example, in response to an increase in the power demand for the Java–Bali power system, PLN (2015) formulated a power development plan to ensure a capacity margin of 32 percent in 2024. In this study, this value was referred to and the parameters of the Supply Reliability Evaluation Model adjusted so that the loss of load expectation for the Java–Bali system would provisionally be 24 hours/year under the condition of the 32-percent power capacity margin in 2035, the target year of calculation, and were used in the calculation for all regions. The number of trials in the Supply Reliability Evaluation Model using the Monte Carlo method was set to around 140,000. As the regions with particularly small demand can receive power supply in an emergency through the interconnected line if it exists, the loss of load expectation of 24 hours/year can be achieved with a very small power capacity margin. Actually, however, for security reasons, at least a certain extent of the capacity margin would be sought even if lower loss of load expectation could be achieved with interconnections. Therefore, the minimum value of the capacity margin was set at 15 percent in this study.

Case settings are shown in Table 1.2-2.

Table 1.2-2. Case Settings

Case name	Description
Case 0	Without grid interconnection
Case 1	Grid interconnection without additional hydro potential
Case 2	Grid interconnection only in the BIMP region, with additional hydro potential
Case 3	Grid interconnection with additional hydro potential
Case 4	Grid interconnection with double capacity, with additional hydro potential

Case 0 is a BAU (Business as usual) case without considering interconnection, where each country maintains the demand-supply balance by means of domestic power generation equipment. In contrast, Case 1 makes the interconnected capacity available up to the level shown in Table 1.2-1. The current interconnection expansion plan (Table 2-1) does not assume any construction of interconnection lines between Central Kalimantan and South Kalimantan, and between South Kalimantan and East Kalimantan. However, interconnection lines are actually aimed to be constructed throughout the whole of Borneo. Therefore, it was assumed that interconnection lines would be constructed between Central Kalimantan and South Kalimantan, and, in the same manner, between South Kalimantan and East Kalimantan, and the capacities and the unit construction costs would be similar to those of the interconnection line between West Kalimantan and Central Kalimantan as shown in Table 1.2-1 (3).

In Case 2 and subsequent cases, in addition to interconnection lines, it was assumed that the potential for hydropower (Section 2-4) would be available. While interconnection lines only in the BIMP region (Borneo and Mindanao) in Case 2 were assumed, interconnection lines for Peninsular Malaysia, Java–Bali, and Luzon were likewise assumed in Case 3. In Case 4, it was assumed that the interconnection capacity would be expanded up to double that of Case 2.

Meanwhile, the maximum limit of coal-fired thermal power capacities in Brunei and Sabah was set to zero because no coal-fired thermal power had ever been introduced in these regions before, nor is there any plan for such.

Table 1.2-3. Costs of Power Generation Plants

Type	Capacity, MW	Thermal Efficiency, %	Initial Cost, US$/kW
Coal 1	< 20	25	2,000
Coal 2	20 – 100	32	2,000
Coal 3	100 – 250	35	1,500
Coal 4	250 <	40	1,500
Natural gas			870
Oil			1,340
Hydro			1,200–1,500

Kw = kilowatt, MW = megawatt.
Source: Authors.

In each of these cases, Kutani et al. (2014) and ADB (2014) were referred to for the construction costs and operation and maintenance costs of power generation plants, and assumptions were made as shown in Table 1.2-3. As mentioned, if the scale of a power system is expanded through interconnection, it will be possible to construct larger-scale and, therefore, more efficient power plants. In this study, the four types of coal-fired power generation (Table 2-3) were assumed and where it was postulated that the type of the plants would differ depending on the scale of the power system.

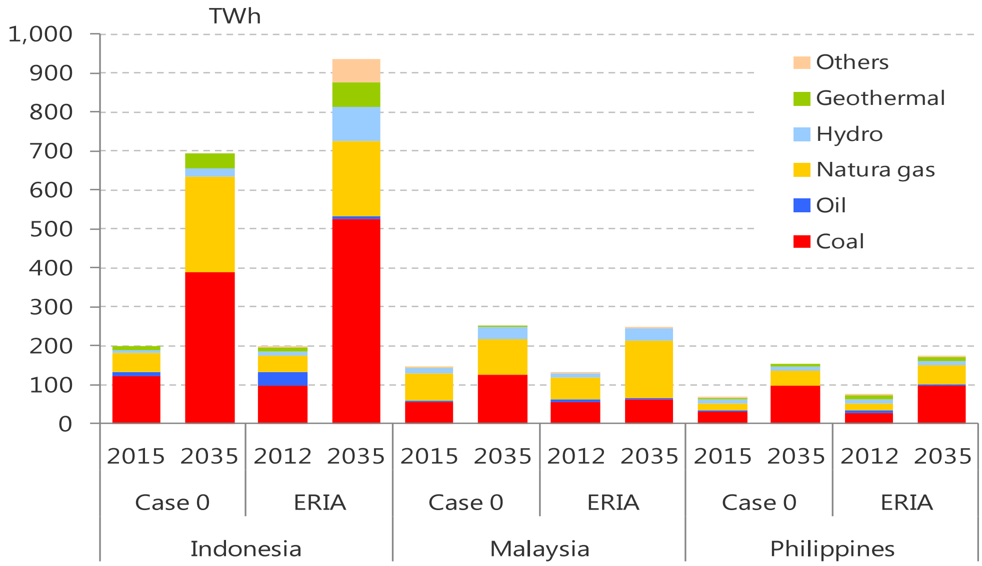
3. Results and Discussions

3.1 Composition of Power Sources in 2035

Figure 1.3-1 shows the power generation mix in Case 0 in 2035 as compared with the ERIA outlook. It should be noted that the result of Case 0 only includes Kalimantan, Java–Bali, and North Sulawesi for Indonesia, and Luzon and Mindanao for the Philippines, while the ERIA outlook includes the entire countries. Thus, in Indonesia, for example, the power generation amount for 2035 is 693 TWh, which is smaller than the 936 TWh projected by ERIA. Reflecting the fact that the share of renewables is larger in Sumatra Island, which is not included in the calculations, electricity output in Case 0 is smaller than ERIA's for hydropower, geothermal, and 'others', including biomass. In Indonesia, however, the result of Case 0 matches that of ERIA's in that thermal power generation will continue to have a large share up to 2035, and that coal-fired thermal power generation has a higher share than natural gas-fired one.

In Malaysia, on the other hand, while the share of coal-fired thermal power generation was similarly higher in the optimised calculation result for Case 0, the share of natural gas-fired in the ERIA outlook increases rapidly up to 2035. According to the Malaysia Energy Committee's outlook (Figure 1.1-5), at least until 2024, coal-fired thermal power is assumed to keep its large share in Peninsular Malaysia, accounting for the largest part of the energy consumption in Malaysia, which is nearer to the result for Case 0. In contrast, the ERIA outlook focuses more on environmental protection, which would have resulted in higher share of natural gas-fired.

Figure 1.3-1. Comparison between the ERIA Outlook and Case 0



ERIA = Economic Research Institute for ASEAN and East Asia, TWh = terawatt-hour.

Source: Authors.

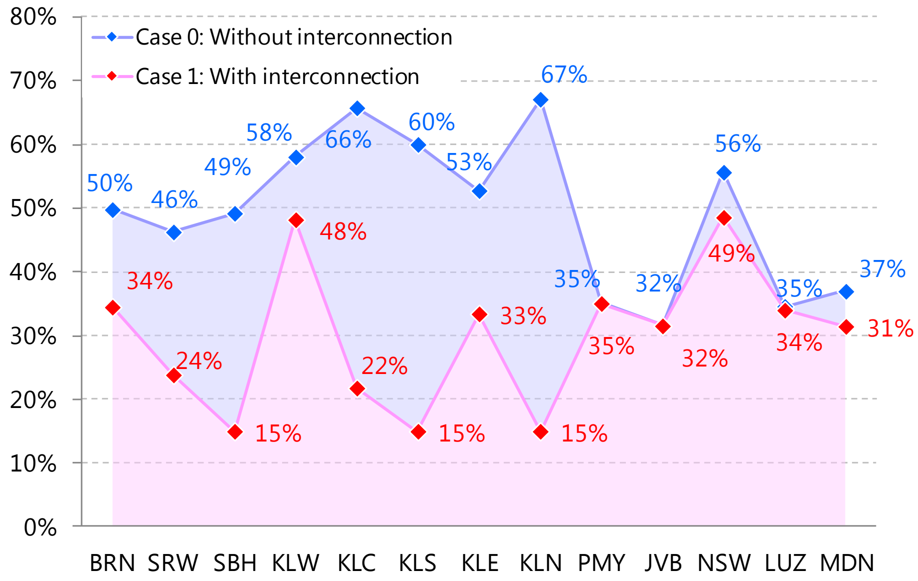
3.2 Effects on Power Capacity Margin Saving

Figure 1.3-2 shows the power capacity margin in Case 0 and Case 1. In Case 0, the parameters were adjusted so Java–Bali's margin would be 32 percent. In general, the capacity margin required to achieve the same loss of load expectation (24 hours/year) is smaller in major consuming regions such as Peninsular Malaysia and Luzon, and larger in small-demand regions such as North Kalimantan and Central Kalimantan. This is because the scale of power plants is relatively larger in comparison with the demand level in small-demand regions and, therefore, even a single trouble can easily lead to blackouts.

In contrast, in Case 1, where interconnection is assumed, the capacity margin does not really change in larger demand regions such as Java–Bali and Peninsular Malaysia, while it becomes considerably smaller in smaller demand regions. This is because when trouble occurs in a power plant of a smaller demand region, the demand can easily be met by power trade from surrounding regions. Among the states of Kalimantan, the reduction of capacity margin is small in West Kalimantan and East Kalimantan, which have a relatively large power demand. It is especially small in West Kalimantan, which is connected with the adjacent regions with small capacity interconnection lines of 0.3 GW. On the other hand, in North Kalimantan and South

Kalimantan, the capacity margin is reduced to the assumed minimum level of 15 percent.

Figure 1.3-2. Results of the Calculation of Power Capacity Margin (Case 0 and Case 1)

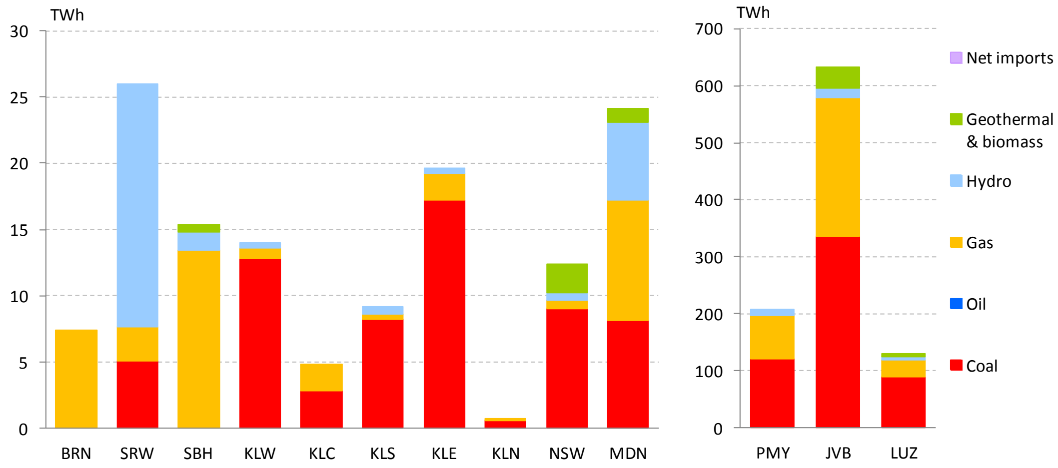


BRN = Brunei Darussalam, JVB = Java–Bali, KLC = Kalteng, KLE = Kaltim, KLN = Kalut, KLW = Kalbar, KLS = Kalsel, LUZ = Luzon, MDN = Mindanao, NSW = North Sulawesi, PMY = Peninsular Malaysia, SBH = Sabah, SRW = Sarawak.
Source: Authors.

3.3 Power Generation Mix and Trade in 2035

Figures 1.3-3 to 1.3-7 show the result of calculating the regional power generation mix in 2035. As shown in Figure 1.3-3, no trade of electricity takes place in Case 0. Coal-fired thermal power generation accounts for large shares in most regions. However, in Brunei and Sabah, where no coal-fired thermal power generation is assumed to be used, electricity is supplied mainly by natural gas-fired thermal power generation.

Figure 1.3-3. Power Generation Mix in 2035 (Case 0)



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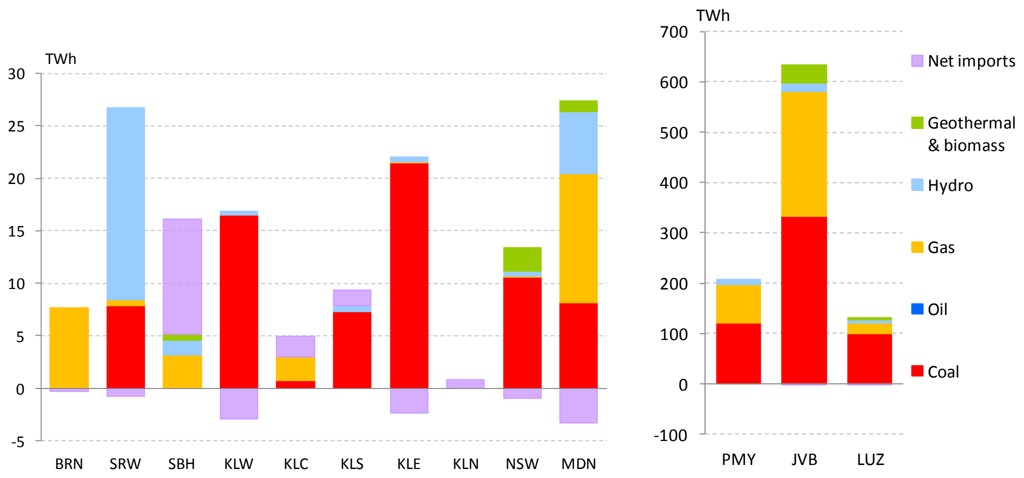
Source: Authors.

Figures 1.3-4 and 1.3-5 show the power generation mix and electricity trades in 2035, assuming grid interconnection. Electricity imports from other regions become more optimal in regions such as Sabah that depend on natural gas-fired rather than coal-fired thermal power generation and regions such as North Kalimantan that depend on inefficient coal-fired thermal power generation. The region that will import the largest amount of electricity in this case is Sabah, which is assumed to be importing electricity from Luzon, Mindanao, and Sarawak.

Figure 1.3-4. Power Generation Mix in 2035 (Case 1)



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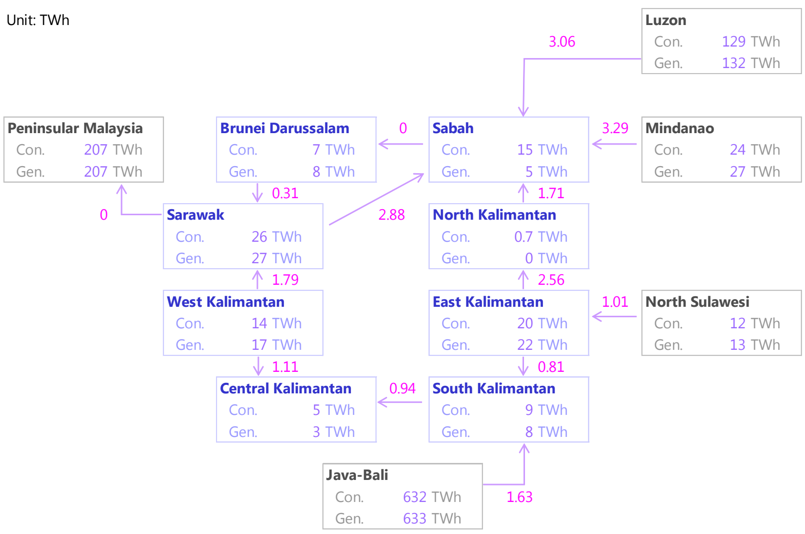
Source: Authors.

Figure 1.3-5. Electricity Trade Flows in 2035 (Case 1)

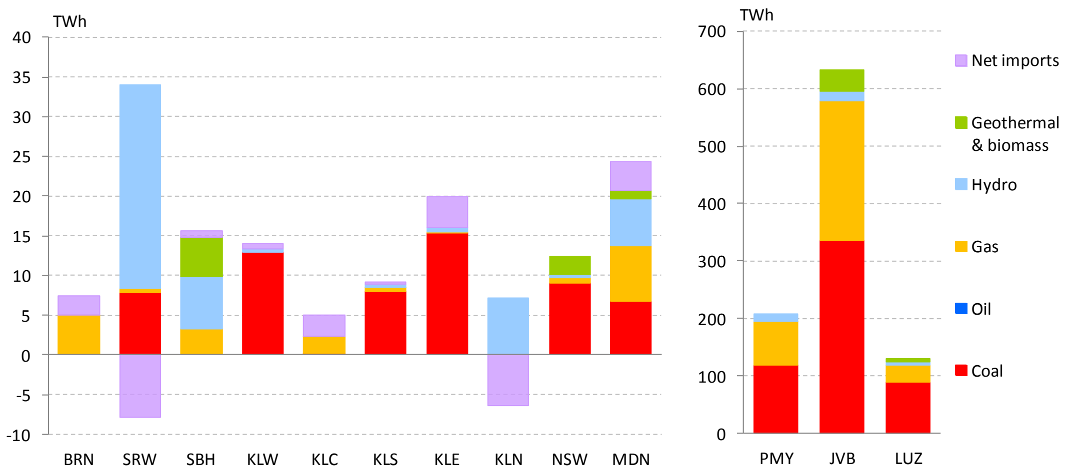


TWh = terawatt-hour.

Source: Authors.

Figures 1.3-6 and 1.3-7 show the result of Case 2, which assumes grid interconnection only in the BIMP region. In this case, electricity is imported from Sarawak and North Kalimantan, which have the potential for exporting hydropower to Brunei, East Kalimantan, and Mindanao. As Peninsular Malaysia, Java/Bali, and Luzon are not interconnected in this case, no electricity is exported to these regions.

Figure 1.3-6. Power Generation Mix in 2035 (Case 2)



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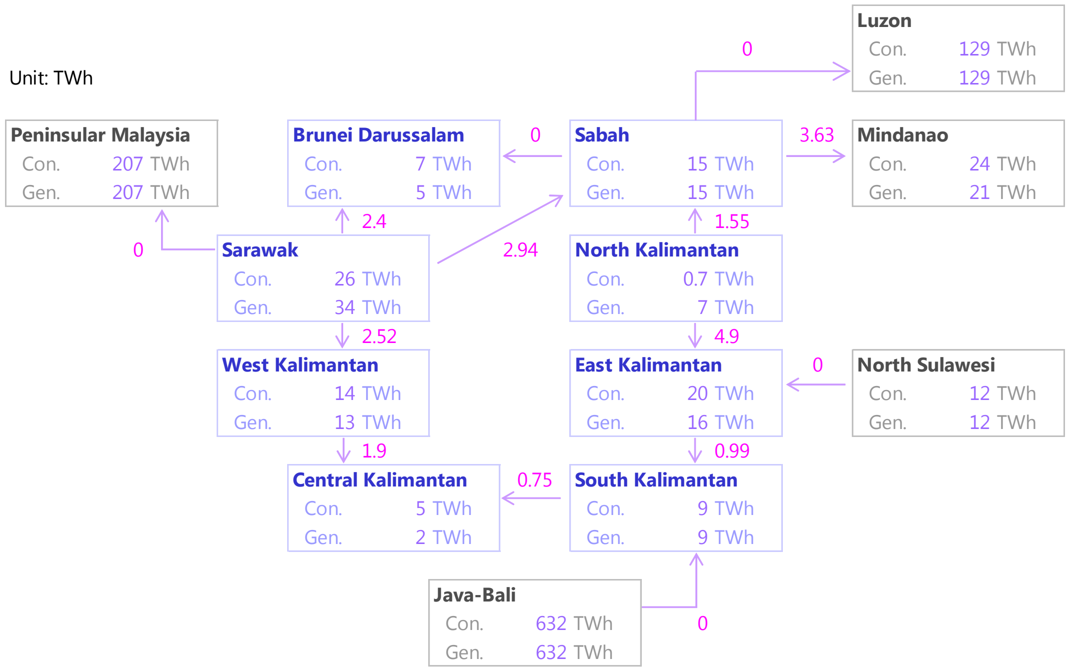
Source: Authors.

Figures 1.3-8 and 1.3-9 show the result of Case 3, which assumes grid interconnections in all regions. In this case, electricity is exported from Sarawak to Peninsular Malaysia and from Sabah to Luzon. The largest trade takes place from Sarawak to Peninsular Malaysia at 14 TWh/year. Hydropower generation in Sarawak is to be expanded from 26 TWh in Case 2 to 41 TWh in Case 3.

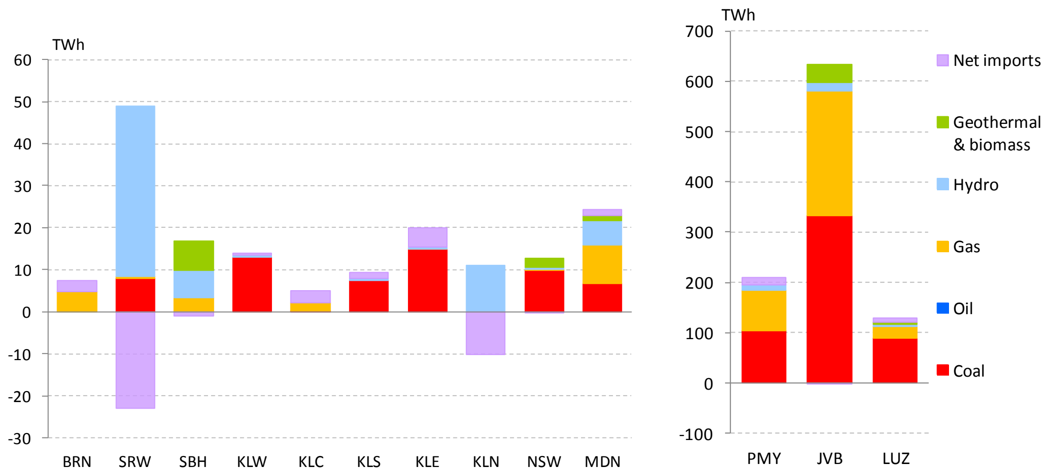
Figure 1.3-7. Electricity Trade Flows in 2035 (Case 2)



TWh = terawatt-hour.

Source: Authors.

Figure 1.3-8. Power Generation Mix in 2035 (Case 3)



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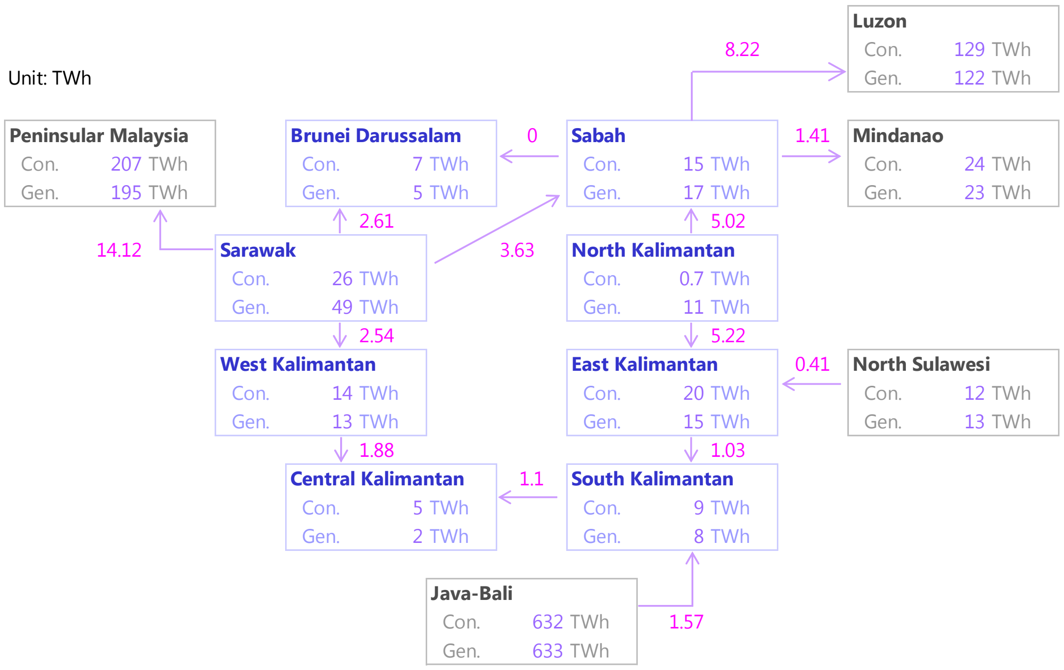
Source: Authors.

Figure 1.3-9. Electricity Trade Flows in 2035 (Case 3)

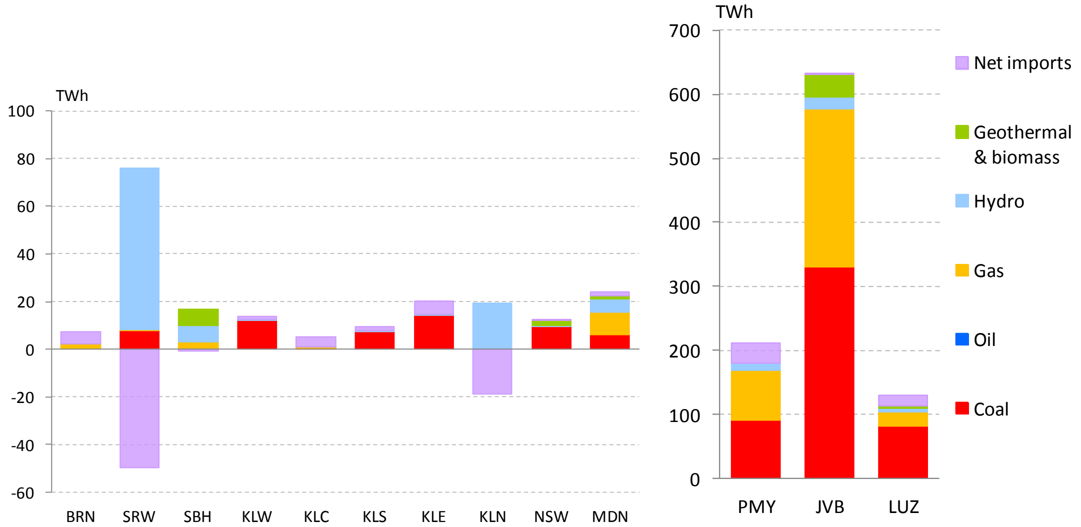


TWh = terawatt-hour.

Source: Authors.

Figures 1.3-10 and 1.3-11 show the result of Case 4, where the capacity of interconnection is set to double that for Case 3. In this case, electricity trade from Sarawak to Peninsular Malaysia is 31 TWh per year, and hydropower generation in Sarawak reaches 68 TWh. Thus, Borneo has a considerably large potential for hydropower especially in Sarawak, and could produce large benefits to enhance interconnection beyond the existing plans.

Figure 1.3-10. Power Generation Mix in 2035 (Case 4)



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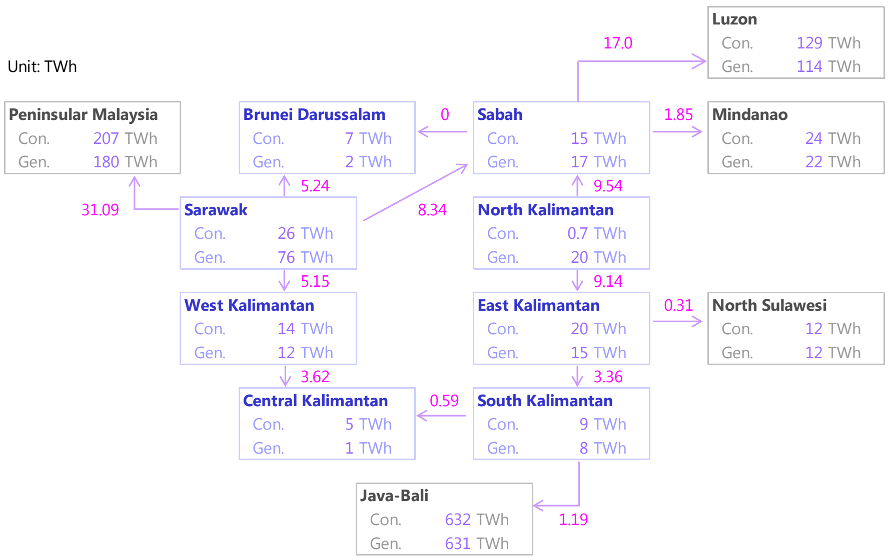
Source: Authors.

Figure 1.3-11. Electricity Trade Flows in 2035 (Case 4)

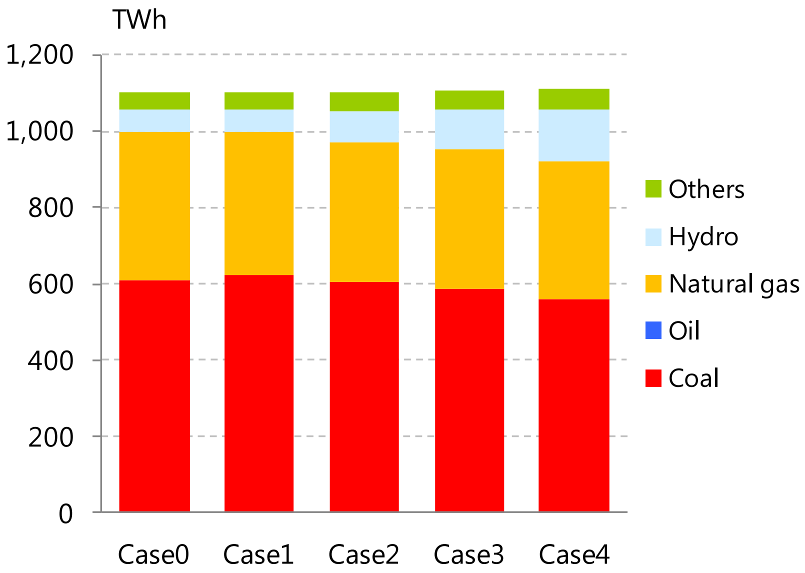


TWh = terawatt-hour.
Source: Authors.

3.4 Composition of Power Sources, CO_2 Emissions, and Cumulative Investments

Figure 1.3-12 summarises the electricity mix in 2035 in all regions for Cases 0 to 4. In Case 0, the share of oil-fired, natural gas-fired, and hydropower in the entire power supply is 55 percent, 35 percent, and 6 percent, respectively, and the total thermal power accounts for 90 percent. In contrast, in Cases 2, 3, and 4, the share of hydropower in 2035 increases up to 7 percent, 9 percent, and 12 percent, respectively. In Case 4, however, even with the share of thermal power generation as high as 83 percent, the regions still continue to depend on thermal power.

Figure 1.3-12. Power Generation Mix in 2035 (Total of All Regions)

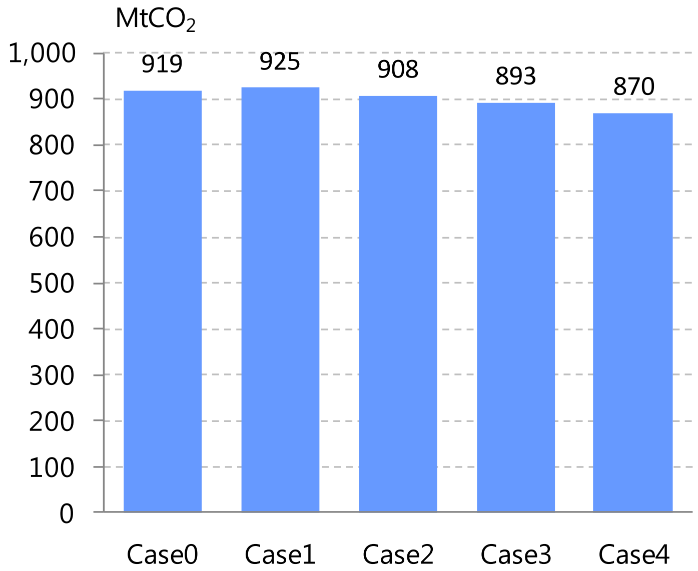


TWh = terawatt-hour.

Source: Authors.

CO_2 emissions from the power generation sector increases from 919 metric tonnes in Case 0 to 925 metric tonnes in Case 1. This is because higher cost natural gas-fired thermal power is substituted by coal-fired thermal power through grid interconnection. In Cases 2, 3, and 4, in line with the increase of hydropower, CO_2 emissions declined by 1.3 percent, 2.9 percent, and 5.3 percent, respectively, compared with those of Case 0.

Figure 1.3-13. CO_2 Emissions in 2035

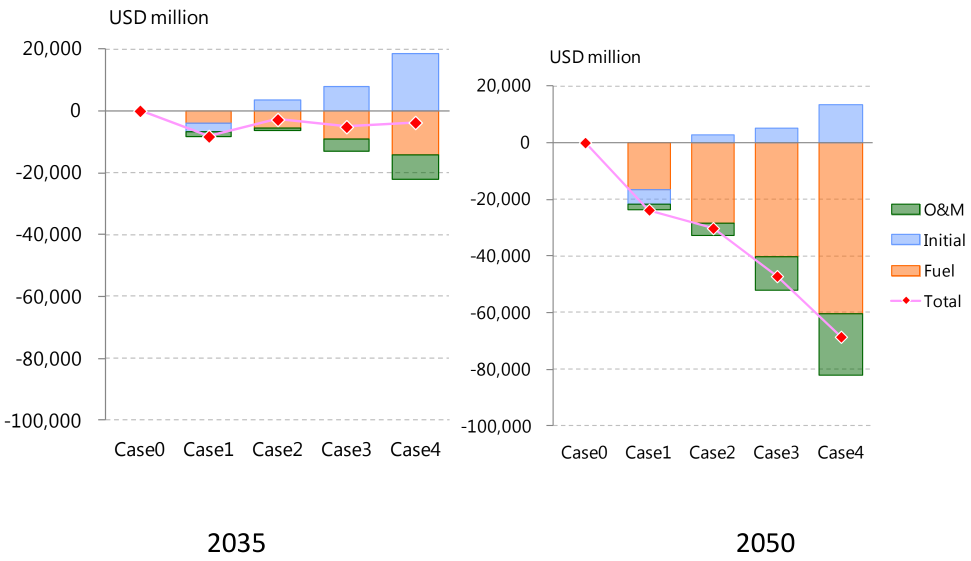


Source: Authors.

Figure 1.3-14 shows the cumulative costs up till 2035 and 2050, which include the increased investments on power generation plants and interconnection lines as the 'initial investment', the reduced fuel costs due to the decrease in thermal power generation as the 'fuel cost', and the reduced operation/maintenance costs as the 'O&M cost'.

In Case 1, the total cost is considerably reduced compared with Case 0, due to decrease in the power capacity margins. On the other hand, when we look at the time period up to 2035 in Cases 2 to 4, as the increased amount of the initial investment cannot be recovered by a decrease in fuels, the reduction in the cumulative total cost is smaller than in Case 1. From a long-term viewpoint through 2050, however, the contribution of the reduction in fossil fuels becomes larger. In particular, the reduction from Case 2 to Case 3 is larger than that from Case 1 to Case 2, which indicates that by expanding interconnection lines not only in the BIMP region but also in the surrounding demand areas, the regional hydropower resource can be utilised more efficiently and a remarkable economic effect could be expected.

Figure 1.3-14. Cumulative Costs up to 2035 and 2050



O&M = operation and maintenance.

Source: Authors.

Table 1.3-1. Cumulative Costs up to 2035 and 2050

Unit: USD million

		Case0	Case1	Case2	Case3	Case4
2030	Decrease in fuel costs	0	3,829	5,495	9,043	14,078
	Decrease in O&M costs	0	1,468	899	3,979	7,985
	Increase in initial costs	0	-2,983	3,599	7,889	18,303
	Total benefits	0	8,280	2,795	5,134	3,760
2050	Decrease in fuel costs	0	16,496	28,326	40,142	60,403
	Decrease in O&M costs	0	1,999	4,390	12,137	21,555
	Increase in initial costs	0	-5,283	2,513	5,129	13,386
	Total benefits	0	23,778	30,203	47,150	68,572

O&M = operation and maintenance.

Source: Authors.

4. Conclusions and the Way Forward

In this study, the benefits of expanding grid interconnection lines in the south ASEAN region and the BIMP region was evaluated by carrying out a simulation with the Optimal Power Generation Planning Model and the Supply Reliability Evaluation Model on the basis of the current expansion plan of grid interconnection. Through the efficient use of the hydropower resources present in Borneo with the expansion of regional interconnection lines, it is possible to reduce fossil fuel consumption, CO_2 emissions, and the costs of power source development. These effects can be expected to a certain extent by expanding the interconnection lines within the BIMP region alone. But even more remarkable effects may be expected by further interconnecting with the large energy-consuming areas like Peninsular Malaysia and Luzon. However, any significant cost reduction can be achieved only from a long-term point of view and within a time frame up to 2050. For this reason, long-term plans by the government of host country and international financial institutions and their steady implementation are indispensable.

The expected effects of interconnection estimated in this study are: efficient use of hydropower resources, reduction of power capacity margin through power interchange in an emergency, and enhancement of coal-fired thermal power generation efficiency by expanding the grids. Evaluating these effects will be relevant when assuming mainly a considerable expansion of hydropower and biomass among renewable energy sources. It must also be noted, however, that the cost of solar power generation has been decreasing recently and its use is aimed to be significantly increased in ASEAN countries in the future. Generally speaking, although there is a limit to increased use of solar power generation that cannot control the output, the contribution of power interchange through interconnection could go over the limit. Further examination of this effect is planned in the future.

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Chapter 2

Road Map for Power Market Integration in the Brunei–Indonesia–Malaysia–Philippines (BIMP) Region[1]

Romeo Pacudan

The Brunei-Indonesia-Malaysia-Philippines (BIMP) region represents the eastern power market cluster of the ASEAN Power Grid. The current power supply and demand imbalances create opportunities for trade and initiate power market integration. The overarching goal of power market integration in the ASEAN is to achieve energy security, accessibility, affordability, and sustainability. Key benefits for the BIMP region includes least-cost option for importing countries, efficiency improvement through aggregation of demand, and lower reserve requirement. This chapter focuses on the possible power market integration structure and characterises the development stages to achieve the target integration arrangement. Due to disparity of electricity supply industry structures and regulatory frameworks, coordination of power system operators would be the most practical approach in market integration rather than consolidating the power market and power system operators. The proposed road map for the BIMP region is divided into four stages of development: (i) stage 1 – incremental development of regional transmission backbone infrastructure; (ii) stage 2 – incremental intra-Borneo power trade; iii) stage 3 – incremental inter-Borneo trade arrangements; and (iv) stage 4 – establishment of a multi-buyer, multi-seller regional power market. The proposed coordination of system operators requires standardisation of practices and harmonisation of measures related to electricity security regulation, planning coordination, cost allocation and wheeling charges, network codes and monitoring. Implementation of this road map faces various challenges but these could be overcome when clear and tangible economic benefits that would be derived from market integration would be underscored.

1. Introduction

Given its geographic arrangement, uneven distribution of energy resources, and disparate levels of economic development of member countries, the ASEAN regional power market is a fragmented market with three sub-regional market clusters that form the three regional power subsystems under the ASEAN Power Grid (APG).

This study focuses on the Brunei–Indonesia–Malaysia–Philippines (BIMP) power market, the market cluster under System C (eastern system) of APG (AIMS, 2010) and covers the power

[1] This research paper is funded by the Economic Research Institute for ASEAN and East Asia (ERIA) under the research project Achieving Integrated, Transboundary Energy Electricity Markets in Southeast Asia.

markets of Brunei Darussalam, Sabah, Sarawak, Kalimantan, and the Philippines. The other systems are System A (northern system), which covers Cambodia, Lao PDR, Myanmar, Thailand, and Viet Nam (referred to in this paper as the Greater Mekong Subregion [GMS] power market cluster); and System B (southern system) which includes Peninsular Malaysia, Singapore, and Sumatra (southern power market cluster).

The three ASEAN power market clusters under APG are at various stages of market integration, with the GMS cluster as the most advanced and the BIMP cluster as the least advanced. The first power trade in the GMS cluster occurred in 1971 while the first interconnection in the BIMP cluster started only in early 2016. Because of the strong support by the Asian Development Bank, the regional economic cooperation on power trade in GMS is more structured than that at the ASEAN level or at other subregional levels. The countries in the GMS cluster have adopted a road map to fully achieve subregional power interconnections (Zhai, 2010).

Strategies and action plans for the implementation of APG are formulated by the heads of ASEAN power utilities/authorities (HAPUA) and reported under the ASEAN Plan of Action for Energy Cooperation (APAEC). The strategies are focused on specific power trade or interconnections while the action plans are key studies to address economic, technical, legal, and regulatory issues related to cross-border trade (ACE, 2015). The APAEC 2016–2025 and the ASEAN Interconnection Master Plan Study 2010, however, did not characterise market integration at the ASEAN level nor at the sub-regional levels.

This paper raises the following key issues: what level of power market integration could be reasonably achieved in the BIMP region and how to characterise the development stages to achieve this level of integration. This paper reviews and situates the current interconnection initiatives under the framework for market integration and outlines a road map for greater power market integration in the BIMP region. This paper is structured as follows: Section 2 presents an overview of the BIMP power market, Section 3 characterises market integration in the BIMP region, Section 4 briefly discusses technical issues, Section 5 outlines the stages of the road map and provides recommendations to realise the road map, and Section 6 summarises the finding of the study.

2. Overview of the BIMP Power Market

2.1. Demand, Supply, and Energy Resources

Central to the BIMP power market is Borneo, the largest island in Asia and the third largest island in the world, and where power interconnections are centrally located. At present, Borneo's imbalances of electricity supply and demand offer an opportunity for trading electricity and developing the regional infrastructure. But with its huge energy resources for power generation, Borneo could, in the long term, trade its surplus capacity with markets outside the island.

Table 2-1 shows an overview of the BIMP power market. The population of Borneo (Kalimantan, Sarawak, Sabah, and Brunei Darussalam combined) is almost as big as that in Mindanao in the Philippines. Kalimantan and Mindanao have relatively lower electrification rates and lower electricity consumption per capita than Sarawak, Sabah, and Brunei Darussalam. The consumption per capita in Brunei Darussalam, however, is almost four times higher than those in Sarawak and Sabah. These disparities indicate prospects for power market growth and development in the BIMP region.

Table 2-1. Overview of the BIMP Power Market

	Unit	**Kalimantan**		**Sarawak**	**Sabah**	**Brunei Darussalam**	**Mindanao**
Capital		Pontianak	Balikpapan - Bontang	Kuching	Kota Kinabalu	Bandar Seri Begawan	Davao
Population 2010	Million	4.39	9.90	2.42	3.12	0.41	21.00
Regional Office		PLN	PLN	SESCO	SEB	DES	NGCP
Area	km^2	146,760	474,422	124,450	73,619	5,770	104,630
Population density	Population per km^2	30	21	19	42	70	201
Electricity consumers	Thousand	834	2,064	549	415	100	2,715
Electrification ratio	%	76	83	91	90	99.7	71
Peak demand 2014	MW	234	847	1,251	1,051	620	1,428
Energy sold 2014	GWh	1,371	5,154	6,575	6,353	3,259	7,506
Consumption per capita	kWh per person	312	520	2,717	2,036	8,022	357

DES = Department of Electrical Services, GWh = gigawatt hour, MW = megawatt, PLN = Perusahaan Listrik Negara, NGCP = National Grid Corporation of the Philippines, SESCO = Syarikat SESCO Berhad, SEB = Sabah Electricity Sdn Bhd.
Source: Asian Development Bank.

Table 2-2 shows electricity peak demand forecasts for 2022. Northern Borneo, consisting of the Malaysian states of Sabah and Sarawak as well as Brunei Darussalam, has peak demand that is almost three times higher than those of Indonesian provinces in Kalimantan. On the other hand, the peak demand of Mindanao in the Philippines is comparable in volume to each of the key markets of Sabah, Sarawak, and Kalimantan.

Table 2-2. Peak Electricity Demand Forecast

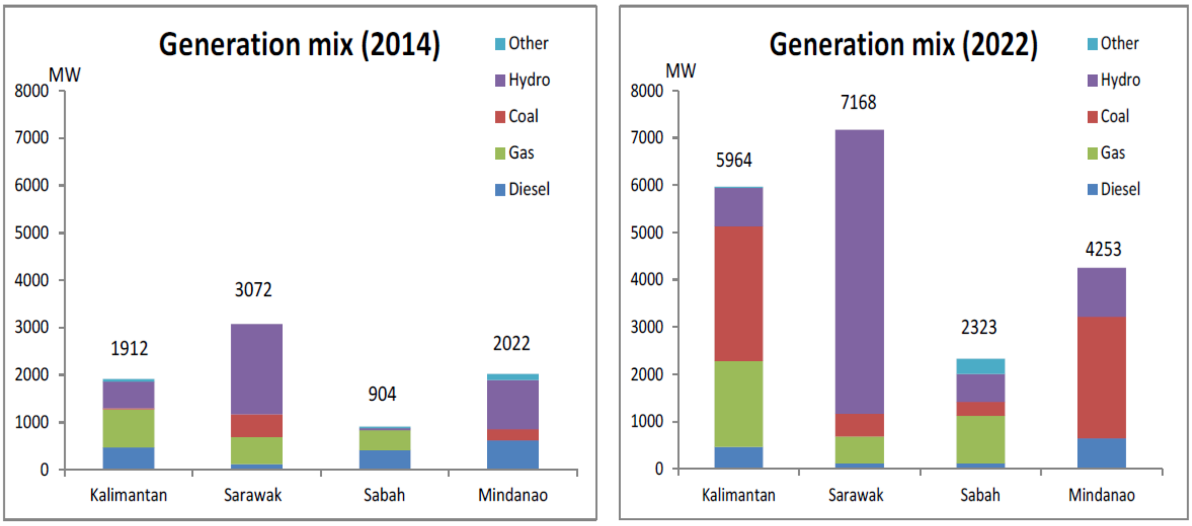
Eastern Subsystem	2013 (MW)	2022 (MW)	Average Yearly Increase (%)
West Kalimantan	234	856	7.6
Central–North–East	847	2,252	7.3
Total Kalimantan	**1,081**	**3,108**	**7.4**
Sarawak (Domestic)	1,251	1,996	4.1
Sarawak (SCORE)	2,217	3,500	10.8
Sabah	1,051	1,993	5.0
Brunei	620	1,004	5.5
Total Borneo	**6,220**	**11,601**	**7.0**
North Sulawesi	311	777	3.7
Mindanao	1,428	2,199	2.6
Philippines	11,305	16,486	2.9
Borneo + Mindanao	**7,648**	**13,800**	**6.3**

MW = megawatt, SCORE = Sarawak Corridor of Renewable Energy.
Source: Asian Development Bank.

The demand forecast also indicates the potential amount of electricity that can be integrated through power trade. The industry's rule of thumb for interconnectors is that their capacity should not exceed the size of the largest generating unit or not more than the reserve capacity which might be about 10–20 percent of peak load (ADB, 2014). This is to ensure that the importing market would continue to operate even when there had been a failure in the interconnectors.
Future demand prospects could also be driven by demand from industrial zones. In Sarawak, the Sarawak Corridor of Renewable Energy is promoting industrial development and currently attracting several energy-intensive industries. As part of its diversification policy, Brunei Darussalam is developing industrial parks that attract energy-intensive manufacturing and petrochemical industries. Sabah is also pursuing industrial investment through the Sabah Development Corridor Plan.

Figure 2-1 shows the power generation mix for the BIMP market cluster. In 2014, hydropower generation was dominant in Sarawak and Mindanao although it also had a significant share in Kalimantan. Natural gas was the main fuel for power generation in Brunei Darussalam and registered an important share in Kalimantan, Sarawak, and Sabah. The projections for 2022 show a significant increase in the share of hydropower in Sarawak while the use of coal would be increasing faster in Kalimantan and Mindanao.

Figure 2-1. Power Generation Mix



MW = megawatt.

Source: Asian Development Bank.

Borneo has significant energy resources for power generation that once developed would be sufficient to meet its long-term demand as well as demand from markets outside the island. Sarawak (Malaysia) and Kalimantan (Indonesia), with their huge hydropower and coal resources, are poised to become major power exporters in Borneo.

- Hydropower resources are abundant in Sarawak (Malaysia) and North Kalimantan (Indonesia). The hydropower potential in Sarawak is estimated to be around 20,000 MW while that in North Kalimantan is around 5,572 MW.
- Gas resources are found in Brunei Darussalam, East Kalimantan (Indonesia), and Sabah (Malaysia). Brunei's gas reserves stood at 13.8 trillion cubic feet in 2012. East Kalimantan has a liquefied natural gas facility in Bontang with a total capacity of 22.2 million metric tonnes per annum. With the non-renewal of some term contracts due to declining production, Bontang's liquefied natural gas is currently being diverted to supply the domestic market.
- Coal resources are found in East and Central Kalimantan (Indonesia) and, to some extent, in Sarawak. Kalimantan is considered to be one of Indonesia's coal-producing regions. Indonesia's measured reserves are estimated to be 12,466

million tonnes while the indicated reserves are around 20,533 million tonnes. Sarawak's coal reserves can fuel an estimated 5,000 MW of power capacity.

- Other renewable energy resources such as biomass, geothermal, solar, wind, and, to some extent, marine energy are also available in the island. These resources can be developed to augment domestic supply but not in a scale enough to support large-scale power exports.

2.2. Market Structure and Regulatory Environment

Power systems in Brunei Darussalam are managed by the Department of Electrical Services and the Berakas Power Management Company, in the Malaysian states of Sabah and Sarawak by the Sabah Electricity Sdn Bhd and the Syarikat SESCO Berhad, respectively. The power systems of the five Indonesian provinces in Borneo are managed by separate branch offices of the state-owned Perusahaan Listrik Negara. Peninsular Malaysia's power system is managed by the Tenaga Nasional Berhad while the grid network in the Philippines is managed by the National Transmission Corporation with the National Grid Corporation of the Philippines as its concessionaire.

Power industries in Borneo (Brunei Darussalam, Sabah, and the Sarawak states of Malaysia, and Kalimantan Province of Indonesia) are vertically integrated and, at the earlier stages of industry liberalisation, with limited private sector participation in generation (Table 2-3). Power systems and network operations are carried out by vertically integrated utilities and access to transmission and distribution networks are not open to independent power producers. Power sector regulations in Brunei Darussalam and Indonesia are carried out by government agencies. On the other hand, Malaysia has an independent regulatory body.

The Philippines is the only country in the BIMP region with competitive wholesale electricity market and partial retail market competition. The Philippines has an independent electricity market operator and third-party access to transmission network is allowed. Economic and technical regulations are carried out by an independent regulatory body.

Table 2-3. BIMP Power Market Structure and Regulatory Environment

Country	Market Structure	Regulatory Body	Independent Market Operator	Open Transmission
Brunei Darussalam	Single Buyer	Department of Electrical Services (government agency)	No	No
Indonesia	Single Buyer	Department of Energy and Mineral Resources (government agency)	No	No
Malaysia	Single Buyer	Energy Commission (independent body)	No	No
Philippines	Competitive	Energy Regulatory Commission (independent body)	Yes	Yes

Source: Author's compilation.

3. Power Market Integration

The overarching goal of the ASEAN market integration under APAEC 2016–2025 is to achieve energy security, accessibility, affordability, and sustainability for all ASEAN member states (ACE, 2015). These objectives are also in line with industrialised countries' objectives of promoting electricity market integration to enhance electricity supply security and promote economic efficiency (OECD/IEA, 2014; ESMAP, 2010).

Specifically, APG aims to assist the ASEAN member states in meeting increasing demand for electricity and improving access to energy services by enhancing trade in electricity across borders, optimising energy generation and development, and encouraging possible reserve sharing scheme (ASEAN Secretariat, 2011).

Based on these strategic objectives, the ASEAN Interconnection Master Plan II has identified optimal interconnection projects for all three ASEAN power market clusters: GMS power market, southern power system market, and BIMP power market (HAPUA, 2010). Results of the 2010 study have been regularly improved, updated, and reported during annual meetings of the HAPUA working committee on the APG.

3.1. Interconnection Projects

The BIMP interconnection projects that cover the intra-Borneo and inter-Borneo interconnections are summarised in Table 2-4. APG has identified six interconnection projects for the planning horizon 2016–2025: four intra-Borneo projects and two inter-Borneo projects. In 'An Evaluation of the Prospects for Interconnections among the Borneo and Mindanao Power Systems (2014)', a study by the Asian Development Bank, at least 11 interconnection projects were identified for the same time horizon. The main difference is that the ADB study included projects in the four main Indonesian provinces in Kalimantan for the intra-Borneo interconnection projects as well as other inter-Borneo interconnection projects such as Kalimantan–Java, Kalimantan–North Sulawesi, and Sabah–Mindanao interconnections.

APG classifies interconnection projects into power purchase and economic exchange (HAPUA, 2010). Power purchase is a unidirectional trade of power and refers to delivery of bulk power to load centres. Economic exchange is a bidirectional trade transaction and refers to economic operation resulting from peak load diversity, peak shaving, and sharing of spinning reserve.

In addition to the strategic objectives of interconnection, clear and specific short-term benefits justify interconnections in the BIMP region. These are:

- Interconnection provides the least-cost option for importing countries and results in lower electricity prices. For example, under the Sarawak–West Kalimantan power trade, the average cost of power generation of PLN in Kalimantan is US$0.25 per kWh while the power supplied under the trade agreement is priced at US$0.10 per kWh. This would also be the case for other power purchase interconnection arrangements such as Sarawak–Sabah and East Kalimantan–Sabah. With huge hydropower resources, Sarawak as a power exporter has the lowest average power generation cost compared with other BIMP power supply markets (Figure 2-2).

Table 2-4. BIMP Interconnection Projects

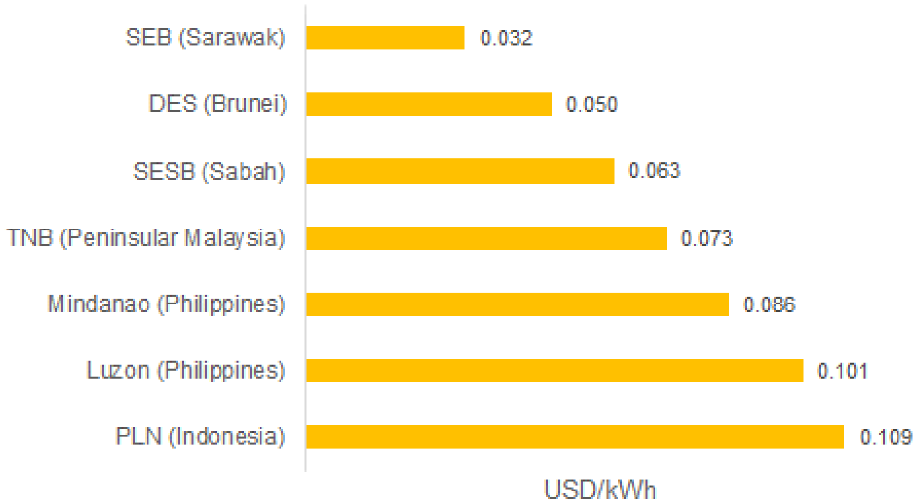
APAEC 2016–2025	Asian Development Bank Study
Sarawak–Peninsular Malaysia, 1,600 MW (2025). Power Purchase.	Sarawak–Peninsular Malaysia, 500 kV HVDC, 2,000 MW (2020)
Sarawak–West Kalimantan, 230 MW (existing). Initially power purchase, later economic exchange	Sarawak–West Kalimantan, 275 kV, 300 MW (existing)
Sarawak–Brunei, 30-100 MW (2019), 100 MW (post 2020). Economic exchange.	Sarawak–Brunei–Sabah, 275 kV, 300 MW (2016)
Sarawak–Sabah, 100 MW (2020). Power purchase.	Sarawak–Sabah, 250 HVDC, 300 MW (2025)
	Sarawak–Sabah–Luzon, 500 kV HVDC, 2000 MW (2025)
Philippines–Sabah, 500 MW (post 2020). Economic exchange.	Sabah–West Mindanao, HVDC, 600 MW (2025)
East Sabah–East Kalimantan, TBC MW (post 2020). Power purchase.	East Sabah–East Kalimantan, 275 kV, 600 MW (2020)
	West Kalimantan–South Kalimantan, 250 kV HVDC, 300 MW (2018)
	South Kalimantan–East Kalimantan, 275 kV, 600 MW (2018)
	South Kalimantan–Java, HVDC, 2,000 MW (2025)
	South Kalimantan–Northern Sulawesi, HVDC, 300 MW (2025)

Note: Power purchase refers to the delivery of bulk power from cheap energy resources to load centres. Economic exchange refers to economic operation resulting from peak load diversity, peak shaving, and sharing of spinning reserve.
Sources: ACE, P. Vongthanet, Asian Development Bank, HAPUA.

- Interconnection improves efficiency and reduces the average cost of generation. The Indonesian provinces in Kalimantan and the Malaysian state of Sabah currently use smaller and older diesel units for power generation. Interconnection will aggregate demand thus allowing utilities to invest in much bigger and more efficient systems. As a standard industry practice, sizing of power plant units are not higher than 10 percent of the peak demand (ADB, 2014).

- Interconnection also lowers reserve requirement and reduces the average cost of generation. Isolated utilities often require from 30 percent to 40 percent operating reserves while a well-interconnected grid requires only around 15 percent (ADB, 2014).

Figure 2-2. Average Power Generation Cost in BIMP (2014)



DES = Department of Electrical Services; SEB = Sarawak Energy Berhad; SESB = Sabah Electricity Sdn. Bhd; TNB = Tenaga Nasional Berhad.

Sources: SEB, SESB and TNB data - Energy Commission (2015); PLN data - PT PLN (2015); Philippine Data – Department of Energy (2015); DES data - author's estimates.

3.2. Market Coordination and Consolidation

Global experience has shown two main models in electricity market integration: consolidation of markets and system operation and coordination of system operators (OECD/IEA, 2014). Consolidation (such as the PJM[2] and MISO[3]) is the main approach in the US while coordination is the main model in Europe. Under consolidation, system operations are merged under a single entity controlling power plants over a control area. Coordination, on the other hand, coordinates neighbouring system operators and involves optimising and harmonising cross-border flows. Consolidation is most suited to real-time market integration in highly meshed networks but may not be feasible in regions where various institutional constraints and barriers exist (OECD/IEA, 2014). In this case, market coordination would be the best alternative although it requires strong coordination of electricity security regulatory frameworks.

[2] Pennsylvania-New Jersey-Maryland Interconnection
[3] Midcontinent Independent System Operator

At present, consolidation of power system operations in Borneo alone would not be possible politically. Coordination of system operation is, therefore, the most practical approach in the short-term for the BIMP region since power trade can be initiated without the need to introduce power sector reforms to modify national market structures and regulatory environment.

At the APG level, market consolidation could, however, be the target power arrangement for each market cluster in the long term (OECD/IEA, 2014). For example, the GMS power market cluster has outlined the evolution of the regional power market integration in the GMS power trade and interconnection road map[4]. The medium-term goal is to transform the regional market into a coordinated market structure but the long-term target is to develop a consolidated market arrangement.

At the ASEAN level, market integration could evolve first among countries within a cluster but two or more clusters could potentially converge in due course. This appears to be the case for the GMS market cluster and the southern market cluster with Lao PDR, Thailand, Malaysia, Singapore planning to pilot power integration project. The southern cluster would also be interconnected with the BIMP market cluster through the proposed Peninsular Malaysia and Sarawak interconnection. Market integration within each cluster of APG could evolve into either coordinated or consolidated market system. Integration of the three market clusters at the APG level could, however, progress toward a coordinated market system (OECD/IEA, 2015).

3.3. Coordination Arrangements

Various coordination models exist under a market integration framework. Coordination arrangements in liberalised European electricity markets are much more complex than what would be needed in a set of countries with vertically integrated power market structure.

At the ASEAN level, several trading arrangement models could be pursued given that most countries have different power market structures and objectives for power trade (OECD/IEA, 2015). Similarly, several coordination modalities in the BIMP region have been identified and could form part of the overall pathway for market integration.

- **Unidirectional trade.** The first intra-Borneo power trade is a unidirectional trade between utilities of Malaysia (SESCO) and Indonesia (PLN). PLN purchases 50 MW from SESCO during Phase 1 (first 5 years) on take-or-pay basis and 180 MW under a take-and-pay contract while Phase 2 of the contract stipulates 230 MW maximum capacity purchases (ADB, 2015). All contracted capacities are from hydropower plants. The border between the two countries is the point of interconnection. Each utility is responsible for the construction of the 275-kV transmission line and substations in each side of the border. Other

[4] The first phase is the development of bilateral trade between pair of countries, the second phase is the third-party access to transmission facilities, the third phase is the development of a regional backbone with multiple buyers–sellers entering cross-border transactions, and the fourth phase is the development of a regional competitive market (Zhai, 2010).

interconnection projects identified in APG that could constitute unidirectional trade include the Sarawak–Peninsular Malaysia, the Sarawak–Sabah, and the East Sabah–East Kalimantan projects (HAPUA, 2015).

- **Bidirectional power transactions**. These refer to the economic exchange arrangement described in AIMS II[5]. Under this trade model, two countries can trade excess capacity or take advantage of inter-temporal cost differences (OECD/IEA, 2015; HAPUA, 2010). Economic exchange may also include short-term transactions and support services during emergencies. Interconnections envisaged to have this type of trade arrangement are the Sarawak–Brunei and the Philippines–Sabah projects, and the eventual trading arrangement between Sarawak and West Kalimantan.
- **Power purchase from an independent power producer (IPP*).*** This trading arrangement is common in the GMS power market cluster. Under this model, a national utility can purchase power from an IPP operating in a neighbouring country. In the BIMP power market, so far, only one interconnection project—the East Sabah–East Kalimantan interconnection—has been identified to have this type of trading agreement. At present, PLN and SESB have a memorandum of understanding with a coal-fired power station IPP for the latter to supply power to Sabah and East Kalimantan (ADB, 2014).
- **Third-party access.** This trading arrangement has not been specified in the APG Master Plan, but the ADB study (2014) on BIMP interconnection has identified the possible evolution of the Sarawak–Brunei–Sabah interconnection into this model. In selling power to Sabah, Sarawak could wheel power through the existing Brunei network instead of investing on dedicated infrastructure linking the two Malaysian states. Brunei will be compensated through wheeling charges. With the transmission infrastructure, Brunei may also sell its excess power to Sabah.
- **Multi-buyer, multi-seller market.** In the long term, a multilateral market system would probably evolve in the BIMP power market once the regional transmission network had been established. This model allows trading between countries irrespective of their market arrangements. A subregional multilateral market system with liberalised electricity markets would be more complex, such as the case of the EU, than market systems with vertically integrated structure, such as the case of the BIMP region. Since there is no long-term power liberalisation plans for power markets in Borneo, the long-term market integration structure envisaged for the BIMP region could perhaps be a multilateral market system for countries or territories with disparate power industry structures (competitive market in the Philippines and vertically integrated power utilities in Borneo).

[5] ASEAN Interconnection Master Plan Studies.

4. Harmonisation of Power Systems

At the proposed levels of integration and the current structure of national electricity markets, technical harmonisation requirements for the BIMP region would be much simpler compared with the liberalised and competitive electricity markets in Europe.

Utilities in Borneo are using the conventional 50-Hz high-voltage alternating current (HVAC) based on the UK (Malaysia) or European (Indonesia) standards. Brunei Darussalam is currently upgrading its high-voltage network to 275-kV AC in anticipation of the power exchange between Sarawak and Sabah. Sarawak, on the other hand, is also building a 500-kV AC network in preparation for the expected power interconnection that would initially be operated at 275 kV.

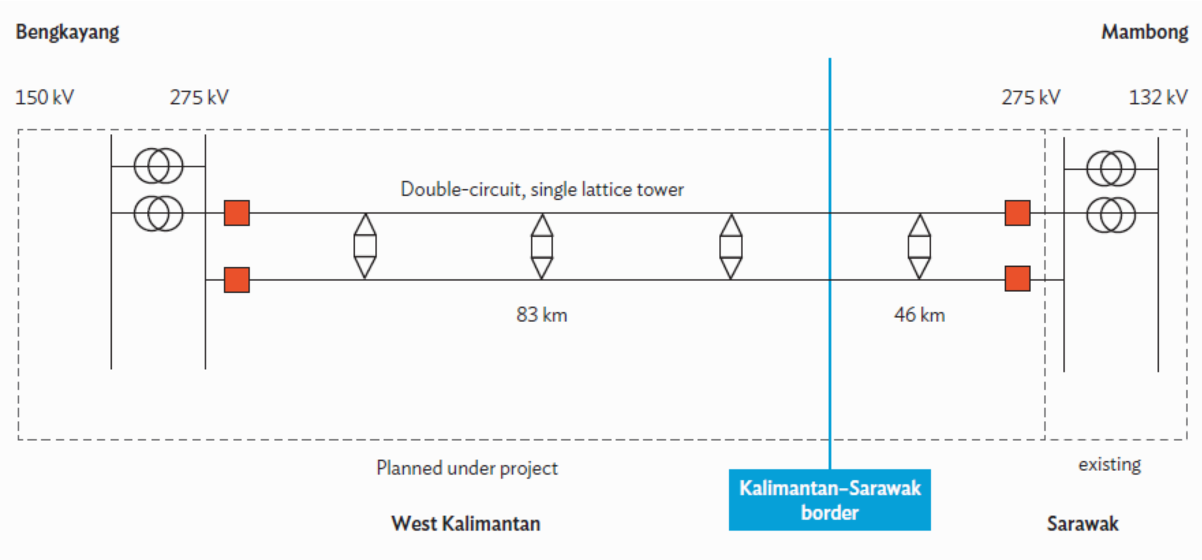
Interconnectors in the Kalimantan side are, however, based on PLN's sub-transmission standard of 150-kV AC, a voltage level that may not be appropriate for inter-provincial transmission lines. ADB (2014) is proposing to develop a 275-kV AC line connecting South Kalimantan to East Kalimantan (Eastern Corridor) to accommodate bigger load in the future. On the other hand, ADB (2014) is also proposing to change the planned 150-kV AC transmission line connecting West Kalimantan to South Kalimantan with HVDC-VSC [6] monopole link to accommodate future power exchange between Kalimantan and Sarawak. The existing interconnection between Sarawak and West Kalimantan is based on 275-kV AC (Figure 2-3).

The inter-Borneo interconnections are being planned using a 500-kV HVDC technology. In the case of Sabah–Philippines interconnection, where Sabah is operating at 50 Hz while the Philippines is at 60 Hz, the HVDC system will act as a buffer, isolating one system from the other and allowing each to operate independently (ADB, 2014).

According to ADB (2014), based on the planned intra- and inter-Borneo interconnections, no significant harmonisation issues need to be addressed. Definitely, technical issues may be encountered for long-distance transmission lines, but the voltage and stability issues can be properly addressed by technical studies.

[6] Voltage source converters (VSC).

Figure 2-3. 275-kV AC Sarawak–West Kalimantan Interconnection



HVTL = high voltage transmission line, km = kilometre, kV = kilovolt.
Source: Asian Development Bank.

5. Market Integration Road Map

The BIMP region is at a certain stage of power market integration. The market integration process at the subregional level is relatively slow and depends on the economic, technical, and political circumstances of electricity-trading countries. Based on the market coordination arrangements described earlier, this section attempts to outline a road map that characterises current as well as programmed developments (both technical and institutional) to realise a greater sub-regional market integration and to maximise the benefits of developing energy resources for power generation in the region.

As presented earlier, the long-term market integration arrangement for the BIMP region could be a multi-buyer, multi-seller market system for power systems with disparate industry structures. The section outlines the intermediate stages to reach this long-term market trading arrangement. Each stage is not time-bounded and stages may overlap each other.

Stage 1. Incremental development of regional transmission backbone infrastructure

The idea of power trade has been recognised by the BIMP countries since the first APG Master Plan in the 1990s. Power exchange has been considered in the long-term power and transmission development plans in some countries in the region. With power interconnection at the backdrop, countries have independently planned for developing a regional backbone that could optimise the use of regional energy resources and reduce reserve capacity requirements.

- Brunei Darussalam has upgraded its transmission network and started constructing a 275-kV transmission line (to be operated initially at 66 kV) in anticipation of the upcoming power exchange with Sarawak and potential wheeling of power from Sarawak to Sabah.
- SESCO has also started building a 500-kV backbone system (to be operated initially at 275 kV) to aggregate demand in the SCORE corridor. This network could be extended to Sabah in the future (without passing through Brunei) and perhaps toward Luzon in the Philippines. The line could also be used by PLN to transmit power to SCORE from a mine-mouth coal-fired power plant to be potentially constructed near the border between the two countries.
- PLN is planning to complement the recently completed Sarawak–West Kalimantan 275-kV transmission line by considering a loop that could complete a 275-kV ring around Borneo. This includes an HVDC link between West Kalimantan and South Kalimantan, a 275-kV line connecting South Kalimantan with East Kalimantan, and another 275-kV line that would connect East Kalimantan to North Kalimantan and all the way to Sabah.

Stage 2. Incremental intra-Borneo power trade based on projects with mutual benefits

The second stage will consist of trade arrangements, either power purchase or economic exchange, between two countries based on projects that generate mutual benefits. This includes the following:

- The recently completed 275-kV interconnection between Sarawak and West Kalimantan facilitating a power purchase by PLN of around 300 MW from SESCO. This would be converted to an economic exchange arrangement once PLN in Kalimantan is able to develop competitive power generation projects based on coal and natural gas.

- All intra-Borneo power purchase or economic exchange arrangements identified under the APG or the ADB study such as the Sarawak–Brunei, Sarawak–Sabah and East Kalimantan–Sabah interconnections.

- Power exchange between Sarawak and Sabah through Brunei transmission network. Brunei's benefits include wheeling charges, access to supply sources from the east and west as well as lower reserve requirements. Sarawak and Sabah may also access the fast-acting gas turbine spinning reserve in Brunei Darussalam.

Stage 3. Incremental inter-Borneo trade arrangements

Stage 3 will consist of all inter-Borneo power interconnections. The inter-Borneo interconnections would represent greater development of energy resources for power generation and accessing electricity markets outside Borneo. This includes the following trade arrangements[7]:

[7] Transfer capacities are estimated by ADB (2014). Power exports are set to be high to justify high cost of interconnection but not to exceed 10 percent of demand of the importing grid.

- Sarawak–Sabah–Philippines. These interconnections would be mainly supported by hydropower supply from Sarawak.
    i. Sabah–Luzon, 500-kV HVDC, 2,000 MW;
    ii. Sabah–Mindanao, 500-kV HVDC, 600 MW.
- Kalimantan–Indonesian Provinces. These interconnections would be supplied by gas-fired and coal-fired power generation in Kalimantan.
    i. South Kalimantan–Java, 500-kV HVDC, 2,000 MW.
    ii. East Kalimantan–North Sulawesi, 500-kV, 300 MW.
- BIMP power market cluster – Southern power market cluster. This will be mainly based on hydropower resources from Sarawak.
    i. Sarawak–Peninsular Malaysia, 500-kV HVDC, 2,000 MW
    ii. Sarawak–Peninsular Malaysia– other load centres in southern power market cluster

Stage 4. Establishment of multi-buyer and multi-seller market

This stage would be attained when a significant number of intra- and inter-Borneo trade arrangements had been achieved and when the regional infrastructure had been established. As presented earlier, this trading arrangement would be for utilities operating under disparate industry structures.

In previous stages, coordination would be mainly done by trading countries or utilities. In this stage, an independent cross-market operator needs to be established (OECD/IEA, 2015). This operator would be responsible for monitoring and management of electricity trade and would act as platform for connecting buyers and sellers. The establishment and the status of this body could be decided in a later stage but could be supervised through HAPUA.

Establishing an independent cross-market operator needs stronger commitments and greater cooperation from BIMP countries. Under stage 1, investment commitments to develop a regional backbone at their territories will mainly come from individual countries; in stages 2 and 3, investment commitments and cooperation would be carried out by trading parties; stage 4 requires multilateral investment commitments and greater cooperation since some of the functions of the national system operators could be assumed by the cross-market operator.

6. Conclusion

BIMP contains significant energy resources that could be developed to stimulate economic growth and development in the region. However, these resources are unevenly distributed. The current supply and demand imbalances create opportunities for trade and initiate power market integration at the subregional level. In the long-term, Malaysia's Sarawak and

Indonesia's Kalimantan could emerge as major power exporters in Borneo. Full development of the BIMP energy resources, however, would only be realised once the BIMP power market cluster is fully integrated in the much broader ASEAN power markets.

Power market integration can be initiated despite the disparity of electricity industry structures and regulatory frameworks between trading countries. Among the approaches for market integration, coordination of power system operators would be the most practical and appropriate for the BIMP power market cluster rather than consolidation of power market and power system operators.

Given the power industry structures and regulatory environment of the BIMP countries, the coordination models that could be applied include i) unidirectional trade, ii) bidirectional power transactions, iii) power purchase from IPP, iv) third-party access, and v) multi-buyer multi-seller market. The interconnection projects and planned power exchanges identified under APG for the BIMP market cluster could be characterised according to these coordination arrangements.

To fully realise the region's economic benefits from developing its energy resources for power generation, this paper outlines a road map for power market integration in the BIMP region. This proposed road map serves as the recommendation to governments in the region on how to proceed with regional power interconnections to achieve greater power market integration. The road map is divided into four stages of development.

- Stage 1. Incremental development of regional transmission backbone infrastructure;
- Stage 2. Incremental intra-Borneo power trade based on projects with mutual benefits;
- Stage 3. Incremental inter-Borneo trade arrangements; and
- Stage 4. Establishment of a multi-buyer, multi-seller regional power market.

The implementation of the road map requires individual country investment commitments. Stage 1 investments would be implemented by each of the countries in their territories. Investments under stage 2 and stage 3 would be carried out by trading parties. Stage 4 requires cooperation commitments from the BIMP countries since the establishment of a multi-buyer, multi-seller market requires multilateral financing and that some of the functions of the national system operators would be transferred to the cross-border market operator.

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Chapter 3

Business Model and Market Design for ASEAN Electricity Market Integration: Principles, Practicalities, and Conditions for Success

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Choo Fook Hoong

Swati Sharma

Since the announced construction of an integrated ASEAN Power Grid (APG) almost 2 decades ago, progress in this ambitious project has been slow. Coincidentally, a similar programme in the European Union (EU) has been fully embraced and has moved well ahead that of the Association of Southeast Asian Nations (ASEAN). As the EU has the most integrated electricity market at present, its experience and lessons on electricity market integration have important implications for ASEAN. This chapter aims to investigate the barriers, especially institutional and political barriers, to electricity market integration in ASEAN. It also discusses practical policy options to accelerate market integration in the ASEAN power sector and the most significant aspects of design, including market coupling arrangements and algorithms, congestion management and capacity auction methods, coordination mechanism and relevant network code among transmission system operators (TSOs) for grid balancing, and auxiliary services and compensation for such services. This chapter discusses these issues by referencing the Nordic and European experiences. Major standing problems and challenges of the European electricity market model are also briefly discussed.

1. Background

At present, the European electricity market liberalisation represents the world's most extensive cross-jurisdiction reform of the electricity sector, involving integration of distinct state-level or national electricity markets (Jamasb and Pollitt, 2005). The energy market liberalisation process in Europe has always focused on electricity market integration and related cross-border issues. The vision of the European Union (EU) was based on an aspiration to create an integrated energy market that ensures cost-effective, secure, and affordable electricity supplies to EU citizens. Over the last two decades, Europe's energy policy has consistently been geared toward producing affordable and competitively priced, environmentally sustainable, and secure energy for everybody in the EU. In 2011, the heads of European states or governments recognised the importance of an internal energy market and set a clear deadline for its completion by 2014, underlining the endeavour that no EU member state should remain isolated from the European gas and electricity networks after 2015 (European Commission, 2012).

It is not difficult to visualise how the intended integrated electricity market would make it possible to produce energy in one EU country and deliver it to consumers in another through common energy market rules and cross-border infrastructure. Additionally, this process intends to keep electricity prices in check by creating competition and giving consumers choices of their energy supplier.

2. History of Development

Europe took the very early steps of market liberalisation more than two decades ago when nine of its member states signed The Single European Act on 17 February 1986, with an aim of creating a single European market (internal) by 1992. The actual liberalisation process, however, started in 1997 with the adoption of Directive 96/92/EC, which defined common rules for the gradual liberalisation of the electricity industry within the scope of the concept of a unique European market as later defined in 1985 (Boisseleau, 2004).

In a nutshell, the ultimate objective of the directive was to create one common European electricity market and increase transmission capacity between regional electricity grids. Previous studies have argued about an understandable consensus of the highest priority to 'encourage cross-border trade' and 'eliminate discriminatory practices' without going much further in details of market design (Boisseleau, 2004). However, the lack of common guidelines on market design, arrangement, and institutions needed to create an integrated market led to a wide range of trading arrangements in each member state.

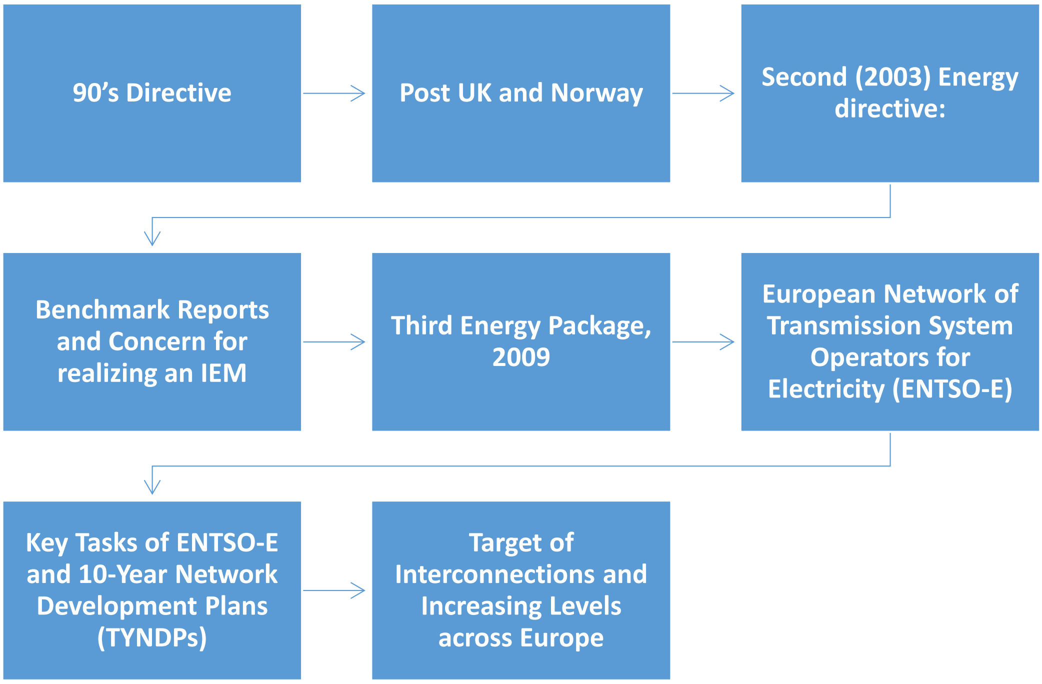
To this end, the liberalisation of electricity market in Europe started with the UK in 1998 when it stepwise opened an electricity market aimed at giving consumers full choice of suppliers. The two kinds of market that emerged were power pools and exchanges. Power pools were public or government initiative for electricity trading that required mandatory participation by all members. Exchanges, on the other hand, were created with an organised market of generators, distributors, and traders as voluntary participants.

Thus, during the liberalisation process in the UK, power pools were expected to stimulate competition in the wholesale market by defining clearing prices on the basis of supply bids and demand forecasts by the National Grid[1]. Replacing the old pool model, the New Electricity Trading Arrangements was established in 2001 and consisted of four voluntary markets: a bilateral market for long-term transactions, a forward market for standardised products, a

[1] The National Grid was owned by twelve regional electricity companies created as a result of reorganisation of area boards.

spot market, and a reserve market. The establishment of this system contributed to a fall in electricity prices for consumers from 2001 to 2004, although prices started rising again in 2005 due to other certain reasons. With the trading arrangements extended to include the Scottish market in 2005 and the British Electricity Trading and Transmission Arrangements recently, the entire UK is now coordinated by one wholesale market (Weight, 2009).

Figure 3.1: Chronology of Events – History of Market Development



IEM = Internal Energy Market, UK = United Kingdom.
Source: Authors.

The Norwegian market was the second to be fully liberalised in Europe (Weight, 2009) in a process that included both reforms and restructuring. While the core element of reform was a decentralised free trade approach, the restructuring included the transfer of the transmission system from a state-owned company (Statkraft) to a new state-owned company (Statnett) while the remaining generation facilities were reorganised to stay with the former. Other substantial reforms included the introduction of a common carrier approach and grid access for third parties, retail liberalisation, and the establishment of voluntary wholesale markets. What made the Norwegian market liberalisation process different from the UK's was the presence of a spot market even before liberalisation. This market was established to facilitate better management of the occasional source of the country's large hydro-generation capacities. In addition, the post-liberalisation spot market Nordpool was opened to allow long-term transactions for market participants.

Again, unlike in the UK, the liberalisation process in the Norwegian market focused on creating market competitions through structural reforms, ownership being a petty concern under the strategy adopted: public ownership of generation facilities remained and generation and supply were not separated. A common Nordic market was formed when other Nordic countries integrated their electricity sectors into one. Sweden joined in 1996, Finland in 1998, Western Denmark in 1999, and Eastern Denmark in 2000. Nordpool was jointly owned by the transmission system operators (TSOs) of the participating Nordic countries: Energinet (Denmark), Fingrid (Finland), Statnett (Norway), and Svenska Kraftnät (Sweden).

The Nordic market was the first to introduce a combination of energy and transmission capacity auctioning. Elspot, a day-ahead cornerstone market in Nordpool, takes care of auctions on a daily basis. Hourly supply and demand bids for the next day are aggregated and matched, generating a market clearing price or system price. If there is no transmission congestion, electricity is traded at system price (Fridolfsson and Tangerås, 2008).

In case of a cross-border congestion signal by a TSO, the bids in the market are allocated to several congestion areas predefined by country borders (in the case of Norway, up to four congestion areas or zones). A different price, called zonal price, is defined for each area or zone although it differs in countries. In the case of Sweden, prices are not allowed to differ in different regions, and holdups are handled by countertrading and/or re-dispatching of power plants). Transmission from one area to another is priced with the difference of the area prices. Congestion within one area is managed through countertrading and re-dispatching of power plants. The resulting congestion rent is split between TSOs.

As evident in both cases, early reforms in the electricity market of Europe in the 1990s included liberalisation, privatisation, and restructuring of the energy supply and distribution industry. The EU has since then been actively engaged in developing a strategic policy for the development of a truly competitive, single, and integrated European electricity and gas market that is expected to open competition among Europe-wide companies. The EU's reform process was mostly dependent on the driving force of the European Commission (EC).

Reform after the directive of the 1990s ran on two parallel tracks. First, under the EU Electricity Market Directives, member countries were required to take at least a minimum set of steps by certain key dates to liberalise their national markets, e.g. determine TSOs and distribution system operators (DSOs) responsible for operating, ensuring the maintenance of, and developing the transmission system in a given area and its interconnection with other systems to guarantee security of supply. Second, EC promoted efforts to improve interfaces between national markets by improving rules on cross-border trading and expanding cross-border transmission links (Tooraj and Pollitt, 2005).

It is important to note that the EU Electricity Market Directives of 1996 and 2003 were focused on unbundling the industry and gradually opening national markets. Over the years, several energy market laws have been adopted and efforts have gradually been shifted from energy market liberalisation to energy market integration.

A particular concern among policy makers related to the realisation of an integrated internal energy market (IEM) was regarding insufficient cross-border capacity and partly inefficient allocation mechanism. The Trans-European Energy Networks Program (TEN-E) started the liberalisation process. As the first directive did not address the issue of cross-border trade, Regulation 1228/2003 and Directive 2003/54/EC were issued to provide a framework for cross-border trade and establish more consistent trading.

While the common rules introduced by the first directive were clearly not effective enough to realise a single IEM, the second EU directive sought to further stimulate competition by fortifying regulation of access to networks and requiring the participation of independent regulators. Regulation of cross-border trade was aimed at facilitating market integration. The second directive's major objectives were (i) the unbundling of TSOs and DSOs from the rest of the industry, (ii) free entry to generation, (iii) monitoring of supply competition, (iv) full market opening, (v) promotion of renewable sources, (vi) strengthening the role of regulators, and (vii) a single European market (Tooraj and Pollitt, 2005).

TEN-E and Regulation 1228/2003 somehow built a framework for cross-border development. Considering interconnection, inter-operability, and development of trans-European networks for transporting energy (electricity and gas) as essential for effective operation of the internal energy market, TEN-E enumerated bottlenecks in need of clearing, provided co-financing of feasibility studies (around 50 percent of budget) (Meuss et al., 2005), and, to some extent, co-financed actual grid investment. The list was revised in 1997, 1999, and 2003. As required by Regulation 1228/2003, revenues from interconnections capacity allocations, called congestion revenues, were to be used for (1) guaranteeing the availability of capacity, (2) network investments, or (3) reducing network tariffs (Weigt, 2009).

Additionally, Directive 2003/54/EC required the member states to open their electricity markets and guarantee non-discriminatory network access to third parties while Directive 2009/72/EC put wider emphasis on cross-border interconnections and the need to mitigate barriers to cross-border trade. As a result, electricity markets across Europe experienced liberalisation, privatisation, and price deregulation in a bid to meet the energy policy goals and targets of sustainability, affordability, and security of supply.

The fourth benchmark report of EC in 2005 concluded that although states were moving in the right direction, some were rather slow in doing so, and eight of them received a warning from the commission. The 2005 report also found that although the market-based allocation of cross-border capacities should have been in place in 2004, 13 of the 25 most-congested connections had none of it (Meuss et al., 2005).

The benchmark report of EC in 2007 concluded that despite encouraging improvements, particularly in cross-border coordination, major barriers to achieving a single IEM still existed, including implementation of European legislation (which was insufficient), empowerment of national regulators, harmonisation of regulatory practices, and regulation of energy prices.

The latest in a row of EU energy market legislation, known as the third package, has been enacted to improve the functioning of IEM and resolve structural problems. The EU's Third Energy Package was proposed by the European Commission in September 2007, adopted by the European Parliament and the Council of the European Union in July 2009, and entered into force in September 2009.

To date, one of the biggest achievements in establishing an IEM has been the founding of the European Network of Transmission System Operators for Electricity (ENTSO-E). ENTSO-E, established and given legal mandates by the EU's Third Legislative Package, represents 41 electricity TSOs from 34 countries across Europe (Table 3.1).

With the key objective of supporting the implementation of the EU's energy policy by promoting closer cooperation across Europe's TSOs, ENTSO-E focuses in the areas of security of supply, standardised market integration, and sustainability. It pursues coordinated, reliable, and secure operations of the interconnected electricity transmission network and is tasked to promote completion of IEM in electricity and cross-border trade by providing standardised market integration frameworks that could be useful in facilitating competitive and integrated central wholesale and retail markets. Furthermore, the secure integration of renewable energy sources such as wind and solar power into the power system to reduce the EU's greenhouse gas emissions is one of the major tasks it pursues under the area of sustainability.

ENTSO-E contributes to the achievement of said objectives primarily through drafting of network codes, development of ten-year network development plans, technical cooperation between TSOs, publication of summer and winter outlook reports for electricity generation, and coordination of R&D plans.

Considering that interconnections play an important role in establishing IEM and for every country benefitting from such connections, it is essential to maintain a high level of exchange capacity (maximum instantaneous electrical power that can be imported or exported between two electricity systems while maintaining the security criteria of each of the systems). In this respect, the EU recommends that the minimum interconnection capacity between countries should represent at least 10 percent of the installed generation capacity in each one of them.[2]

The European Union Package 2015 again cited the urgency of achieving interconnection level target (Energy Union Package, 2015), recognising security of supply, affordable prices in the internal market, sustainable development, and decarbonised energy mix as benefits of an interconnected energy system.

[2] In 2002, the European Council agreed on the 'target for Member States of a level of electricity interconnections equivalent to at least 10 percent of their installed production capacity by 2005'. The target was reiterated by the European Council in October 2014 for 'all Member States to achieve interconnection of at least 10 percent of their installed electricity production capacity by 2020' (Barcelona European Council, 2002; European Commission, 2015)

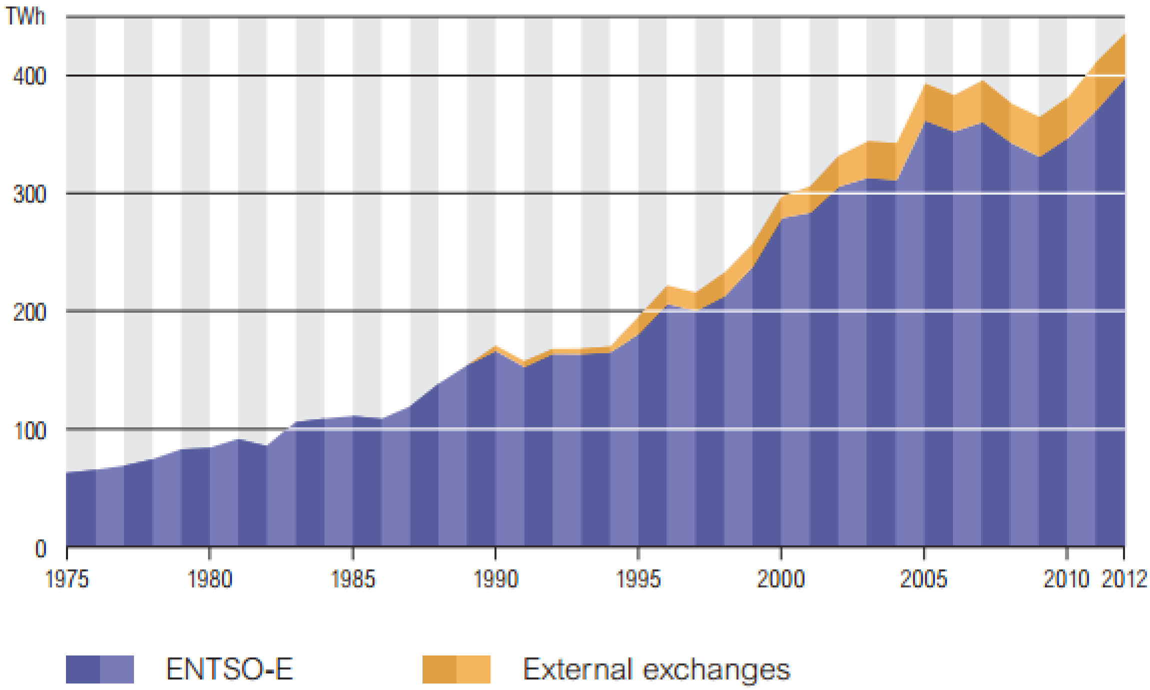
Table 3.1. TSOs Across the European Network of 34 Countries

Country	Company
Austria (AT)	Austrian Power Grid AG Vorarlberger Übertragungsnetz GmbH
Bosnia and Herzegovina (BA)	Nezavisni operator sustava u Bosni i Hercegovini
Belgium (BE)	Elia System Operator SA
Bulgaria (BG)	Electroenergien Sistemen Operator EAD
Switzerland (CH)	Swissgrid ag
Cyprus (CY)	Cyprus Transmission System Operator
Czech Republic (CZ)	ČEPS a.s
Germany (DE)	TransnetBW GmbH, TenneT TSO GmbH, Amprion GmbH and 50Hertz Transmission GmbH
Denmark (DK)	Energinet.dk
Estonia (EE)	Elering AS
Spain (ES)	Red Eléctrica de España S.A.
Finland (FI)	Fingrid OyJ
France (FR)	Réseau de Transport d'Electricité
United Kingdom (GB)	National Grid Electricity Transmission plc, System Operator for Northern Ireland Ltd, Scottish Hydro Electric Transmission Limited and Scottish Power Transmission plc
Greece (GR)	Independent Power Transmission Operator S.A.
Croatia (HR)	Croatian Transmission System Operator Ltd.
Hungary (HU)	MAVIR Magyar Villamosenergia-ipari Átviteli Rendszerirányító Zártkörűen Működő Részvénytársaság
Ireland (IE)	EirGrid plc
Iceland (IS)	Landsnet hf
Italy (IT)	Terna - Rete Elettrica Nazionale SpA
Lithuania (LT)	Litgrid AB
Luxembourg (LU)	Creos Luxembourg S.A.
Latvia (LV)	AS Augstsprieguma tīkls
Montenegro (ME)	Crnogorski elektroprenosni sistem AD
FYR of Macedonia (MK)	Macedonian Transmission System Operator AD
Netherlands (NL)	TenneT TSO B.V.
Norway (NO)	Statnett SF
Poland (PL)	PSE S.A.
Portugal (PT)	Rede Eléctrica Nacional, S.A
Romania (RO)	C.N. Transelectrica S.A
Serbia (RS)	JP Elektromreža Srbije
Sweden (SE)	Svenska Kraftnät
Slovenia (SI)	Elektro Slovenija, d.o.o.
Slovak Republic (SK)	Slovenska elektrizacna prenosova sustava, a.s.
Observer Member	
Turkey (TK)	TEIAS

Source: ENTSO-E.

It is important to note that cross-border exchanges have increased prominently since the end of the 1990s with the start of the market opening process (Figure 3.2). Since the establishment of ENTSO-E, however, a substantial growth of around 23 percent has been achieved in five years (2010–2014) as compared to the 16 percent rise in the previous decade (2000–2010) (Figure 3.3).

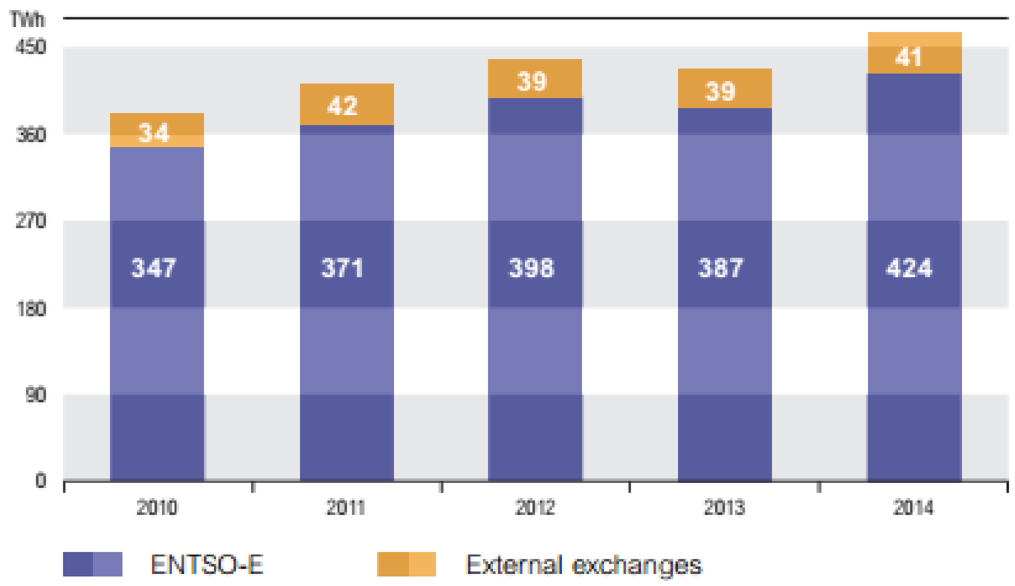
Figure 3.1. Development of Overall Cross-border Exchanges of ENTSO-E Member Countries Since 1975



Source: ENTSO-E, Memo 2012.

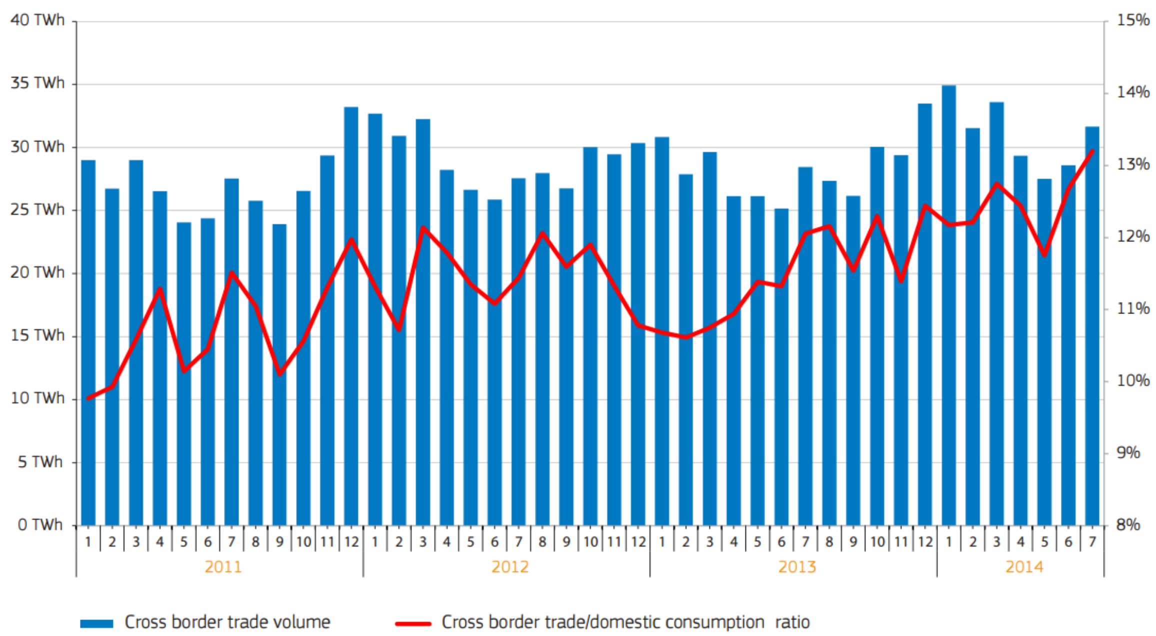
Monthly cross-border physical power flows across the EU in May–July 2014 reached an average 29.3 TWh, 10 percent higher than in the same period of 2013. Electricity consumption only slightly increased (by 1.6 percent) in May–July 2014 compared to the same months of 2013, while the combined traded volume of power increased by 3.3 percent on the major electricity trading platforms in the EU (ENTSO-E, 2014). In 2014, 10 countries within the ENTSO-E perimeter exported more than 10 percent of their annual national generated power to neighbouring countries. Thirteen other countries of ENTSO-E imported more than 10 percent of their annual internal electricity consumption from other ENTSO-E countries. The ratio of cross-border physical flows and electricity consumption in the EU reached 13.2 percent in July 2014, the highest in the last four years (Figure 3.4). The increase in cross-border physical flows outnumbered both the increase in electricity consumption and traded volume of power, pointing to improving liquidity, growing interdependency, and further integration of electricity markets in the EU.

Figure 3.3. Development of Overall Cross-border Exchanges of ENTSO-E Member Countries



As in 2013, exports from countries along the North–East to South–West axis increased and were related to an energy mix based on hydropower, coal, and renewables.

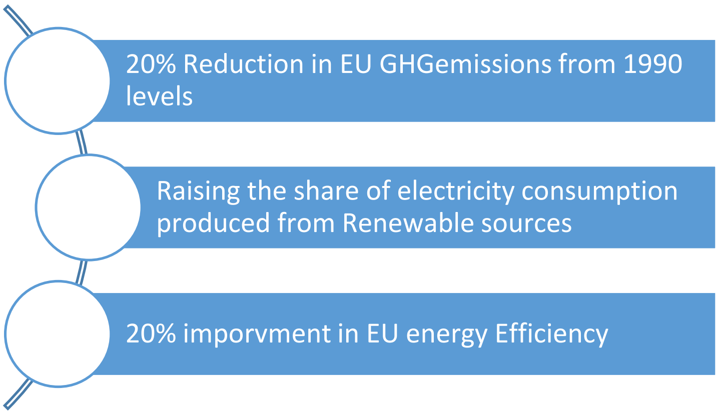
Figure 3.4. Monthly Volume of Cross-Border Trade of Electricity and its Ration with Consumption



3. Legislative and Regulatory Framework

In March 2007, a commitment by EU leaders to the 2020 energy objectives came as a turning point for the European power systems and all market participants. As closer cooperation of transmission grid operators was needed to ensure security of supply, the completion of IEM, and significant increase in power generation from renewable energy sources (Figure 3.5), a set of new directives and regulations, called the Third Energy Package, was adopted in 2009. This package, was created the ENTSOs for gas and electricity (i.e. ENTSO-E and ENTSO-G) and the Agency for the Cooperation of Energy Regulators (ACER).

Figure 3.5. EU Energy Objectives 2020



Source: Authors.

3.1 The Third Energy Package 2009

The Third Energy Package, ratified to improve the functioning of IEM and resolve structural problems, is a set of two European directives and three regulations:

- Common Rules for the Internal Market in Electricity Directive (2009/72/EC)
- Common Rules for the Internal Market in Natural Gas Directive (2009/73/EC)
- Regulation Establishing an Agency for the Cooperation of Energy Regulators (713/2009/EC)
- Regulation on Conditions for Access to the Network for Cross-Border Exchanges in Electricity (714/2009/EC)
- Regulation on Conditions for Access to the Natural Gas Transmission Networks (715/2009/EC).

These regulations set out ENTSO-E's responsibilities in enhancing the cooperation between its 41 member TSOs across the EU to assist in the development of a pan-European electricity transmission network in line with the EU's energy policy goals. The Third Energy Package covers five main areas:

Table 3.2. Three Recommended Options of Unbundling

Ownership unbundling	No majority stake of production/supply company in TSO
Independent system operator	Can formally own electricity transmission networks in cases where entire operation, maintenance, and investment in the grid are being done by an independent company
Independent transmission system operator	An independent transmission system operator in cases where energy supply company still owns and operates gas or electricity networks

Source: Compiled from various public domains

Unbundling: unbundling aims to separate energy supply and generation from the operation of transmission networks to facilitate fair competition in the market (Table 3.2).

Strengthening the independence of regulators: The Third Energy Package requires regulators to be free from both industry and government interests. Regulators hold the power to impose penalties upon non-compliant companies. Electricity generators, gas network operators, and energy suppliers are required to provide precise data to regulators, while regulators have a mandate to cooperate with each other across all EU countries.

Establishment of ACER: Tasked to ensure a smooth functioning of internal energy market, ACER is involved in (1) drafting guidelines for the operation of cross-border electricity networks, (2) reviewing the implementation of EU-wide network development plans, (3) coordinating with national regulators, and (4) monitoring internal market functioning.

Cross-border cooperation: The Third Energy Package ensures a smooth transportation of electricity across borders and optimal management of EU networks through ENTSO-E and the European Network for Transmission System Operators for Gas (ENTSO-G).

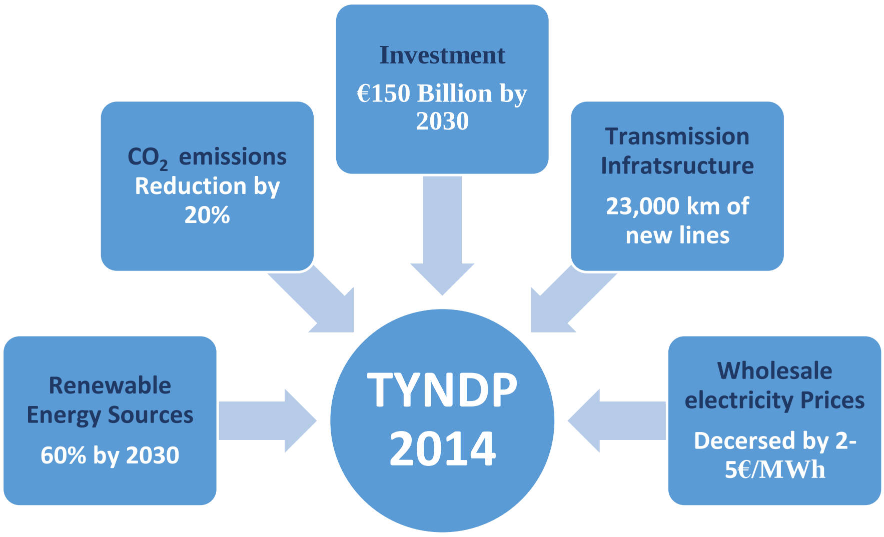
Transparency in retail markets to benefit consumers: The Third Energy Package empowers European energy consumers to choose or change suppliers without extra charges, receive information on energy consumption, and quickly and cheaply resolve disputes.

3.2 Ten-Year Network Development Plan (TYNDP)

The prime objective of TYNDP is to ensure transparency with regards to the electricity transmission network and support decision-making processes at regional and European levels. To this end, TYNDP aims to ensure electricity transmission infrastructure investments across 34 European countries. TYNDP is a non-binding plan, meant to be updated every 2 years. The pilot TYNDP was published in 2010, followed by successive versions in 2012 and 2014.

TYNDP 2014 (Figure 3.6) proposes the integration of up to 60 percent of renewable energy by 2030 by strengthening Europe's electricity power grid. This integration aims to achieve cost efficiency and energy security under certain broad categories:

Figure 3.6. TYNDP 2014 and its Major Aim



Source: Compiled information from various public domains.

Renewable energy sources. Major driver for grid development until 2030:

A major shift in power generation is expected by 2030, starting from likely replacement of obsolete fleet of conventional generating units with modern ones, which are located distantly from load centres and with higher share of renewable energy sources.

Interconnection capacity enhancement. Need for stronger market integration with mainland Europe of the four main electric peninsulas[3] in Europe:

TYNDP has identified interconnection bottlenecks that are in dire need of reinforcement and is working to double interconnection capacity (on average across Europe) by 2030.

Massive investment and wholesale electricity prices. The total investment cost for pan-European significance projects under TYNDP is €150 billion, of which €50 billion relates to subsea cables. Although said investment represents only two percent of the bulk power prices or approximately one percent of the total electricity bill, the consequent increased market integration has led to a significant lowering of average electricity prices across Europe.

[3] Targeted is the interconnection of the Iberian Peninsula, the Italian peninsula, the Baltic states, Ireland, and Great Britain to mainland Europe.

Emissions mitigation, technical leadership, and future energy policies: By directly connecting renewable energy sources, avoiding spillage, or running more environment-friendly power generation units, TYNDP 2014's project portfolio aims to directly contribute to reducing CO_2 emissions by approximately 20 percent by 2030. Also, investment projects requiring appropriate grid reinforcement solutions have led to adoption of cutting-edge technologies. As various market situations simulated for project portfolio under TYNDP 2014 are required to be analysed for different policy visions, TYNDP is considered to be contributing to the implementation of 2050 energy goals. Moreover, as TYNDP aims for network development up to 2030, this serves as energy policy to bridge the gap between EU's energy targets from 2020 to 2050.

3.3 Trans-European Energy Network (TEN-E)

With building and financing important energy infrastructure as purpose, TEN-E lists and ranks projects eligible for community assistance in line with a series of guidelines adopted under Decision No. 1229/2003/EC of the European Parliament and of the European Council of 26 June 2003. TEN-E identifies and gives push to corridors that require urgent infrastructure development to connect EU countries currently isolated from European energy markets. Thus, such infrastructure strategy has potential to strengthen existing cross-border interconnections and help integrate renewable energy sources. More details regarding TEN-E are included in Section 4 below.

4. Infrastructure Development

With the need to upgrade current European grid infrastructure, EC has estimated €200 billion as the required investment for transmission grids and gas pipelines. A major part of infrastructure upgrade includes urgent infrastructure to connect EU countries currently isolated from European energy markets, strengthen existing cross-border interconnections, and help integrate renewable energy.

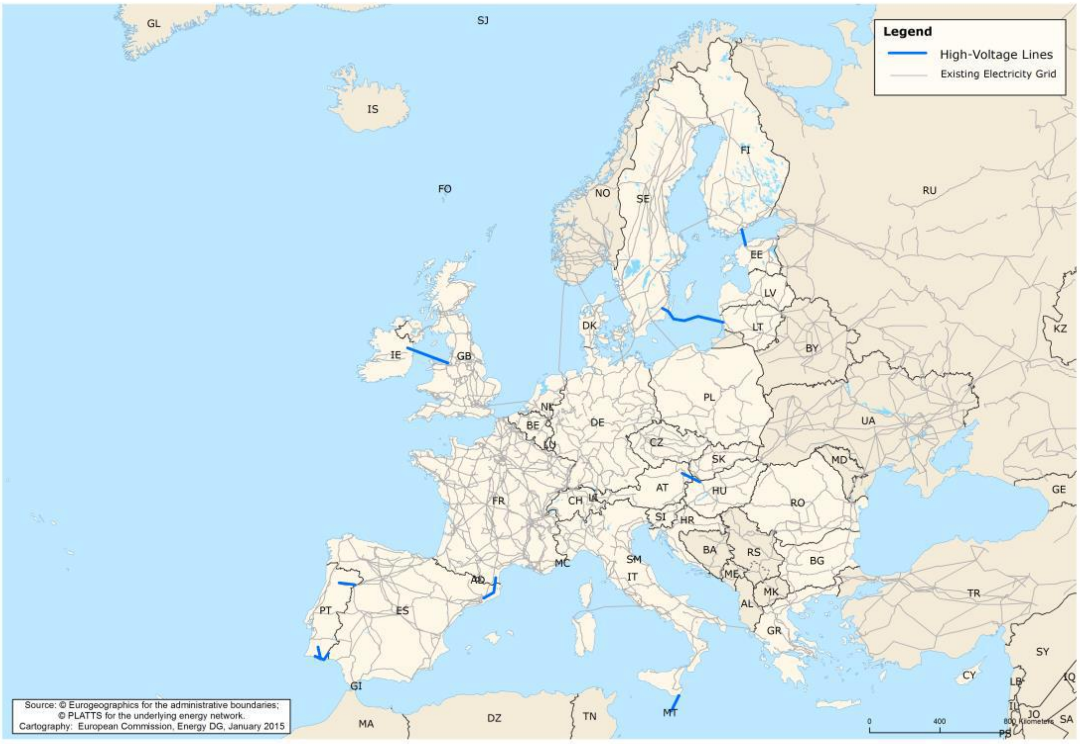
Although a significant increase in interconnection capacities was seen in the last decade, 12 member states, mainly in the periphery of the EU, still fall below the 10 percent electricity interconnection target and are thus isolated from IEM (Table 3.3).

Table 3.3. Electricity Interconnection Level, 2014

Member State	Interconnection Level (%)
Member states with above 10% interconnections target	
Austria (AT)	29
Belgium (BE)	17
Bulgaria (BG)	11
Czech Republic (CZ)	17
Germany (DE)	10
Denmark (DK)	44
Finland (FI)	30
France (FR)	10
Greece (GR)	11
Croatia (HR)	69
Hungary HU	29
Luxemburg (LU)	245
The Netherlands (NL)	17
Slovenia (SI)	65
Sweden (SE)	26
Slovak Republic (SK)	61
Member states with below 10% interconnection target	
Ireland (IE)	9
Italy (IT)	7
Romania (RO)	7
Portugal (PT)	7
Estonia (EE)	4
Luthuania (LT)	4
Latvia (LV)	4
United Kingdom (UK)	6
Spain (ES)	3
Poland (PL)	2
Cyprus (CY)	0
Montenegro (MT)	0

Source: Energy Union

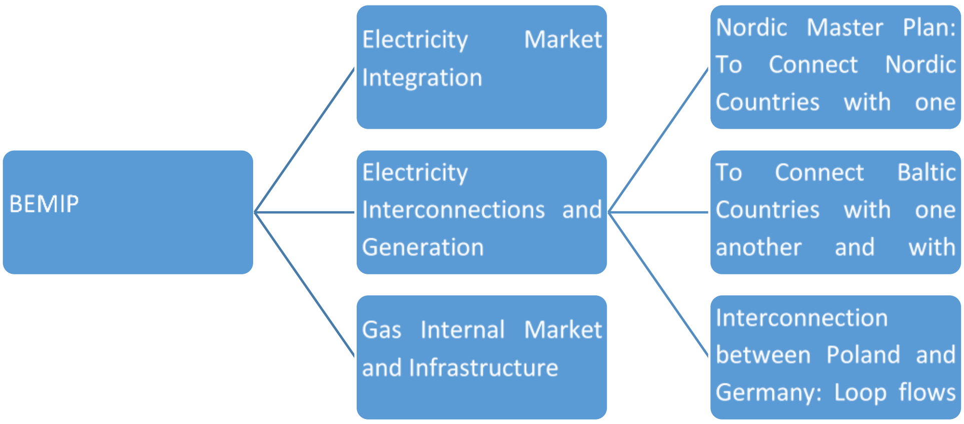
Figure 3.7. Interconnections Supported by EEPR



Source: Energy Union Package.

To this end, the EU has been working on infrastructure upgrade for a long time now, with interconnection networks at the forefront. The regulations of EEPR and TEN-E are among the most prominent policies for enhanced interconnections of member states.

Figure 3.8. BEMIP and Related Major Interconnection Projects



Source: Compiled information from various public domains.

EEPR, which focuses on identifying interconnection projects across the EU, spent around €650 million on electricity interconnections. Thus, the programme has made some significant interconnections that previously could not have been made due to lack of funds. One of the major interconnections backed by EEPR is the Baltic Energy Market Interconnection Plan (Figure 3.8). As shown in Table 3.2, Estonia, Latvia, and Lithuania still lack adequate electricity connections. The Baltic Energy Market Interconnection Plan intends to integrate the energy market of the Baltic States by building more infrastructure/interconnections. Some of the more prominent interconnections being made under the plan include linking Finland and Sweden (Fenno–Skan II) under the Nordic Master Plan, the Great Belt project in Denmark, linking Sweden and Lithuania (NordBalt), linking Poland and Lithuania (LitPol), and linking Poland and Germany to deal with loop flows caused by increased wind electricity in northern Germany (See Figure 3.9).

Figure 3.9. Interconnections Under BEMIP

Source: European Commission, Energy.

With the broad objective of interconnection, interoperability, and development of trans-European networks for transporting electricity and gas, the TEN-E Regulation sets out guidelines for streamlining the permitting processes for major energy infrastructure projects that contribute to European energy networks.

Under the TEN-E regulations, EC has drawn up energy infrastructure projects, known as projects of common interest (PCIs), that can benefit from accelerated permit granting, improved regulatory conditions, and access to financial support totalling €5.35 billion from the Connecting Europe Facility. The funding is intended to speed-up project implementation and attract private investors. Energy infrastructure projects requiring community assistance have been categorised as:

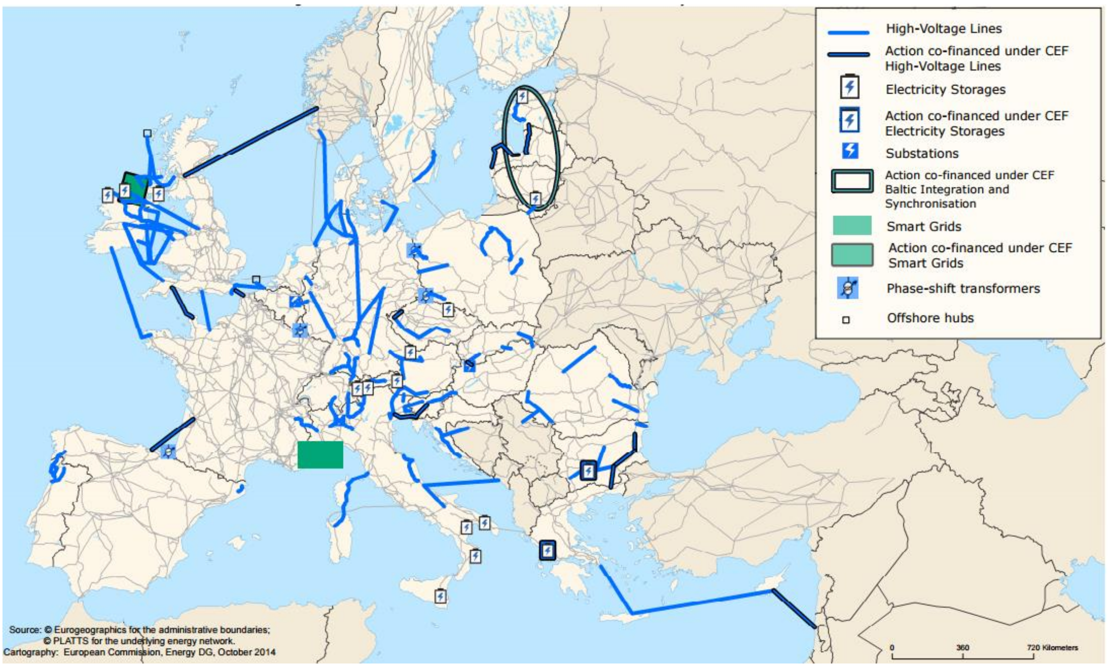
Projects of common interest. Economically viable electricity and gas networks projects.

Priority projects. Projects of common interest with significant impact on the proper functioning of the internal market, security of supply, and/or use of renewable energy sources. Priority projects get community financial assistance.

Projects of European interest. Certain priority projects of cross-border nature or having significant impact on cross-border transmission capacity.

Of the 248 PCIs on the 2013 list, 137 are related to electricity, including 52 electricity interconnections and one project with anticipatory investments to enable future interconnections (Figure 3.10). Of these, 37 projects involve member states whose current interconnection level is below 10 percent. Around 6 percent of PCIs on the 2013 list were supposed to be completed by 2015 while some 75 percent are planned to be completed by 2020.

Figure 3.10. Projects of Common Interest on the 2013 List



Source: European Commission.

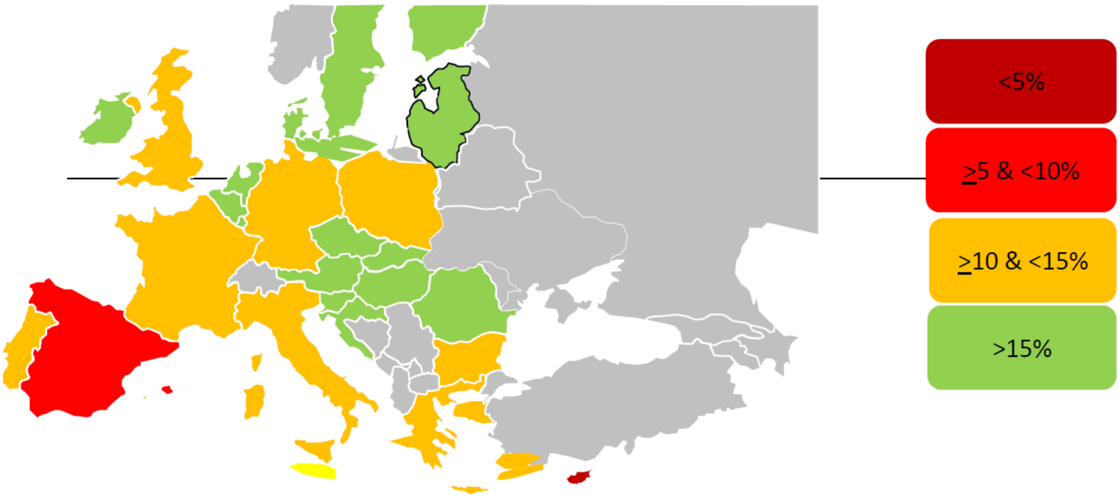
Table 3.4. Interconnection Projects under PCI and EEPR

Interconnection Project	Related Policy	Status	Intended Outcome
Interconnection between Baixas (France) and Santa Llogaia (Spain)	EEPR	Inaugurated in February 2015	Double electricity interconnection capacity between France and the Iberian Peninsula
Interconnection between Aquitaine (France) and the Basque country	PCI	Currently under detailed studies, financed by EC grants	Double electricity interconnection capacity, reaching the interconnection target of 10%
Interconnection between Vila Fria– Vila do Conde-Recarei (Portugal) and Beariz-Fontefría (Spain)	PCI	Underway	Increased interconnection capacity between Portugal and Spain (of current 7%) and above 10% by 2016
Interconnection between Nybro (Sweden) and Klaipeda (Lithuania)	EEPR	Project Nordbalt under process	Improved integration of the future power market between the Baltic member states and Nord Pool Spot from mid-2016
Interconnection between Lithuania and Poland	PCI	Underway	Double interconnection level of Poland to 4% by the end of 2015
Interconnection between Vierraden (Germany) and Krajnik (Poland)	PCI	Underway	Increased interconnectivity of Poland above 10% by 2020
Interconnection between the United Kingdom and Belgium, France, and Ireland	PCI	Underway	Ten percent target reached by the UK; less congested interconnections
Extension of existing interconnection between Ireland, the United Kingdom, and France	PCI	Underway	Above 15% percent increase in interconnection capacity of Ireland by 2020
Interconnection between Romania and Serbia	PCI	Underway	Above 9% increase in interconnection capacity of Romania by 2017 in comparison to the current 7% level.
Cyprus Euroasia Interconnector	PCI	Prefeasibility phase, to be completed in 2023	Over 100% interconnection level for Cyprus when completed in 2023
High-voltage interconnection between Malta and Sicily (Italy)	EEPR	Underway	Increased interconnection level for Malta, from the present 0% to approximately 35%

Source: Energy Union Package, 2015.

The PCI list is updated every 2 years to include newly needed projects and remove obsolete ones. The next PCI list is under process and will be released in 2017. Priority will be given to projects capable of significantly increasing the current interconnection capacity from below the established 10 percent objective. It is worth mentioning that numerous interconnects projects are underway that, when completed, would help member states reach the 10 percent target (Table 3.4).

Figure 3.11. Interconnection levels in 2020 as planned under current PCI



Source: European Union Package.

As mentioned in the 'Energy Union Package Communication from the Commission to the European Parliament and the Council', the implementation of PCIs is expected to bring Europe closer to achieving the 10 percent electricity interconnection target between member states once the projects are completed in 2020 (Figure 3.11).

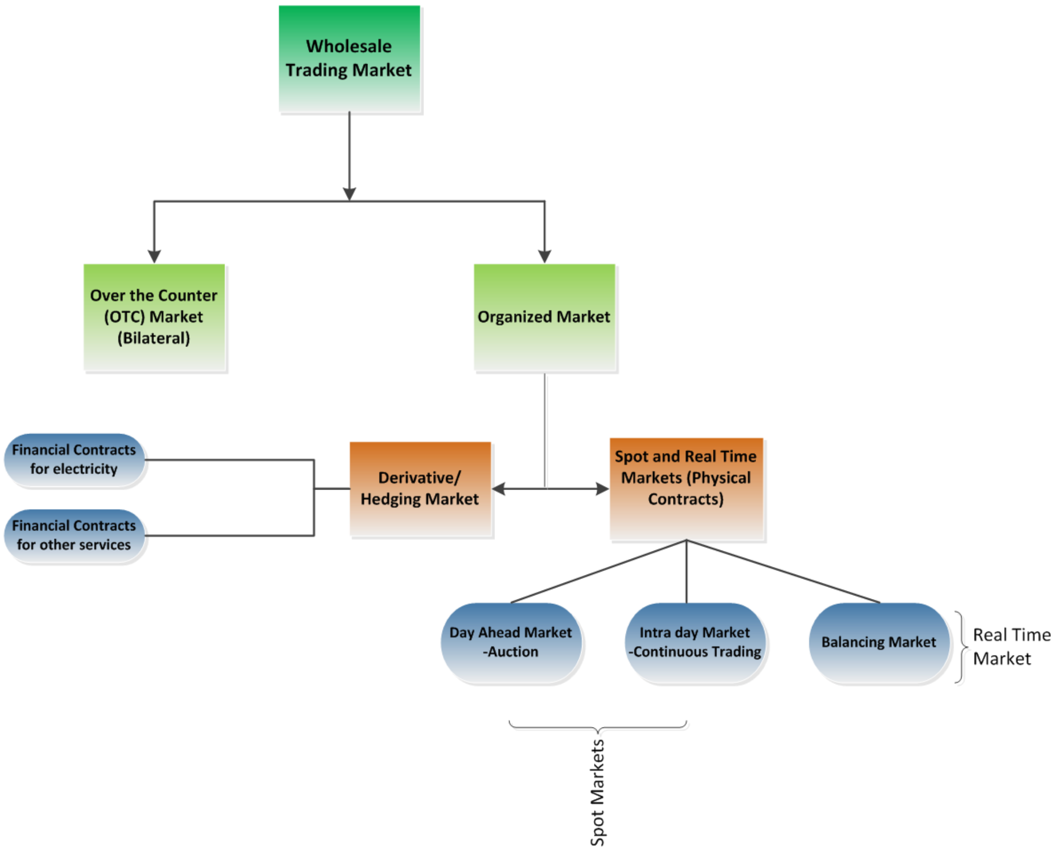
5. Market Design

Over a period of time, Europe was able to liberalise a major share of its electricity market that ultimately created a need for organised markets for wholesale trade of electricity. Initially, organised markets started developing under two concepts: power pool and power exchange. However, in contrast to power exchanges that emerged as voluntary marketplace as a result of private sector initiatives, power pools were public initiatives mandating the participation of member countries or parties. Power exchanges are now the obvious favourite of market players[4] as power pools are not being practiced by many European countries these days.

[4] Market players refer to generators, distribution companies, traders, and large consumers.

Before the establishment of the New Electricity Trading Arrangements, the pool of England and Wales was a typical example of power pool concept. After consecutive directives by the EU from the 1990s to 2003, power exchanges have emerged as competitive wholesale (energy only) trading facility/market for spot electricity trading. In this market, once trading results – which disclose traded volume of electricity and corresponding market clearing price – have been announced, independent system operators[5] take the responsibility of facilitating the physical delivery of electricity (transmission) to dedicated hubs. Thus, the power exchange can be defined as a voluntary marketplace in contrast to the classic bilateral over-the-counter market. Figure 3.12 shows a typical structure of power trading market.

Figure 3.12. Typical Structure of Wholesale Market



Source: Authors.

[5] As mandated by the second EU directive (2003), most member states have to create independent TSOs, although their levels of independence can be differentiated by ownership, legal, and management categories. For instance, UK, Finland, Sweden, and other member states have chosen to appoint a separate legal entity (different from other entities under supply chain of electricity production) as TSOs while Belgium, Germany, and France have opted for TSOs that are independent in terms of management (Boisseleau, 2004).

Day-ahead Market

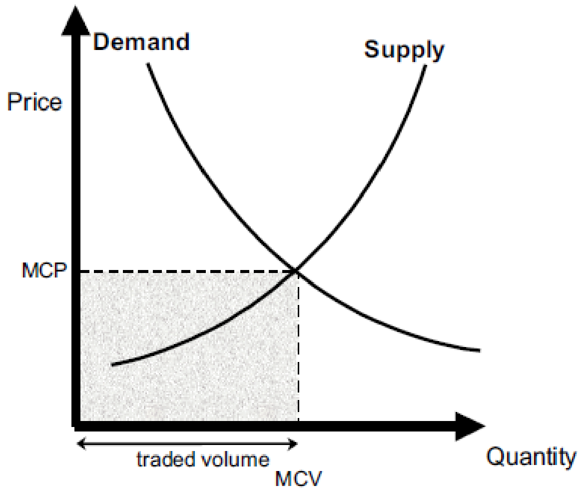
Across Europe[6], over-the-counter or bilateral markets are still the dominant market in terms of volume of trade, while day-ahead markets are the main arena for electricity trading under organised markets (through power exchanges). Day-ahead markets (e.g. Elspot of Nordpool) are short-term (spot) markets where contracts are made between seller and buyer for delivery of power the following day. In general, a day-ahead market is composed of four stages. In stage 1, both seller and buyer submit bids for electricity trade for a chosen period within a day[7]. In stage 2, price and volume information are fed in an advanced computing system of exchanges where market clearing price (MCP) is computed using specific algorithms. In general, MCP and market clearing volume (MCV) are computed at the equilibrium point of the supply and demand curve (Figure 3.13). In stage 3, all transactions are settled on the basis of MCP and MCV. In stage 4, once the transactions are settled, the information is transferred to system operator to ensure physical delivery of electricity. NordPool, the largest market for electricity trading in Europe, has almost 360 buyers and sellers in their day-ahead market, placing around 2,000 power trading orders daily. Deadline for submitting bids (for power to be delivered the following day) is 12:00 CTE, and hourly prices (or MCP) are typically announced to the market at 12:42 CET or later (Nord Pool, 2015).

Intraday market (e.g. Elbas of Nordpool) compliments the day-ahead market and provides flexibility through continuous trading. Although majority of trading volume across Europe is traded on the day-ahead market, the intraday market plays a key role by providing a platform for balance between supply and demand to account for any sudden changes in power supply (generation) or demand (e.g. a fossil fuel or nuclear power plant may suddenly stop working due to some technical snag or renewable energy sources such as wind power plants, for instance, may start generating more than the predicted volume the day before. Continuous trading (24 hours a day, 7 days a week, 52 weeks a year) and price formation take place in intraday market. In some major intraday markets, like those in the Netherlands, trading can take place even five minutes before final delivery. Intraday markets are becoming more important as the share of renewable energy is going up in total power-generation capacity across Europe. Table 3.5 shows a snapshot of major organised markets across Europe.

[6] Over-the-counter trade represents more than 90 percent of total electricity consumption in the Netherlands, Germany, and France. Nordic countries also trade more than 75 percent consumed electricity in over-the-counter market (Boisseleau, 2004).

[7] Duration is usually one hour. However, it goes up to two hours depending upon the protocols of different exchanges.

Figure 3.13. Auction Model under Day-Ahead Market



Source: Boisseleau.

Table 3.5. Major Organised Markets Across Europe

Market	Country
Nordpool	Norway, Finland, Sweden, Denmark
Operadora del Mercado Espanol de Electricidad (OMEL)	Iberian Peninsula (Spain, Portugal)
APX	The Netherlands, United Kingdom, Belgium
EPEX SPOT[8]	France, Germany, Austria, Switzerland
Leipzig Power exchange (LPX)	Germany
European Energy Exchange (EEX)	
EXAA	Austria
United Kingdom Power exchange (UKPX)	UK
Gestore Mercato Electricco (GME)	Italy
The French Power Exchange (Powernext)	France

Source: Compiled information from various public domains.

[8] EPEX SPOT is 100 percent owner of APX Group.

Derivatives/Hedging Market

Derivatives or hedging market is a financial/commercial market where price-securing contracts are traded to manage future risks. Financial markets trade futures power and other derivatives that are settled against future spot prices. Future contracts ensure liquidity by targeting system spot price[9] (Bang et al., 2012).

Balancing Market

Day-ahead market creates preliminary round of balance in the power system. However, balance markets or real-time markets are responsible for keeping the real time physical balance in the power system. Imbalances are typically caused by deviation between day-ahead planning/forecasting and actual consumption/generation. This is managed by ordering regulating power from regulating power market.

Regulating power is a manual reserve, defined as increased or decreased generation that can be fully activated within 15 minutes, or demand that is increased or decreased. Activation can start any time and duration can vary. Regulating markets are operated by TSOs and share many designs and functions similar to day-ahead market such as:

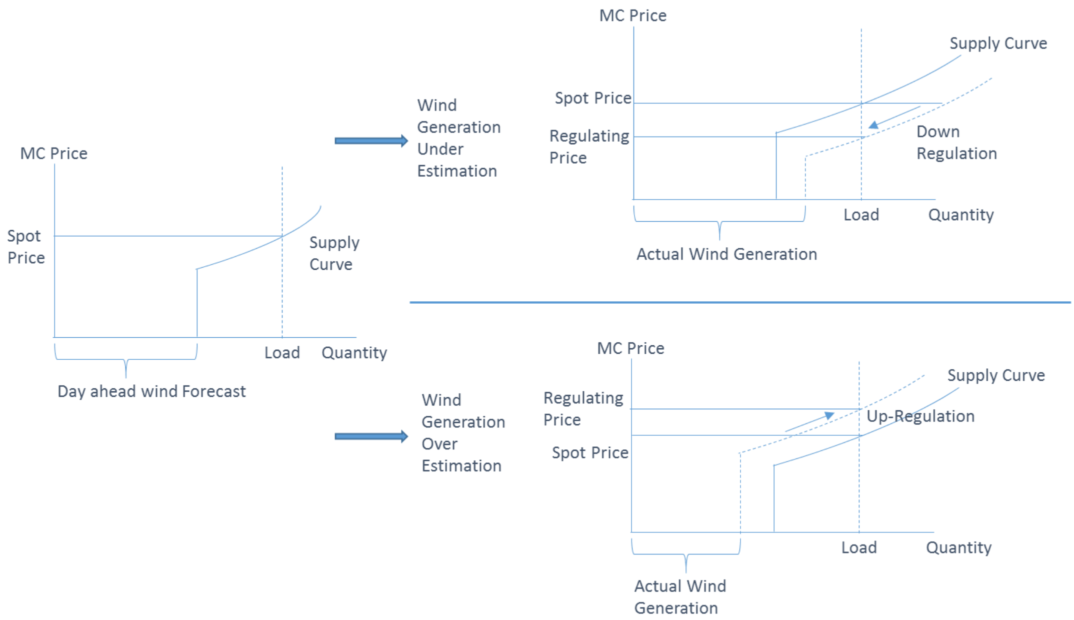
- Merit order supply curve based on bids submitted by market players
- and the bids and offers of all players participating in the same bidding zone are settle at a single price.

All bids for delivering regulating power are sorted on a list of increasing prices for up-regulation[10] (above spot price) and decreasing prices for down-regulation[11] (below spot price) (Figure 3.14). The day-ahead market (spot) price represents the minimum price for up-regulating power bids and the maximum price for down-regulating power bids. Imbalance settlement cost is settled with all market players in line with certain market rules.

It is worth noting that although the initial features of regional organised markets included only price and quantity of power market, Europe is actively working on IEM agenda and cross-border cooperation to ensure a smooth transport of electricity across borders. Transmission constraints during electricity trading are additional features that the market needs to consider. ENTSO-E ensures closer cooperation of Europe's independent TSOs by acting on standardised market integration frameworks.

[9] MCP when there is no congestion.
[10] More generation- less demand.
[11] Less generation-more demand.

Figure 3.14. Pricing in Regulating Market



Source: Interviews with EnergiNet DK.

As mentioned, European markets are moving toward greater physical integration. Although quite a few regulations and energy programmes are actively working to enhance interconnection capacities among European countries (Refer to Section 4: Infrastructure development), having IEM is still challenged by limited transmission capacity between countries. Thus, taking into account transmission capacity during cross-border trade among European countries and adopting a relevant market design are two of the most complex, albeit most important, design features of the European electricity market.

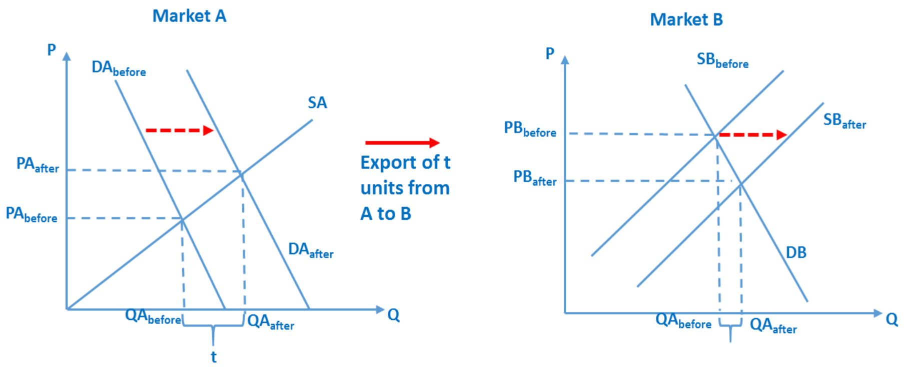
There are typically two market-based options to combine cross-border trade and cross-border transmission capacities: explicit and implicit capacity auctions (market coupling). Under the target model[12] for completing IEM, regional market coupling is the market design being implemented by ENTSO-E in close cooperation with member TSOs, power exchanges, and other stakeholders.

[12] 'The target model for the European electricity market is the vision shared by stakeholders on the future market design. The model is the blueprint with top-down guidance for regional market integration projects and is being implemented bottom-up through regional market coupling projects and top-down through the network codes that ACER, EC, and ENTSO-E develop.' (ENTSOE, 2014).

5.1 Market Coupling and Congestion Management

Market coupling is a method for integrating electricity markets in different areas. It is a congestion-management method where allocation of cross-border transmission capacity is determined according to demand on respective energy markets (Moffatt Associates, 2007). Market coupling is basically an implicit auction approach used in day-ahead market to facilitate flow of power toward the high-price area.

Figure 3.15. Principle of Market



DA	Demand Market A	SA	Supply Market A	PA	Price Market A
DB	Demand Market B	SB	Supply Market B	PB	Price Market B
QA	Quantity Market A	Before		Before Market Coupling	
QB	Quantity Market B	After		Before Market Coupling	

Source: Böckers et al.

Figure 3.15 illustrates a simplified example of market integration through market coupling and related auction method.

Market coupling is considered to be a way to integrate different energy markets into one coupled market. With market coupling, the daily cross-border transmission capacity between various areas is not explicitly auctioned among market parties but is implicitly made available through energy transactions on the power exchanges on either side of the border (hence the term ‘implicit auction’). Thus, energy transactions can involve sellers and buyers from different areas, restricted only by electricity network constraints. It means that buyers and sellers on a power exchange benefit automatically from cross-border exchanges without the need to explicitly acquire the corresponding transmission capacity (Belpex, 2016). The efficiency of the mechanism is further revealed by an increasing price convergence between market areas.

5.2 Market Splitting

Under market splitting, one power exchange operates across several price zones. To understand it more clearly, market splitting defines relevant local submarkets according to congestion. If there is no congestion at a specific point in time between two areas, then both are treated as a single area. For instance, Sweden, Denmark, Norway, and Finland are linked via market splitting. Sweden has no single area but fragments, defined by transmission capacities and potential congestion. Thus, power prices may vary even in Sweden while the remaining markets may have same prices.

Box 1. Capacity Auction Mechanisms

Explicit Capacity Auction

An explicit auction is when the transmission capacity on an interconnector is auctioned to the market separately and independently from the marketplace where electricity is auctioned.

An explicit auction is a relatively simple method of handling cross-border capacity and was previously widely used in Europe. The capacity is normally auctioned in portions, through annual, monthly, and daily auctions (Moffatt Associates, 2007).

Implicit Capacity Auction

In implicit auction, the capacity between bidding areas is made available to the spot price mechanism operated by the power exchanges in addition to bid/offers per area. Thus, the resulting prices per area reflect both the cost of energy in each internal bid area (price area) and the cost of congestion.

In case of sufficient capacity availability, market becomes one: bids in the high-price market can be matched against offers in the low-price market. However, if sufficient capacity is not available, prices congregate but remain different, and the gap represents the cost of congestion (Moffatt Associates, 2007).

Two main inefficiencies are associated with the explicit auction concept and that have mostly been resolved in implicit auctions as described below:

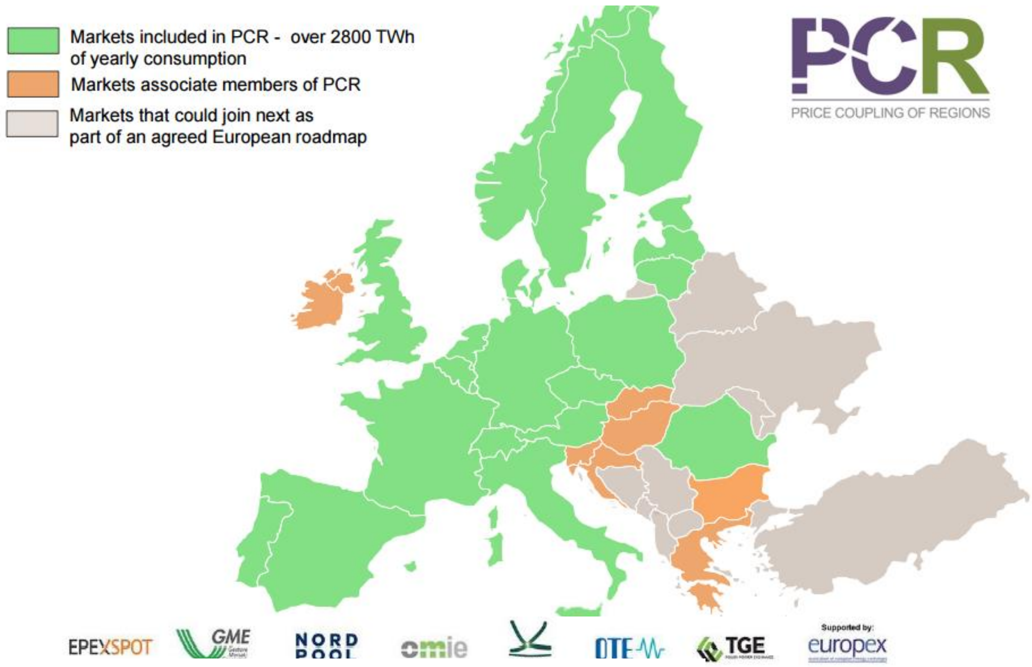
Explicit Auction	Implicit Auction
Flow on interconnector is not taken into account. Instead, transmission capacities are booked for both directions. Hence, the possibility of getting capacities booked for wrong directions.	Flow on interconnector is taken into account based on market data from the market place in the connected markets.
Cross-border transmission capacities are booked prior to the actual day-ahead market. Thus, auctions are based on predicted day-ahead prices. **Therefore, the booked transmission capacity is not necessarily equal to the power units finally sold.**	Usually, information on availability of transmission capacities is required to be gathered from various transmission system operators and incorporated in the algorithm that optimises respective power auctions in both markets.
Higher transaction cost	Implicit auction takes place in a single auction office, thus, leading to decreased transaction cost. However, a single auction office being a monopoly, it is crucial that the auctioneer remains independent from other market participants and does not discriminate among different generators and/or traders.

5.3 Single Price Coupling of Regions: Multi-Regional Coupling Project

With a vision to acquire a single price market coupling[13] for day-ahead market with implicit allocation of cross-border capacities, the multi-regional coupling project of ENTSOE-E aims to achieve full price coupling of major regional day-ahead markets, e.g. North-West Europe.

The North-West European price coupling project encompasses fully coupled day-ahead market enforcing same coupling approach in all involved countries and covers Central-West Europe (Belgium, France, Germany, Luxembourg, and The Netherlands), the Nordic-Baltic region (Denmark, Sweden, Finland, Norway, Latvia, Lithuania, and Estonia) and Great Britain, as well as the Swepol link between Sweden with Poland (ENTSOE, 2014). The North-West European project was launched on 4 February 2014 while the full price coupling of the South-West Europe and North-West Europe day-ahead electricity markets was achieved on 13 May 2014. Parallel to the multi-regional coupling project, the '4M' market coupling project aims to extend the day-ahead market coupling of the Czech Republic, the Slovak Republic, and Hungary to Romania and Poland.

Figure 3.16. Geographical Spread of PCR and Involved Power Exchanges



Source: Price Coupling of Regions.

[13] Under single-price market coupling mechanism, market prices and traded volumes of power are calculated by a single centralised system on the basis of all relevant information, e.g. cross-border capacity, order book of individually involved power exchanges, etc.

Similarly, price coupling of regions is the single-price coupling solution initiated by seven European power exchanges (EPEX SPOT, GME, Nord Pool, OMIE, OPCOM, OTE, and TGE) to calculate electricity prices across Europe[14] and allocate cross-border capacity in a day-ahead market. Price coupling of regions is implemented in both the multi-regional coupling region and 4M MC as shown in Figure 3.16.

Price coupling of regions is generally based on three main principles: single algorithm, decentralised operation, and decentralised governance.

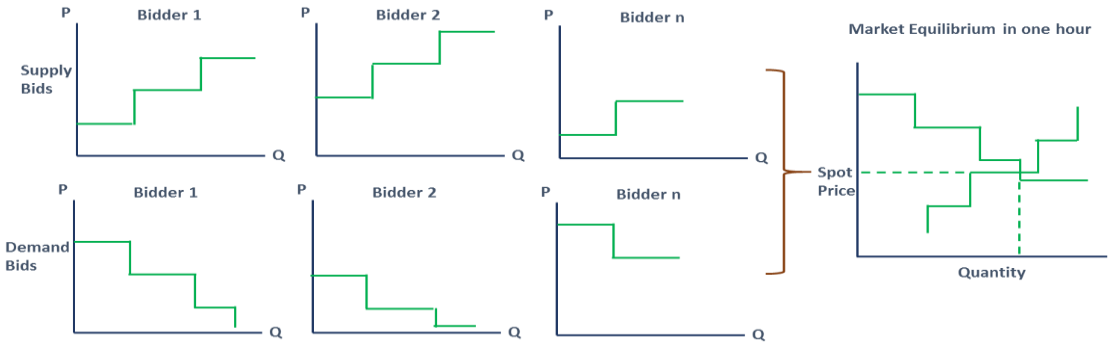
Under the old scenario of separate national markets and power exchanges, different power exchanges used to use different algorithms, such as COSMOS, SESAM, SIOM, and UPPO, to arrive on various electricity price and volume,. Nonetheless, the concept of single-price market coupling seeks a single-price coupling algorithm that can compute energy allocation and relevant prices for participating markets with a high degree of transparency.

Accordingly, the Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA) is a single-price coupling algorithm used in price coupling of regions to cover all the requirements of pricing and capacity allocations in coupled day-ahead markets.

Bidding Areas: Taking into account the constraints in transmission systems and regional market conditions in terms of price, a coupled day-ahead market is divided into different bidding areas based on information provided by TSOs as input to the algorithm (EUPHEMIA in the case under consideration). Bidding areas may vary according to the change in interconnections. In general, what first determines bidding areas is congestion on national boarders, although congestion within a country is also considered as a separate zone. For instance, the Nordic Part of North-West Europe is divided into 15 bidding areas; the Norwegian internal market, five bidding areas; Eastern Denmark and Western Denmark, two separate bidding areas; Finland, Estonia, Lithuania, and Latvia, one bidding area each; and Sweden, four bidding areas.

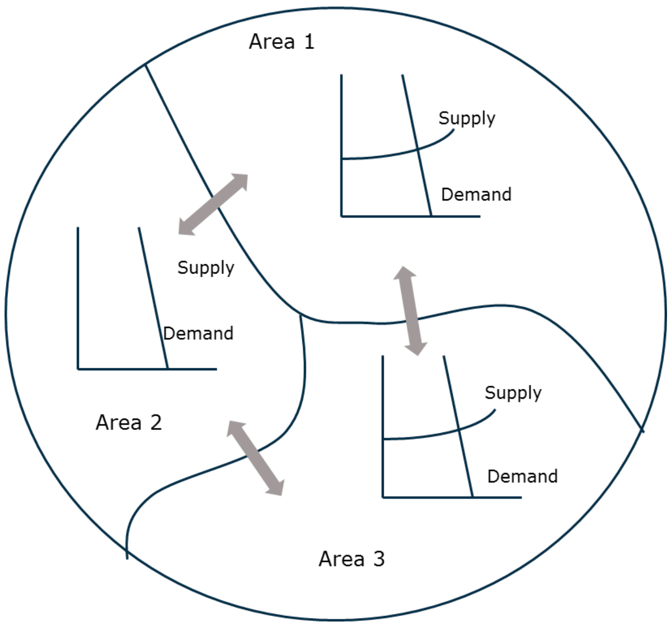
[14] It covers Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Hungary, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, and the UK.

Figure 3.17. MCP-System Price



In the case of regional markets connected through market splitting (Nordpool, for instance), once the TSO declares the bidding areas, buyers and sellers submit their bids to market operator or exchange (e.g. Nordpool Spot) for each bidding area. Using applicable algorithm, market operator groups all submitted marginal cost supply and demand bids on a supply and demand curve and computes MCP, a single price across all exchange areas (Figure 3.17). MCP computed in such a way is called system price and does not take into account transmission constraints.

Figure 3.18. Congestion Management and Least-cost Option



Source: Interviews with EnergiNet.

Thus, if bidding areas are not congested between them, entire bidding area is considered one and system price becomes its area price. However, cross-border or internal congestion between bidding areas has to take into account the interconnection capacity and can lead to separate area prices. For instance, if congestion occurs between three bidding areas (Figure 3.18), the whole market is divided into three separate areas and prices are computed accordingly. To reach the least cost option in such situation, power exchanges facilitate the flow of power from low-price area to high-price area until prices in both areas are the same (increased demand in low-price area raises price while increased available supply in high-price area pushes down price, and/or interconnector capacity is fully utilised (or congested)

The difference between area prices of two bidding areas represents the congestion rent. Such amount is collected by exchange and divided between relevant TSOs (Figure 3.19). Congestion rent is used to develop and enhance the capacity of cross-border interconnections. To summarise the process, power exchange collects generation and consumption bids and determines the optimal market outcome, i.e., the market outcome with maximum social benefit (consumer surplus, producer surplus, and congestion rent or revenue).

5.4 Capacity Allocation Mechanism

On 29 July 2011, ACER adopted the Framework Guidelines on Capacity Allocation and Congestion Management (CACM) for Electricity[15], the core elements of which include regular review and updates of bidding zones to maintain overall market efficiency, maximum possible trade between bidding areas or flow-based capacity calculation (Please see Box 2) in meshed networks, efficient allocation of cross-zonal capacity in forward markets (explicit auctions in day-ahead market, implicit auctions in intra-day market), and financially and physically firm explicit and implicit auctions, respectively.[16]

In line with the Commission Regulation (EU) 2015/1222 issued on 24 July 2015 and establishing guidelines on capacity allocation and congestion management, TSOs are required to reckon the available cross-border capacity by establishing a common grid model, [17] including estimates on generation, load, and network status for each hour. Available capacity computation should be in accordance with flow-based capacity model[18]. The available cross-border capacity is one of the inputs to further calculations. Under the distinctive feature of

[15] http://www.acer.europa.eu/en/electricity/FG_and_network_codes/CACM/Pages/default.aspx

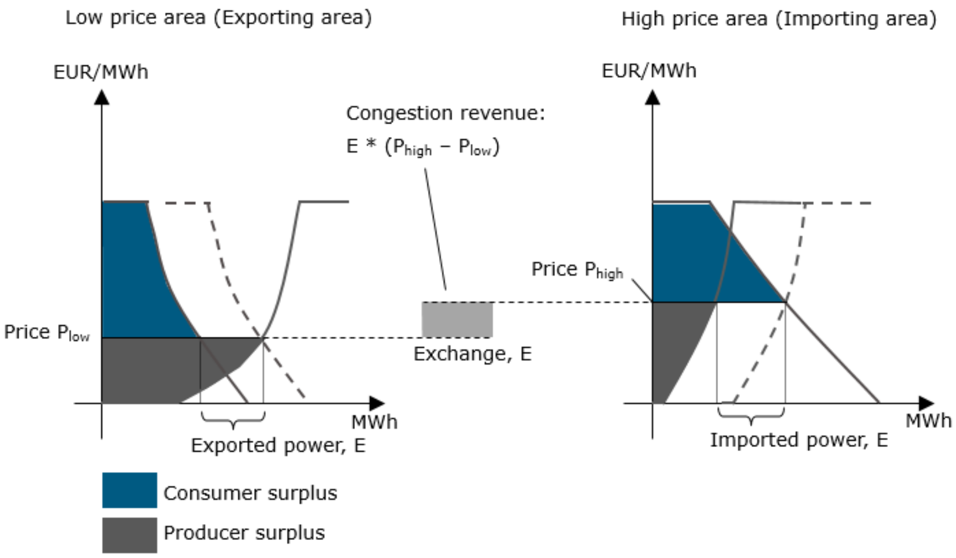
[16] Based on guidelines for CACM, 'firmness' means a guarantee that cross-zonal capacity rights will remain unchanged and that compensation will be paid if they nevertheless changed.

[17] The common grid model includes a model of the transmission system, location of generation units, and loads relevant to calculating cross-zonal capacity. Accurate and timely information by TSOs is key to creating a common grid model. Each TSO generates its single individual grid model that can be merged later with grid models of other TSOs to create a common grid model.

[18] The flow-based capacity model takes into account that electricity can flow via different paths and optimise the available capacity in highly interdependent grids.

PCR of decentralised operation and governance, the market coupling operator is tasked to use a specific algorithm to optimally match bids and offers and make the results available to all member power exchanges. Accordingly, power exchanges have to publish result of successful bids and offers before energy is transferred across the network. The capacity allocation process for single day-ahead and intraday coupling is similar, with their trading rules (continuous process throughout the day in intraday coupling and one single calculation in day-ahead coupling) as the only exception.

Figure 3.19. Congestion Revenue and Consumer/Producer Surplus



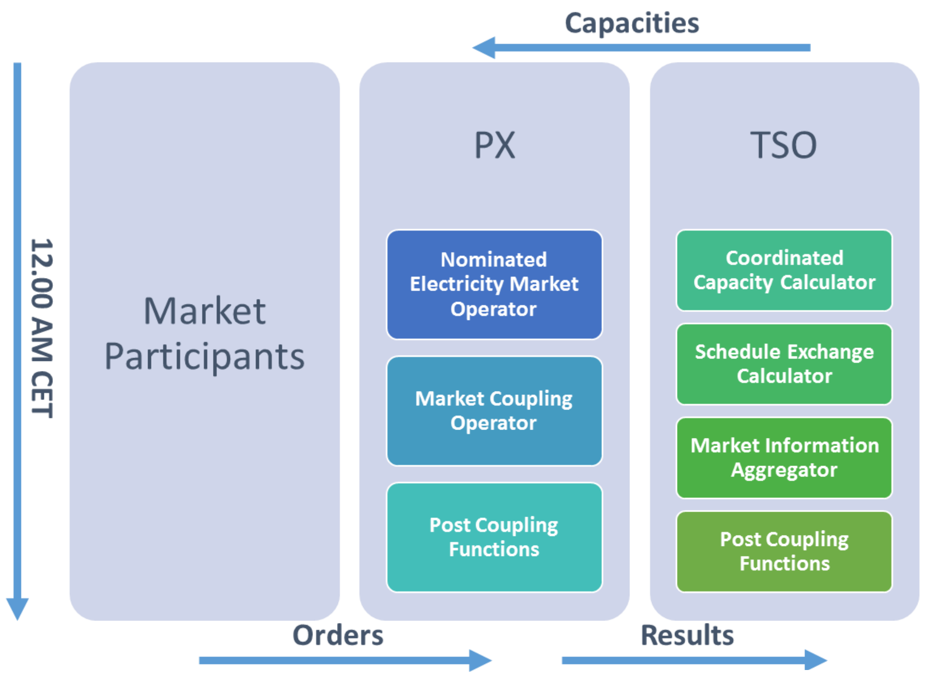
Source: EnergiNet DK.

ACER is responsible in appointing a single regulated entity, called nominated electricity market operator (NEMO), to perform common functions of market coupling operator relating to the market operation of single day-ahead and intraday coupling. As of the time of interview with the European power exchanges during the development of this report, the appointment of market coupling operators was a function developed and operated jointly by NEMOs. There is always one NEMO in charge as coordinator on a rotational basis.[19] (A broad snapshot of the role of each entity in CACM framework and market coupling task is shown in Figure 3.20;

[19] The Commission Regulation (EU) 2015/1222 states that 'each Member State electrically connected to a bidding zone in another Member State shall ensure that one or more NEMOs are designated by latest 4 months after the entry into force of this Regulation to perform the single day ahead and/or intraday coupling'.

further terms are explained in footnote[20].). Thus, power exchanges act as market operators in national or regional markets in cooperation with TSOs in single day-ahead and intraday coupling. Their major tasks involve receiving orders from market participants, taking overall responsibility for matching and allocating orders in accordance with the single day-ahead and intraday coupling results, publishing prices, and settling and clearing the contracts from the trades according to relevant agreements and regulations of participants.

Figure 3.20. Day-ahead Market: Market Coupling and CACM



PX = power exchange, TSO = transmission system operator.

Source: ENTSO-E.

[20] According to the Commission Regulation on Capacity Allocation and Capacity Allocation and Congestion Management, scheduled exchange means the transfer scheduled between geographic areas for each market unit and for a given direction. Schedule exchange calculator does such calculations. Post coupling functions involve scheduling and nominating cross-border flows, settling exports and imports on relevant exchange, distributing congestion revenue to TSOs, and so on. In addition, TSOs work as market information aggregators, required to publish, as soon as matched, at a minimum, the execution status of orders and prices and ensure that this market information is published and made publicly available in an accessible format for a period of not less than 5 years (where such historical data exists).

Under the Commission Regulation, the two permissible models for cross-border capacity calculation are the flow-based model and the available transmission capacity (ATC) model. However, the flow-based market coupling model (FBMC) is the best recommended model, while ATC is suggested when cross-zonal capacity is not depended on each other (Refer to Box 1.2).

In addition to calculating remaining available margin (RAM) and power transfer distribution factors of critical lines (or transmission constraints) under FBMC (Refer to Box 1.2 for further details on FBMC model), calculation of the inputs to capacity calculations includes operational security limits or contingencies relevant to capacity calculation and allocation constraints, and generation shift keys[21] and remedial actions.

Also, all TSOs in each capacity calculation region shall, as far as possible, use harmonised capacity calculation inputs by 31 December 2020.

[21] Generation shift key represents forecast of the relation of a change in the net position (net position is the net sum of electricity exports and imports for each market time period for a given bidding zone) of a bidding zone to a specific change of generation or load in the common grid model.

Box 1.2. Evaluation of Cross-Border Allocation Methods

The initial day-ahead market coupling in Europe (trilateral market coupling of the Belgian, Dutch, and French day-ahead markets in 2006; South-West and North-West Europe market coupling in 2014) was based on available transfer capacity (ATC) method for cross-border allocation still being practiced by most market zones in market coupling.

However, in line with the Commission Regulation (EU) 2015/1222, FBMC is used for cross-border capacity allocation in Central West European day-ahead markets now (Belgium, the Netherlands, Luxembourg, France, and Germany/Austria), replacing the ATC method (Bergh et al., 2015).

Power exchange collects generation and consumption bids and determines the optimal market outcome or the maximum social welfare (sum of consumer surplus, producer surplus, and congestion revenue). Accordingly, algorithm for optimal market outcome is subject to market clearing conditions (net exchange or net clearing position on the basis of net generation, consumption, import, and export) and constraints by available transmission capacity.

Therefore, the problem of cross-border capacity allocation consists of two sub-problems: transmission capacity available to the market and relationship between the net exchange positions and flows through the grid.

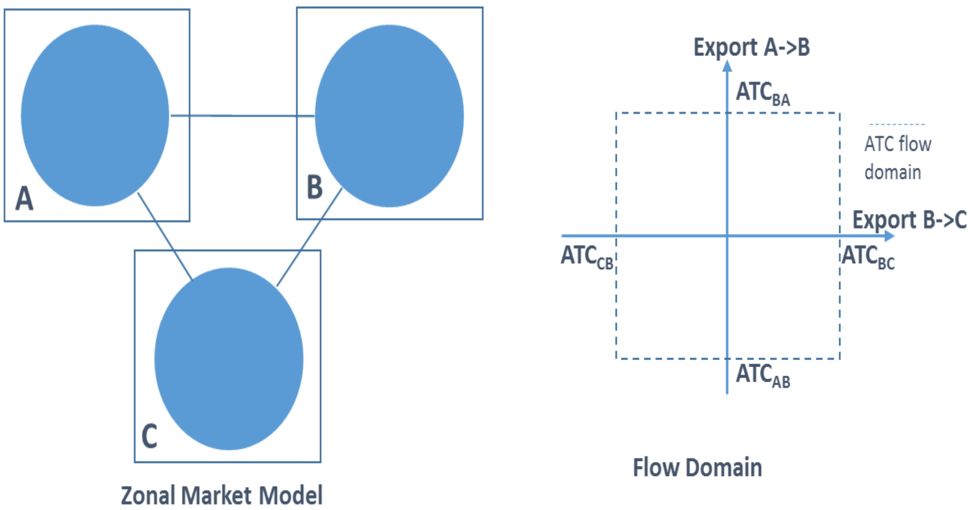
Considering that electricity does not flow directly from generator to consumer but spreads out over parallel paths in the network according to Kirchhoff's laws, there is a fundamental difference between commercial flows (i.e. the shortest path in the network between generator and consumer) and physical flows through the grid. Consequently, the transmission capacity between two market zones cannot be fully allocated to commercial trade between these market zones since some of the capacity will be used by parallel flows resulting from trade between or within other market zones. These two permissible approaches (ATC and FBMC) for calculating cross-border capacity under Regulation on CACM are further described below:

Available Transfer Capacity

ATC is calculated as the maximum commercial exchange between two market areas, compatible with the physical transmission constraint. A cross-border link's ATC is independent of the flow on other cross-border links. To calculate ATC, TSOs estimate parallel flow due to market outcome or on the basis of a base case (ex-ante to the market clearing) and ATC value is determined for each cross-border link and depends on the flow direction of the line, e.g. minimum ATC and maximum ATC representing negative and positive direction, respectively, in algorithm. An incidence matrix is also included in computation algorithm to provide information whether a cross-border link is starting at a market zone (with value of incidence = 1), or ending at a market zone (with value of incidence = -1) or not connected to a market zone at all (with value of incidence = 0).

As shown in Figure 3.21 (Bergh et al., 2015), only one equivalent node per zone is considered, with one cross-border link connecting the market zones, thus a simple grid in ATC method considers a zonal network of three nodes and three cross-border links. The ATC flow domain (shown by dotted line in Figure 3.21) is a rectangle, characterised by the ATC values.

Figure 3.21. ATC Model

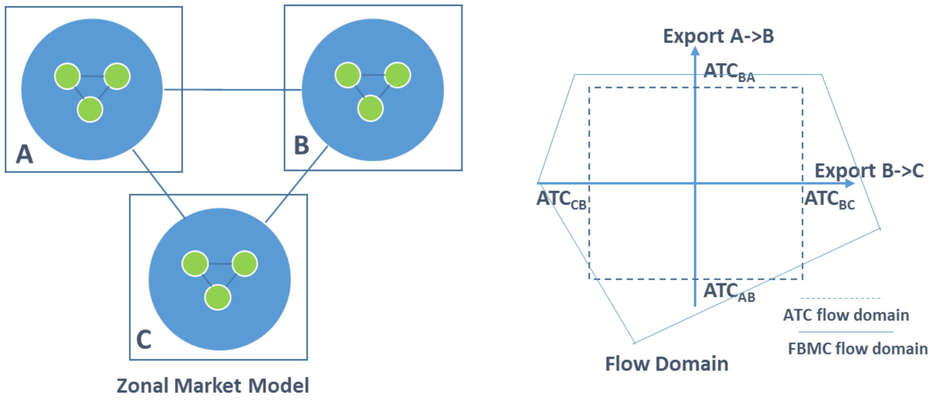


Source: Drawn on the basis of information available in Bergh et al.

Flow-based Market Coupling

Capacity allocation in FBMC takes place partly ex-ante with the market clearing and partly simultaneously with the market clearing. Although FBMC works on the zonal approach as in ATC, it takes into account the physical transmission constraint as well. Unlike ATC, the allowable commercial export/import between two market zones in FBMC is no longer independent from the allowable commercial export/import between other market zones. As a result, the FBMC flow domain is likely larger than the ATC flow domain, as shown in Figure 3.22 (Bergh et al., 2015). The transmission constraints in market clearing algorithm of FBMC depends upon the remaining available margin and PTDF of critical lines (or transmission constraints).

Figure 3.22: FBMC Method



PDTF represents the approximation of the real physical characteristics of the grid and can be derived from generation shifts key. These keys give the nodal contribution to a change in zonal balance, e.g. GSKn,z = 0.3 indicates that the generation at node n increases with 0.3 MW if the zonal balance of zone z increases with 1 MW.

The remaining available margin is the line capacity that can be used by the day-ahead market and depends upon two key components: critical branches (transmission element, e.g. cross-border line, internal transmission line or transformer) and critical outages. Like ATC, a base case is needed in FBMC and for calculating remaining available margin and PDTF. In general, the calculation of remaining available margin and PDTF starts two days before the delivery date (i.e. D-2) and finishes before the morning day-ahead so that they can be used in the day-ahead market clearing.

Base Case (Day-2 Congestion Forecast)

The base case, also referred to as day-2 congestion forecast, is a forecast, made two days before the delivery day, of the state of electricity system at moment of delivery. The base case is needed for (certain) methods of generation shift keys and to determine the reference flows in calculation of remaining available margin.

Every TSO estimates the local base case for its own control area and then different local base cases are merged into one common base case. Base case is estimated on the basis of a reference day, i.e. a day in the past with the similar conditions, e.g. winter, summer, etc.
The reference day outcome is then updated with D-2CF-renewable generation forecasts, load forecasts and outage schedules for generation units, and grid elements. Ultimately, TSOs coordinate the net exchange positions of the reference day to have a balanced CWE (Central Western Europe) system and to update it even if each TSO applies a slightly different methodology.

All TSOs are also required to develop robust fall-back procedures to ensure efficient, transparent, and non-discriminatory capacity allocation in the event that the single day-ahead coupling process is unable to produce results.

Any costs incurred to provide firm capacities and to set up entire processes are supposed to be recovered in a timely manner through network tariffs or appropriate mechanisms. NEMOs are entitled to recover their incurred costs if they are efficiently incurred, reasonable, and proportionate. (For further details, see ITC mechanism in a separate box).

TSOs and NEMOs are required to jointly organise the day-to-day management of the single day-ahead and intraday coupling by meeting regularly to discuss/decide on day-to-day operational issues. TSOs and NEMOs invite ACER and the European Commission as observers to these meetings and publish summary minutes of the meetings.

Under the CACM regulation, NEMOs are required to develop, maintain, and operate a price coupling algorithm and a continuous trading matching algorithm.

Box 1.3. Inter-TSO Compensation Mechanism

Inter-transmission system operator compensation is a mechanism designed to compensate TSOs for (i) costs associated with losses resulting from hosting transmission flows on networks and for (ii) costs of making infrastructure available to host cross-border flows of electricity. ENTSO-E is responsible for establishing an ITC fund to provide such compensation to TSOs.

According to Articles 4.2 and 4.3 of the Annex, Part A, of Commission Regulation (EU) No 838/2010 ENTSO-E, the amount of losses incurred on national transmission systems is computed on the basis of difference between '(1) the amount of losses actually incurred on the transmission system during the relevant period; and (2) the estimated amount of losses on the transmission system which would have been incurred on the system during the relevant period if no transits of electricity had occurred'.

Compensation for transmission losses is required to be calculated separately from compensation for costs incurred associated with making infrastructure available to host cross-border flows of electricity.

ENTSO-E is responsible for computation of transmission losses while ACER verifies the same to ensure a fair and non-discriminatory computation.

The costs of facilitating infrastructure have to be calculated on the basis of forward-looking long-run average incremental costs, taking into account losses, investment in new infrastructure, and an appropriate proportion of the cost of existing infrastructure.

A separate mechanism has been established for inter-TSO compensation for countries sharing a common border with at least one third country.

Regarding contribution to compensation fund, TSOs contribute to the system in proportion to the absolute value of net flows onto and from their transmission system, relative to the total of this measure across the EU. Net flow of electricity means the absolute value of the difference between total exports of electricity from a given national transmission system to countries where TSOs participate in the ITC mechanism and total imports of electricity from countries where TSOs participate in the ITC mechanism to the same transmission system.

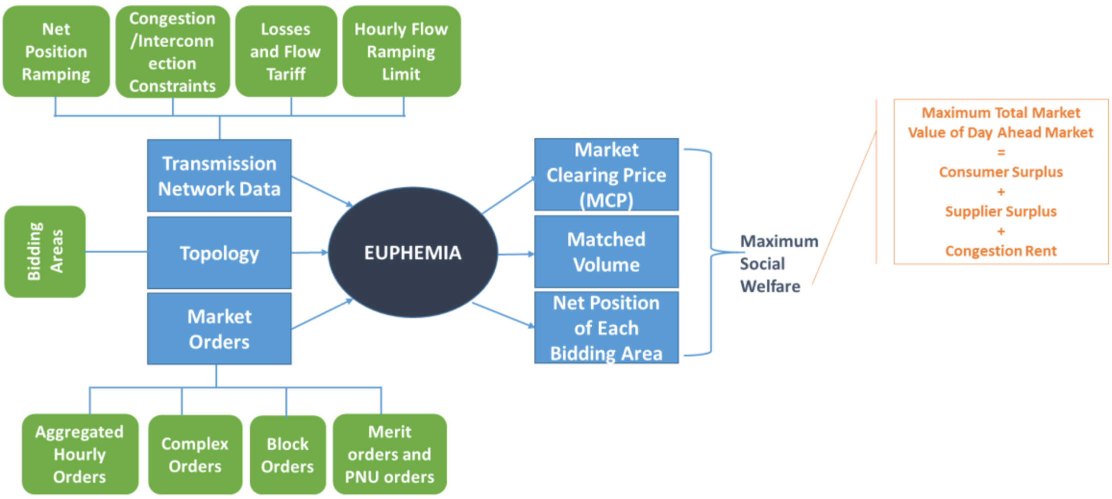
The annual cross-border infrastructure compensation shall be distributed among participating TSOs on the basis of transit and load factor with weightage of 75 percent and 25 percent, respectively.

Transit factor is a proportion of transits on a particular national transmission system state to total transits on all national transmission systems while load factor is the square of transits of electricity in proportion to load plus transits on that national transmission system relative to the square of transits of electricity in proportion to load plus transit for all national transmission systems.

In the case of coupled markets in PCR, EUPHEMIA has evolved a new and precise algorithm for single price coupling and congestion management. Under this mechanism, market participants from each bidding area submit their bids to respective power exchanges. These bids are collected and submitted to EUPHEMIA that then computes an MCP for each bidding area and each period along with a corresponding net position[22]. This algorithm decides on acceptance of orders to maximise social welfare[23] and keep net position[24] of each bidding area below the interconnection capacity.

In general, EUPHEMIA receives a large set of input data containing information for bidding areas, interconnection constraints, net position ramping, losses, flow tariff, and a complex set or market orders, and process it with a sole objective of maximising social welfare or total market value of day-ahead market (function of consumer surplus, supplier surplus, and congestion rent) and ultimately providing with market clearing price, matched volume, net position of each biding areas, and flow in interconnectors (Figure 3.23).

Figure 3.23. Input and Output Data Flow in EUPHEMIA



Source: Price Coupling of Regions, 2016; visit and interaction of study team with various power exchanges across Europe.

EUPHEMIA handles more sophisticated order types (e.g. aggregated hourly orders, complex orders, block orders, merit orders, and PUN [Prezzo Unico Nazionale] orders; see Box 1.4 for further description) and equally treats orders submitted by participants. It matches all bidding areas at the same time to find initial good solution. It keeps computing, however, to increase

[22] Difference between matched demand and supply.
[23] Social welfare = consumer surplus + producer surplus + congestion rent across the regions.
[24] Net position is the difference between the matched supply and the matched demand quantities.

overall welfare. General rule for accepting orders in reference to MCP applies as described below. However, there are specific conditions of acceptance for each order type:

Price of demand order > MCP Price of supply order < MCP	In-the-Money Orders	Must be fully accepted
Price of demand order = MCP Price of supply order = MCP	At-the-Money Orders	Can be either accepted (fully or partially) or rejected Exception applies to regular block orders: That cannot be accepted partially, totally rejected or accepted (condition of fill or kill)
Price of demand order < MCP Price of supply order > MCP	Out-of- the-Money Orders	Must be rejected

Box 1.4. Various Order Types Under EUPHEMIA

Various order types per local market rule at the same time as below (Price Coupling of Regions, 2016)

Aggregated Hourly Orders (Major Regional Markets: OMIE, APX, Belpex, GME, OTE, NORDPOOL and EPEX)	• All demand and supply orders are aggregated on a curve computing aggregated demand and respective supply (for each period of the day) • Sorting of demand orders: highest to lowest prices • Sorting of supply orders: lowest to highest prices • Aggregated hourly orders can be of linear piecewise curve containing interpolated orders or stepwise curve in which two consecutive points will always have same quantity or same price. • Moreover, hybrid curves can contain property of both piecewise and stepwise curves.
Complex Orders	• **Complex minimum income condition (MIC) orders:** Complex MIC is a set of simple supply stepwise hourly orders bound by a constraint to cover supply production cost, which is the sum of fix and operating cost of power plant (Euros/MWh). • **Complex load gradient orders:** In such orders, the amount of energy matched at certain period is constrained by a maximum increment and decrement condition to the energy matched in previous period of the same day. • Complex order can combine properties of both MIC and load gradient orders
Block Orders	• The key elements of block orders are sense (supply or demand), price limit, number of periods, different volumes for different periods, and minimum acceptance ratio. • **Regular block order:** May consist a consecutive set of periods with the same volume and minimum acceptance ratio of 1. • However, in more diverse cases, volume might be different for different periods. Having consecutive periods is not necessary; acceptance ratio might be less than 1. • **Linked block order:** Acceptance of two block orders can be linked to each other by a particular set of rules. • **Exclusive groups of block order:** Combined various block orders with cumulative acceptance ratio of 1 or less. • **Flexible hourly block order:** Regular block order with flexible period of an hour; hour of supply is determined by EUPHEMIA using optimisation criteria.
Merit Orders and PUN Orders	• **Merit order:** Individual stepwise order for a given period in a bidding area ranked according to merit order (taking into account the most crucial congestion in particular bidding areas). • The lowest the merit order, the highest the chance of acceptance • Works as a mechanism in choosing between different orders in an uncongested adjacent bidding areas offering same price (that is equal to MCP). • **PUN Order:** Merit order (in GME-Italy) cleared on PUN price rather than on MCP. • PUN stands for 'Prezzo Unico Nazionale', Italian for single national price.

To manage transmission constraint better, cross-border flow between bidding areas is allowed under the ATC model, the flow-based model, and the hybrid of both as described below:

Available transfer capacity model: In the ATC model, lines interconnect bidding areas and are limited by available capacity of such lines. Bidding areas are divided into source and sink bidding areas on the basis of direction of possible flow of power. Thus, nomination of the lines or interconnectors is based on its ATC.

EUPHEMIA also takes into account line losses between bidding areas during physical flow of power. Moreover, levy (cost/MWh) to line operator is considered as flow tariff and included in algorithm as loss with regards to congestion rent with a condition:

- If (MCP of Bidding Area A- MCP of Bidding Area B)<Flow Tariff, No Flow
- If (MCP of Bidding Area A- MCP of Bidding Area B)=Flow Tariff, Flow of Power Until Congestion
- If (MCP of Bidding Area A- MCP of Bidding Area B)>Flow Tariff, Positive Congestion Rent

EUPHEMIA puts a constraint on hourly flow ramping limit on individual lines and set of lines as well.

Flow-based model[25]: Under this model, modelling of physical power flow is based on RAM and PTDF. With all bidding areas connected in a meshed network, this model expresses the constraints arising from Kirchhoff's laws and physical elements of network in different contingency scenarios considered by TSOs. It translates into linear constraints on the net positions of different bidding areas.

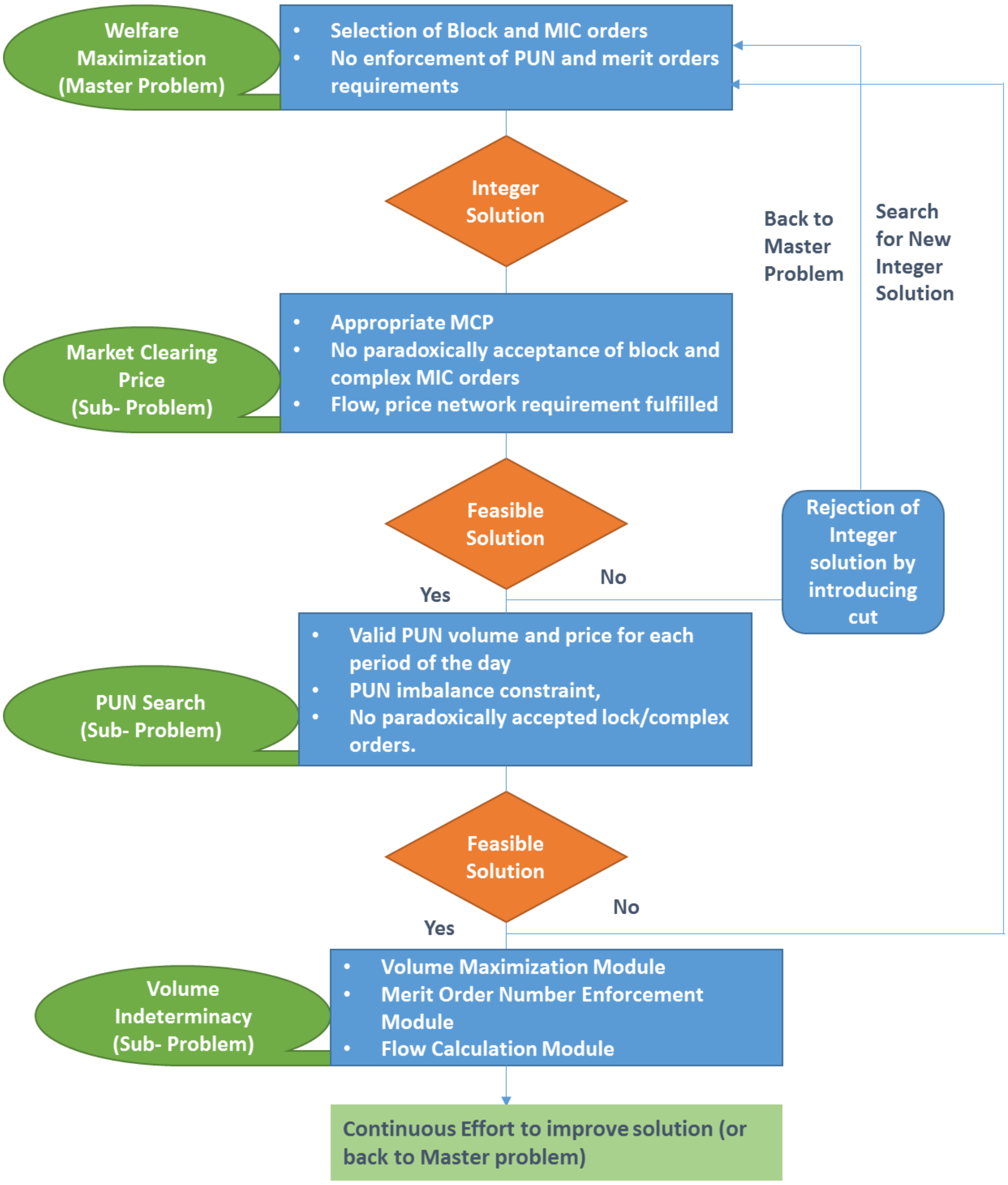
The net position of a bidding area is subject to hourly and daily ramping[26] to add the necessary reserve capacities recurrently.

How the algorithm works: To solve a complex market coupling problem, EUPHEMIA breaks it into simpler problem and models it as quadratic programme. It runs a combinatorial optimisation process aimed to solve a master problem of welfare maximisation and three interdependent sub-problems: price determination, PUN search, and volume indeterminacy (Figure 3.24).

[25] The feasibility of using flow-based model for market coupling is being analysed by several projects and regions across Europe.

[26] Hourly net position ramping refers to a limit on the variation of the net position of a bidding area from one hour to the next. Daily net position ramping is a limit on the amount of reserve capacity that can be used during the day.

Figure 3.24. Algorithm Working Process



MCP = market clearing price, MIC = minimum income condition, PUN = Prezzo Unico Nazionale.
Source: Price Coupling of Regions, 2016; Visit and interaction of study team with various power exchanges across Europe.

Consequently, once completed, the algorithm provides price per bidding area, net position per bidding area, flows per interconnection, matched energy for each block, and MIC and PUN orders. EUPHEMIA produces feasible solutions and chooses the best in line with welfare-maximisation criteria. The chosen results are explainable to market participants and published solution represents the ones with the largest market value while respecting all market rules.

6. Problems and Challenges

The key problems and challenges of the EU target model and PCR for IEM involve:

- **No exclusive provision for integration of renewable energy (specifically wind power) into integrated electricity market:** In addition to achieving an IEM soon, Europe has been working keenly to achieve its targets for reduction of GHG emissions and certain percentage of electricity from renewables under the 2020 and 2030 Climate and Energy Framework. Accordingly, in addition to being a blueprint for market integration, the EU target model for IEM could be the best model to house the guidance rules for renewable energy integration as well and unlock the benefits for electricity market by large-scale deployment of renewable energy technologies. This might also help, under the PCR, to maximise overall welfare by lowering market risks, reducing cost of balancing services, and, ultimately, for generators by lowering market risks in a truly competitive market, for system operators by reducing operation costs of balancing and reserves, and for customers by lowering electricity prices while reducing exposure to fuel and carbon price risk. However, as concluded in Baritaud and Volk (2014), since various renewable energy sources are potential risk for market integration, better coordination and integration of real time markets and harmonisation of integration policy and regulatory frameworks are the recommended approach as adopted under the EU target model.

- **Framework for integrated intraday and balancing markets:** At present, PCR only targets integrated day-ahead market. However, cost-effective and efficient integration of electricity market and closer cooperation between member states might require rolling out a plan to integrate intraday and balancing market (or entire market for ancillary services) as well.
  The resultant large procurement area due to market integration of ancillary services can also help improve the market economy for balancing market and ease the integration of renewable energy systems into the market as widely available resources would take out the pressure from system operator to cut down on renewable energy generators to keep the grid balanced.
- **Demand response management:** As demand response management becomes need for the future as an essential part of smart grids and developed communication solutions, it is unclear how integrated day-ahead market fits well with the concept of demand response bids.

7. Key Findings and Linking with Southeast Asian Region

As concluded in Chang and Li (2012), rapidly increasing energy demand in Southeast Asia and uneven endowment of natural resources make it a perfect case for considering integrated electricity market.

To link the European model to the circumstances in Southeast Asia, the key issues to be discussed include the target model, coordination in network planning and capacity development, developing common algorithms, common business models for generation and transmission, open competition, and sharing infrastructure on the basis of fair compensation.

Looking at the situation of liberalisation and deregulation of electricity markets across Southeast Asia, Singapore was the first country to launch a competitive, liberalised, and deregulated electricity market. The Philippines and Viet Nam have followed the trend by establishing competitive wholesale electricity market. Thailand has yet to introduce whole competition in its electricity market although the state-owned Electricity Generating Authority of Thailand has the sole right to purchase power from private producers including neighbouring countries (Wu, 2012). Similarly, Indonesia has made some efforts toward liberalisation but none has succeeded so far. Malaysia enjoys partial liberalisation. Given this situation, Southeast Asian countries have a long way to go to be able to liberalise, deregulate, and introduce reforms and restructure their electricity markets.

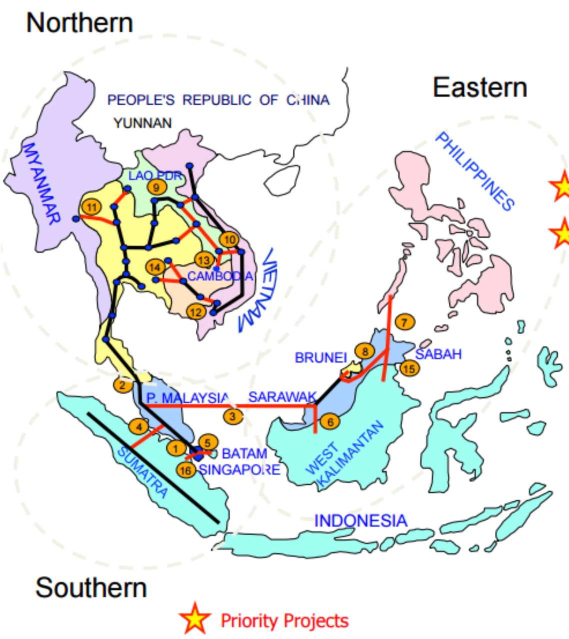
As far as bilateral trade is concerned, significant progress can be seen in terms of a few interconnection projects being promoted by HAPUA under APG (Figure 3.25). However, the cluster 1 and 2 research study aims to highlight the most feasible interconnections across the region and develop optimal power planning and supply reliability evaluation model by using BIMP interconnection.

The policy implications suggested here are deregulation and unbundling, domestic reforms, and subsequent harmonisation of regulation standards.

Considering the findings (Section 2), the European Commission, under the EU's successive energy packages, has put things together by issuing directives and regulations for needed liberalisation, unbundling of TSOs and DSOs, strengthening independence of energy regulators, transparency in the market, and cross-border cooperation.

The Southeast Asian counterpart HAPUA that has been around since 1981 and has recently made efforts toward APG and GMS can potentially play a role similar to that of the European Commission to expedite the efforts to achieve integrated electricity market in Southeast Asia by coming out with directives and regulations.

Figure 3.25. Interconnection Projects, APG



		Earliest COD
1)	P.Malaysia - Singapore (New)	Post 2020
2)	Thailand - P.Malaysia	
•	Sadao - Bukit Keteri	Existing
•	Khlong Ngae - Gurun	Existing
•	Su Ngai Kolok - Rantau Panjang	2016
•	Khlong Ngae – Gurun (2nd Phase, 300MW)	2016
3)	Sarawak - P. Malaysia	2025
4)	P.Malaysia - Sumatra	2019
5)	Batam - Singapore	2020
6)	Sarawak - West Kalimantan	2015
7)	Philippines - Sabah	2020
8)	Sarawak - Sabah – Brunei	
•	Sarawak –Sabah	2020
•	Sabah – Brunei	Not Selected
•	Sarawak – Brunei	2016
9)	Thailand - Lao PDR	
•	Roi Et 2 - Nam Theun 2	Existing
•	Sakon Nakhon 2 – Thakhek – Then Hinboun (Exp.)	Existing
•	Mae Moh 3 - Nan - Hong Sa	2015
•	Udon Thani 3- Nabong (converted to 500KV)	2019
•	Ubon Ratchathani 3 – Pakse – Xe Pian Xe Namnoy	2018
•	Khon Kaen 4 – Loei 2 – Xayaburi	2019
•	Thailand – Lao PDR (New)	2015-2023
10)	Lao PDR - Vietnam	2016-2020
11)	Thailand - Myanmar	2018-2026
12)	Vietnam - Cambodia (New)	2020
13)	Lao PDR - Cambodia	2016
14)	Thailand - Cambodia (New)	Post 2020
15)	East Sabah - East Kalimantan	Post 2020
16)	Singapore – Sumatra	Post 2020

Source: ASEAN Power Grid.

Some of the initiatives that worked as a foundation of integrated electricity market in Europe and could be followed by Southeast Asia include:

- Unbundling of TSOs and DSOs from other players of supply chain;
- Establishment of network of transmission system operators across various countries;
- A short-term plan/network to build a framework for cross-border development, including interconnection and interoperability for a trans-ASEAN power grid network;
- Non-discriminatory network access to third-parties;
- A periodic review of progress by a governance body, e.g. HAPUA, and subsequent feedback and suggestions for way forward to each member country;
- Strengthening the independence of energy regulators; and
- Viable funding mechanisms to support interconnections and other infrastructure to support cross-border trading

As far as infrastructure development is concerned, as recommended in Wu (2012), infrastructure should be at the core of integrated electricity market in Southeast Asia. Europe worked strategically to mandate a minimum x% of interconnections (of their total production capacity) for each country to connect previously isolated countries with European electricity market. Similarly, should Southeast Asia choose to work on a similar theme, a minimum interconnection level for each country is required? As it is, with construction and planned interconnection across Southeast Asia (Figure 3.24) and potential regional integration between CLMV (Cambodia–Lao PDR–Myanmar–Viet Nam) and BIMP (Brunei–Indonesia–Malaysia–the Philippines), a minimum level of interconnection is not being followed so far. For instance, with East Timor intent on joining ASEAN soon, targeting a minimum level of interconnection might help this country in a big way as it is planning to achieve mere eight percent electrification rate in the country.

Prioritising infrastructure projects in general and interconnections in particular could be developed on the basis of Europe's 'project of common interest' mechanism or economically viable projects on interconnections and renewable energy.

Regarding market design and harmonisation of technicalities, standards, and principles, the potential integrated market in Southeast Asia should aim for integrated organised market with provision for real time and spot market.

Balance market and financial markets are necessary for wholesale market to function properly.

Southeast Asia could focus on gradual price coupling of day-ahead regional markets. As Southeast Asia has just embarked on a journey to achieve an integrated market and as some of the countries are still working to achieve liberalisation in national markets, it is not possible to follow Europe's footsteps in each and every aspect of market coupling. However, the recommended steps as of now are gradual price coupling of day-ahead markets, e.g. price coupling of BIPM region, and exploring the option to adopt implicit auction mechanism so capacity and energy could be auctioned together in a day-ahead market.

As price coupling of day-ahead market uses a single algorithm to find market clearing price and matched volume, allocates efficiently cross-border capacities, and focuses on optimum social welfare, it would require comprehensive efforts from authorities (e.g. HAPUA) to develop a similar algorithm and work closely with TSOs in each region to identify and bifurcate considered regions into different bidding areas.

As to technical details of cross-border capacity allocation, ATC and FBMC are the latest mechanisms used in Europe. Considering the present limited interconnections in Southeast Asia, FBMC could be used to interconnect more efficiently and take into account the congestion in critical lines.

The major challenges we see regarding market coupling of spot markets across Southeast Asia are the need for comprehensive and precise institutional mechanism and overall governance to actively work on harmonisation of standards, codes, roles, and responsibilities of all parties involved; close coordination among TSOs and with market operators; fair selection of nominated market operators; and various other related aspects.

To conclude, on the basis of all the problems and challenges identified in Section 6 and 7, the key findings of the Europe study model, and linking the countries in the region under consideration, a preliminary model of integrated electricity market across Southeast Asia will be developed under research work of cluster 3 in year 2.

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Chapter 4

Electricity Market Integration in ASEAN: Institutional and Political Barriers and Opportunities

Yanrui Wu

Since the announcement of the construction of an integrated ASEAN power grid (APG) almost 2 decades ago, progress in this ambitious project has been slow. Coincidentally, a similar programme in the European Union (EU) has been fully embraced and moved well ahead of ASEAN's. The EU now has the most integrated electricity market. Its experience and lessons have important implications for ASEAN. This report aims to investigate the barriers, especially institutional and political barriers, to electricity market integration in ASEAN. It also discusses practical policy options to accelerate market integration in the ASEAN power sector.

1. Introduction

Electricity market integration was initially promoted by countries aiming to interconnect their domestic grids and develop nationwide integrated domestic power markets. Examples include the United States and the United Kingdom (Wu, 2013). Domestic market integration has naturally been extended to cross-border integration, partly driven by cross-border power trade. Traditionally, the perceived benefits from an integrated market include economies of scale, better management of peak demand and improved efficiency in power supply, and potentially lower electricity prices (Wu, 2013). The development and growth in renewable energies have provided new impetus for the promotion of cross-border electricity market integration aimed to help countries deal better with peak demand and intermittency in production and use abundant renewable energy resources more efficiently. These factors are also cited as the drivers for the development of an integrated electricity market among the economies of the Association of Southeast Asian Nations (ASEAN), particularly the construction of the ASEAN Power Grid (APG). APG aims to ensure regional energy security, enhance cross-border electricity trade, promote efficient utilisation of resources, and share surplus reserve generation capacity between member states (Ibrahim, 2014).

Only 3 percent of total electricity output is exported globally compared to about 64 percent of oil, 31 percent of gas, and 16 percent of coal (Oseni and Pollitt, 2014). ASEAN is a net power importer (from China) and its total trade in electricity accounted for about four percent of total electricity output in 2013 (IEA, 2015a, 2015b). Thus, progress in cross-border trade in electricity has been slow globally as a result of various economic, social, and geopolitical factors.

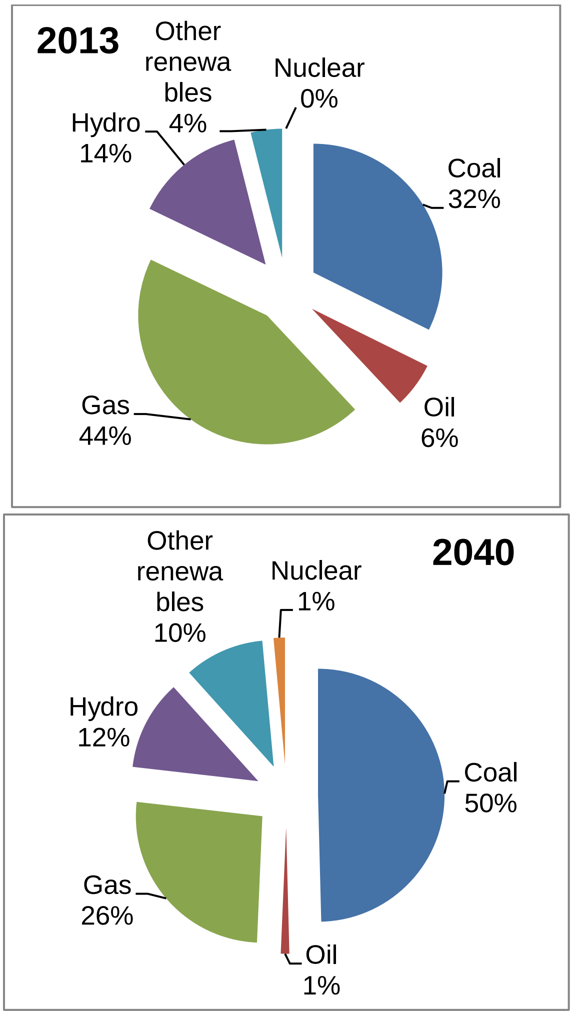
This report aims to explore the institutional and political barriers to electricity market integration in ASEAN and provide policy recommendations for discussion and possible implementation by policymakers. The research method is based on a comparative study of the electricity market of the European Union (EU). Section 2 is a brief review of the electricity sector in ASEAN. Section 3 is an assessment of electricity market integration in the EU. Section 4 discusses the institutional and political barriers to electricity market integration in ASEAN. Policy recommendations are provided in Section 5. The chapter concludes with a summary of the main findings in Section 6.

2. ASEAN Electricity Sector

Electricity generation in ASEAN is projected to grow by 3.9 percent annually from 2013 to 2040. This is almost double the two percent growth rate of final energy consumption during the same period (IEA, 2015b). The largest power-consuming sectors are residential and service buildings and industry. In 2013, 82 percent of ASEAN power was generated by fossil fuels with the remainder coming from renewables which are dominated by hydropower. This situation will largely be unchanged by 2040, with 77 percent electricity-generation share from fossil fuels, 22 percent from renewables, and 1 percent from nuclear power (Figure 4.1). Coal-fired power generation will maintain its dominance in ASEAN.

In 1997, APG was proposed as a flagship programme of the ASEAN Version 2020 and was further promoted in 2003 as part of the plan to establish an ASEAN Economic Community (AEC) by 2015 (Figure 4.2). Its anticipated benefits include effective development and optimal use of power-generation resources, reduced capital investment by capitalising on the difference in peak demand time, and ensured security and reliability of regional electricity supply (Chang and Li, 2013 and 2015; Hermawanto, 2015). It was also argued that an integrated power market would give ASEAN a bigger role politically in regional and global energy affairs and a louder voice at the table when negotiating with the large economic powers (Deloitte, 2015).

Figure 4.1. Electricity Generation Shares by Fuel in 2013 and 2040



Source: IEA.

Although APG and a similar integration programme in Europe were initiated almost at the same time, progress in APG has been much slower than the EU programme (Figure 4.2). In 2015, the EU formally adopted the Energy Union strategy at the same time that the ASEAN Plan of Action for Energy Cooperation (APAEC) 2016–2025 was announced. APAEC is a series of documents on guiding policy to support energy cooperation and advance market integration within ASEAN. The theme of APAEC 2016–2025 is the enhancement of energy connectivity and market integration in ASEAN to achieve energy security, accessibility, and sustainability for all.

Figure 4.2. Timetable of Power Market Integration in Europe and ASEAN

Europe	Year	Southeast Asia
European Economic Community	1959	
	1967	ASEAN
	1992	AFTA
European Union	1993	
First electricity directive	1996	
	1997	APG (ASEAN Power Grid)
Euro	2002	
Second electricity directive	2003	ASEAN community by 2015
Third legislative package	2009	
Energy Union	2015	APAEC 2016–2025

Source: Author's own work.

With the heads of ASEAN power utilities/authorities (HAPUA) coordinating, some cross-border connectivity has been achieved since the implementation of the ASEAN Interconnection Master Plan Study 2003 (AIM I) (Table 4.1). Under the ASEAN Interconnection Master Plan Study 2010, nine projects were supposed to be completed by 2015 and six more after (Wu, 2013). According to Hermawanto (2015), 11 cross-border interconnections with power capacity of 3,489 MW exist. Ten projects with capacity of 7,192 MW are in progress and their completion expected in 2018/2029. Beyond 2020, there will be at least 17 cross-border interconnections with power capacity of 25,424 MW (Hermawanto, 2015).

Table 4.1. ASEAN Power Grid Interconnections and Projects (MW)

Connection	Existing	Ongoing	Future
Lao PDR–Cambodia		300	
Lao PDR–Viet Nam	248	290	
Malaysia–Indonesia		600	
Malaysia–Singapore	450		600
Philippines–Sabah			500
Sarawak–P. Malaysia			3,200
Sarawak–Sabah–Brunei		200	100
Sarawak–West Kalimantan		230	
Singapore–Indonesia			1,200
Thailand–Cambodia	100		2,200
Thailand–Lao PDR	2,111	3,352	1,865
Thailand–Malaysia	380	100	300
Thailand–Myanmar			11,709-14,859
Viet Nam–Cambodia	200		
Total	3,489	5,072	21,674-24,824

Source: Hermawanto.

In 2002, countries in the Greater Mekong Sub-region (GMS) signed an inter-governmental agreement on regional power trade, after which a regional power trade coordination committee was formed the following year. One of the committee's tasks is to investigate options for a future GMS power market. By 2016, a formal market is yet to emerge.

Although the process in market integration is slow, some connectivity has already been achieved among the GMS economies (Cambodia, China's Yunnan province, Lao PDR, Myanmar, Thailand, and Viet Nam). In particular, bilateral trade is expanding (Table 4.2), with China, for example, starting to export electricity to Viet Nam in 2004. China's total exports reached 5.7 billion kWh in 2010. China also started importing electricity from Myanmar in 2008 that reached a total of 1.7 billion kWh in 2010. China's exports to Lao PDR started in 2009. In the lower Mekong region, Viet Nam and Thailand are net importers of electricity while Lao PDR is a net exporter (Table 4.2). Electricity exports from Lao PDR amounted to about 30 percent of total national exports and 10 percent of the country's gross domestic product (Lamphayphan et al., 2015). Cambodian electricity imports amounted to 385 million kWh from Thailand and 1162 million kWh from Viet Nam in 2010 (Poch and Tuy, 2012). Combined, these two sources accounted for about 60 percent of total electricity consumption in Cambodia that year.

Table 4.2. GMS Power Trade, 2010 (GWh)

Member	Import	Export	Total
Cambodia	1,546		1,546
Lao PDR	1,265	6,944	8,210
Myanmar		1,720	1,720
Thailand	6,938	1,427	8,366
Viet Nam	5,599	1,318	6,917
PRC	1,720	5,659	7,379
Total	17,069	17,069	34,138

GWh = gigawatt hour.
Source: Nai.

The latest development is to carry out the Lao PDR, Thailand, Malaysia, and Singapore Power Integration Project (LTMS-PIP), a multilateral trade pilot project, endorsed at the 32nd ASEAN Ministers on Energy Meeting in 2014, that aims to export 100 MW of electricity from Lao PDR to Singapore via Thailand and Malaysia. This pilot project is expected to showcase multilateral electricity trading beyond neighbouring borders in ASEAN. However, a much-anticipated LTMS memorandum of understanding was not signed during the meeting in October 2015 (AMEM, 2015) because Singapore has a competitive bidding system for power supply while the electricity utilities in the other three countries are vertically integrated. The four countries have to figure out how to absorb the 100 MW transmitted power.

Overall, electricity market integration in ASEAN is making slow progress. APAEC 2016–2025, ASEAN's latest policy document, has no clear timetable. Multiple factors are slowing down progress toward integration, with the unequal level of development of member state economies within ASEAN, poor infrastructure in the power sector, and domestic protectionism as some of the commonly cited economic factors (Ibon, 2015). It was also argued that the December 2015 deadline for the completion of APG was overly ambitious (Dosch, 2015). The political and institutional barriers that slow the progress in market integration are discussed later in this chapter.

3. Electricity Market Integration in the EU

The EU leads the world in electricity market integration. Thus, understanding the EU process of electricity market reform and integration may offer important insights for the development of an integrated power market in ASEAN. While the formation of the EU has its origin in the creation of the European Economic Community in 1957, the idea of developing a single electricity market only emerged in the 1980s (Pellini, 2014). European countries took the first step to integrate their electricity market through the enactment of the first electricity derivative in 1996 (1996/92/EC). The EU 1996 derivative introduced competition in the production and supply segments of the power industry and allowed non-discriminatory third party access to networks. It was extended and strengthened by the second electricity derivative (2003/54/EC) in 2003 and the third legislative package (2009/72/EC) in 2009. For about 2 decades, EU members have been working on harmonising national market and network rules for the electricity and gas sectors and making investment in these sectors easier. By 2011, the EU's electricity exports of 315 TWh amounted to 10 percent of the total demand of 3,080 TWh (Newbery et al, 2015). In February 2015, the French and Italian grids were connected, linking the major power markets in the EU. In the same year, the EU formally launched the Energy Union strategy, with the new target of reaching 15 percent interconnection capacity by 2030 (IEA, 2015b).

Since the release of the first electricity derivative 20 years ago, the EU electricity markets have become increasingly integrated, even if the targeted completion of the integration process in 2014 was not met. Several factors may have been responsible for the delay. It is argued that legislative adjustment by some member states has been slow due to concerns with national interests (de Menezes and Houllier, 2016). The most important among these concerns is energy security, which is being linked with other economic and political affairs (Karan and Kazdagli, 2011). These concerns are forcing EU member states to maintain significant control of their domestic energy markets and relationship with energy exporters (Belkin, 2008). Some member states also fear that interconnections may affect their energy producers who might resist new investment in infrastructure (Lada et al, 2016). Failure to realise network development plans makes it difficult to trade across borders and could even force markets to split. Zachmann (2015) reckons that energy and climate-change policy-making in the EU is being renationalised, a trend that is hindering the progress of market integration. In some cases, overcapacity of generators has led to lack of incentives for innovation (Karan and Kazdagli, 2011).

However, the Russia–Ukraine and Russia–Belarus disputes in 2005 and 2007, respectively, alerted the members of the EU to the potentially undesirable consequences of relying upon external energy resources. Some observers have characterised the two crises as wake-up calls for the EU's energy security (Karan and Kazdagli, 2011). In March 2007, due to increasing concerns about the EU's energy security and global climate change, its member states agreed to forge an energy policy for Europe and many members set up targets for renewable energy development. For example, the EU/20/20/20 aims to reduce overall greenhouse gas emissions by 20 percent and increase energy efficiency by 20 percent relative to the 1990 levels by 2020. To achieve these goals, the EU targets to generate 20 percent of total electricity required through renewable energies by 2020 (Boethius, 2012). In addition, the EU has also committed itself to reduce emissions by 80–95 percent by 2050.

In summary, apart from economic factors (not discussed in this chapter), political drivers are underlying the EU electricity market integration. Continuous concerns with energy security are transformed into strong political will among EU leaders to explore and make better use of internal energy resources or renewables. The growing political will has timely coincided with climate change commitments. This is the background for the proposal to establish an energy union in Europe, the objective of which is to provide energy security, promote decarbonisation, and improve competition in the electricity market (Helm, 2015). In addition, it is also argued that an integrated power market could boost the EU's influence on energy matters at the global level (Boethius, 2012).

4. Institutional and Political Barriers in Southeast Asia

Even though the EU missed its target of completing electricity market integration process by 2014, it remains the most successful region in terms of institutional building and market integration and offers important lessons for other regions, particularly Southeast Asia. Given their current economic, social, and political conditions, Southeast Asian economies must overcome several institutional and political obstacles to develop an integrated electricity market.

First, political will is important to develop an integrated power grid in Southeast Asia. In the case of the EU, the desire to achieve energy sustainability, competitiveness, and security of supplies has made the integration of the European electricity markets one of the EU's top political and economic projects (Boethius, 2012). There are many similarities and differences between the EU and ASEAN, among the main differences of which is that, with the exception of Denmark and the Netherlands, almost all EU countries are net importers of oil and gas while ASEAN member states are either net importers or net exporters (Table 4.3). While there is no shortage of official exchanges and cooperation in the ASEAN energy sector, political will still plays an important role in the eventual realisation of APG. It has been reported that governments may be less keen to support APG due to the need to protect their own energy sectors (Kumar, 2015) while others emphasise the priority of developing their national grids (Olchondra, 2016). As the power sector is still dominated by state utilities in most ASEAN economies, a top-down approach could be very effective. The direct involvement of governments in the power sector implies relative ease in reaching internal consensus about rules, regulations, and reforms. Therefore, if ASEAN authorities can work out some consensus-based minimum requirements for power sector integration, these could easily be accepted and implemented by the member states.

Table 4.3. ASEAN Oil and Gas Import Dependency in the 2000s

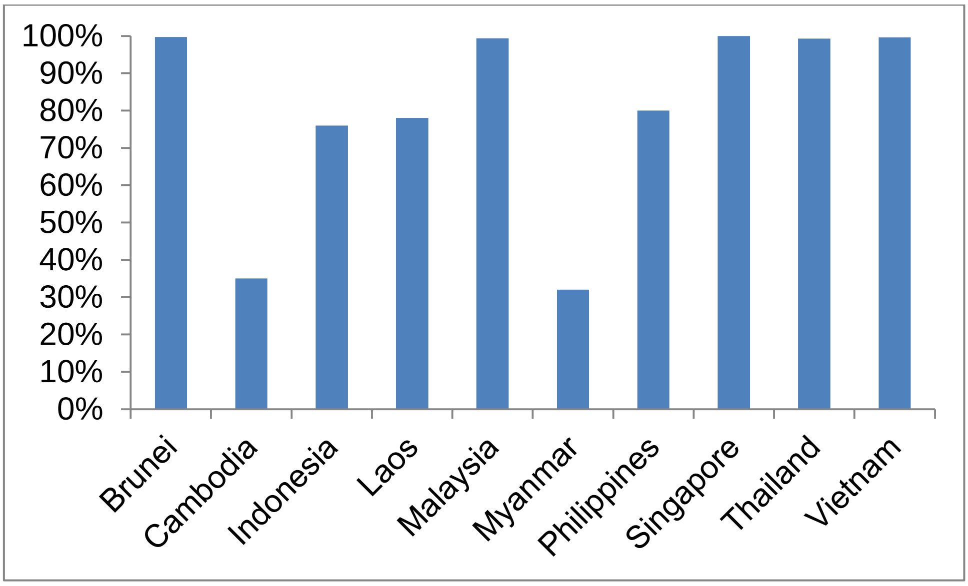
Member	Oil	Gas
Brunei	Negative	Negative
Malaysia	Negative	Negative
Indonesia	42%	Negative
Myanmar	50%	Negative
Viet Nam	Negative	0%
Cambodia	100%	0%
Lao PDR	100%	0%
Philippines	95%	0%
Thailand	70%	24%
Singapore	100%	100%

Source: Author's own work using information from Boethius (2012), Swe (2013), Enerdata (2014), and Sinocruz et al. (2015).

Second, while the top-down approach toward electricity market integration may be important, an integrated power market cannot be developed without the participation of the private sector. It is argued that achieving interconnection in ASEAN depends on how its member states and involved companies cooperate and deepen their relationships (IEA 2015b). In fact, the private sector plays a key role in electricity market integration in Europe (Boethius, 2012). Through public–private partnerships, the EU has made strategic investment in European energy infrastructure, energy research, and clean energy production. The private sector in Europe has also become a key stakeholder, actively lobbying for the integration of the EU electricity markets. In 2014–2015, a research project on 'public–private partnership (PPP) to be applied to the APG' was conducted by the HAPUA Working Group 4 (Ibrahim, 2014). It seems ASEAN policymakers are addressing this matter with public–private partnership guidelines through formal discussions (Zen and Regan, 2014; ERIA 2015).

Third, the role of international organisations, especially regional organisations such as the Asian Development Bank and the Asian Infrastructure Investment Bank, is important. Many countries in the region are underdeveloped in terms of transmission grids and other electricity infrastructure. For example, the rate of electrification in some ASEAN member countries is still very low (Figure 4.3). The construction of APG needs substantial investment in capacity building (Kutani and Li, 2014; Li and Chang, 2015). Other regions in the world have to overcome the same problem in their pursuit of electricity market integration. For example, the central African power market, established in 1998, received substantial financial support from multilateral lenders, with the Inter-American Development Bank providing over half of the initial funding (Oseni and Pollitt, 2014). One of the main factors that underline the success of the Nordic power market is its sufficient transmission capacity (Boethius, 2012). To achieve the goal of an integrated electricity market, ASEAN needs financial support from regional and international organisations.

Figure 4.3. Electrification Rates in ASEAN, 2012



Note: The rates for Brunei, Cambodia, and Laos (Lao PDR) are from information collected in 2011 and that for Thailand in 2013.
Source: IEA.

Fourth, it is argued that cross-border trade in electricity may lead to more use of low-cost coal for power generation or more development of hydropower and that these may worsen the natural environment situations in power-exporting countries. This argument, however, is not supported by empirical evidence. On the contrary, Antweiller et al. (2001) have argued that electricity trade can help the spread of low-emission technology and thus is generally good for the environment. In Southeast Asia, where hydropower plays an important role in cross-border trade, the environmental impact of said power resource is not limited to the exporting countries as multiple countries share water systems such as the Mekong River. Damming the river could have serious environmental consequences and might lead to conflicts between neighbours. The Lao PDR government has already been criticised for relying exclusively on hydroelectricity and for its inaction in development of renewables (Pryce, 2015). ASEAN member states have to work together to minimise negative externalities and expand the production of wind and solar power.

5. Policy Recommendations

This section summarises five policy recommendations for ASEAN policymakers. These recommendations call for institutional capacity building, coordination in national capacity building and reforms, increasing cross-border power trade and establishment of sub-regional electricity markets, public–private partnership, and promotion of renewables.

5.1 Strengthening and Building Institutional Capacity

In general, ASEAN has been successful in building institutional capacity in the region since its inception in the late 1950s. In the energy arena, HAPUA was initially created by ASEAN-5 (Indonesia, Malaysia, the Philippines, Singapore, and Thailand) in 1981. Other ASEAN member states joined later.

It has been commented that ASEAN's tendency to focus on reforms within individual member economies rather than between countries may be a major barrier to the progress of APG (IEA, 2015a). HAPUA could adopt some consensus-based minimum requirements for implementation by member countries as the EU did through its electricity derivatives in 1996, 2003, and 2009 (Jamasb and Pollitt, 2005). Given that most ASEAN member states are still developing their own regulatory systems and reforming their power sectors, consensus-based minimum standards could be adopted with relatively little resistance and their implementation would lay a good foundation for the eventual market integration. These minimum standards could be related to technical, legal, and regulatory aspects and would serve as key building blocks for important ASEAN institutions in the near future.

Improving coordination in national capacity building and reforms

ASEAN countries are still expanding their power facilities and undertaking regulatory reforms. Ideally, national capacity building and reforms could accommodate some of the consensus-based objectives of regional market integration. Achieving this goal involves coordination between individual member states and ASEAN. Without interfering in a member state's internal affairs, ASEAN could work with relevant authorities so that the national capacity building and reforms of the member state are at least partially if not fully aligned with the goals of an integrated ASEAN power market. This could be a cost-effective way of minimising differences between member states and accelerating regional integration.

Encouraging bilateral or sub-regional power trade

International experience shows that market integration is realised through three steps. The first is the emergence of bilateral cross-border trade. In the case of ASEAN, this took place in 1972 when the first dam was commissioned in Lao PDR and hydropower was sold to Thailand (Lamphayphan et al., 2015). The second step is encouraging sub-regional power trade. Currently, GMS is the leader in ASEAN. A subregional power market involving GMS countries may emerge in the future. It is argued that bilateral and subregional trade is much less complicated than multilateral trade as the latter involves many specific and technical issues which ASEAN can deal with in the future. Using bilateral and subregional trade as a catalyst for an integrated market has also been adopted in other regions. For example, the EU promoted the Nordic, UK–Ireland, Western Europe regional markets as intermediate stage toward full interconnection before market integration (Jamasb and Pollitt, 2005). Empirical evidence also shows that geographically close or well-connected electricity spot markets have longer periods of price convergence (de Menezes and Houllier, 2016). Another example is the Southern African Power Pool established in 1995 (Oseni and Pollitt, 2014). South African power generation is dominated by coal (74 percent) and hydro (20 percent). Initially, South Africa's bilateral trade accounted for 90–95 percent traded energy. While bilateral trade agreements provide security of supply, these are not flexible enough to accommodate varying demand and price profiles. South Africa's cross-border trading led to a rise in investment in national capacity building and a day-ahead market was introduced in 2009. Although only six percent of energy demand was traded in the day-ahead market in 2012–2013, the Southern African Power Pool has now become the most integrated system in Africa (Oseni and Pollitt, 2014). Thus, while the construction of APG is slow, ASEAN could adopt policies to encourage more bilateral and subregional trade.

In addition, it is argued that ASEAN's achievements so far are based on the so-called 'ASEAN way' (Deloitte, 2015), a uniquely Southeast Asian approach to multilateralism that rests firmly on the principles of consensus, non-binding, non-interference, and non-confrontation (Bosch, 2015). Although it has served ASEAN well for decades, it has its share of criticisms for its lack of regulatory advancement. It is due to the 'ASEAN way' that progress in integration has been slow but steady (Deloitte, 2015). Bosch (2015) reckons that ASEAN is still the most 'effective and coherent organisation' outside the EU. When consensus is hard to reach, a mechanism such as the 'ASEAN-X' system can help move things forward by exploring the options of establishing subregional markets first. Possible candidates include GMS, BIMP, and ASEAN-4 (Indonesia, Malaysia, Singapore, and Thailand) regions. A GMS market is possible because of existing interconnection facilities and trading activities. The ASEAN-4 market could be an option because of the geographic closeness and relative economic prosperity of these countries. However, these markets should be established within the framework of the broad regional market development.

Building public–private partnership

Most ASEAN member states are still confronted in their power sectors with the problems of accessibility and affordability. Investment infrastructure is facing a shortage of capital. PPP not only brings important sources of funding from the private sector but also provides skills and knowledge to private investors by way of their involvement in similar projects in other places of the world. With the private sector's participation, ASEAN governments or regional authorities can focus on their regulatory roles to create a legal environment for rule-based and transparent market institutions. In addition, ASEAN could also partner with other regional and international organisations such as the Asian Development Bank and World Bank to leverage additional capacities and knowhow which can contribute to the realisation of APG.

Table 4.4. Renewable Development Targets by ASEAN Member States

Member	Commitment	Year
Brunei	10% power	2035
Cambodia	More than 2 GW hydropower	2020
Indonesia	23% of total primary energy	2025
Lao PDR	30% of total energy consumption	2025
Malaysia	34% of installed capacity	2050
Myanmar	15–20% of installed capacity	2030
Philippines	15 GW of installed capacity	2030
Singapore	350 MW solar capacity installed	2020
Thailand	25% of total energy consumption	2021
Viet Nam	6% of power generation	2030

Source: Velautham.

Promoting renewable energies

The growth of renewable energies has been the new driver for electricity market integration as interconnection allows better accommodation of intermittency. This is particularly the case in regions where renewable resources are abundant. According to APAEC 2016–2025, ASEAN aims to increase the share of renewable energy to 23 percent of total energy demand by 2025. Some member states are expected to reach a higher level (Table 4.4). This growth in renewables could be exploited to help promote interconnectivity and attain electricity market integration. Currently, ASEAN's renewables are dominated by hydropower. Policy makers could explore the possibility of expanding other forms of renewables such as wind and solar energies.

6. Conclusion

This report discusses the political and institutional barriers to the formation of an integrated ASEAN electricity market. A brief review of the power sector development in ASEAN identifies considerable progress toward cross-border power interconnection or APG, one of the broad ASEAN economic integration goals. However, compared with the EU integration process, the progress in ASEAN has been very slow. Many economic, social, institutional, and political factors underline the slow progress. This report focuses on the institutional and political aspects. First, although politicians in Southeast Asian countries have for several decades shown leadership in building ASEAN as a community, their political will could have been compromised due to vested interests, nationalism, and so on. Second, one of the factors underlying the EU's success is the participation of the private sector through the integration process. ASEAN, particularly APG, is pretty much an inter-governmental and consensual programme with little input from the private sector. This may reflect the inter-governmental approach toward integration in ASEAN, in contrast with the EU that adopts a legalistic approach based on a stringent regulatory framework. The latter provides a necessary level playing field for the private sector. The absence of the private sector's participation hinders access to the much needed private capital and expertise. Third, large disparity exists among member states in terms of economic and infrastructure development. The requirement for investment is far beyond the resources available in ASEAN. Thus, apart from the private sector, regional and international organisations should play a crucial role in ASEAN's capacity building. Experience from other regional integration practices shows that expertise and funds from regional and international organisations can accelerate market integration. Finally, due to development gaps and diversity among member economies, bilateral cross-border power trade could be encouraged as an intermediate step toward multilateral trade and eventually a fully integrated ASEAN power market.

Given the institutional and political barriers discussed, this report offers the following policy recommendations for ASEAN authorities.

- *Strengthen and build institutional capacity.* HAPUA could adopt some consensus-based minimum requirements for implementation by member states.
- *Improve coordination in national capacity building and reforms.* Member states can align domestic reforms and capacity building with consensus-based regional market integration objectives.
- *Encourage bilateral and sub-regional power trade.* As bilateral trade expands, trading partners are likely to clamour for more changes and compliance which form the basis for more connectivity and eventual integration.
- *Build public–private partnership.* Private sector capital and experience gained in other parts of the world can help build an integrated ASEAN power market.
- *Promote renewable energies.* Renewable growth demands a large interconnected grid and helps ASEAN member states meet their emissions control obligations.
- *Explore the possibility of subregional market integration.* This can be used as an intermediate step toward full market integration.

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