

Power Interconnection in ASEAN Region

Lessons learned from international experiences

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Abbreviations and Acronyms

ACE	ASEAN Centre For Energy
ACER	Agency for the Cooperation of Energy Regulators
ADB	Asian Development Bank
AERN	ASEAN Energy Regulators' Network
AIMS	ASEAN Interconnection Master Plan Studies
APAEC	ASEAN Plan of Action for Energy Cooperation
APG	ASEAN Power Grid
APGCC	ASEAN Power Grid Consultative Committee
ASEAN	Association of South East Asian countries
BLNS	Botswana, Lesotho, Namibia and Swaziland
BOOT	Build-Operate-Own-Transfer
BOT	Build-Operate-Transfer
BPC	Botswana Power Corporation
CAPP	Central African Power Pool
CBA	Cost-Benefit Analysis
CCGT	Combined Cycle Gas Turbine
CEC	Copperbelt Energy Corporation
CEE	Central and Eastern Europe
CEER	Council of European Energy Regulators
CEF	Connecting Europe Facility
CfD	Contract for Difference Contracts
CHP	Combined Heat and Power
COMESA	Common Market for Eastern and Southern Africa
CSG	China Southern Power Grid
CWE	Central and Western Europe
DEPD	Department of Energy Promotion and Development
DIS	Directorate of Infrastructure and Services
DOE	Department of Electricity, Laos
DSO	Distribution System Operator

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EAPP	Eastern Africa Power Pool
EDC	Electricité du Cambodge
EDL	Electricité du Laos
EDM	Electricidade de Mozambique
EGAT	Electricity Generating Authority of Thailand
EMA	Energy Market Authority, Singapore
EMC	Energy Market Company, Singapore
ENE	Empresa Nacional de Electricidade
ENTSO-E	European Network of Transmission System Operators for Electricity
EPAD	Electricity Price Area Differentials
EPEX	European Electricity Exchange
ERC	Energy Regulatory Commission
ERIA	Economic Research Institute for ASEAN and East Asia
ESCOM	Electricity Supply Corporation of Malawi
ESI	Energy Studies Institute, Singapore
ESMAP	Energy Sector Management Assistance Program
ETS	Emission Trading Scheme
EU	European Union
FIT	Feed-in-Tariff
FPM	Forward Physical Market
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GMS	Greater Mekong Subregion
GWh	Gigawatt-Hour
HAPUA	Heads of ASEAN Power Utilities/Authorities
HCB	Hidroeléctrica de Cahora Bassa
HVDC	High-voltage direct current
ICEM	International Centre for Environmental Management
ICER	International Confederation of Energy Regulators
IEA	International Energy Agency, France
IEEJ	Institute of Energy Economics, Japan
IGA	Intergovernmental Agreement
IGSO	Independent Grid System Operator
INDC	Intended Nationally Determined Contribution
IPP	Independent Power Producer
ISO	Independent System Operator
ITC	Independent Transmission Company

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KAS	Konrad-Adenauer Stiftung
LEC	Lesotho Electricity Corporation
LHPC	Lunsemfwa Hydro Power Company
LHSE	Lao Holding State Enterprise
LMB	Lower Mekong Basin
LNG	Liquified Natural Gas
LPG	Liquified Petroleum Gas
LTMS	Laos, Thailand, Malaysia, Singapore
MEA	Municipal Electricity Agency
MEM	Ministry of Energy and Mines
MoEN	Ministry of Energy
MoF	Ministry of Finance
MoU	Memorandum of Understanding
Mt	Million tonnes
MTI	Ministry of Trade and Industry, Singapore
Mtoe	Million Tonnes Oil Equivalent
MW	Megawatt
NEM	New Economic Mechanism
NEMS	National Electricity Market of Singapore
NEPC	National Energy Policy Council
NEW	Northwestern Europe
NPC	Nord Pool Consulting
NRA	National Regulatory Agency
OCGT	Open Cycle Gas Turbine
OTC	Over the Counter Contracts
PCI	Projects of Common Interest
PEA	Provincial Electricity Agency
PIDA	Programme for Infrastructure Development in Africa
PPA	Power Purchase Agreement
PPP	Public–Private Partnership
REC	Regional Economic Community
REMIT	Regulation on Energy Market Integrity and Transparency
RERA	Regional Electricity Regulators Association
RPCC	Regional Power Coordinating Center
RPTCC	Regional Power Trade and Coordinating Committee
SADC	Southern African Development Community
SADCC	Southern African Development Coordination Conference

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SAPP	Southern African Power Pool
SEC	Swaziland Electricity Company
SGX	Singapore Exchange
SIDA	Swedish International Development Agency
SNEL	Societe Nationale d'Electricite
SOME	Senior Official Meeting on Energy
SPV	Special Purpose Vehicle
SWE	Southwestern Europe
TAGP	Trans-ASEAN Gas Pipeline
TANESCO	Tanzania Electricity Company
TAU	Technical and Administrative Unit
Tcf	Trillion Cubic Feet
TNB	Tenaga Nasional Berhad of Malaysia
TSOs	Transmission System Operators
TWh	Terawatt-Hour
TYNDP	Ten-Year-Network-Development-Plan
UN	United Nations
WAPP	West African Power Pool
ZESA	Zimbabwe Electricity Supply Authority
ZESCO	Zesco Limited

Foreword

The demand for electricity is steadily increasing in ASEAN member states in tandem with ongoing economic and population growth. Although ASEAN countries have abundant and diversified energy resources, the uneven distribution of these resources and different stages of economic development among the member states make addressing growing demand needs challenging. International Energy Agency (IEA) states that ASEAN needs to deploy 354 gigawatts of additional capacity for power generation by 2040 which would require investments of US\$618 billion in generation and US\$690 billion in the transmission and distribution sectors.

The ASEAN Plan of Action for Energy Cooperation (APAEC) recognises that integrating power grids and enabling cross-border electricity trade can help ASEAN address its regional energy challenges. Interconnections increase energy security and power system reliability, create economic opportunities and empower forming new partnerships. There has been particular interest in tapping the hydropower potential in Mekong region for domestic use and cross-border interconnections to supply growing demand in Thailand, Malaysia and Singapore.

This report analyses development of power interconnection in ASEAN with a focus on the recently announced pilot project between Lao PDR, Thailand, Malaysia and Singapore (LTMS). In our analysis, we provide an overview of the evolution of electricity interconnection and trade in three international markets we believe to be relevant for ASEAN, specifically: Southern African Power Pool, European electricity markets and Nord Pool. We also discuss the progress of the ASEAN countries in regional energy integration with a particular focus on the Greater Mekong Subregion (GMS) interconnection, the first significant project in ASEAN that involves several countries sharing power.

Drawing upon some common themes across three international cases, we finally draw lessons for pursuing integration activities between LTMS countries and discuss possible approaches in establishing a common market for electricity in ASEAN.

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The opinions expressed in this article are the authors' own and do not reflect the position of the the Konrad-Adenauer-Stiftung (KAS).

Executive summary

This report analyses development of power interconnection in ASEAN, focusing on the recently announced interconnection line between Lao PDR, Thailand, Malaysia and Singapore (LTMS). In our analysis, we provide an overview of the evolution of electricity interconnection and trade in three international markets we believe to be relevant for ASEAN, specifically: Southern African Power Pool (Chapter 2), European electricity markets (Chapter 3) and Nord Pool (Chapter 4). We also discuss the progress among ASEAN countries in regional energy integration with a particular focus on the Greater Mekong Subregion (GMS) interconnection, the first significant project in ASEAN that involves several countries sharing power.

In the review of the experiences of selected regional electricity markets around the world, we identify some key elements of integration that emerged independently as those markets evolved. These are:

- coordinated physical infrastructure development;
- standardized and harmonized rules of operation;
- some form of market competition; and
- empowered governing or coordinating institutions.

Prioritization of these elements and the sequence of steps to achieve them the steps are not straightforward, as they depend on the regional market's environment and history. As such, these elements are still undergoing development in studied international markets.

Market integration in Europe adopted a more top-down integration approach, capitalising on the legal system of the European Union. In contrast, Nordic and Southern African markets developed on incremental and voluntary basis, driven by the utilities themselves. Given diverse regional circumstances in ASEAN and absence of an overarching legal system like in the EU, we believe that the latter approach is more suitable for ASEAN.

The importance of coordinated infrastructure development is particularly important in markets with growing electricity demand, such as SAPP and ASEAN. Insufficient generation and transmission infrastructure in Southern Africa seriously limit the progress of the otherwise successful market and undermine the benefits of market integration. Lack of infrastructure development there is driven by non-cost reflective tariffs, low market transparency and weak protection of third party investors. These aspects deserve consideration by ASEAN, where the required generation capacity is expected to double by 2040.

Another important question is whether deregulated electricity sectors in particular ASEAN countries create barriers for cross-border power trade. While this is matter for national policy in each sovereign country, we note that deregulated markets allow cross-border power trade until a fairly advanced stage. Nevertheless, separation of generation and transmission is highly recommended in order to make such markets more efficient. Choosing market design is particularly different for the LTMS project, where Laos Thailand and Malaysia have single buyer models while Singapore has competitive electricity markets. Hydropower imports will also undermine the competitiveness of the non-subsidized gas-fired power generation in Singapore.

Tapping on hydropower potential in the Mekong basin is the crucial aspect in the current vision of ASEAN electricity market integration. We note that virtually all existing regional interconnection studies do not sufficiently analyse profound environmental and socioeconomic impacts caused by planned damming of Mekong and its tributaries. These impacts are: loss of biodiversity of global importance, increased food insecurity for millions of people and increased international tensions – all of which could outweigh the collaborative push resulting from electricity market integration. All these aspects should be considered by policy makers in ASEAN when designing a vision of a common resource use.

Given the commitment of ASEAN member countries to increase cross-border interconnection and power trade, we suggest below three market design options and required steps to achieve

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them. In setting out these options, we have sought to incorporate important lessons derived from international experiences analysed in this study.

Option 1 Multilateral trade of excess power via long-term contracts	Option 2 Multilateral trade with spot exchange	Option 3 Fully competitive power markets
<u>Closest analogue:</u> Nordic countries before 1990	<u>Closest analogue:</u> Southern African Power Pool	<u>Closest analogue:</u> Nord Pool, some European countries
<u>Steps required:</u> <ul style="list-style-type: none"> - Formulation of institutional and contractual arrangements for cross-border power trade - Some harmonisation of technical and regulatory standards - Coordination of system operation between countries for electricity transfers - Signing of contracts between state-owned utilities on pre-arranged terms - Setting up separate entity to trade power in country with competitive markets (e.g. Singapore) on pre-arranged terms - Transit charge is optional, although desired 	<u>Steps required:</u> <ul style="list-style-type: none"> - Formalising the market institution with relevant committees - Setting up independent and empowered association of energy regulators - Agreement on coordinated infrastructure development plans - Development and adoption of comprehensive network codes including grid connection codes, system operation codes and market codes - Deeper harmonisation of existing national standards with grid codes - Setting up market operator and legal market entity - Phasing out energy supply subsidies 	<u>Steps required:</u> <ul style="list-style-type: none"> - All steps under Option 2 plus: - Vertical unbundling of state-owned utilities - Full independence of TSOs from electricity production - Unrestricted and non-discriminatory grid access to all participants - High market transparency and access to information for all market players - Sophisticated methods of system balancing and transmission capacity allocation
<u>Pros:</u> <ul style="list-style-type: none"> - Easy to implement - Does not require power sector reforms - Provides mutual benefits in system security 	<u>Pros:</u> <ul style="list-style-type: none"> - More efficient than Option 1 - Provides greater benefits to all efficient participants - Can react to market signals - Creates pathway for Option 3 	<u>Pros:</u> <ul style="list-style-type: none"> - Most efficient of all options - Reduces wholesale electricity prices - Provides greater benefits to all efficient participants - Increased market liquidity - Attracts private sector investments
<u>Cons:</u> <ul style="list-style-type: none"> - Inefficient - Low flexibility as market signals are missing - Retains non-competitive practices - Infrastructure investments are difficult, particularly in transmission 	<u>Cons:</u> <ul style="list-style-type: none"> - Presence of unbundled state-owned utilities deters private sector participation - Information asymmetry - Transmission system operators are not independent 	<u>Cons:</u> <ul style="list-style-type: none"> - Requires difficult domestic reforms - Requires high level of technical sophistication and experience in operating power markets - Requires stable political climate with high protection of participants' rights

Chapter 1: Political economy of electricity interconnections

Introduction

An electricity interconnector is a physical link which permits the transfer of electricity across two separate control areas (e.g. state or international boundaries), each with their own, separate, market operators. Interconnector companies derive their revenue from arbitrage arising from price differentials between the two areas.¹ Thus, interconnectors should ensure that wholesale electricity prices are equalized across the boundaries unless a physical or political constraint is present, or a profit maximizing merchant interconnector indulges in some form of strategic behavior.

In general, the welfare benefits from interconnection are broadly similar to those that arise from international trade. However, even if there is an overall net improvement in welfare across jurisdictions, its distribution may be skewed to the extent that it creates both winners and losers. In addition, positive market externalities (e.g. enhanced security of supply) and unpriced environmental impacts (e.g. reduction in greenhouse gas (GHG) emissions) may be present that private investors cannot capture. The latter therefore may be reluctant to invest in interconnectors even though, in a cost-benefit framework, they provide net welfare benefits to society as a whole.

This chapter addresses the economics of interconnectors in the context of a subset of the ten ASEAN nations; focusing on the possible route between Lao PDR, Thailand, Malaysia, and

¹ Merchant interconnectors operate in this fashion. Regulated interconnectors, as the name suggests, operate and receive revenue according to a "regulated" rate" imposed by the relevant market operator(s).

Singapore. In doing so, it draws comparisons with the Southern African Power Pool (SAPP) which exhibits similar characteristics to the proposed ASEAN interconnected electricity grid.

Welfare effects of interconnection

In order to evaluate the net economic value to society of an interconnection, a cost-benefit framework can be utilized. The costs are predominantly made up of the initial capital investment (which will be known if the interconnector has already been constructed), plus future operation and maintenance costs over the investment's planned lifespan, which will likely constitute only a small part of the total.

The benefits however are far less well defined and, for some benefits, their quantification may be problematic since monetary values may be difficult to derive. In addition, there is no guarantee that positive welfare benefits will actually arise from such an investment.

For a new connector, benefits will comprise cost savings from one or more of the following (adapted from Turvey 2006):

- Deferral of investment in new generating plant;
- Reduction in unserved energy (which can be valued at the value of lost load);
- Reduction in fuel and other variable operating costs (net of transmission and distribution losses) by substitution of cheaper generation for more expensive generation;
- Reduction in the cost of frequency control, spinning reserve, and other ancillary service costs;
- Enhanced levels of energy security;
- Enhancement of competition in energy supply; and
- Reduction in greenhouse gas emissions.

Other potential indirect economic benefits of an interconnection include the impacts of improved power supplies in fostering development of local industry, improvements in public

The occurrence and extent of all these benefits may differ significantly according as to whether the markets being interconnected have different generation technologies and demand profiles.

Real welfare effects may arise through increases in both productive and allocative efficiency. The former can occur when more extensive use of the cheapest source of generation occurs as a result of the interconnector. Thus, if Country A has a lower marginal cost of electricity production than Country B, it would be welfare enhancing in aggregate to generate the marginal power in Country A rather than Country B.

resulting

Figure 1: Interconnection capacity between country A and B

Adapted from (Hakvoort and de Jong 2007)

increase in total demand, leading to a move up the merit order and consequently higher wholesale prices and higher infra-marginal rent. Thus, generators in Country A will benefit, whilst domestic consumers will suffer, from higher prices. The reverse will happen in country B. Imports will displace generators in the merit order, resulting in lower prices and lower infra-marginal rent for generators, but the benefit of lower prices for consumers.

How such trade can increase aggregate welfare is illustrated, in a static context, in Figure 1, where the line NS_A represents net supply in the exporting country, A. This curve shows how the price in Country A would increase as a function of export capacity. Similarly, ND_B represents net demand in the importing country, B, showing a price decrease in the country when importing a given capacity.

K_0 represents the situation where there is no interconnector capacity between the two countries. Assume that Country A now has a transmission capacity to export of K_1 , then the price in Country A would rise to P_A whilst the price in the importing Country B would fall to P_B . The triangle, BCD, reflects the deadweight loss arising from a lack of sufficient transmission capacity. From the perspective of a private investor, the revenue benefits of the interconnector are given by the area $P_A P_B BD$ (i.e. the marginal price of congestion, $P_B - P_A$, multiplied by the capacity of the new interconnector, $K_1 - K_0$). This is the area that a merchant interconnector will attempt to maximize. From a social perspective, however the value of the interconnector is given by the area of the trapezium ABDE. The actual distribution of this social value between the consumer and producer surplus depends however on who actually pays for using the interconnector and who then benefits from the resulting revenues.

Note that if there were no constraints, i.e. the interconnector capacity is K_2 , the social value of the interconnector is maximized at this point and given by the triangle ACE. However, from a private investor perspective the revenue benefits are zero at this point. Thus, it is in the financial interests of a merchant interconnector to have a degree of congestion in the system, otherwise there would be no revenue from the investment to cover its capital costs. By implication, a regulated interconnector would not need to maintain a price differential since it could recover its capital costs from its regulated assets base. However, if it is assumed that $(P_B - P_A)$ reflects the unit cost of capacity (i.e. we are assuming that the interconnector is not reaping monopoly profits and that operating costs are negligible), this could actually result in a net welfare loss compared with the constrained case, since the area BCD is smaller than the area given by $(P_B - P_A) \cdot (K_2 - K_1)$.

Factors affecting the benefits of interconnection

The benefits of interconnection are likely to be higher the more diverse the generation technology mix between the two countries. Thus, a country with a high capacity of variable, low SRMC, technologies (such as wind and solar) may export during favorable weather conditions to the neighboring country that relies almost exclusively on fossil fuel generators. Whilst this asymmetry may increase the value of the interconnector, the volatility of the variable technologies may result in uncertainty as to the direction of flow on it.

Finally, wholesale electricity prices generally track changes in the daily pattern of demand, itself driven by consumer behavior and industrial requirements. Thus, price differences between two countries are likely to be more favorable for interconnectors when their respective demand profiles differ.

Security of supply benefits of interconnectors

The more isolated the market, the higher the level of installed capacity required to meet peak demand, and regulating and contingency reserves. Thus, interconnection with a neighboring

country's electricity market will permit both countries to not only reduce price volatility but will also reduce the requirement for peaking and contingency back-up plant that is rarely used. However, some jurisdictions may be uncomfortable with reliance on imports to cover extreme events and would interpret security of supply to mean "domestic supply".

In the case of major interconnections, supply security must involve ample spinning reserve to address the case of an unexpected complete loss of supply through the interconnector.

Environmental costs and benefits

To the extent that an interconnector reduces GHG emissions, the benefits will accrue explicitly in the CBA if the countries involved have a carbon market, although the values will reflect control rather than damage costs. Logically, the former should be less than the latter, so one would expect an underestimate of the benefits.

Local environmental impacts are clearly site-specific, most of which would probably have their greatest impact during the construction stage. However, with hydropower one issue is security in times of drought which implies that sufficient back-up power must be available to take up any supply shortfall. There are also negative issues associated with constructing dams on river ecosystems, which can change the natural flow with resulting adverse impacts on downstream fisheries and agriculture.

For further reading, a very comprehensive review of issues arising from development and use of power interconnections is provided in (UN 2006).

Chapter 2: Southern African Power Pool

Introduction

The Southern African Power Pool (SAPP) is the first and probably the most relevant case study for potential power interconnection projects in ASEAN. This multilateral trading scheme has been established in 1995 between power utilities of 12 Southern African countries. The starting point for the power pool was the pre-existing bilateral trade and interconnections among the South African power utilities. SAPP has also established a power exchange with day-ahead and intraday spot trading in a move to a more competitive market structure. There are also plans to add an ancillary services market, and to further improve the performance of existing markets. As of today, roughly 5% of electricity is traded in the exchange.

The generation and transmission infrastructure in SAPP is fairly well developed, partly dating back to discovery and rise of Copperbelt during the colonial times. Later, several large hydropower projects were built and connected to the main grid with help of international donors in 1960s and 1970s. The interconnectors allowed better sharing of available energy resources in the region and diversification of electricity supply sources. This is particularly important for the northern region with ample hydropower which is exposed to droughts and man-made interruptions in water supply.

Years of ongoing economic development created the need for additional generation and transmission infrastructure in SAPP. The widening shortage of supply capacity causes load shedding and emergency electricity imports for some countries. There is a multitude of reasons behind lagging infrastructure development such as lack of coordinated development, no clear endorsement of intended projects, no aggregated demand forecasts, bureaucracy and non-cost reflective electricity tariffs. Many of these issues are pertinent to the countries in ASEAN which also face similar socioeconomic and political conditions as countries in Southern Africa.

Historical development

South African Power Pool (SAPP) was formally inaugurated in mid 1990s but the history of cooperation in electricity sector in southern Africa can be traced much further back. The colonial period plays a major role in the establishment of SAPP. Under the colonial rule, the development of most generation and transmission projects in SAPP was closely tied with inception and growth of mining and industries in today's South Africa, Zambia, Zimbabwe and DRC. The expansion of industrial activities to Botswana, Mozambique and Namibia has led to development of hydropower projects in those countries and linking of their power grids with the neighbours (ECA 2009).

1980s

The formal push for establishing a power pool in Southern Africa started in 1980, when the Southern African Development Coordination Conference was formed. SADCC is the predecessor of the today's socio-economic cooperation agency SADC. A Technical and Administrative Unit (TAU) consisting of SADC officials was formed in Angola. TAU has conducted regular discussion meetings and roundtables that paved way for energy integration planning in the region. For example, TAU's initiative was creation of an electricity subcommittee which was inaugurated in 1990. This subcommittee comprised the national utilities of the member countries and acted as technical advisers to the energy officials and ministers on issues relating to enhancing cooperation in the electricity sector. At that point in time, South Africa with its largest electricity sector in the region was still not allowed to participate in SADC because of the apartheid government (IRENA 2014).

1990s

Two key events in early 1990s have led to formal establishment of SAPP. The first event was the abolishment of apartheid in South Africa which removed sanctions on country's participation in regional cooperation. SADCC was transformed to the SADC in 1992 which included South Africa as a member state. Other SADC members became willing to cooperate

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with the new government in South Africa. This allowed formal multiparty intergovernmental and inter-utility agreements to be signed between Mozambique, South Africa, and Zimbabwe for the Cahora Bassa interconnector and between Botswana, South Africa, and Zimbabwe for the Matimba interconnector. On the basis of these agreements, funding was rapidly arranged to build the 400 kV transmission lines from the Zimbabwe system to South Africa via Botswana (commissioned in 1996) and to Cahora Bassa (commissioned in 1997).

The second key event was the extreme drought in 1991–1992 which has severely affected hydropower production in the Zambezi basin, leading to economically and socially disruptive load shedding in Zimbabwe and Zambia. The drought has exposed the over-reliance of the northern network on the weather sensitive hydropower and a lack of drought-resistant backup. As a consequence, Zimbabwe, Zambia and the Democratic Republic of the Congo (DRC) have signed a multiparty agreement to source power from DRC to Zimbabwe with Zambia being a transit party. Diversification of supply sources was achieved through other interconnection projects to connect Zimbabwe to the South African grid and to the Cahora Bassa power station. The interconnections allowed the drought-resistant coal-fired capacity of South Africa to provide backup in case of extreme weather events. Around the same time, a 400 kV link between South Africa, Swaziland and Mozambique was constructed to provide power to the aluminium smelter project in Mozambique (ECA 2009).

Inauguration of the power pool

By mid-1990s the SADC region has already had numerous examples of successful cooperation between national utilities/governments and developed physical interconnection links among SADC members. The Electricity Subcommittee took advantage of these developments to create similar frameworks as the founding agreements for the power pool. This paved the way for SAPP to be created in August 1995. SAPP was established from a neutral institutional standpoint as a non-binding entity. It was not expected to forcefully intervene in trading arrangements among members and national capacity development plans. Rather it an institutional framework enabling a common vision for an interconnected electricity market for

the future benefit of the whole region. The formal establishment of SAPP was also a strengthening point for the region's political agenda of economic integration (SAPP 2016, ECA 2009).

2000s

In its first five years SAPP relied solely in bilateral and multilateral agreements between the member countries. In 2001, the SAPP the short-term spot market, which was designed as a precursor to a future fully competitive electricity market. In 2007, this market was closed down due to limited power supply and transmission capacity (SAPP 2016).

In 2006, the SAPP received a grant from the government of Norway and SIDA to develop a spot exchange with day-ahead and intraday markets. The day-ahead was developed by 2007 but its implementation was delayed due to ongoing study on nodal pricing for transmission wheeling and losses. After the testing phase between 2007 and 2009, the day-ahead market was launched in late 2009. The intraday market was inaugurated in 2013 (SAPP 2016b, ECA 2010).

Benefits of market integration

It should be noted that no centralized studies on feasibility, costs and benefits had been done for SAPP before it was formally launched. However, participating utilities performed own reviews of existing bilateral and multilateral electricity interconnection schemes and exchanged visits with experts from the established power pools in North America and Europe before launching SAPP. After its establishments, studies were performed in crucial areas with international donors' support. In 2002 a cost-benefit study funded by USAID concluded that were benefits in the short- and long run from coordinating electricity investments (around US\$100 million annually from short-run optimization of regional opportunities to US\$1.5 billion in net present value of investment savings). The coordination of regional capacity development plans under one umbrella could result in savings of US\$48 billion by 2025,

compared to a scenario with uncoordinated capacity plans undertaken by each country (IRENA 2015, ECA 2010).

Vision and objectives

SAPP was formally launched with the vision and objectives that indicate a goal of developing a competitive electricity market while maintaining the region's political agenda of regional economic integration. SAPP's vision has an integrated electricity market that will (SAPP 2016b):

- Facilitate the development of a competitive electricity market in the SADC region.
- Give the end user a choice of electricity supplier.
- Ensure that the southern African region is the region of choice for investment by energy intensive users.
- Ensure sustainable energy developments through sound economic, environmental and social practices.

SAPP was launched as a "cooperative pool" scheme which advocated SAPP members to share information about generation and transmission costs for the purpose of establishing prices. The price would be determined as the midpoint between the marginal or average cost of the exporter and the avoided cost of the importer, similarly to the principles embedded in the already existing bilateral and multilateral agreements. Moving forward, SAPP would have to evolve into a "competitive pool" where prices would be determined on the basis of a supply-demand equilibrium. Liberalisation of electricity markets has been a major trend around the world since 1990s. Liberalised markets give the participants more freedom in choosing electricity supplier and can better respond to short-term supply-demand fluctuations. It is also theoretically more beneficial for private sector participation, albeit there is no unanimous experts' view on this issue.

While the SAPP objectives include increasing electricity access for rural regions, SAPP has so far been focused on large-scale transmission interconnections due to its industry-driven history.

This is different from other regional power organizations such as the West African Power Pool (WAPP), which actively promotes cross-border distribution interconnections that directly benefit rural communities. However, there is no documental evidence that rural electrification is not a major part of the SAPP scheme (SAPP 2016b, IRENA 2015, IRENA 2014).

Geographical coverage

SAPP can generally be divided into two networks, shown in Figure 3, which rely on different electricity supply sources. The southern region has mainly coal-fired thermal capacity, while the northern region has been mainly using hydropower. The interconnection allows the southern part of the region to take advantage of cheap hydro energy generated in the north during the rainy season, with the net flow reversed during the dry season when the thermal south would export energy to its northern neighbours.

Southern region

The southern region comprises South Africa, Lesotho, Swaziland, Botswana and Namibia. Among these countries, South Africa has been historically the dominant player, both as a producer and as a consumer. South Africa, being a large industrialized nation, developed an extensive coal-fired generation capacity that exported excess electricity to its neighbours. Furthermore, the national grids of Botswana, Lesotho, Swaziland and Namibia were developed as extensions of the South African grid. The Cahora Bassa hydroelectric project was developed in 1979, to supply hydropower from Mozambique to South Africa (ECA 2009).

Northern region

The northern region has a large number of hydropower projects located on Zambezi and Congo rivers. These projects were developed to address the growing electricity demand of the mining industry in the Copperbelt. Kariba scheme was the first significant grid interconnection project in the northern area, developed in 1950s to supply electricity to the Copperbelt and

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running through today's northern Zambia and the southern Democratic Republic of Congo (DRC). After Zambia's independence in 1964, the 900 MW, Kafue Gorge power station and the 600 MW Kariba North power station were developed with support of donor agencies in order to make Zambia energy self-sufficient (ECA 2000).

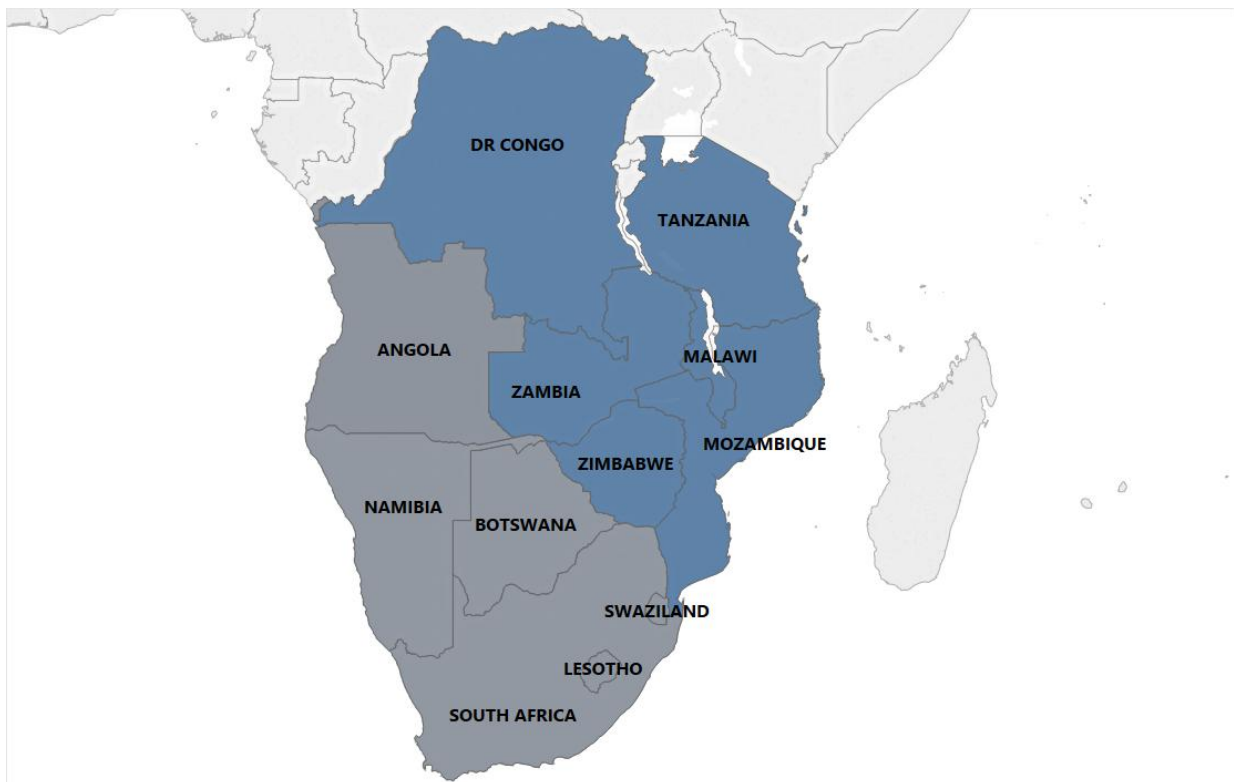


Figure 2: Northern and Southern regions in SAPP

In the former Belgian Congo, the Inga hydroelectric project on the Congo River supplied the Katanga Copperbelt. The Inga line also served as a back-up for the Zambian Copperbelt region through an interconnection built in 1956 with Zambia. Subsequently this link provided a backup for the Zimbabwe and SAPP grids through the first multiparty agreement to trade power. Electricity was transmitted between Zimbabwe and Congo while Zambia received a transmission payment (wheeling charge). The experience with this arrangement provided

useful experience for the future establishment of transmission charges scheme in SAPP (ECA 2009).

SAPP members

There are currently 16 SAPP members summarized in Table 1 including:

- Twelve national power utilities from the 12 continental SADC countries;
- Two IPPs: Hidroeléctrica de Cahora Bassa (HCB) of Mozambique (which is SPV) and Lunsemfwa Hydro Power Company (LHPC) of Zambia; and
- Two independent transmission companies (ITCs), Copperbelt Energy Corporation (CEC) of Zambia and MOTRACO of Mozambique. CEC is also an IPP.

The majority of these members are national utilities of respective countries operating under the single-buyer model. Aggregated capacity of IPPs is less than 1% of total. Nine of the national utilities are interconnected and are SAPP operating members. The remaining three non-operating members – ENE of Angola, ESCOM of Malawi and TANESCO of Tanzania – are not yet connected to the SAPP grid. Two countries, DRC and Tanzania, are also members of the Eastern Africa Power Pool (EAPP) while The DRC is also a member of the Central African Power Pool (CAPP) (SAPP 2016b, SAPP 2015).

Table 1. SAPP members in 2015

SAPP MEMBERSHIP			
Full Name of Utility	Status	Abbreviation	Country
Botswana Power Corporation	OP	BPC	Botswana
Electricidade de Mozambique	OP	EDM	Mozambique
Electricity Supply Corporation of Malawi	NP	ESCOM	Malawi
Empresa Nacional de Electricidade	NP	ENE	Angola
Eskom	OP	Eskom	South Africa
Lesotho Electricity Corporation	OP	LEC	Lesotho
NamPower	OP	NamPower	Namibia
Societe Nationale d'Electricite	OP	SNEL	DRC

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Swaziland Electricity Company	OP	SEC	Swaziland
Tanzania Electricity Company	NP	TANESCO	Tanzania
Zesco Limited	NP	ZESCO	Zambia
Copperbelt Energy Cooperation	ITC	CEC	Zambia
Lunsemfwa Hydro Power Company	IPP	LHPC	Zambia
Zimbabwe Electricity Supply Authority	OP	ZESA	Zimbabwe

Adapted from (SAPP 2016)

Figure 3 shows the map of SAPP member countries, some power plants and an approximate layout of the regional transmission network. The operation of the interconnected grid is split into three control areas covering Botswana, Lesotho, Southern Mozambique, Namibia, Swaziland and South Africa (Area 1), Zimbabwe and Northern Mozambique (Area 2) and DRC and Zambia (Area 3). Within each control area one system operator is responsible for balancing of the electrical system and managing the power flows between the control areas. These operators are ESKOM (Area 1), ZESA (Area 2) and ZESCO (Area 3). Most of the power exchanges take place within the eastern and central area (IRENA 2014).

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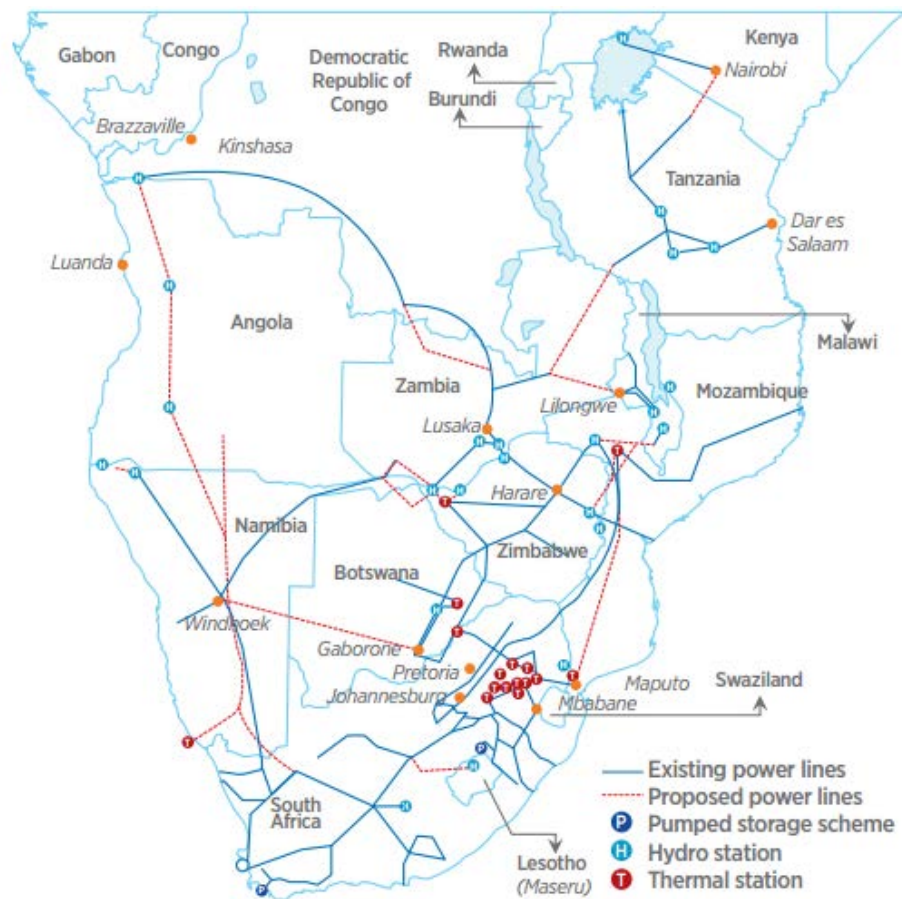


Figure 3. Generation and transmission infrastructure in SAPP

From (IRENA 2014)

Electricity markets

SAPP operates a physical electricity market which can broadly be divided into long-term and short-term market, or power exchange. Electricity is the only product traded on all the markets. In 2015, roughly 8.3 TWh were traded in all markets with roughly 6% traded in the power exchange (SAPP 2016a, SAPP 2016b).

The market is open to participants who: have been licensed or given permission by the host country to undertake cross border trading; were accepted a Market Participant by SAPP Executive Committee, are physically connected to one of the SAPP Control Areas and have

arrangements for provision of balancing services; signed the SAPP Market governance documents; and opened the requisite accounts for trading purposes (SAPP 2016a).

Long-term contracts

The majority of electricity is traded via long-term contracts between the member utilities. These contracts are basically over-the-counter contracts (OTC) which are signed between two parties, with terms agreed outside of the power exchange. The contracts are arranged for a period from one to five years. Although the exact contract details are not disclosed, the electricity is priced based on the production cost, but can also vary between consumption periods which can be peak, standard and off-peak. Naturally, supply delivered at peak hours is priced higher. Trading arrangements are mutually agreed between bilateral parties and the transmissions paths are secured in advance (SAPP 2016b).

The contractual agreements can be firm and non-firm. Firm contracts cannot be interrupted and hence the buyer is paying reliability premium. Non-firm contracts can be interrupted with a notice. Prices are not necessarily related to domestic prices, unless the parties agree. Most contracts are subject to review on an agreed periodic basis to take account of changed circumstances, usually inflation or quantities supplied or demanded (SAPP 2016a, SAPP 2015, ECA 2009).

Forward physical market

Forward physical market (FPM) is a part of the power exchange market operating on the timescale between a week and a month. This trading platform provides shorter-term products for parties involved in bilateral contracts. FPM is open for market participants to trade monthly (FPM-M) and weekly (FPM-W) products. The monthly product is “primarily base load generation” delivered at uniform price and output level for all hours of month. The weekly market has two products, including on- and off-peak generation. Each of these products must have uniform price and output levels within their respective hours and cannot overlap with the monthly products (SAPP 2016). Trading in FPM-W is done on a Thursday every week Forward

markets have an auction-trading model similar to day-ahead markets discussed below (SAPP 2016b).

Day-ahead and intraday markets

The power exchange in SAPP has also day-ahead and intraday markets, trading short-term products. The markets is based on the price matching auction model. Bid (sales order) or Ask (purchase order) are submitted to the market where they are matched automatically by the system on price or a buyer or seller can accept and take an order in the market. The market contracts are settled at the matched price. The intraday market is mainly for trading of imbalances remaining after the day-ahead trading. As of 2015, short-term markets had more purchase than supply offers (SAPP 2016a, SAPP 2016b).

Market statistics shows that the majority of electricity is traded via long-term and forward contracts. This intuitive, given the short history of the power exchange and that the market consists of very few large players. Since 2013, the share of traded electricity in day-ahead and intraday, has been increasing compared to previous years while the share of long term contracts has decreased. In 2013, less than 100 GWh of electricity was traded, while in 2014 the volume grew to almost 510 GWh, and to almost 630 GWh in 2015. Nevertheless, the share of day-ahead and intraday markets in the total market volume is still rather low, constituting 6% (SAPP 2016b, SAPP 2015).

The charges for provision of balancing services are calculated within each control zone and are not linked to electricity prices. A new scheme that could link these two components together is being under study (SAPP 2016a).

Transmission allocation and pricing

The transmission capacity allocation in SAPP is tied to contractual arrangements. Transmission capacity which remains available after settling bilateral contracts is allocated in the short-term market. Transmission capacity is priced in SAPP with a transit fee which is based on the booked

size of transmission capacity and the distance between the supplier and the buyer. The further a buyer is from the source, the higher is the charge. The collected revenue is equally distributed among the countries lying on the assumed wheeling path.

The problem with this scheme is that it prioritizes trading over short distances and does not account for potential transmission bottlenecks (line congestion). The MW-km method also overestimates transmission costs for power “swap” agreements and loads all costs on the purchaser (IRENA 2015, ECA 2009). Many other markets around the world, such as Europe and Nord Pool, have moved to more advanced methods of transmission capacity pricing such as zonal pricing and implicit transmission capacity allocation. Zonal pricing calculates the price for power transfer based on the available transmission capacity and irrespective of length of the line. When there are no transmission constraints in the power pool, the whole pool has a distance-based transmission price. If an area becomes congested, local area or zone prices are used. Zonal prices are determined based on short-run marginal costs of transmission, or costs associated with supplying an additional unit of transmission service without necessarily increasing transmission capacity. Such costs include energy wheeling charges, congestion charges and energy losses within the transmission network. Zonal prices can better address problems with transmission bottlenecks compared to the MW-km method. The zone price would increase for congested areas sending market signals to promote new transmission capacity development in order to alleviate congestion. This methodology also shares the transmission costs more equitably between sellers and buyers. The zonal pricing approach is currently being studied by the SAPP Market Committee (SAPP 2016a).

Electricity prices and tariffs

Average market clearing prices are available for forward, day-ahead and intraday markets. There was a general increase in market clearing prices in the competitive market 2015/16 (average of USc 8.1/kWh from April to July 2015) compared to an average of USc 6.7/KWh recorded in 2014/15). The aMoUnt of electricity traded in short-and medium term markets has also increased during the same time (SAPP 2015). According to estimates by IRENA, the

emergency energy rates for 2011 ranged from USc 4.6 per kWh to about USc 21 per kWh (IRENA 2014).

Figure 4 displays average electricity tariffs in Southern African countries. It can be seen that the tariffs are very close or, in some countries, even below the cost of producing and transmitting power. The tariffs in SAPP member countries have been historically low due to governmental subsidies. Because of the subsidies, independent power producers (IPPs) may find it difficult to agree on power purchase agreement (PPA) terms with state-owned utility companies who are buying monopolies. Low price environment also deters potential IPPs from developing of new generation projects.

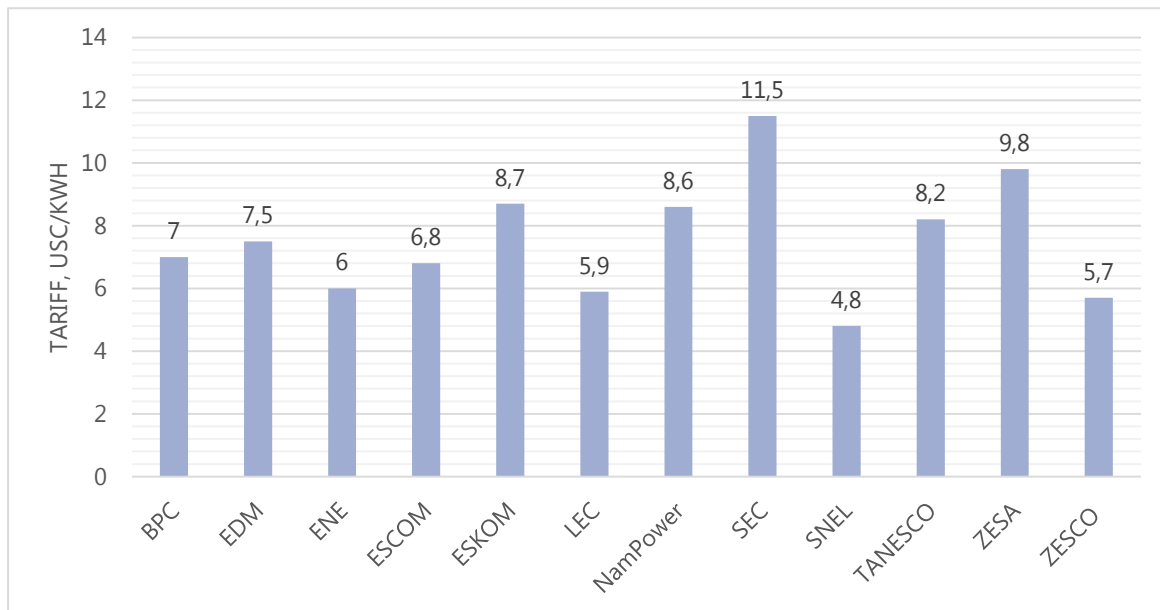


Figure 4. Average electricity tariffs in SAPP member countries

From (SAPP 2015)

There is no available data on transmission prices which are added to the generation cost, although IRENA, provides a band of rates of US\$ 1.4-28/kW per year. This reflects big variations in the costs and lengths of transmission assets used for transactions. The study noted that these charges compared well to those in other international markets: US\$1-23/kW/year in England and Wales and US\$2-17/kW per year in Brazil (IRENA 2014).

Protection of interests

Parties involved in electricity transactions are formally protected by intergovernmental agreements which are discussed below in more detail. These agreements authorize national utilities of member states participate in SAPP and also provide security for financial liabilities of buying utilities. If a utility fails to commit to its payment obligations for delivered power, it exposes its government to the liability of payment. The supplying utility is allowed to get the support of an own government if it is prevented from carrying out normal credit control measures such as switching off supply for non-payment. Although this scheme looks good on paper, the available data suggests that it is not effective, as many utilities show poor financial performance, high numbers of debtor days and report inconsistent data (IRENA 2014, ECA 2009).

Current state of supply and demand

Supply mix and capacity

The total installed capacity in SAPP was roughly 62 GW in 2015 while the available capacity was about 52.5 GW and the operational capacity was about 47 GW (SAPP 2015). The annual report estimated the generation capacity shortfall at 8.3 GW in 2015. Figure 5 shows that the majority of installed capacity is coal-fired (62%) and located mainly in South Africa and neighbouring countries. Hydropower is the second major source (21%), coming from Zambezi and Congo basins. South Africa accounts for nearly four-fifths of the installed and available generation capacity and an average of 85% of the energy sent out and sold, as shown in Table 2 and Table 3 below. The country is currently the largest energy trader and a net exporter, taking large shares in imports from Botswana, Namibia and Mozambique. Hydropower project Cahora Bassa in Mozambique is the largest source of non-coal imports for South Africa.

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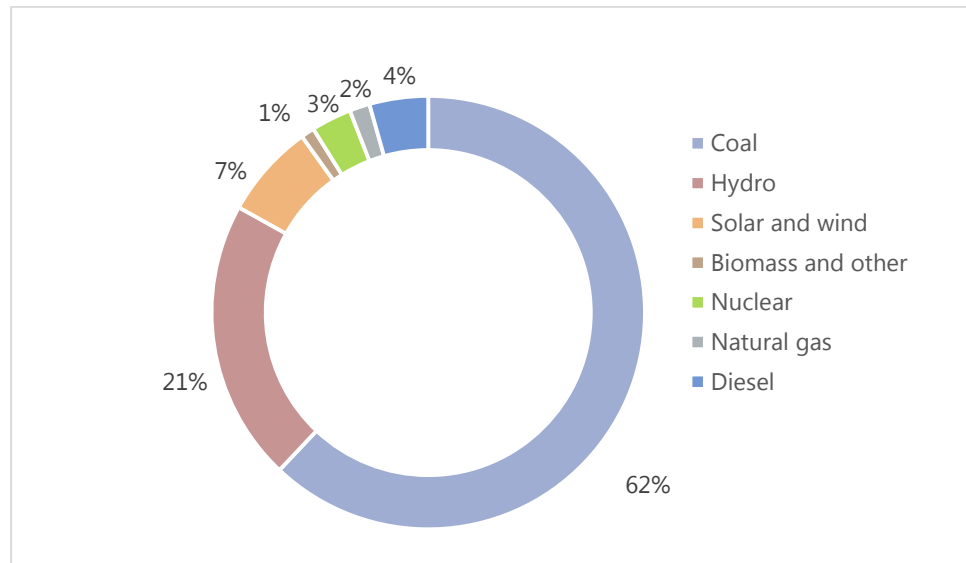


Figure 5. Installed capacity by fuel type in 2015

From (SAPP 2015)

Table 2. Installed capacity by member utilities in 2015

SAPP UTILITY GENERATION MIX,MW															
Technology/ Utility	BPC	EDM	ENE	ESCOM	Eskom	LEC	NamPower	SEC	SNEL	TANESCO	ZESA	ZESCO	LHPC	HCB	Total
Baseload hydro		498	1,528	351	2,000	74	348	61	2,442	717	750	2,107	49	2,075	13,000
Coal	732		492		35,721		132	9			1,295				38,381
Nuclear					1,860					-					1,860
OCGT	160	-	190	1						585					936
Distiallte		151			2,409		21			78		50			2,709
Wind					2,492										2,492
Solar CSP					600										600
Solar PV					1,821										1,821
Landfill					18										18
Biomass					42										42
Total	892	649	2,210	352	46,963	74	501	70	2,442	1,380	2,045	2,157	49	2,075	61,859

Table 3. SAPP electricity trading statistics in 2015

Country	Utility	Installed Capacity	Net Capacity	Maximum Demand	MD Growth	Sales	Sales Growth	Number of Customers	Number of Employees	Generation Send Out	Net Imports	Net Exports	Transmission System Losses	Revenue US\$ Million	Debtor Days	Rate of Return	Net Income USD
		MW	MW	MW	%	GWh	%			GWh	GWh	GWh	%			%	Million
Angola	ENE	2210	1805	1599	49%	3427	-5.10%	251952	4009	5613	0	0	10	513.4	64	n/a	n/a
Botswana	BPC	892	460	610	6%	3118	0.30%	251773	1868	372	1207	0	3.7	216	69	-6	22
DRC	SNEL	2442	1485	1381	18%	7584	11.81%	746902	7372	8185.2	95	0	10	309.6	150	n/a	n/a
Lesotho	LEC	71	72	150	16%	488	6.20%	58900	563	486	175	2.7	11	31.5	32	5.2	5.1
Malawi	ESCOM	351	351	326	17%	1476	2.00%	204955	2398	1809	0	0	9	90	74	15	38
Mozambique	EDM/HCB	2308	2279	830	18%	2380	13.00%	1010780	3244	390	1004	233	6.4	n/a	37	n/a	n/a
Namibia	NamPower	501	392	629	3%	3648	1.20%	3449	910	1305	1337	37	3.2	310	41	6	53
South Africa	ESKOM	46963	41074	36170	1%	224446	2.70%	4653750	39034	237430	542	4909	3.27	13649	17	2.91	1247
Swaziland	SEC	70.6	70	221	8%	1018.6	3.70%	97000	567	288.1	889	0	6	114.4	70	7	9.7
Tanzania	TANESCO	1380	1143	935	5%	3770	20.90%	932285	5950	3034	0	0	6.12	277.3	240	4.86	-19.1
Zambia	ZESCO	2128	2029	1987	12%	10688	7.20%	418651	5234	11381	165	3441	4.6	350	107	9	60
Zimbabwe	ZESA	2045	1600	1671	8%	7.367	4.50%	579006	5773	6951	979	1231	4	469	157	-34	-120

From: (SAPP 2015)

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Electricity demand and consumption

Electricity demand in the SADC region has been increasing in tandem with ongoing economic growth and is currently higher than the available generation capacity. This stand of things can be even more dramatic in future as electricity demands continues to grow. However, there is a lack of robust estimates and consensus on the future demand data in SAPP. The electricity demand forecast in SAPP is based on projections prepared by member utilities, most of which are inaccurate and underestimate the actual demand growth (IRENA 2014). SADC members have also adopted electricity access targets through the African Union's Programme for Infrastructure Development in Africa (PIDA) which assumes a 4.4% electricity demand growth rate in SAPP. Meanwhile, estimates by the Common Market for Eastern and Southern Africa (COMESA) assume a 7% annual growth rate which is much higher than 4.4% assumed by PIDA. Even though there are conflicting views on the pace of the demand growth, the forecasts are unanimous about the general trend. A more detailed analysis of the demand forecast would be helpful because this information is crucial for generation and transmission expansion planning and timelines for project implementation in SAPP (IRENA 2014).

The largest share of electricity demand in SAPP comes from the energy intensive industrial and mining sectors. However, the future growth will also be driven from the increased electricity access in SAPP member countries. As of today, electricity access is still limited in the region as seen by the low access to electricity in rural areas of the SADC Member States. Access in these areas is below 30% for eight of the 12 SADC States on the mainland. In comparison to other Regional Economic Communities (RECS), SAPP's electricity access rate is at 24% which is behind that of East Africa Power Pool (36%) and the West Africa Power Pool (44%). In some countries, access in rural areas is lower than 5% (IRENA 2013).

Geographical power flows

The geographical power flows are happening between major supply and demand centres. The mining and manufacturing industries in South Africa, BLNS ²countries and in the Copperbelt are the largest electricity consumers. Over 80% of generation capacity is located in South Africa, followed by hydropower in Congo and Zambesi basins. Consequently, power flows mostly through interconnectors in the eastern and the central regions. The main exporters in 2015 were South Africa, Zambia and Zimbabwe. Power exports from South Africa meet almost all of Botswana's demand and nearly half of Namibia's demand. South Africa also imported electricity from Mozambique's Cahorra Bassa project (around 10 TWh in 2012), but much of this was then exported back to Mozambique's southern region to supply Maputo (and particularly the Mozal smelter) (SAPP 2015, IRENA 2014, IEA 2014b).

Infrastructure bottlenecks

Generation

In its early stages, SAPP had excess generation and transmission capacity to enable smooth electricity exchange between the members. This situation has changed after years of population and economic growth which were not met with adequate generation capacity. Moreover, the existing power plants deteriorate with age and cannot be fully utilised at times due to frequent maintenance. As a result, the region has been experiencing a supply gap since 2007, which became a local issue for almost every member country. Table 4 shows that most countries do not even have enough domestic capacity to be self-sufficient. Countries primarily affected by the supply gap are hydropower-dependent nations which have no alternative sources in the case of water shortage. Countries like Zambia and Zimbabwe had to turn to planned load shedding measures for the population and emergency electricity imports which come at a high price (SAPP 2016b, IRENA 2014, IRENA 2013).

² Botswana, Lesotho, Namibia and Swaziland

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Table 4: Available generation capacity and peak demand of SAPP members

From (IRENA 2013)

Country (Utility)	Installed Capacity	Peak Demand*	Available Capacity	
	MW	MW	MW	% Peak Demand
Angola (ENE)	1793	1341	1480	110
Botswana (BPC)	352	604	322	53
DRC (SNEL)	2442	1398	1170	84
Lesotho (LEC)	72	138	72	52
Malawi (ESCOM)	287	412	287	70
Mozambique (EDM)	233	636	204	32
Mozambique (HCB)	2075	-	2075	-
Namibia (NamPower)	393	635	360	57
South Africa (ESKOM)	44170	42416	41074	97
Swaziland (SEC)	70	255	70	27
Tanzania (TANESCO)	1380	1444	1143	79
Zambia (ZESCO)	1870	2287	1845	81
Zimbabwe (ZESA)	2045	2267	1600	71
ALL	57182	53833	51702	96

Transmission and distribution

Addressing the mentioned supply gap through trade is difficult because of bottlenecks in the transmission system. The competitive trading in short-term markets exposed transmission network constraints, especially within the eastern and central corridors of the interconnected grid around the Zambezi Basin. This state of affairs is adversely affecting cross-border power trading. Transmission constraints have been limiting day-ahead and intraday liquidity by 40-50% of what could have been traded on a daily basis if there was sufficient transmission available (SAPP 2015, SADC 2012).

Infrastructure development

Infrastructure development in SAPP is independently undertaken by participating utilities. There were some efforts to coordinate these developments, but the progress has been stagnant. In 2009, SAPP released a regional master plan with help of international agencies, estimating the financial benefits of co-ordinated regional planning in the region. Although this document outlined some significant benefits, promoting coordinated resource planning,

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regional optimisation and equitable sharing of benefits, it is non-binding and allows countries to determine the level of autonomy and self-sufficiency they desire. This makes it difficult to establish a coordinated guideline for generation and transmission capacity development.

One of the causes for weak implementation of the master plan is due to national priorities overriding regional interests. Proponents of national interests argue that major events in the past (like military conflict or drought) have created a need to put national interests of energy security before the regional interests of economy and affordability. Countries positions vary between national and regional capacity planning exercises with more emphasis on self-sufficiency in the national development plans (IRENA 2014).

Private sector participation in infrastructure development remains very limited in the whole region. The main reasons for it are non-cost reflective tariffs, high perceived risks and weak protection investors' interests. Although this stand of issues is noted in numerous publications covering the region, little progress has been achieved so far in attracting private sector investments (IRENA 2014, Kapolo and Lalk 2012). A notable exception is the 300 MW coal power plant built by a mining company in Zambia after the country decided to increase electricity tariffs for industries.

Organizational structure

SAPP is a subsidiary institution under the Southern African Development Community (SADC) which evolved from SADCC in 1994. SADC is committed to regional integration and poverty integration in the region. SADC comprises fifteen member countries – twelve on the continent and three island nations of Mauritius, Seychelles and Madagascar. SAPP reports to the SADC Secretariat through the Directorate of Infrastructure and Services (DIS).

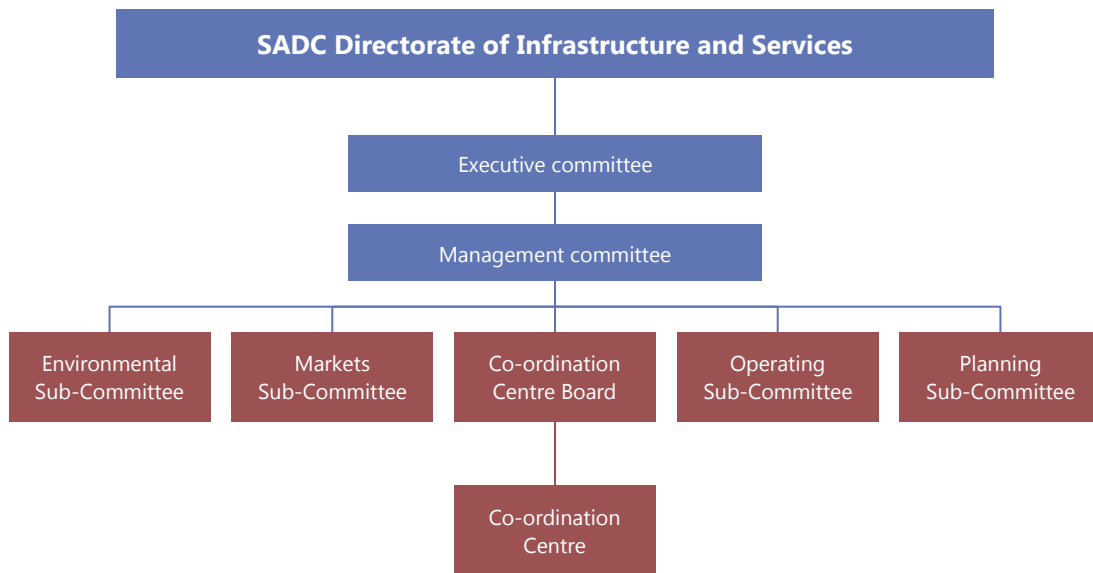


Figure 6. Organizational structure of SAPP

From: (SAPP 2016)

The structure of SAPP is shown in Figure 6. The top level is the SADC Directorate of Infrastructure and Services which governs energy-related matters in the regions. SADC government ministers and officials are responsible for overall policy matters relating to the electricity sector. They determine both the institutional structure and market conditions in each member state. The two main committees of SAPP itself are the Executive Committee and the Management Committee.

The Executive Committee, consisting of the heads of the participating utilities, acts as the board of directors of the power pool. The Management Committee, consisting of the senior managers of member utilities and the respective energy trading departments, is responsible for collating information from the five subcommittees (planning, operating, markets, and environment, and the Coordination Centre Board), preparing proposals for the Executive Committee, and presenting reports to the Executive Committee.

SAPP has four working committees: the Environmental Sub-Committee, the Markets Sub-Committee, the Operating Sub-Committee and the Planning Sub-Committee under a Management Committee which in turn reports to the Executive Committee. The Coordination

Centre acts as a secretariat for the SAPP committees and subcommittees and repository of all minutes, documents, information and data of the power pool. The centre also manages the energy trading and helps to co-ordinate the development of multinational projects. The members of SAPP fund the activities of the Coordination Centre through an annual subscription (SAPP 2016b).

The interests of the participants are protected by the Inter-Governmental Memorandum of Understanding. The utility that fails to meet its payment obligations exposes its government to the liability. The supplying utility can also fall back on its government for support if it is prevented, for political reasons, from carrying out normal credit control measures such as switching off supply for non-payment (SAPP 2016b, IRENA 2014).

Regulation

SAPP has an association regional electricity regulators, the Regional Electricity Regulators Association (RERA), which has 10 out of the 12-member state representatives. RERA is responsible for harmonisation of rules and regulations and to regulate inter-country issues that are not under the jurisdiction of the national regulators. An important point is that RERA is not a regional regulator with authority and power in regulatory matters in the region, but is instead at this stage merely an association of national regulatory institutions. RERA currently has the following three strategic objectives (ECA 2009):

- **Capacity building and information sharing.** Facilitate electricity regulatory capacity building among members at both national and regional levels through information sharing and skills training.
- **Facilitation of electricity sector policy, legislation and regulations.** Facilitate harmonized electricity sector policy, legislation and regulations for cross-border trading, focusing on terms and conditions for access to transmission capacity and cross-border tariffs.

- **Regional regulatory cooperation.** Deliberate and make recommendations on issues that affect the economic efficiency of electricity interconnections and electricity trade among members that fall outside national jurisdiction, and exercise such powers as may be conferred on RERA through the SADC Energy Protocol.

The RERA's institutional position mirrors that of SAPP at the time of its establishment. Both parties started on a non-binding cooperative basis from where they expect to evolve along with the development of SAPP. At the same time, the institutional roles of RERA and SAPP indicate the current shallow stage of SAPP integration (IRENA 2014, RERA 2011, ECA 2009).

Financing

SAPP is registered as a non-profit organisation incorporated in Zimbabwe. All generators and interconnectors within SAPP are in public ownership of the respective national utilities. In some cases, special-purpose vehicles (SPVs) have been formed to execute joint projects (such as MOTRACO, which is jointly owned by Eskom, SEB and EDM). Hidroeléctrica de Cahora Bassa is something of an exception because the ownership is directly by the governments involved (Mozambique and Portugal, Mozambique purchasing majority ownership in 2007). The only significant private company is Copperbelt Energy Corporation which is IPP and ITC.

All regional infrastructure investments are financed and undertaken by the respective national utilities. SAPP has been receiving donations from international organisations including World Bank, European Investment Bank and other development agencies of various countries. Many of these agencies have also indirectly provided support for SAPP through their bilateral aid in the SADC member states. In the early- to mid-1990's, the Nordic countries were particularly active in funding projects that became key elements of the interconnected grid, such as the Cahora Bassa interconnector as well as the extension and the refurbishment of the Zimbabwe and Mozambique transmission networks (IRENA 2015, IRENA 2014, ECA 2009) .

The operating budget of SAPP covers the cost of running the work of the sub-committees through the coordination centre. The expenses are shared among members whereby the largest utility (ESKOM) and the coordination centre host utility (ZESA) carrying half of the budget. This formula has been recently reviewed to make it more equitable, where IPPs, ITCs and other members are charged 5% of the SAPP operating budget. Financing for the execution of various studies of common interest for the pool members is also sourced from the member states (ECA 2009).

Conclusions

The example of SAPP provides a relevant experience of cross-border power trading which started from bilateral agreements between 12 vertically integrated national utilities and later developed an international spot market without domestic market liberalisation. SAPP has a well-defined institutional structure involving all the relevant stakeholders and a system of guiding documents that have been agreed to by all the participating nations to ensure smooth working of the pool. SAPP is based on a collaborative approach to market integration with a high emphasis on self-sufficiency and sovereignty of decision making. On the other hand, this approach provides few available instruments to influence developments in member states and to promote harmonisation of rules and regulations.

SAPP has a fairly advanced power exchange offering products in monthly, weekly, day-ahead and intraday markets. The amount of electricity traded in spot markets has been growing, particularly after improvement of day-ahead and intraday markets in recent years. Nevertheless, the share of electricity traded in power exchange is still low, with about 6% out of total electricity traded. This issue could be due to a relatively short history of the power exchange, whereby participants are still inexperienced in short-term trading and require time to adjust. Another cause could be high market concentration with South Africa's Eskom having over 75% of the total share and trading with 11 other national single buyer utilities. Such an environment favours long-term contractual commitments. Linked to this point, long-term

contracts also allow parties to secure the scarce transmission capacity well in advance. Finally, the low volume of the spot market could be due to its unstable functionality and limited efficiency of matching trade offers.

The most notable challenge for SAPP that its generation and transmission facilities are currently unable to provide the SADC region with a reliable electricity supply. Although coordinated infrastructure development is promoted by the SADC community, most of the projects never move beyond the planning phase and. Some of the reasons for insufficient capacity development are lack of bankable projects due to electricity subsidies, lack of available project financing and weak regulatory and institutional arrangements which hurt the investment environment. As a result, even though generation and transmission projects have been identified and prioritised, completion dates continue to be moved forward.

The generation deficit and transmission constraints negatively affect the economies of the SADC countries and contribute to social tensions. Particularly affected are the countries in the northern region which have no other choice of supply than weather-dependant hydropower. Infrastructure bottlenecks also limit electricity trading and reduce the trust in the benefits of electricity market integration.

Chapter 3: European Electricity Markets

Introduction

The establishment of a common market for energy has been one of the most significant campaigns in the European Union (EU). Since the early stages which date back to late 1980s, Europe has achieved some important steps in creating the world largest integrated electricity market, although more works remains to be done. Achieving deeper energy market integration is one of five dimensions of the EU Energy Strategy along with energy efficiency and renewable energy targets (EC 2016).

The integrated European electricity market is expected to achieve economic, security and environmental benefits on the European level. Cost savings will come from avoided generation capacity investments and a more competitive generation landscape. The security benefits will come from an increased choice of electricity suppliers in well-interconnected networks, which is more secure than the isolated markets of individual member countries. Integrating and distributing higher shares of renewable energy will reduce the greenhouse gas emissions in electricity generation which one of the most GHG-intensive industry sectors in Europe.

This section presents an overview of the European electricity markets which is the world-largest initiative of electricity market integration. The section covers historical development, market mechanism, trends and the institutional framework that have helped countries to exchange power more freely. Liberalized power sectors and unrestricted grid access have been the cornerstones of the European integration strategy. European experience in establishment of cooperation bodies between national transmission system operators (ENTSO-E) and regulators (ACER and CEER) is particularly valuable for the ASEAN region. Coordinated infrastructure development (TYNDP) and transmission system pricing and allocation are other valuable lessons from the European experience.

Historical Development

The vision of a uniform energy market has been one of the main pillars of a common market for goods and services between the EU member states. The first significant steps for market integration were achieved in 1985 and 1986 with Delors White Paper and Single European Act which set out an ambitious plan to establish a single internal market by 1992. However, neither of these documents had energy on its agenda. The importance of integration of energy markets became more apparent in late 1980s, but it took another 8 years until an agreement on electricity has been reached (AEMI 2016).

Figure 7 highlights three stages of electricity market integration in Europe between 1996 and 2009. These stages are outlined in more detail in the following sections. It is important to keep in mind that European countries had already had well-developed electricity infrastructure, by the time the process of market integration has commenced. In early 1990s, most national power sectors operated under state-owned monopolies or single buyer models while first stages of market liberalization were introduced in Great Britain.

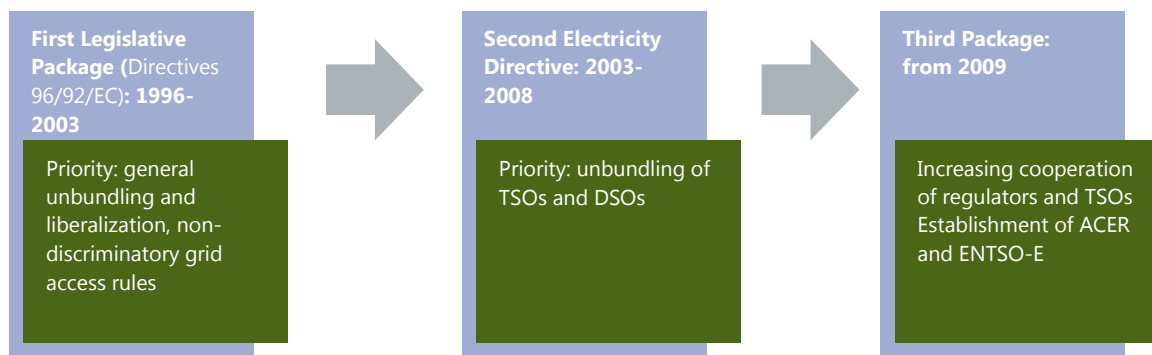


Figure 7. Three liberalization stages of European electricity markets

1996-2003 First Electricity Directive

The first agreement on electricity market integration was signed in 1996, with the first electricity directive (96/92/EC) after prolonged discussions between the member states. The directive was to be transposed into member states' legal systems by 1998.

The first directive set out common rules for the internal market in electricity. The aim of the directive was to guarantee the free movement of capital, i.e. the right to freely establish power companies, construct and operate power stations across the EU, and the free movement of goods to serve final customers. It also sought to unbundle transmission system operators (TSOs), and the unbundling of commercial operations from generation and distribution. Key features of the directive were:

- Full liberalization of the generation sector and allowing all large and medium-sized companies to choose their electricity supplier;
- Access to the grid was enabled through unbundling of the vertical state-owned companies, and guarantees of non-discriminatory access for all new market players.

However, during negotiations between the European Council, Parliament, and the Commission, the liberalization of retail markets was watered down, and only liberalization of industrial customers was retained. Vertically integrated companies still enjoyed advantages in insider information compared to the independent power producers. Other issues included absence of cross-border coordination regarding general market design, lack of independence of regulators from the political agenda and the slow transposition of the Directive by member states into the national law. These shortcomings were addressed in the Second Legislative Package in 2003 (AEMI 2016, EC 2016a, Sioshansi 2012).

2003-2009 Second Electricity Directive

The Second Electricity Directive came into force in 2003 and was required to be transposed into the national law by all EU member states by July 2004. The Second Package was comparable to the First with regards to scope and focused on outlining the design for cross-

border markets. According to the package, all non-household and industrial customers were eligible for choosing their suppliers and by July 2007 and all customers were to be liberalized (EC 2016a).

The overall direction of the Second Package was providing more independence to TSOs and DSOs in market operations as well as to separating regulators from the governments of the member states. With respect to TSOs and DSOs, the directive demanded at least unbundling the operator in legal terms, which meant establishing a separate legal entity and ensuring that the management was not part of the structures of the integrated company. The directive also stipulated the establishment of sector-specific regulatory authorities across the EU member states, but since no requirement for political independence was made, the former situation in many member states persisted. The EU regulators were thus not particularly effective in enforcing unbundling of network operators from competitive parts of vertically integrated companies (Karan and Kazdagli 2011).

Overall, though the first two directives made progress, weaknesses persisted. The main issues were lack of unrestricted third-party access to networks due to continuing vertical integration, weak regulatory function, limited competition in the small consumer segment, insufficient liquidity in wholesale markets and this an underutilized interconnection capacity.³ There were also problems with access and high-access charges, inadequate unbundling of TSOs and lack of an institution representing TSOs' interests on the EU-wide level. Member states were still found to be protecting their national incumbents (AEMI 2016, EC 2016a, Sioshansi 2012).

At the adoption of the Second Package, the European electricity market was a conglomerate of regional markets, which were more or less physically connected. There were seven broad regional energy markets, some of which overlapped. The countries in the Western Europe had electricity exchanges offering trading in both spot and futures contracts. Bilateral (or OTC contracts) represented the majority of trades, although the share of spot trading had been increasing, albeit at different rates in different power exchanges. Some of these markets

³ Ibid.

started to broaden their activities beyond the national borders. The countries in the Eastern Europe relied almost entirely on the OTC trading with a very low degree of unbundling. In 2009, OTC trading amounted to roughly 7,800 TWh or approximately 75% of the total amount of power traded in Europe (ACER 2013).

From 2009: Third Energy Package

To address the shortcomings of the First and the Second directives, the EU adopted the Third Package in 2009 which was enforced in 2011. The aim of this package was to improve the functioning of the market and to resolve the key structural problems such as utility unbundling and the independence of the regulators. Key goals of this directive were:

- A complete unbundling of TSOs from generation companies facilitated through either of three pathways depending on the individual preference of EU countries:
 - 1) Full unbundling requiring generation companies to sell off their gas and electricity networks;
 - 2) Creating an independent system operator (ISO), where energy supply companies may still formally own electricity transmission networks but must leave the entire operation, maintenance, and investment in the grid to an independent company; and
 - 3) Creating an independent transmission operator (ITO), where energy supply companies may still own and operate gas or electricity networks but do so through a subsidiary while key decisions are to be taken independently of the parent company.
- Establishing of Agency for the Cooperation of Energy Regulators (ACER), an institution representing regulators' interests. This unit is responsible for publishing non-binding Framework Guidelines that specify the objectives and principles of the finalized network codes. The codes constitute the integrated market design in Europe.
- Establishing of European Network of Transmission System Operators for Electricity (ENTSO-E), an institution representing interests of the national TSOs and DSOs. ENTSO-E was

established to facilitate cooperation and align interests between TSOs in achieving the efficient use and development of interconnectors. Given significant differences in operating standards between EU states, ENTSO-E designs common network codes to harmonize the flow of electricity between different transmission systems. It also designs infrastructure development plans in cooperation with European Commission and ACER.

- Increased transparency through information disclosure in retail markets to benefit consumers.

Of these, the most significant rules are those on unbundling and establishing of ACER and ENTSO-E. As of 2015, a significant progress has been made due to the Third Package, with 96 of the approximately 100 TSOs in Europe being certified as compliant with one of the unbundling models, specified above (EC 2014a). The role of ACER and ENTSO-E is to foster cooperation in cross-border trade and coordinate the new capacity investments, given a large size and complexity of the European electricity markets. It must be stressed that these targets are set without jeopardizing the interests of the national regulators and TSOs who retain the right of final word within their respective electricity systems.

Coupling of national markets and the “Target Model”

Over the past decades, countries in Northern and Western Europe have progressively liberalized their electricity sectors and introduced multiple competitive markets or power exchanges. The “Target Electricity Model” is a framework of gradual coupling these exchanges into one entity, operating under a single auction platform. Market coupling is a complex process that requires series of actions aimed at harmonization of technical, market and regulatory standards across the market borders. In order to maximize the benefits of market coupling, this process should be accompanied by a development of interconnection capacity that serves as a supporting pillar of the integrated market.

As of today, the most progress in Europe has been achieved in coupling of the day-ahead markets. The day-ahead markets have been synchronized across Europe to a great extent,

using single price algorithm (ACER 2016). This algorithm calculates electricity prices across Europe, taking into account available transmissions capacity, while still maintaining a certain degree of independent operation within national systems. Day-ahead coupling started between France, Germany and BeNeLux in 2010. The approach of determining day-ahead electricity prices in each national market independently has been replaced with a uniform algorithm, calculating prices across the whole region, based on the available transmission capacity. As a result, exchange of electricity went more smoothly and the prices across the regions converged. Another important consequence was that transmission capacity allocation has become the integral part of the price calculation algorithm, while prior to this transmission prices have been calculated separately.

In 2014, price coupling has been achieved in day-ahead markets of the South-Western Europe and North Western Europe. These two regions were linked in 2015 and the now-coupled area, displayed in Figure 8, covers now 19 countries, standing for about 85% of European power consumption. (ACER 2016).

Power Interconnection in ASEAN Region

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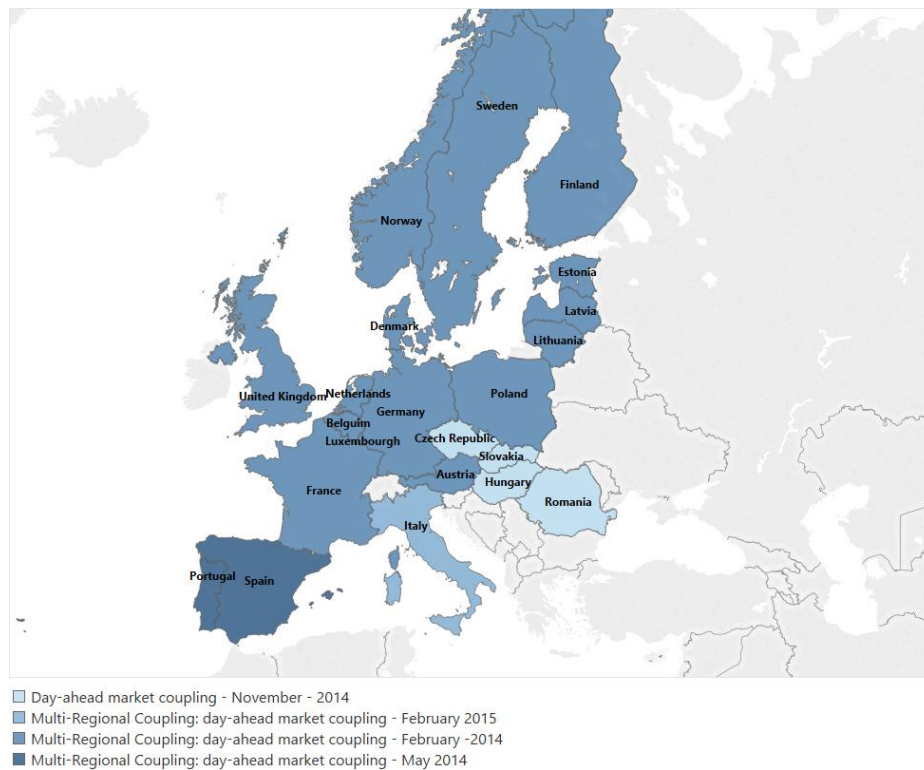


Figure 8: Progress of EU day-ahead market coupling as of 2015

From (ACER 2016)

Coupling of other markets, such as intra-day and balancing, are likely to be the next major milestones for the European market. While coupling of balancing markets remains a rather unexplored territory, some progress has been achieved in coupling of intra-day markets under the XBID initiative discussed in more detail in the markets section of this chapter.

Geographical coverage

The integrated European electricity market is planned for 28 EU-member states, shown in Figure 9. Norway is physically connected and synchronized with the EU member states through the Nord Pool market. Switzerland has so far not agreed on the terms of joining the European power market, despite the available physical infrastructure. Countries of Albania, Bosnia and Herzegovina, the former Yugoslav Republic of Macedonia, Kosovo (in line with UNSCR 1244 and the ICJ Opinion on the Kosovo declaration of independence), Moldova, Montenegro,

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Power Interconnection in ASEAN Region



Serbia, and Ukraine - these countries are known as the 'contracting parties'. This collaboration aims to extend the EU's internal energy market to South Eastern Europe and the Black Sea region (EC 2016a, EC 2016b).

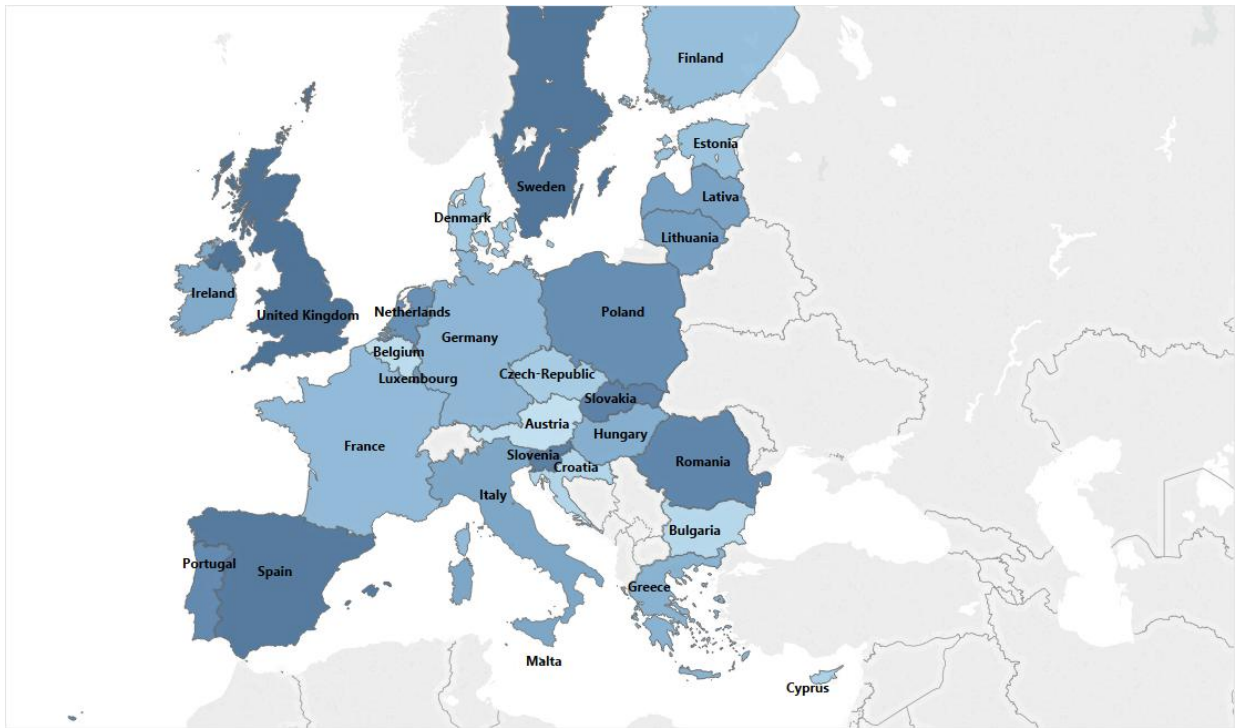


Figure 9: European Union Member States

Integrating European electricity markets has proved to be a difficult venture. National power sectors in Europe are extremely diverse in terms of their mix of electricity generation and had evolved independently before a common vision for market integration has been established. Faced with slow progress of full market coupling, the EU has established four regional markets that will serve as intermediate stages for the common European market. The four markets include the Nordic region, the Northwestern/central Europe, the Iberian islands and the Southeast Europe (AEMI 2016).

Vision and objectives

European electricity market has a multifaceted vision, which at initial stages was achieving power sector liberalization and free exchange of electricity between the member states based on principles of market competition. The countries involved are also expecting significant economic benefits arising from the market integration which are discussed in a separate section (Newbery 2015).

Faced with global environmental challenges and the new objectives of the EU policy on energy and climate change, the vision of the integrated market has evolved in tandem. According to EU Commission, "an internal electricity market for Europe is not an end in itself. It is urgently needed to achieve the objectives of the Union policy on energy. Those include: secure and competitively priced supplies; renewables and climate change targets of 2020 and beyond; and a significant increase in energy efficiency across the whole economy. That market should be based on fair and open competition" (EC 2016a).

The current vision for European electricity market is strongly linked with goals of the recently adopted 2030 Climate & Energy Framework and the mechanism of the European Emission Trading Scheme (ETS). The 2030 Climate & Energy Framework has legally binding EU-wide targets and policy objectives for the period between 2020 and 2030, aiming to help the EU achieve a more competitive, secure and sustainable energy system as well as to meet its long-term 2050 greenhouse gas reductions target. The reduction target will be achieved through an emission trading mechanism (ETS) which imposes a hard cap on emission allowances in various sectors. Energy generation plays the pivotal role in emission trading, as it produces the majority of greenhouse gas emissions in Europe. An important consequence of this package for the European electricity market is that the future market design needs to make a positive contribution to the successful delivery of these objectives. Decarbonization and renewable energy targets raise a plethora of other questions including optimal balance of baseload power, long-term investments in power generation technologies, idle fossil fuel capacity, variable renewable energy integration and energy storage. These issues, albeit important,

extend beyond the scope of this report. Following sources offer detailed information on this topic: (EC 2016a, EUELECTRIC 2016), (Genoese and Egenhofer 2015a) and (Genoese F and Egenhofer C. 2015b).

Market Participants

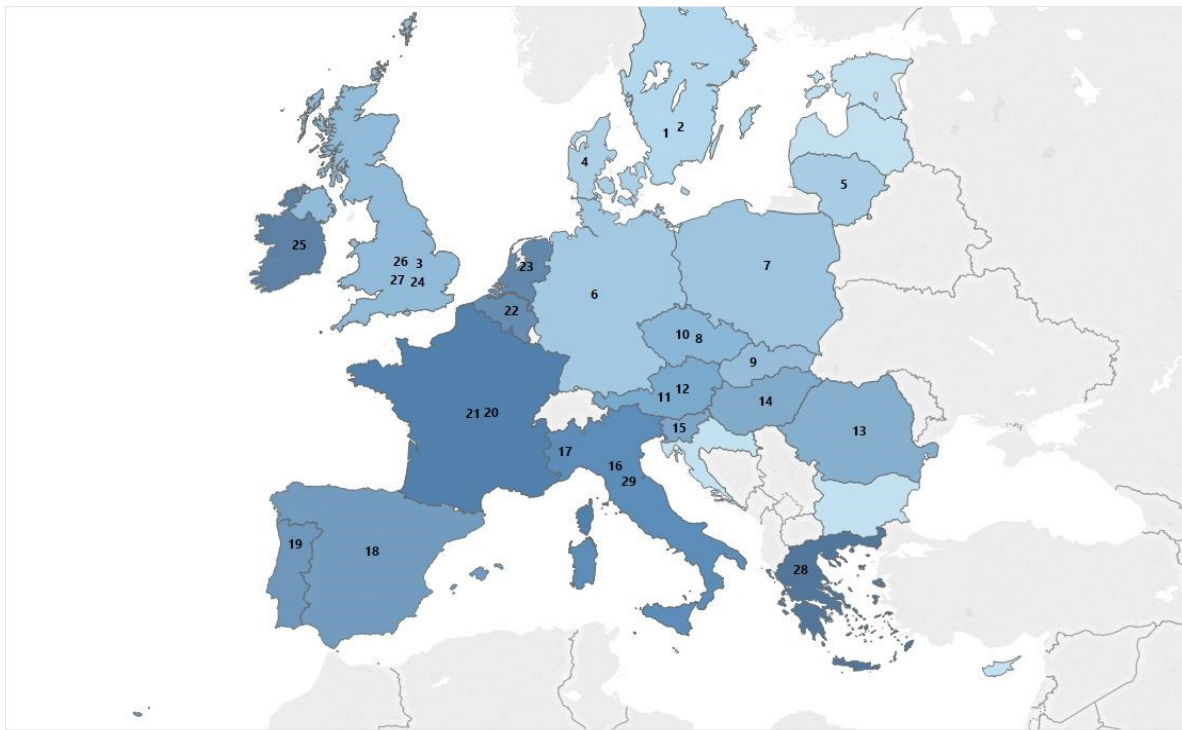
The European power market consists of regional markets of EU member states and non-EU members (Norway and Switzerland) which are linked to a different extent. In the North, European market is linked with Nordpool, although Nord Pool is commonly treated as a separate market. Market integration has been more advanced in the Northern and Western regions.

An overview of regional power markets across Europe is given in Figure 10. The markets have numerous participants which can broadly be divided into following categories:

- National utilities and independent power producers;
- Transmission system operators and distribution companies;
- Power industry regulators;
- System operators;
- Institutions (e.g. ENSTO-E and ACER); and
- Industry groups and market brokers.

Power Interconnection in ASEAN Region

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Index

- 1-NASDAQ OMX Commodities
- 2-Nord Pool Spot N2X
- 3-N2EX
- 4-Gaspoint Nordic
- 5-BaltPool UAB
- 6-EEX, European Energy Exchange
- 7-POLPX
- 8-OTE a.s.
- 9-OKTE, a.s. — Organizator kratkodobeha trhu s elektrinou
- 10-PXE, Power Exchange Central Europe
- 11-EXAA, Energy Exchange Austria
- 12-CEGH, Central European Gas Hub
- 13-OPCOM SA, Operato Pietei de Energie Electrica
- 14-HUPX, Hungarian Power Exchange
- 15-BSP Regional Energy Exchange (SouthPool)
- 16-GME. Gestore dei mercati energetici/ S.p.a.
- 17-Borsa italiana
- 18-OMIE, Operador del Mercado Iberico de Energia S.A.
- 19-OMIP, Operador de Mercado Iberico de Energia S.A.
- 20-Powemext SA
- 21-EPEX Spot SE
- 22-Belpex SA
- 23-APX NL
- 24-SEMO, Single Electricity Market Operator
- 25-ICE Index
- 26-ICE Futures Europe
- 27- APX UK
- 28-LAGIE, Electricity Market Operator S.A
- 29-IDEX, Italian Derivatives Energy Exchange

Figure 10. Power exchanges in the EU

Adapted from (ACER 2016 and ACER 2015)

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Electricity markets

Electricity markets of European countries are widely diverse in terms of operational mode and products offered. The state of vertical unbundling is uneven across Europe, with Northwestern Europe reaching the most advanced stage with multiple power exchanges operating there. Trading in Southeastern Europe is still done predominantly via long-term contracts. The “EU Target Model” defines four markets, including day-ahead, intra-day, balancing and forward markets, that could commonly be developed and linked across European countries in future years.

Trading in electricity markets takes place both in physical and financial markets, as highlighted in Table 5. Physical contracts involve the physical delivery of electricity or balancing services, while financial contracts are risk-hedging instruments which can also be traded by parties outside of the energy sector (e.g. banks and trading houses). Some of the energy exchanges within the EU operate both in the physical and financial markets, whilst other exchanges operate in only one of the two market segments (ACER 2015). The gradual transition towards the integrated European market is ongoing in the energy-only market, while balancing is undertaken independently by TSOs in accordance with respective national guidelines. To provide a better coordination of cross-border balancing efforts, TSOs exchange information in real time, aided by ENTSO-E.

Table 5: Products traded in physical and financial markets

Market Segments	
Physical Markets	Financial Markets
Balancing markets	Derivatives markets
Spot markets	<ul style="list-style-type: none"> • Financial forwards • Futures • Swaps • Options
<ul style="list-style-type: none"> • Interday or within-day products • Day-ahead products • Week-end, weekly and brock products until the end of the ongoing month 	
Physical forward markets	From (ACER 2015)

Bilateral trading can be done either in over-the-counter markets or in respective power exchanges, given that a member state is participating in a power exchange. The importance of both channels is discussed in more detail below.

Bilateral contracts

Bilateral or OTC contracts has been traditionally the dominant channel for electricity trade on the European level. OTC deals comprised about 70% of the traded volume in 2012 (ACER 2014). However, the importance of OTC has been declining over the years, particularly in the Northwestern region. As highlighted in Figure 11, the importance of OTC is different among national exchanges today. For instance, while OTC fraction has been dominant in the UK it comprised less than a half of total market volume in Nord Pool. OTC trading is either purely bilateral or carried out via a broker. Whilst transactions carried out at energy exchanges are anonymous and screen-traded, with brokers transactions can be handled via public communication channels (ACER/CEER 2015). Forwards is another example of instruments of OTC trading besides bilateral contracts which provide additional flexibility to contract parties.

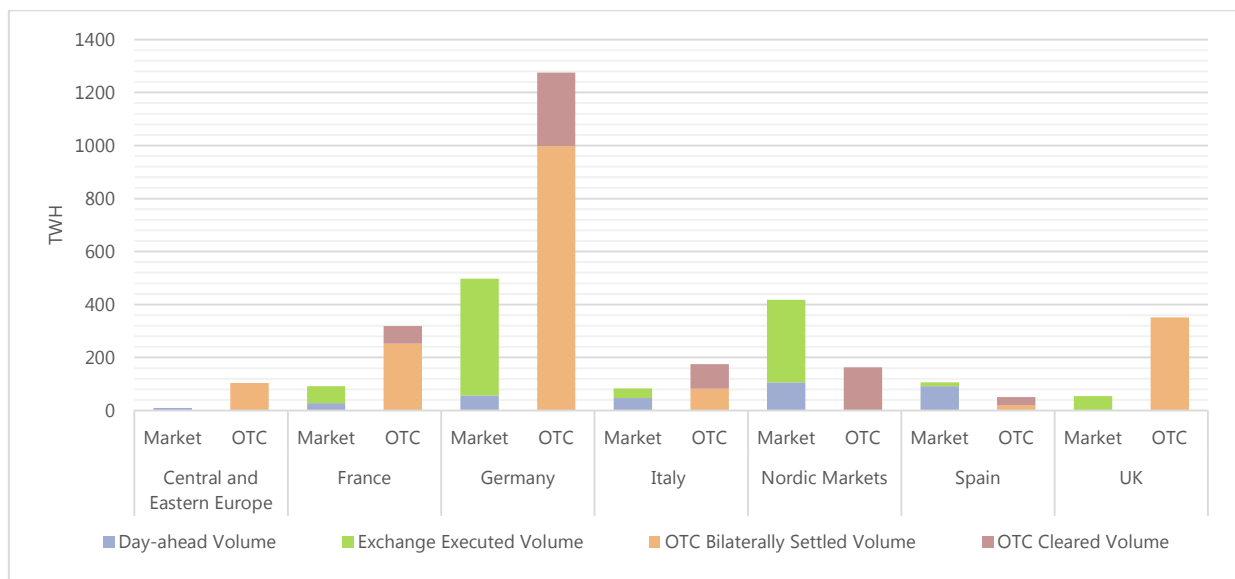


Figure 11. Comparison of electricity traded volumes in some important regional markets in Q1 2016

Adapted from (EC 2016b)

Power exchanges

Power exchanges, or wholesale markets trade various product from short-term spot to long-term forward contracts. The market is divided into bidding zones (as opposite to bidding nodes) featuring equal prices within every zone. Any consumer within one zone is allowed to contract electricity with any generator without limitations such as physical network limits. However, market participants trading electricity with another bidding zone have to take into account grid constraints.

Table 5 shows physical and financial products traded in wholesale markets. Physical products range from hourly contracts traded in the intraday market to long-term futures. Financial products include various derivatives. A more detailed overview of products traded at European power exchanges can be found in (ACER 2014).

Day-ahead markets and coupling of day-ahead markets

Day-ahead markets in Europe operate under the common principle of a uniform clearing price paid to all generators. One of the significant achievements in advancing the integration of European markets is the coupling of the national day-ahead markets that has been ongoing since 2010. As of 2015, day-ahead markets of 19 countries have been successfully coupled, standing for about 85% of European power consumption (EPEXSPOT 2016, ACER 2016).

Market coupling involves synchronizing day-ahead operations of different markets with respect to gate closure times, operation procedures, types of products available for trading and transmission capacity allocation across borders. The harmonization enables joint market clearing, making available all cross-border supply and demand bids for trading at the same time, which can be matched automatically with the available cross-border transmission capacity. This allows simultaneous inclusion of available transmission capacity in the optimization process, also known as implicit allocation, as opposed to separate or explicit allocation. This enables parties to obtain automatic access to cross-border energy and capacity

without having to procure them from separate markets which also achieves synchronization of energy and transmission markets.

Intraday markets

Due to different characteristics of national intraday markets, we summarize all real-time electricity trading happening within the 24 hours as intra-day markets. The volume of electricity traded in intraday markets is typically smaller compared to day-ahead and forward markets and mainly consists of imbalances remaining after the day-ahead trades. The increasing VRE penetration in recent years has caused more uncertainty in short-term output and more trading in some intraday markets.

Coupling of intraday markets is the next major step for the integrated European market. The target is to achieve a degree of market coupling similar to the one in day-ahead markets. The integration progress has been slow so far, especially in many countries in the Eastern Europe where intra-day markets do not exist.

Integrated intraday markets could help optimize the interregional power system in the short-term. Currently, all short-term adjustments are made using expensive resources from balancing markets. Intraday markets could change this and yield cost savings as well as increase the efficiency of the balancing market.

In order to help to realize this goal power exchanges, together with the TSOs from 12 countries, have launched an initiative called the XBID Market Project to create a joint integrated intraday cross-zonal market. The purpose of the XBID Market Project is to enable continuous cross-zonal trading and increase the overall efficiency of Intraday trading on the single cross-zonal Intraday market across Europe. The wider XBID solution will create one integrated European Intraday market, linking the local trading systems operated by the Power Exchanges, as well as the available cross-zonal transmission capacity provided by the TSOs. Orders entered by market participants in one country can then be matched by orders similarly

submitted by market participants in any other country, provided there is cross-zonal capacity available (EPEXSPOT 2016).

Balancing markets

Balancing is provided whenever there is a mismatch between market supply and demand and helps to maintain equilibrium, in and near real time. The requirements for balancing services can be very different across Europe due to inherent characteristics of national power systems, available balancing resources and ongoing electricity trade (Ocker et al. 2014). Integration of balancing markets is the final building block according to the “target model” of an integrated European electricity market. To date, the progress in integrating national balancing markets has been limited, mainly due to significant differences in existing national balancing markets or the absence of such.

The initial step towards an integration happened in 2012, when ACER adopted its Framework Guidelines on Electricity Balancing. These aim at providing a solid framework for the integration of national balancing markets and the achievement of the single European electricity balancing market. The target for European market integration envisages cross-border trading of manually activated reserves (replacement reserves). Various balancing market models have been proposed, based on the degree of harmonization between markets and TSOs, albeit no concrete solution has been agreed upon yet. These models range from cross-border extension of national balancing mechanisms to bilateral or multilateral TSO-TSO exchanges.

In general terms, balancing services can be provided by TSOs, balancing responsible parties (BRP) or demand-response participants. As of 2016, balancing services are traded in the respective power exchanges or allocated by national TSOs within respective control areas. Also, there is little cross-border harmonization of balancing markets mainly due to significant differences in existing national rules on balancing. According to ACER, while most of these

arrangements can be harmonized to a certain degree, some differences appear to be inherent to differences in balancing resources being available in member states (ENTSO-E 2016).

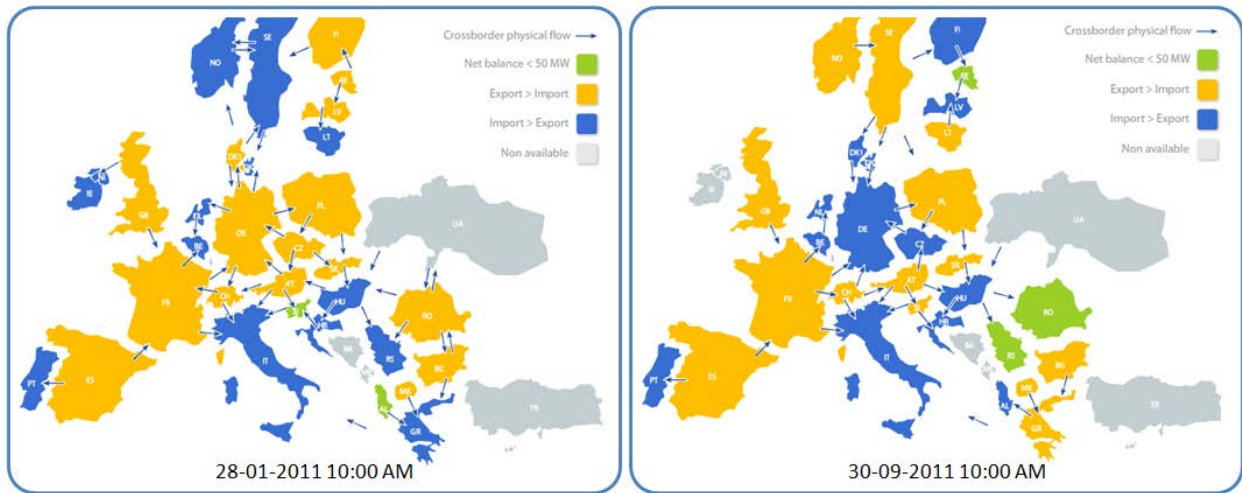
Geographical power flows

Patterns and magnitude of power flows across the regions provide some good insights into the process of market integration. In Europe, the proportion of cross border trade volumes compared to national electricity consumption has been increasing since the adoption of the Third Package, which shows good signs of integration of the wholesale electricity markets.

According to ACER, the monthly average cross border electricity trade was 17.8 TWh in 2010, while in 2013 it amounted to 21.7 TWh, showing a growth of 23% in this period (Eurostat 2016). The total amount of electricity generated in the EU in 2012 was 3,295 TWh (EC 2014b). Although monthly cross border trade volumes showed a high degree of seasonality between 2010 and 2013 (being higher in winter months, as electricity need increases, and lower during the summer periods), an upward trend in monthly trade volumes could clearly be observed. At the same time gross inland electricity consumption in the EU showed only a modest increase (being less than 2%). The growth in cross border trade as opposed to modest increase in electricity consumption resulted in an increase in the ratio of electricity cross border trade volumes compared to consumption, up from 6% in January 2010 to 9.8% in December 2013 (Eurostat 2016).

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Source: entsoe.net

Figure 12. Example of regional power flows in Europe

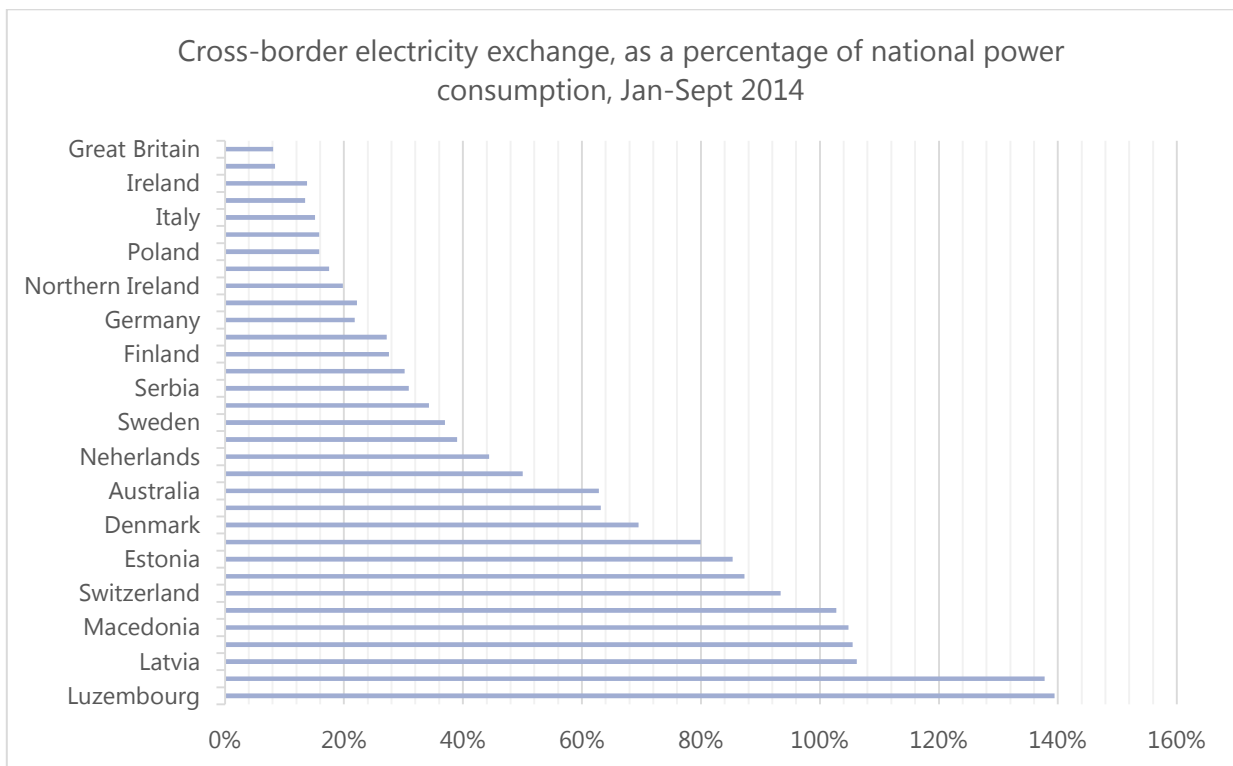


Figure 13. Relationship between cross-border power exchange and domestic consumption in Europe

From (ENTSO-E 2016)

Figure 12 shows cross-border trade patterns observed in January and September 2011. Most notable is the stable exporting status of France which has a lot of nuclear capacity. The

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direction of some flows and the status of some countries (mainly Germany) change depending on the season. This is due to differences in seasonal electricity demand patterns and due to a growing renewable energy generation in Europe. The share of cross-border exchange as a fraction of domestic generation is shown in Figure 13. The values are generally higher for smaller economies, which is intuitive given their lack of domestic resources, small size and developed transmission lines with neighboring countries.

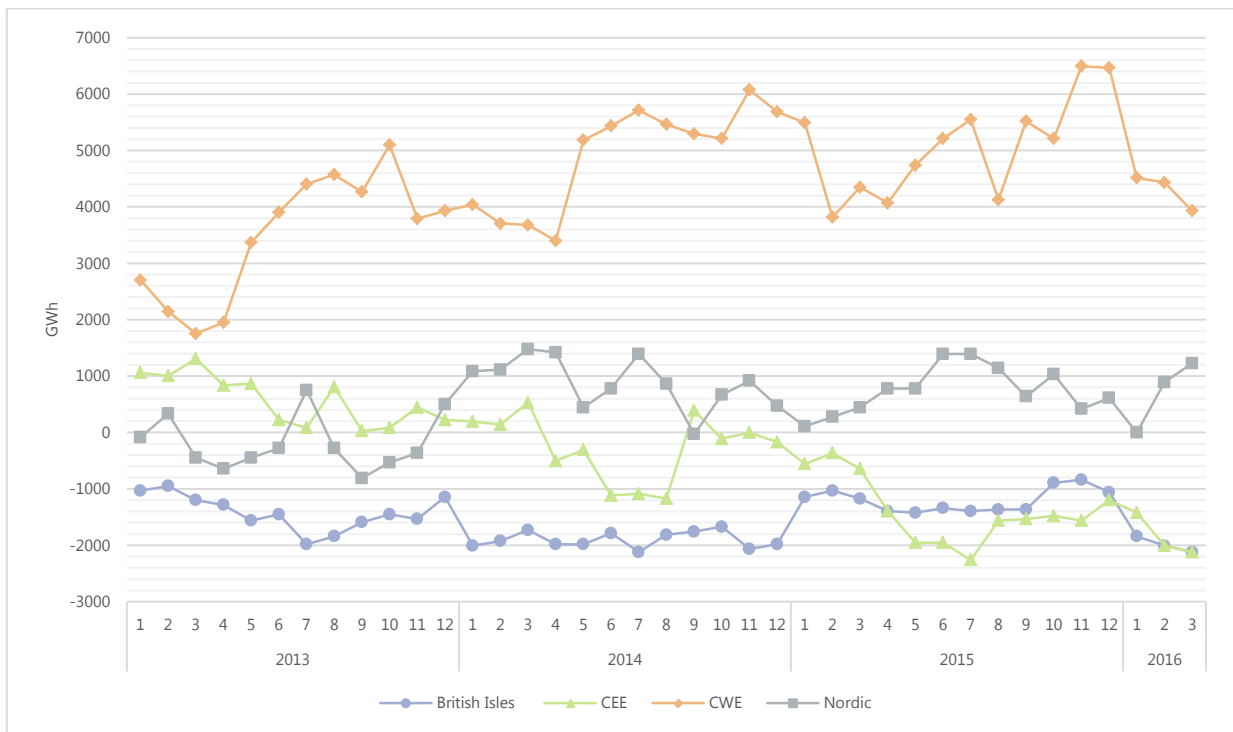


Figure 14. Power imports and exports by region

Adapted from (EC 2016b)

A more recent trend in regional power trade in Europe is shown in Figure 14. In the fourth quarter of 2015 the Central Western Europe (CWE) power region exported the largest volume of electricity over the last few years, which was primarily due to its abundant and cheap renewable based power generation. The region could export significant amount of electricity to the UK, Italy and the Iberian markets.

In the first quarter of 2016, as price differentials decreased across power regions in Europe, net exports from the CWE region also started to decrease. Central Eastern Europe (CEE) have become increasingly net importer over time; as abundant renewable generation in the CWE region represents in many periods cheap import alternative to domestic carbon-intensive electricity generation. In abundant hydro generation periods, South Eastern Europe can also export electricity to Central Europe.

The key drivers of the direction of flow are:

- Demand levels and particularly weather sensitive demand;
- Plant availability and hydro storage levels;
- The relative short run marginal costs of thermal plants, predominantly driven by commodity prices and thermal plant efficiencies; and
- Prevailing output levels of 'must run' intermittent renewable capacity.

Cross-border traded volumes

Despite the electricity demand in EU declined by 6.3% between 2008 and 2014, there has been a simultaneous increase in cross-border power trade and market liquidity ratio, as shown in Figure 15 (EU 2014b).

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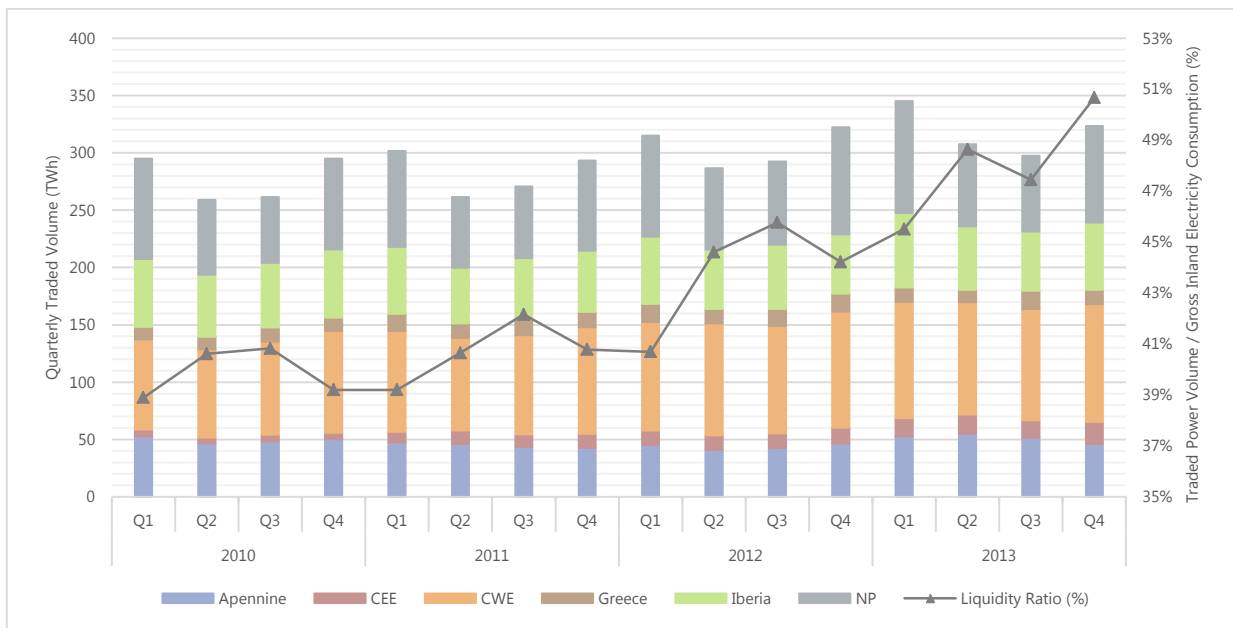


Figure 15. Traded volumes and market liquidities of the major European markets

Adapted from (EC 2014b)

The highest traded volume of power in this period took place in Central Western European (CWE) markets and in the Nord Pool. Nord Pool has also been the most liquid market, with a liquidity ratio of 96% in the fourth quarter of 2013, being above 80% during most of 2012 and 2013. The CWE region had a ratio of 34% in the fourth quarter of 2013. The volume of electricity traded in the Central and Eastern European (CEE) region has been the smallest in Europe, although the balance has shown some impressive growth and the liquidity ratio has risen from 6.4% to 21.4%.

The overall European market liquidity, incorporating both mandatory and non-mandatory markets, rose from 39% to 51% between the first quarter of 2010 and the fourth quarter of 2013. Besides increasing traded volume in power this increase in the market liquidity was also due to decreasing gross inland electricity consumption in this four-year long time period (EU 2014b).

Electricity prices

Along with increased power flows between interconnected regions, the convergence of wholesale electricity prices can be an important indicator of market integration. Figure 16 provides an overview of hourly price convergence in day-ahead markets in different geographical regions in Europe.

In general, price convergence has been showing a fluctuating trend with a recent decline across almost all regions. However, this decline is only partly attributed to bottlenecks in cross-border power flow and has some other underlying reasons. For example, decoupling of the Finnish prices from (lower) prices in neighboring zones, exacerbated by declining electricity imports from Russia, has decreased the overall level of convergence in the Nordic region. In the CEE region, decrease in price convergence is mainly due to the opposite price trends in Poland and Hungary (increase) as opposed to the Czech Republic and Slovakia (decrease). In the Baltic region, decline in convergence is attributed to transmission bottlenecks preventing Latvia on tapping on cheap power from the Nordic region, as opposed to Estonia (ACER 2015).

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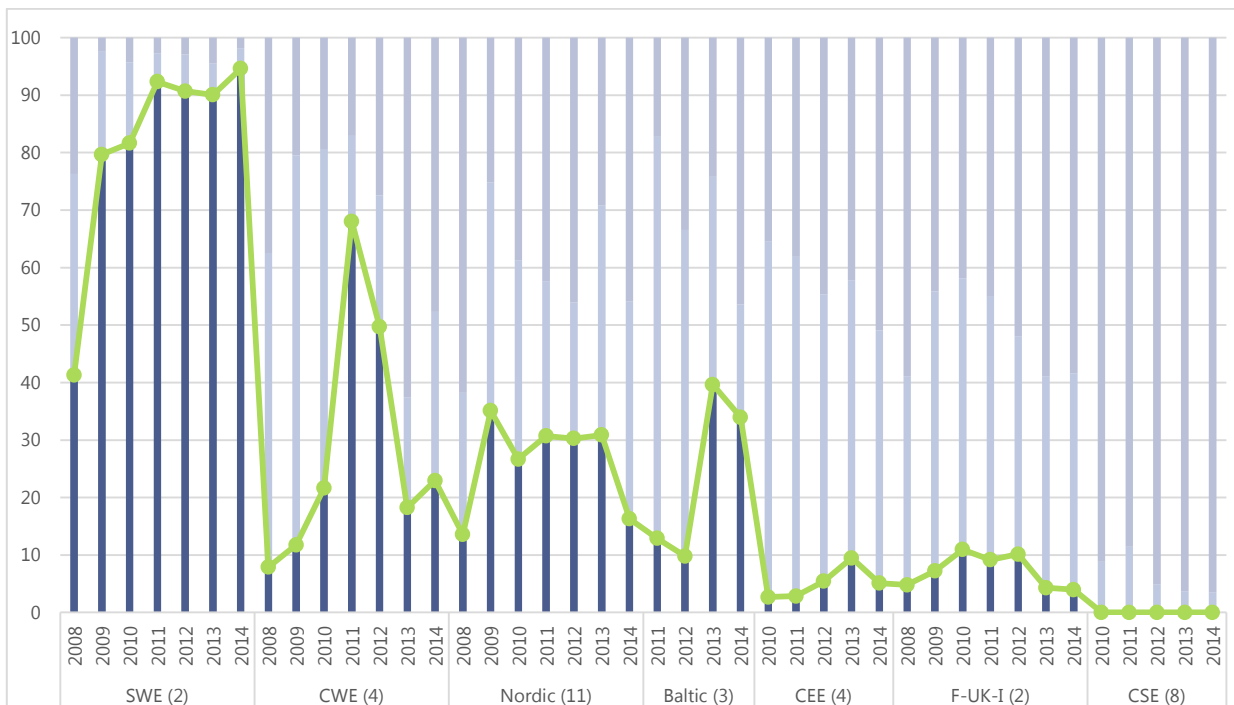


Figure 16. Convergence of hourly prices in day-ahead markets in major trading regions

Adapted from (ACER/CEER 2015)

Figure 17 displays the evolution of wholesale and retail electricity prices in some significant European power markets. The picture shows a strong decline in wholesale power prices, while retail prices have increased. Also, the differences between the cheapest and the most expensive wholesale electricity markets shrunk. The decline in wholesale electricity prices across Europe is attributed to decreasing coal prices, oversupply of CO₂ allowances and weaker than expected electricity demand which resulted in generation overcapacity. The increase in retail electricity prices is attributed to an increase in levies, taxes and network costs (IEA 2016a).

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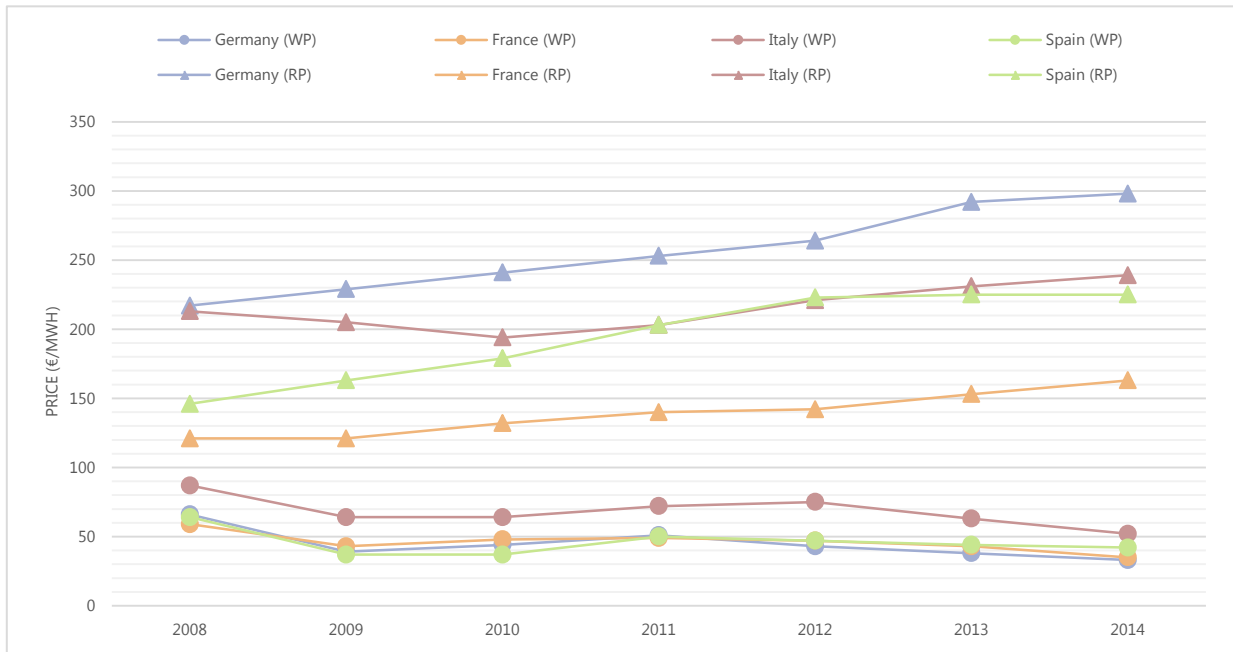


Figure 17. Evolution of wholesale and retail electricity prices in Europe

Adapted from (Genoese and Egenhofer C. (2015a), and (Genoese and Egenhofer C. 2015b)

Transmission capacity allocation

Developing a common mechanism for interconnection capacity allocation remains one of the main priorities for the European market. Traditionally, cross-border interconnection capacity has been calculated before final flows are known, one border at a time and without considering bilateral trading impacts on neighboring systems. This approach is also known as explicit auction. Explicit auction results in TSOs frequently restricting flows across borders under different security standards, even when restrictions are not justified by the physical flows of power. A significant achievement of market integration is moving to an implicit transmission capacity allocation. In simplified terms, this mechanism instantly includes transmission capacity into the wholesale electricity price calculation within one bidding zone. Implicit transmission capacity allocation has been implemented along with day-ahead market coupling.

Another refinement of the transmission allocation mechanism is flow-based capacity allocation which minimizes the occurrence of unscheduled flows. These distortive flows occur in complex interconnected systems with many linking points and reduce the available interconnection capacity. Flow-based allocation model provides a more comprehensive solving algorithm which takes into account relationships between multiple interconnectors. It helps to better manage congestion across borders in the absence of infrastructure upgrades (ENTSO-E 2015).

To co-ordinate adjacent markets closer to real time, interconnector capacity must be allocated to different users. In Europe, this is mainly achieved through forward transmission allocation, years or months before the day-ahead market. The forward transmission rights are nominated a few hours before the clearance of the day-ahead market. Once nominated, the TSOs can net out the rights nominated in the opposite direction and calculate the resulting available transfer capacity for the day-ahead time frame. The market coupling of neighboring markets then ensures optimal use of this available transfer capacity. Currently, it is not possible to keep these transmission rights in the intra-day market, though they may be reserved for balancing in specific circumstances. For longer periods, it is possible to obtain long term transmission rights, which can be useful to contract cross-border deliveries of electricity for a period longer than a day. This is useful for market participants to hedge themselves against congestion costs (ENTSO-E 2016, IEA 2014a).

Implementing a single algorithm for day-ahead market coupling as well as implicit capacity allocation and flow-based allocation of transmissions have improved the utilization of the existing interconnection capacity. As shown in Figure 18, the efficient utilization of electricity interconnections has increased from around 60% in 2010 to 86% in 2014 (ACER 2015). "Efficient" use means that whenever there is a price difference between the bidding zones, electricity can freely flow from the zone of low price to the zone of high price, thus converging prices. Although expected in theory, this has not always been the practice prior to implementing of these mechanisms.

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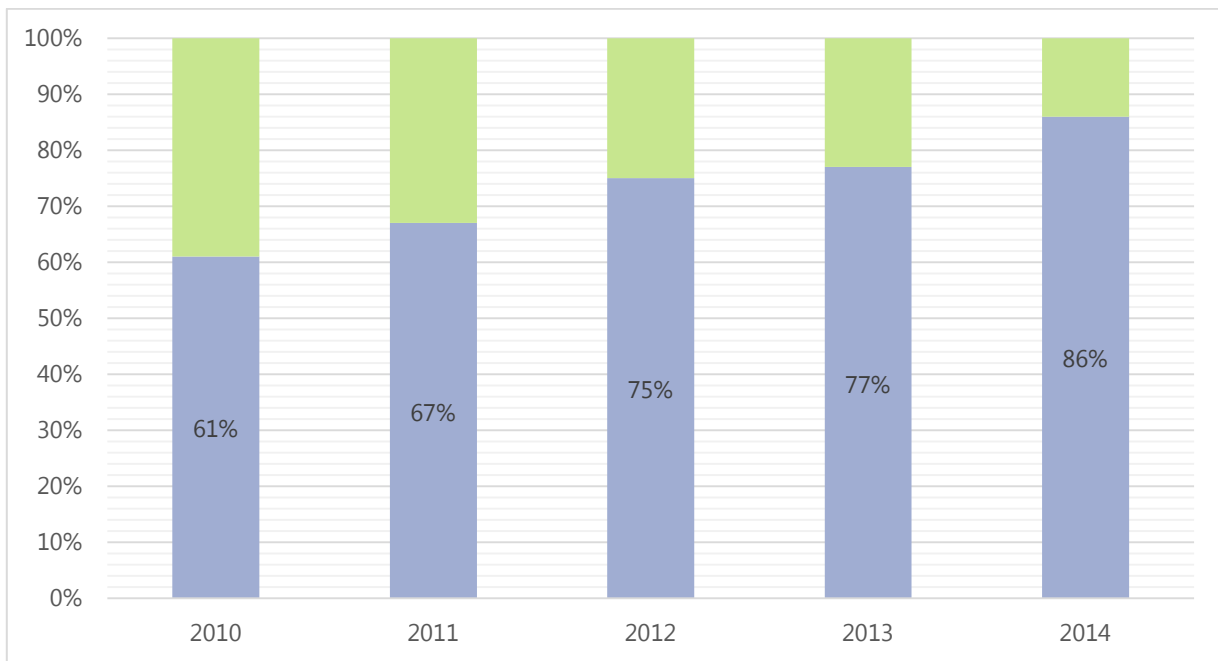


Figure 18. Effectiveness of interconnectors' utilization

Adapted from (ACER/CEER 2015)

ENTSO-E

Since the adoption of the Third Energy Package, the role of Transmission System Operators has systematically evolved. The liberalization of electricity markets and ongoing market integration required a structure facilitating cooperation and transparency of operations between different TSOs. Some important questions that remained unsolved were harmonization of technical and market standards while increasing the degree of cross-border interconnection.

The ENTSO-E was created in 2009 from six predecessor organizations and currently contains 42 European TSOs. ENTSOE-E is a non-binding institution which operates on a consultative basis. The collaborative nature ensures that national goals of TSOs are not violated. Upon its creation, ENTSO-E was tasked with developing standards and drafting network codes that would later be formally adopted in EU legislative processes, to harmonize the flow of electricity across different transmission systems and coordinate the planning of new network investments

and development of transmission capabilities. The Network Codes on Capacity Allocation and Congestion Management, Forward Capacity Allocation, and Electricity Balancing, provide a complete set of rules for trading electricity across Europe at different points, starting from a year before real time and finishing immediately before the point where energy is delivered. Without harmonized rules, the amount of available cross-border transmission capacity, prices for every part of Europe and the flows between different parts of the Europe will not be calculated in the same way.

The ENTSOE-E operates through the following committees organized on continental and regional structures: legal and regulatory, system development, system operations, market and research & development. The work of the committees is monitored by the Agency for the Cooperation of Energy Regulators (ACER) whose mandate is to ensure harmonization of regulatory frameworks to facilitate the achievement of a single EU energy market for electricity and natural gas.

ENTSO-E is also required to publish a Europe-wide 10-year investment plan to identify investment gaps every two years. A surprising development has been the creation of multinational network companies, such as Elia and Tennet, which owns assets in several member states. The downside is that there is an unresolved conflict of interest as ENTSO-E is responsible for network planning, while at the same time, their member companies build and operate the assets they have been planning (ENTSO-E 2016a, ENTSO-E 2016b)

ACER and CEER

The EU established the independent Agency for the Cooperation of Energy Regulators (ACER) to boost cooperation between different national regulators as a part of Third Package. Rather than functioning as a national regulator, ACER was an attempt to bundle all competencies related to cross-border trade, while other regulatory competencies remained with the national regulators. Through ACER, the EU attempted to: (i) reinforce the European Commission's (EC) role as the responsible body for undertaking negotiations with third countries; (ii) affirm the

independence of regulators from both the EC and member states; (iii) reduce the complexity of the current system, and (iv) bundle technical expertise within EU bodies. The independence of regulators from both industry interests and the government was ensured under the Third Package by creating legal entities at the national level with sufficient funds provided by national governments and authority over their budgets. With the Third Package, regulators had enforcement powers and could issue binding decisions to companies at the member state level and impose penalties in case of non-compliance. Regulators were also empowered with access to data from generators, network operators and other companies. Cooperation was encouraged between regulators of different EU countries to promote competition; however, this cooperation has been slow to develop (ACER 2016).

The Council of European Energy Regulators (CEER) was established in 2000 for the cooperation of the independent energy regulators of Europe. While ACER deals more with the legislation issues, CEER is involved in regulation part. CEER also represents Europe in the International Confederation of Energy Regulators (ICER) which brings together similar associations from across the globe including NARUC (America), ERRA (Central/Eastern Europe) and MEDREG (the Mediterranean region). Established as a “not-for-profit” organization of regulators’ collaboration, CEER aids ACER in preparing the yearly market monitoring reports (CEER 2016).

European Commission

The European Commission is the executive body of the European Union which represents the interests of the Union as a whole. Through its Directorate-General for Energy, European Commission is responsible for developing and implementing a European energy policy. The Directorate General works with national governments contributing to achieving three main goals across the EU: security of supply, competitiveness and sustainability. The European Commission works closely with ENTSO-E and ACER when implementing technical and market standards for electricity markets and making network codes into EU-wide law.

In developing a European energy policy, European Commission ensures that EU-wide targets, such as 2020 Energy strategy, are met. The Commission also proposes legislation which is then adopted by the co-legislators, the European Parliament and the Council of Ministers and enforces the EU-wide law.

Current state of supply and demand

According to Eurostat, total net electricity generation in the EU-28 total electricity generated in Europe in 2015 was 3,278 TWh in 2015 which was the first year with increased demand after four years of consecutive negative trend between 2011 and 2014. As such, the level of net electricity generation in 2015 was about the peak level of 2008 (3,220 TWh). The most obvious reason for fall in demand was the economic crisis of 2008-2009. However as shown below, the economic recovery did not cause the electricity demand to rebound at the same rate, suggesting that power demand in Europe could be moving towards saturation (Eurostat 2016, ENTSO-E 2016b).

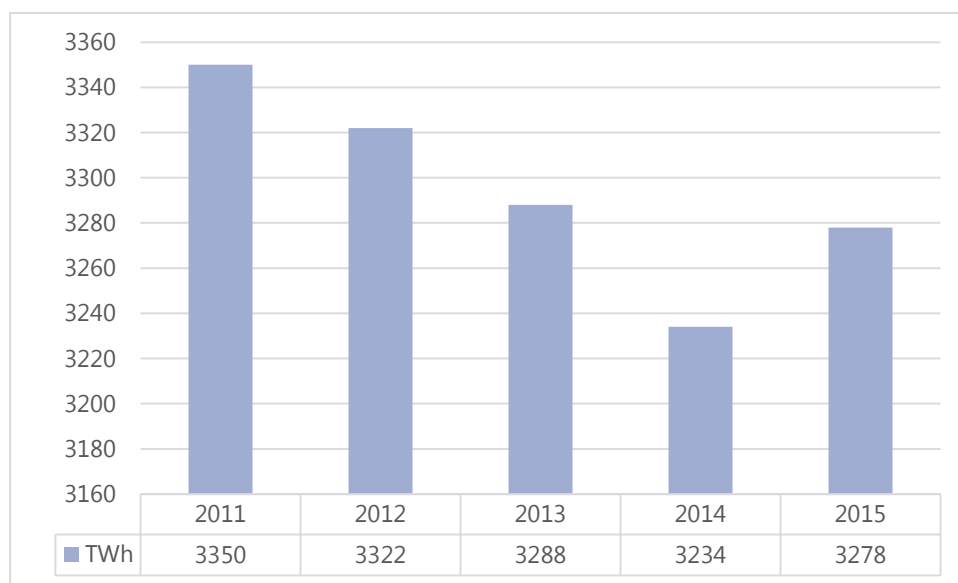


Figure 19: Electricity demand in Europe

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Adapted from (ENTSO-E 2015)

Figure 20 shows that although the EU economy has started to recover (in terms of GDP growth), electricity demand in 2014 was still lower than in 2010 and has been rather stagnant over the

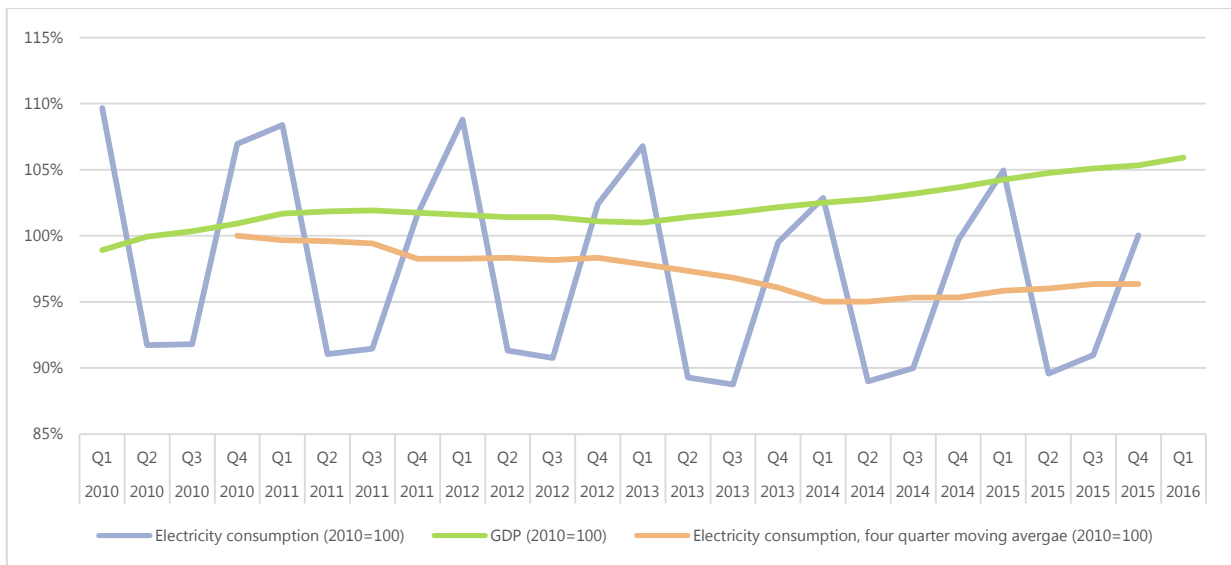


Figure 20. Relationship between GDP and electricity consumption in Europe

From (EC 2016b)

last three years. While EU electricity consumption decreased between 2010 and 2014 by 3.5%, GDP increased by almost 6% at the end of 2015 compared to 2010 baseline. This trend is partly attributed to an improved energy efficiency as well as structural changes of the EU economy (Genoese and Egenhofer 2015a). Another possible driver is an increase in distributed power generation which is not always stated in statistics provided by TSOs (EC 2016b).

Figure 21 highlights that the largest EU economies are also the main electricity consumers in Europe. The top three consuming nations in 2014 were Germany, France and the UK. The trend observed for the EU-28 of falling electricity generation has affected the majority of EU Member States. Over the same time period, the net electricity generation rose in Romania, Sweden, Poland, Slovenia, Bulgaria, the Czech Republic and Malta. In 2014, the largest annual increases in electricity generation were recorded for Romania (12.1 %), Slovenia (9.1 %) and Bulgaria (8.6

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%), while none of the other EU Member States reported growth of more than 3.0 %. By contrast, 18 Member States reported a fall in electricity generation, with the largest reductions recorded for Latvia (-18.4 %), Belgium (-12.8 %) and Greece (-11.1 %) (Eurostat 2016).

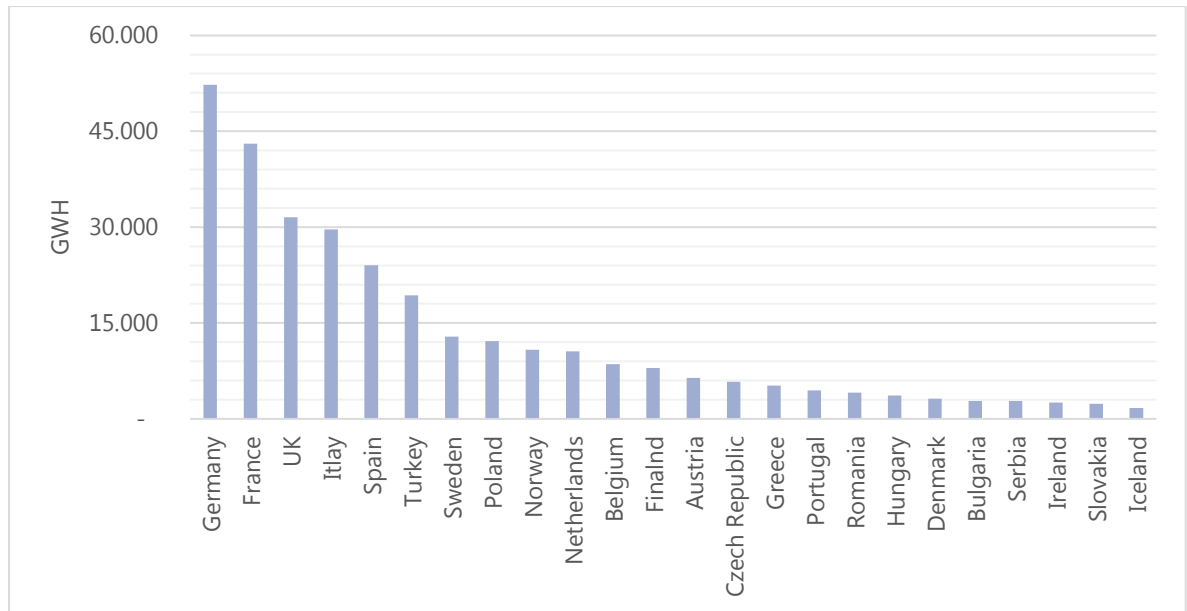


Figure 21. Electricity consumption of EU-28 in 2011

Adapted from (Eurostat 2016)

The EU-wide electricity supply mix broken down by fuel types in 2014 is shown in Figure 22. The largest share consists of fossil with 47.6%, Nuclear energy sources came second, contributing more than one quarter of all gross electricity generation in 2012 (27%). The share of electricity generated from renewable sources including large-scale hydro has reached almost one quarter of all gross electricity generation in the EU28 in 2014 (24.7%). Overall, the share of fossil fuels and nuclear decreased since 1990, while the share of renewables including hydro has almost doubled since 1990 (Eurostat 2016).

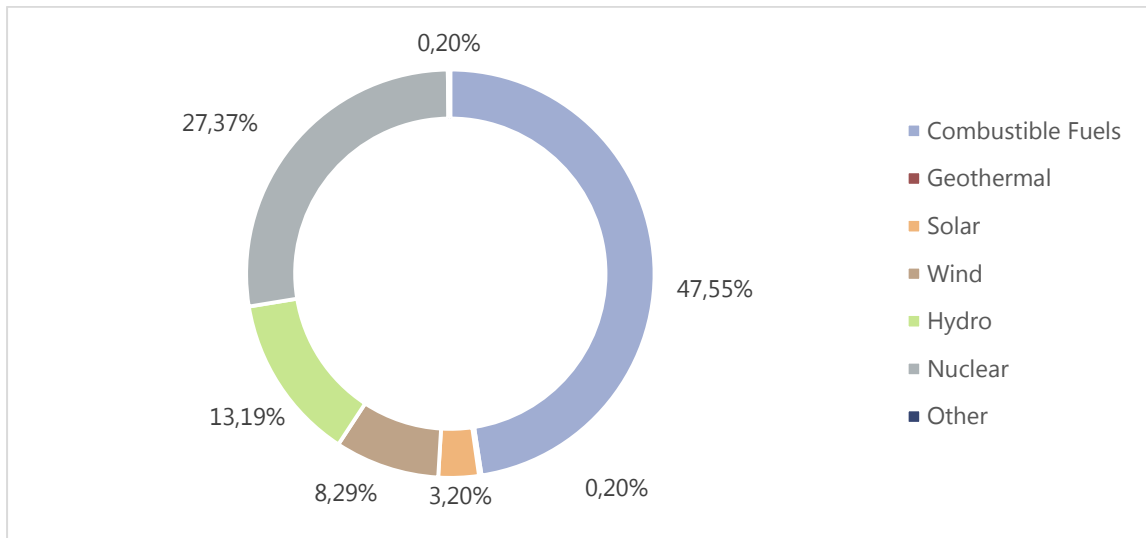


Figure 22. Electricity supply mix by fuel in 2014, %

Adapted from (Eurostat 2016)

Governance and policy

The integration of European electricity markets is collaborative in its nature. The integration is meant to achieve a greatest common benefit for participating member states while maintaining a certain degree of autonomy of the national power sectors. The institutional influence of the EU in the energy sector was particularly increased since the adoption of the Lisbon Treaty (Article 194) in 2009 which set the overall strategic direction EU's energy sector (integration, security and minimization of environmental impacts). However even after the adoption of the Treaty, many policy competences remained at the national member state level. For example, each country is allowed to choose its fuel mix as long as it complies with EU regulations on safety and environmental protection. The progress in EU-wide policy levels required voluntary cooperation of participating countries.

Development and implementation of new policy instruments is a complex process. New initiatives must be reviewed by European Commission and go through a voting process in the European Parliament before they obtain legally-binding power within EU. ENTSO-E and ACER play a crucial role advising the European Commission on infrastructure development and

prioritization of interconnections. These institutions are also responsible for development of technical standards of cross-border market operations such as network codes and codes of operation. Some of the main policy documents relevant for the electricity market integration include:

2030 Energy Strategy

The 2030 Energy Strategy is the main directive shaping the development of the future electricity market that underlines two legally-binding initiatives including carbon dioxide emission reduction and renewable energy and energy efficiency targets. These targets are based on a thorough analysis jointly undertaken by the member states and have been agreed upon. In 2014, the European Parliament voted for the adoption of these targets (EC 2016a).

- A binding target to cut emissions in EU territory by at least 40% below 1990 levels by 2030. In addition member states can have nation-wide targets extending beyond these levels. The majority of emission reductions would be achieved through a reformed emissions trading system (ETS) – to this end, the ETS is to be reformed and strengthened. Emission trading scheme creates important implications especially for carbon-intensive electricity generation sources such as coal, diesel and gas.
- A binding target at EU level to boost the share of renewables to at least 27% of EU energy consumption by 2030.
- On the basis of the Energy Efficiency Directive, the European Council has endorsed an indicative energy savings target of 27% by 2030. This target will be reviewed in 2020 having in mind a 30% target.

Furthermore, European Commission has called member states to achieve a 10% interconnection target by 2020, although this target is not legally binding (EC 2015)

The Electricity Directive

The Directive 2009/72/EC concerning common rules for the internal market in electricity establishes common rules for the generation, transmission and distribution of electricity. This

Directive includes a list of definitions regarding power generation, transmission, distribution and supply terms, however the concept of electricity storage is not mentioned in the document.

The Directive also addresses the dispatching and balancing issues requiring in Article 15 (3) to give priority to electricity from renewable sources (see also Article 16 of Directive 2009/28/EC6). In Article 15 (7), transparent market based mechanisms are promoted for balancing. Article 37 (6) requires the national regulatory authorities to ensure that balancing tariffs are non-discriminatory and cost-reflective, while providing appropriate incentives to network users for balancing their input and off-takes (EC 2016a).

Framework Guidelines and Network Codes

Network codes are rules that govern the actions of operators and determine how access is given to users. In the past, these grid operation and trading rules were drawn up independently by the member states. With an increased interconnection between the countries, it became evident that a system of EU-wide rules should be put in place. These rules, known as network codes or guidelines, are Commission Regulations containing legally binding rules. Network codes regulate, who may use the electricity networks to transport energy across borders and under which conditions.

Development of network codes is primarily carried out by ACER and ENTSO-E. The overall direction is set by the 'annual priority list' prepared by European Commission through public consultation and inputs from ACER and ENTSO-E. ACER then develops framework guidelines, which serve as in intermediary stage rules. Network codes are then developed by ENTSO-E in coherence with the principles that ACER sets out in the framework guidelines. Network codes can be made legally binding by a separate Commission decision (ACER 2016, ENTSO-E 2016b).

Infrastructure development

Ten-Year-Network-Development-Plans

The 10-year network development plans (TYNDP) is an important set of documents for the grid infrastructure development in Europe. The TYNDPs are non-binding in nature – rather they outline transmission expansion that could bring economic, security and environmental benefits for the Union.

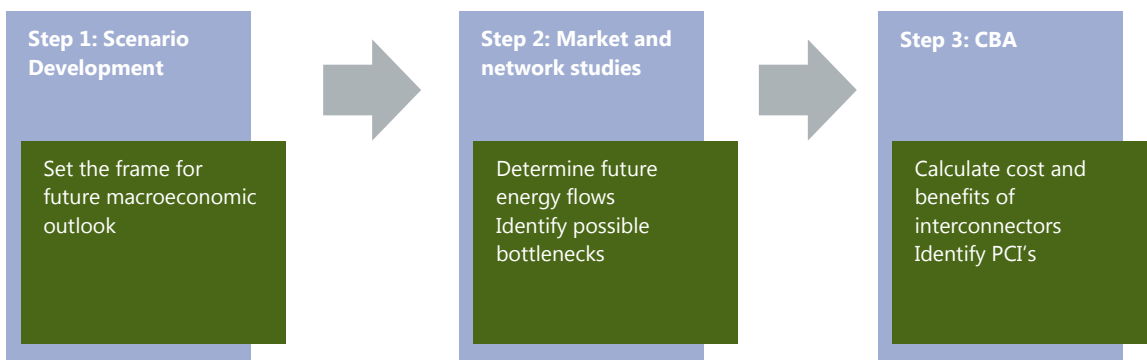


Figure 23. Steps of development of TYNDP

The process of preparing the TYNDPs is shown in Figure 23. In the first step, the analysis scopes four scenarios for the development of the power system based on different fuel mixes and demand projections. Based on these scenarios, 200 experts of 41 TSOs in 34 European countries then carry out bottom-up analysis and identify possible infrastructure bottlenecks under each scenario. A set of additional projects is proposed through agents which can be either systems operators who are non-members of ENTSO-E, or electricity storage promoters or other relevant parties. The results of the planning studies are then combined into series of infrastructure projects and undergo cost-benefit analysis as well as environmental and security assessments. ACER then identifies any inconsistencies between the ten-year network development plan and national plans and recommends amendments. Based on the network development plans, TSOs can decide which projects to undertake. The financing of these expansions comes from national sources (ENTSO-E 2016a).

The TYNDP 2016 projects around €150 billion of investments in grid infrastructure supporting 200 projects in transmission and storage. It also explores the possibility of a power system where 80% of the emissions will be cut by 2030 and congestion hours reduced by 40% (ENTSO-E 2016c).

The importance of TYNDPs is that they align the efforts in infrastructure development between different countries and avoid unnecessary investments if those were made by member states separately. However, TYNDPs are not without problems. One particularly difficult area is aligning TYNDPs with countries' energy security goals, especially in light of unclear trend of natural gas imports from Russia. Moreover, there is a notion that TYNDPs should not be developed by TSOs, who are responsible for building, owning and operating of interconnection projects, and therefore could have a vested interest in a particular outcome of TYNDPs. Finally, some projects developed between two or more countries can bring disproportional benefits to the involved parties, or even benefit a third country which does not need to develop any new network. In such a case, to what extent should all affected countries contribute to the budget of a project, cannot be easily agreed upon. Lastly, infrastructure projects face difficulty in receiving social acceptability (AEMI 2016).

Projects of common interest

Projects of common interest (PCI) are priority infrastructure developments within TYNDP's which require an urgent action from the European Commission. These projects include development of new cross-border interconnectors, strengthening existing ones, and helping integrate renewable energy. Due to the urgency of these developments, PCIs may benefit from accelerated planning and permit granting, improved regulatory conditions, lower administrative costs due to streamlined environmental assessment processes, increased public participation via consultations, increased visibility to investors and access to financial support totalling €5.35 billion in 2014-2020 (EC 2016a). Some of the current PCIs are summarized under: Priority Corridor Northern Seas Offshore Grid, Priority Corridor North-South Electricity Interconnections in Western Europe, Priority Corridor North-South Electricity Interconnections

in Central Eastern and South Europe and Priority Corridor Baltic Energy Market Interconnection Plan. The detailed list of projects can be found in (ENTSO-E 2013).

Economic benefits of market integration in the EU

Several studies quantify economic benefits resulting from ongoing market integration in the EU region. Notable examples are publications by (Booz & Company 2013), (Newbery et al. 2015) and some of the yearly Market Monitoring Reports by ACER. The studies generally agree that increased market integration and more efficient use of interconnectors will have an economic net benefit. The benefits will stem from price convergence across the regions, fuel cost savings, decreased capital expenditures and more efficient use of the interconnection capacity.

The analysis carried out by (Booz & Company 2013) estimates the benefits of a shallow market integration at €2.5 billion to €4 billion per year which is consistent with values in (Newbery et al. 2015) and in (ACER 2013). About 58%-66% of this benefit has already been achieved due to the level of market coupling as of 2013, especially in the large electricity markets of Northwestern Europe and the Nordic region. The remaining 34%-42% are projected to be achieved with the completion of the Target Electricity Model.

Disaggregated results of market integration benefits published in (Newbery et al. 2015) state that increasing cross-border trade from 10% to 15% of the total EU-wide demand (i.e. by 158 TWh), assumed an average price difference of €10/MWh between the trading points, would result in a benefit of €1.58 billion per annum or 1% of the value of wholesale demand. Another Considering other sources of benefits, such as price arbitrage from coupling of day-ahead and intraday markets and balancing, realizable benefits could be €2.4 billion per annum.

The theoretical benefits resulting from a deep market integration published in (Booz & Company 2013) could have a much higher magnitude compared to the current state. Deep market integration could achieve benefits, ranging from €12.5 billion to €40 billion per year by 2030, or more than ten times of the current value. The results show a magnitude of more than

200% which corresponds to a large number of development scenarios tested. Worth mentioning are also high potential benefits of a common market for renewable energy in the order of magnitude between €16 billion and €30 billion a year.

The role of market transparency

The Third Package puts a high value on the transparency of the future market platform. Transparency of information is crucial for achieving a level playing field between market participants and avoiding the abuse of market power. Transparency in electricity market information has improved significantly over the past few years, partly thanks to ENTSO-E's Transparency Platform, operational since 2007. Many data items of great interest to electricity traders are published daily on the platform.

On 5 January 2015, in compliance with Regulation (EU) No 543/2013 on the submission and publication of data in electricity markets, ENTSO-E launched a new central transparency platform: the ENTSO-E Transparency Platform. This new ENTSO-E Transparency Platform replaces entsoe.net (which remains available for consultation), and will publish as much as three times more data for the open public. The ENTSO-E Transparency Platform provides free, continuous access to pan-European electricity market data for all users, across six main categories: Load, Generation, Transmission, Balancing, Outages and Congestion Management (ENTSO-E 2016).

Conclusions

The general consensus among the stakeholders is that the integration of European electricity markets has delivered many positive results. The 2014 progress report published by the European Commission noted that cross-border trade electricity between EU countries has increased wholesale electricity prices declined by one-third, consumers have more choices when it comes to picking an energy supplier many missing infrastructure links between EU

countries have been built or are under construction. A major milestone has been achieved with price coupling of day-ahead markets (European Commission 2014).

The progress in market integration is reflected by steadily increasing volumes of cross-border power trades despite reduction of the total demand. Market monitoring results show an increase in the efficient use of European electricity interconnections from around 60% in 2010 to 86% in 2014.

However, the assessment of the level of market integration and of the efficiency in the use of interconnectors published by ACER shows that, despite some progress in recent years, important barriers to market integration still remain. There are inefficiencies in the use of existing transmission networks stemming from inefficiencies in cross-zonal capacity calculation, in cross-zonal capacity allocation, and, possibly, in the definition of bidding zones. The same report mentions the need of more investment in electricity network infrastructure to support trade between areas characterized by large price differentials (ACER/CEER 2015). A similar notion was also mentioned in the single market progress report by the European Commission (EC 2014a). At the same time, some of the experts argue that infrastructure development through TYNDP may lead to an unequally developed interconnection capacity. The reason is due to a conflict of interests between the TSOs who are responsible for network planning and simultaneously receive profits from network operations. The social acceptance of large infrastructure projects in the densely populated European countries also remains an unresolved issue.

The EU initiatives seek to increase the share of renewables in the overall supply to 20% and 27% by 2020 and 2030 respectively. Individual member states have deployed various policies such as subsidies and feed-in-tariffs to encourage more renewable generation, bypassing the normal market incentives such as wholesale price signals and the carbon price signal from the EU-ETS. The renewables support policies reduce the demand for electricity generated from conventional sources which depress market wholesale prices and reduce utilization rates. Another consequence is higher demand for backup power from conventional sources, because

of the fluctuating nature of renewables. The reduced operating hours of the conventional power plants thwarts investments in the fossil capacity which is needed alongside the renewables to provide baseload and balancing power. The European electricity markets will need to adapt to this development in the coming years by providing some stable long-term price signals for available capacity, even if it does not provide power. Some EU member states have already implemented or are preparing to implement capacity markets that pay generators for availability at any given time. However, this type markets is currently not foreseen in the EU "Target Model" and is subject to national regulation.

Overcapacity in the generation sector which was caused by the economic crisis, renewable energy development and improving energy efficiency, is another problem for the European electricity market. It is expected that due to falling wholesale prices more capacity will become unprofitable and will be retired naturally. Linked to EU ETS price signals, the retired capacity would also likely be the most polluting. However, this is not the case as of 2015 (CEPS 2015). Therefore, some market incentives might be needed to encourage decommissioning of carbon-intensive power plants.

Chapter 4: Nord Pool

Introduction

Nord Pool is the joint Nordic Power Exchange which today operates as a part of the European electricity market but has developed independently from it. Before the move to the international power exchange, Norway, Sweden, Finland and Denmark relied on bilateral trading between domestic state-owned enterprises who also controlled the national grids, though there were differences in structure, ownership, and regulation. In early 1990s, the Nordic countries started to implement power sector reforms which were targeted at improving efficiency and the level of competition in the industry. These reforms naturally opened the way for establishing the first multilateral power exchange in the world, the Nord Pool spot in 1996.

The Nord Pool spot was first opened between Norway and Sweden and was soon joined by Finland, Denmark and the Baltic States. Shifting to the market structure has greatly improved the functionality of cross-border power exchange between the Nordic countries. Though there are still issues to be resolved, it should be acknowledged that Nord Pool is the most advanced multilateral power market in the world and serves as an example for other regional actors, most notably the EU.

The Nord Pool model has also drawn a significant attention in ASEAN because of its successful transition from a rather simple bilateral contracts' market trading excess power between vertically-integrated national utilities to a vibrant power exchange and a financial market with hundreds of participating actors.

This chapter presents the overview of the Nord Pool market including the historical background, market structure, policies and regulation. Given the ongoing integration of the Nord Pool with European power exchanges and that all Nord Pool members except Norway are members of the EU, some sections in this chapter are rather brief and refer the reader to the previous chapter of this report in order to avoid duplication.

Historical Development

This section presents an overview of the Nord Pool's historical development which is broadly divided in two phases, before and after opening the power exchange.

The old structure

Nord Pool can trace its roots as far back as 1970s with the creation of the Nordic Council of Ministers. The oil crisis highlighted to the Council the importance of the energy policy, forcing each country to adopt and develop a robust national energy framework and promote sharing of available energy resources between the Nordic countries.

At that time, the power sectors of Norway, Sweden, and Finland all had an oligopoly structure, with dominant state-owned utility companies that also controlled the national grids, though there were differences in structure, ownership, and regulation. Denmark had two national grids for geographical reasons with a similar organizational structure (AEMI 2016).

Trading of electricity between the countries was done through long-term bilateral contracts (source). The coordination body was Nordel, the organization set up to promote regional cooperation between the large utility companies. The purpose of trading was to achieve optimal dispatch of a larger interconnected system—and investment in interconnection was generally based not on net exports but on expected savings from pooling available generating capacity. The countries exchanged information about their marginal cost of production and trading took place, at a price that was the average of the two marginal costs (World Bank 1999). The energy ministers considered the region as a whole market and commissioned studies to standardize and remove existing technical barriers to boost the trade volume.

In 1990 Norway led by passing a new Energy Act which paved the way for deregulation of the domestic power industry in order to make it more efficient. In addition, all transmission networks were opened to third-party access, and integrated companies had to adopt separate accounting for generation, distribution, and supply activities.

As a result, the main Norwegian utility company and establishing of two new companies: Statkraft (for generation) and Statnett (for the main transmission grid and central system operation). Unbundling was the key building block of the reform program to address the oversupply of electricity in Norway and the resulting market inefficiencies. Sweden, Finland, and Denmark also started unbundling in the 1990s, facing dissatisfaction from the private sector companies and consumers over restricted grid access (AEMI 2016).

An interesting note here is that unbundling of the national companies in Norway, Sweden, Finland and Denmark happened without the privatization process. Instead, the new market forced incumbents to adapt their operations to a new competitive environment which caused large internal restructuring and improvement in operations (AEMI 2016). Some experts argue that retaining and reforming the incumbents instead of breaking them up, has helped the Nordic utilities to become among the most competitive in Europe.

Creation of Nord Pool

In 1996, a joint Norwegian-Swedish power exchange was established under the name Nord Pool ASA. Nordel, which was a co-operation body between the transmission system operators in Denmark, Finland, Iceland, Norway and Sweden, assessed the requirements needed to develop the Nordic electricity market, and examine neighboring development in the EU and Baltic regions. In 1998, Nord Pool became the first multinational common electricity market with inclusion of Finland, followed West Denmark in 1999, East Denmark and Estonia in 2000.

Nord Pool's in the last 10 years has been on smoothening the market operations and implementing common standards for cross boundary electricity markets. The percentage of power traded in day-ahead and intraday markets has been steadily increasing over this period. Given the ongoing development of the European electricity markets, Nord Pool participants sought to develop stronger ties with the latter and jointly worked on the issues of congestion management and transmission capacity allocation. At the same time, given a more advanced stage of Nord Pool compared to the rest of the EU, the Third Energy Package did not interfere with the Nord Pool's regulations (AEMI 2016, World Bank 1999).

In 2009 Nordel, which was a body representing interests of TSOs, was wound up and all operational tasks were transferred to ENTSO-E. In 2013, Nord Pool was joined by Latvia and Lithuania and in 2014 Nord Pool Spot took the sole ownership of the UK electricity market. In the same year, Nord Pool together with three other Power Exchanges and 13 Transmission System Operators (TSOs) successfully launched the North-Western Europe (NWE) day-ahead price coupling project (Nord Pool Spot 2016).

Vision and objectives

Nord Pool is the most advanced electricity market in Europe and has a vision of “Pioneering European Power Markets⁴”. Nord Pool’s objective is to provide efficient, transparent, and secure energy markets to the customers. The integrated market provides competitive energy for customers in seven countries, good short-term generation adequacy and one of the world’s lowest emission levels per produced kWh (Nord Pool Spot 2016).

Geographical coverage

The geographical area of Nord Pool is shown in Figure 24. It is common to differentiate the region into the Nordic states including Norway, Sweden, Finland and Denmark and the Baltic states including Lithuania, Latvia and Estonia. Nord Pool also operates the spot market in the UK and has operations in 10 European countries. Nord Pool has offices in all the countries it operates in. Each office has its own functions, but the main office remains in Norway where 50% of the workforce is based. Finland is the second largest office hosting most Nord Pool Spot’s IT department and organizations.

Nord Pool also assists and supports other power exchanges that were subsequently launched. Some examples are the German and French energy markets: Nord Pool provided the software and capacity building through Nord Pool Consulting (NPC).

⁴ <http://www.nordpoolspot.com/About-us/>

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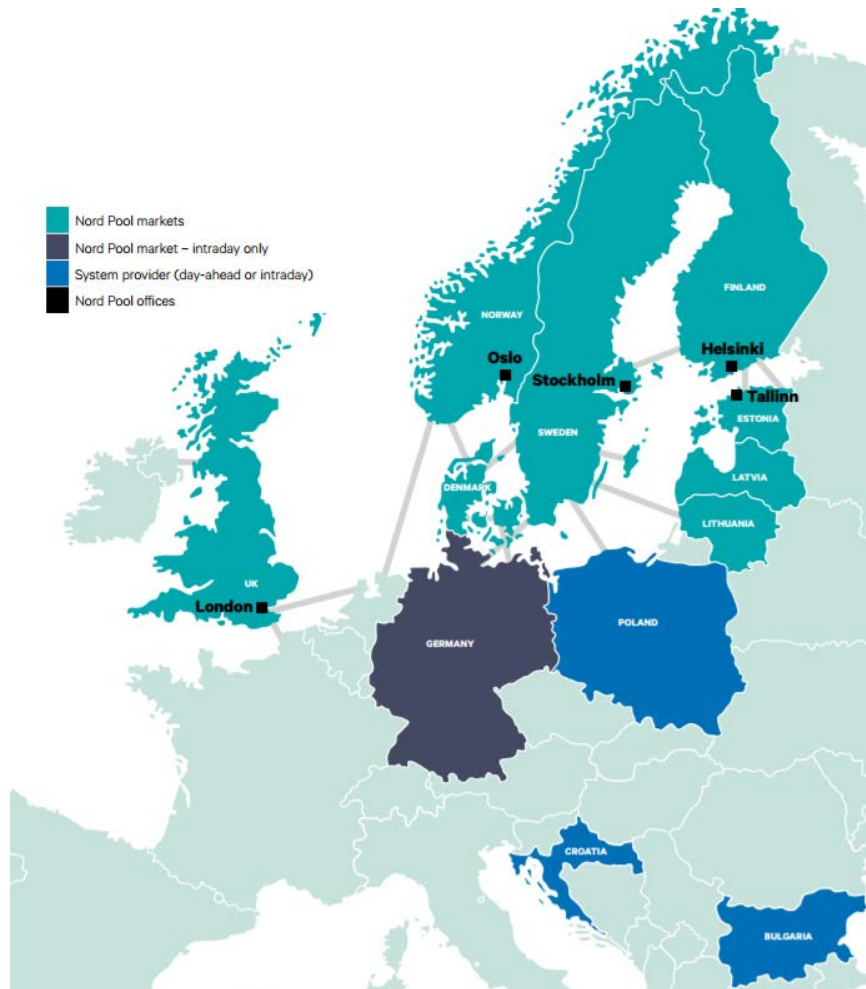


Figure 24. Countries of Nord Pool operations

From (Nord Pool Spot 2015)

Market principles

One of the key successes of Nord Pool is that it operates based on principles rather than on clear cut rules which gives the market participants more flexibility. Detailed rules can then be defined and maintained in market participant agreements which include much more information. As shown below, the focus of the principles is on the transparent and open market operations and at the same time on protection of the key information which gives a participant a competitive advantage. Some of the key points include (AEMI 2016, Nord Pool Spot 2015):

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- Neutrality and non-discriminatory behavior of the market participants, including ensuring impartiality of all parties and efficient access to information that is of importance to price formation;
- Interest protection of the participants through collateral and settlement obligations that ensure confidence and predictability for the parties;
- "Reasonable" profit from the organization and operation of the marketplace for the licensee;
- Licensee's duty to disclose information to NRA;
- Primary capital requirements;
- Market surveillance; and
- Confidentiality of the information concerning market participants' business which it will be of competitive importance.

Market participants

The Nordic power markets can be divided into two distinct markets: the physical electricity market and the corresponding financial market which makes them very similar to the European power exchange (Fortum Energy Review 2015). Compared to the European power exchanges, Nord Pool is the most liquid power exchange (in % terms, see Figure 15), with a large amount of underlying financial transactions. We thus place more focus on the discussion of both markets in this chapter.

Electricity markets

Nord Pool operates the electricity markets and officially sold off its control of the financial market (formerly known as Eltermin) in 2010 to NASDAQ OMX Commodities. The electricity market has both a day-ahead (Elsport) and an intra-day (Elbas) markets. Participants in the electricity market include (ECA 2015):

- **Grid owners.** Grid owners build, operate and maintain the grid in their specified area. They are responsible for submitting hourly transmission capacities to the TSOs to set the area prices.
- **Transmission System Operators (TSOs).** TSOs are mainly responsible for balancing the grid by ensuring smooth market operations in the day ahead market and balancing market and handling unexpected contingencies in the real-time market. The TSOs for the Nordic, Baltic and UK grid are Statnett SF for Norway, Svenska Kraftnät for Sweden, Fingrid for Finland, Energinet.dk for Denmark, Elering for Estonia, Litgrid for Lithuanian, AST for Latvia and National Grid for the UK respectively.
- **Regulators.** Nord Pool has NordREG which is the umbrella organization of all Nordic energy regulators, and is the overall body responsible for the Nordic electricity market. Besides regulating the institutional framework and ensuring the efficiency of the electricity market, NordREG is also seemingly responsible for ensuring the efficiency of the financial market for electricity. To illustrate this, NordREG released a report in 2010 assessing the degree of efficiency in the Nordic financial electricity market and to consider measures for improving the functioning of the market. The report considered issues of liquidity, competition and transparency. A more detailed description on the role of NordREG will be provided later.
- **Other Market Participants.** Other market participants include generators, retailers, traders and larger end-users.

It is reported that the Elspot has an estimated 360 members (buyers and sellers) (Nord Pool 2016). Generators include public utilities and other power generation companies who operate both in the wholesale market and the electricity markets. Retailers serve smaller end-users who are closed to the wholesale electricity markets, while larger end-users may decide to purchase their electricity directly in the electricity market. Traders are entities that take positions in the electricity markets to gain profits on market mispricing who otherwise have no stake in the electricity markets.

Financial markets

NASDAQ OMX Oslo ASA is official financial exchange platform for electricity derivative products in the Nord Pool. The market participants in the financial market can be divided into the following categories (Nord Pool 2016, ECA 2015):

- **The Clearing House.** One of the key participants in a standardized financial market would be the clearing house. The official clearing house for the Nord Pool financial derivatives market is NASDAQ OMX Stockholm AB, a subsidiary under NASDAQ OMX Oslo ASA. Some reports also claim that OTC financial products are cleared in the Nord Pool exchange.
- **Financial Regulators.** Interestingly, NASDAQ and its subsidiaries are responsible for both the exchange trades and over the counter trades. Under the Exchange Regulation ('Børsforskriften') governing NASDAQ OMX, it is required to have an internal regulating and monitoring body that supervises trading activity, among other duties which is the Market Surveillance department. The Market Surveillance department's role is to maintain market transparency by reporting all OTC trades and disclosing all inside information; monitor, highlight and investigate behavior in violation of Market Conduct Rules, such as insider trading and market manipulation. Furthermore, Nasdaq OMX is placed also under the financial regulation of the Financial Supervisory Authority of Norway, Finanstilsynet, whereas the clearing house is supervised under the Swedish Financial Supervisory Authority, Finansinspektionen. These independent bodies ensure that both the trading and clearing are in alignment with trading and clearing rules set by the Norwegian Ministry of Finance and the Swedish Financial Supervisory Authority, respectively.

Compared to its counterparty NordREG in the electricity markets, the financial regulators mentioned in this paragraph are responsible solely for the trading of the financial instruments and do not ensure liquidity and efficiency of the market which is the NordREG's task.

- **Other Market Participants.** Other market participants in the financial markets can be divided into players from the electricity sector who wish to hedge their risk exposure (eg: generators, retailers and large end-users) and the financial market actors who wish to make profit based on speculations (eg: banks and trading companies). While some market players are engaged directly in the financial market through membership agreements with the Nord Pool, a larger proportion participates through a representative or a broker. It is estimated that as of 2014, there are about 400 market players in NASDAQ market for electricity derivatives in Nord Pool.

The Nord Pool financial market remains a largely regional market, with Nordic participants currently dominating the financial market, hosting about 86% of the market players.

Electricity Markets

The electricity markets in Nord Pool offer a broad variety of products. Since the establishment of Nord Pool Spot as the first multinational exchange for trading electricity, the majority of trading of electricity in Nordic countries has now shifted away from bilateral contracts to power exchange trading.

Due to many similarities of the Nord Pool electricity markets to the power exchanges in Europe, this section will focus on the key market trends instead of explaining them in greater detail.

Bilateral contracts

The importance of bilateral or OTC contracts has been decreasing over the past years. Available market statistics show that the participants are gradually shifting away from OTC to spot market trading. This trend is common to many places with established power exchanges and increasing confidence in spot markets.

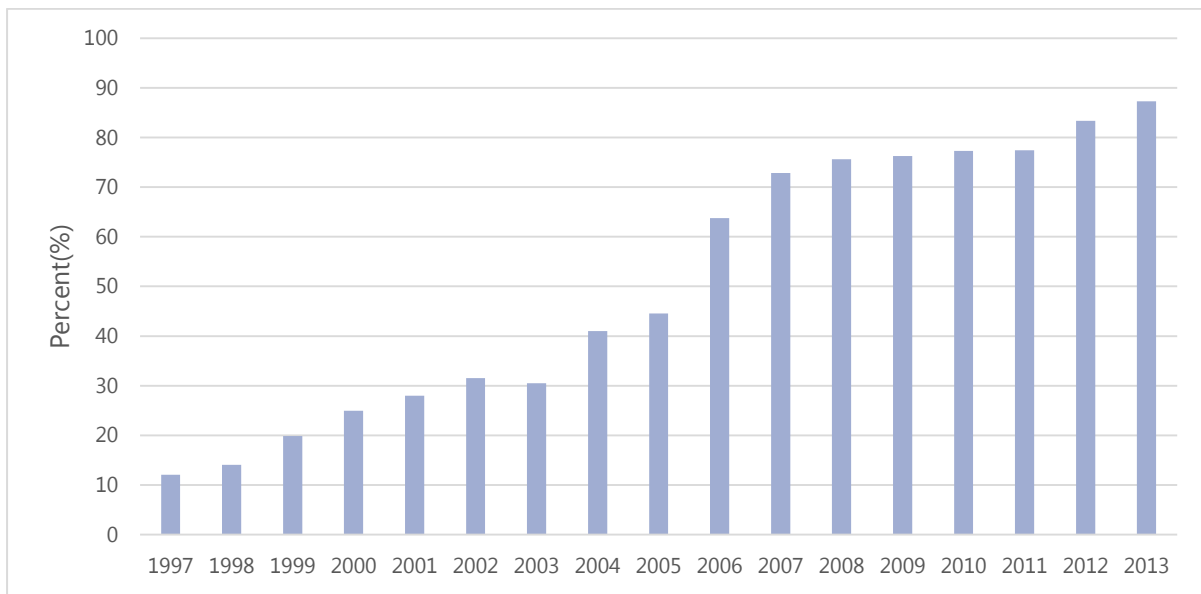


Figure 25. Volumes traded at Nord Pool Spot market as a percentage of total Nordic consumption

Adapted from (NordREG 2014)

As of 2016, the Nordic electricity market has the lowest percentage share of OTC in Europe (see Figure 11). This is very different to early 2000s, when the majority of the electricity generated was traded through bilateral OTC contracts⁵. As of today, the price point of the Nord Pool spot is valued and used as an important reference point in determining OTC contract prices.

Day-ahead market

The Elspot has a day-ahead spot market which is synchronised with other European electricity markets under the day-ahead price coupling scheme. Elspot has 24 one-hour trade contracts in a single day. The Elspot is a double bidding day-ahead market, where buyers and sellers submit hourly bids day before the actual delivery, although bidding can start up to 12 days ahead. The system price is calculated at the equilibrium point (where demand meets supply)

⁵ Modeling highly volatile and seasonal markets: evidence from the Nord Pool electricity market Rafal Weron, Ingve Simonsen, Piotr Wilman

for each of the 24 hours. The system price is announced close to an hour after bidding closes and contracted volumes are to be physically delivered at the designated intervals accordingly the next day. To accommodate for transmission bottlenecks, hourly zonal market prices for specific areas may be artificially raised to reduce demand and ease transmission constraints. Zonal prices are set by using the system price (price if there are no congestions), coupled with power transmission capacities submitted by transmission service operators on the day before trade. This is known as the implicit capacity allocation and is described in the European markets chapter in more detail. It should be noted that Nord Pool was one of the pioneers of this mechanism.

The total amount of electricity traded in Nord Pool day-ahead markets (including UK) was 489 TWh in 2015 (Nord Pool 2015). For comparison, the total electricity generated in Europe in 2015 was 3,309 TWh (ENTSO-E 2015).

Intraday market

Elbas the intraday market covering the Nordic, Baltic, UK and German markets and operating in 24h resolution. The intraday market supplements the day-ahead market through evening out short-term imbalances between supply and demand in the power market. Capacities available for trading in the intraday market for the next day are announced at 14:00 CET daily. Trading occurs continuously and closes one hour prior to delivery. Prices are set on a first-come, first-served principle, where best prices come first – highest buy price and lowest sell price. With increased penetration of wind energy, intra-day markets are expected to trade more and more electricity in the future (Nord Pool 2016).

Balancing market

Nord Pool has successfully launched a synchronised balancing market between Norway, Sweden, Finland and Denmark during 2002-2008 which is an impressive achievement. The final agreement on the cross-border TSO cooperation was reached in 2008 and was approved by

the Nordic governments. This agreement was preceded by years of feasibility studies carried out by the Nordic regulators. Eventually, the TSOs agreed on the following harmonization measures:

- Common gate closure for offers to the regulation power market and for final production and trade plans;
- Harmonized cost base for balance settlement; and
- Common model for the settlement of imbalances.

These measures were introduced by Denmark, Finland and Sweden in January 2009, and in Norway in September 2009 (NordREG 2010). The main differences in balancing markets between the common market of Norway, Sweden, Finland and Denmark, and Europe are shown below:

Table 6: Difference in balancing markets between Nordic and European markets

	Continent	Nordic
balancing	per country	for the entire Nordic region
based on	difference between scheduled and measures tie-line interchange	frequency difference
controller	one per country/TSO	one for the entire Nordic region
objective	return difference with scheduled within 15 minutes	keep the frequency within the 49.9-50.1 Hz band
activation time	5-15 min	120s (hydro)

From (Stattnett 2014)

Financial market

Prior to 2010, Nord Pool used to operate the financial exchange (Eltermin) that hosted the majority of electricity derivatives. In 2010, Nord Pool decided to transfer the ownership of Eltermin to NASDAQ OMX, who now retains the ownership of the financial market for Nord Pool derivatives. The financial market trends are shown in Figure 34. It shows that volume turnover in the Nordic market has been decreasing between 2011 and 2013. Official sources cite high hydropower reservoir levels, low wholesale prices and moderate expectations for the

economic growth, that have decreased the need for and the cost of hedging during past years. In 2013, the volume turnover on the financial market was still 4.7 times the volume of the physical market (NordREG 2010).

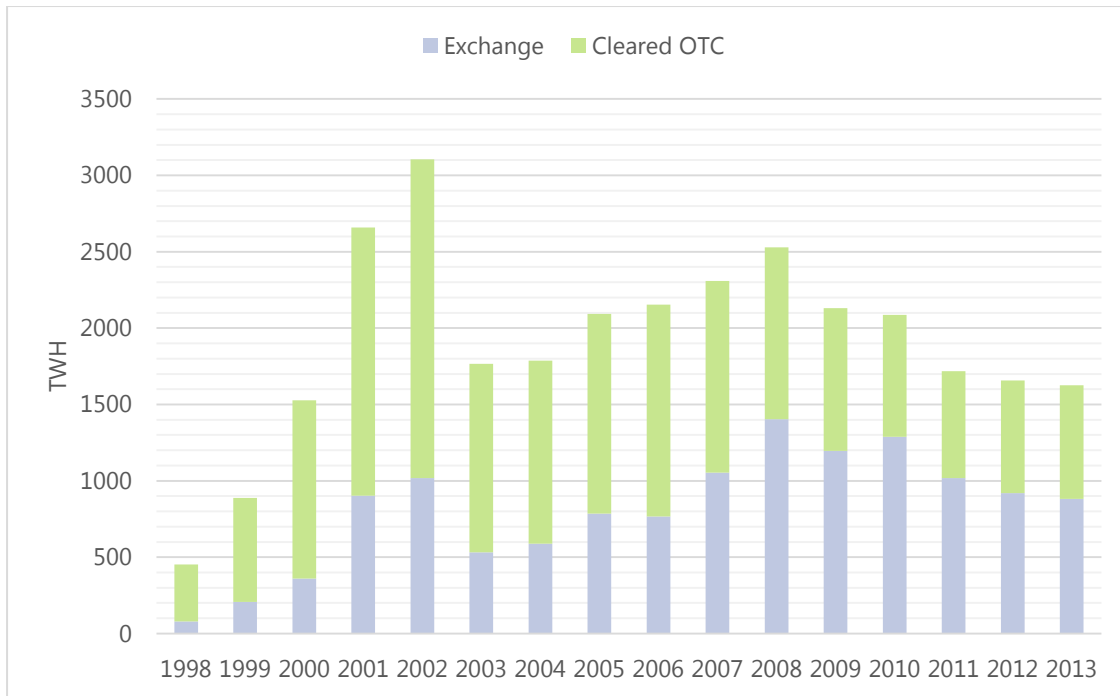


Figure 26. Volume turnover in the Nordic financial electricity market

Adapted from (NordREG 2014)

OTC market

Power derivatives can be traded through brokers in the over-the-counter (OTC) markets. Clearing is done at Nord Pool Clearing for exchange-listed products and at NOS clearing for non-listed contracts. Previously, trading in the OTC market was more significant in the last decade, but in recent times, trading in the exchange is gaining momentum (ECA 2015, NordREG 2010).

Electricity futures

Products listed on the exchange include Nordic, German, Dutch and UK power derivatives, such as base and peak load futures, Deferred Settlement Futures (DS Futures) and options. These exchange-listed contracts with settlements ranging from daily, to weekly, monthly, quarterly to annual contracts, covering positions up to ten years. The system price from Nord Pool Spot is used as the reference price for settlement of electricity future. Being a financial market, there is no actual delivery of electricity, and as such transmission costs are not taken into account during settlement. Instead, cash settlements based on the positions taken are conducted throughout the trading and/or delivery period, based on characteristics of the financial contract (ECA 2015).

Transmission-related futures

For end-users and power generators, additional transmission related congestion costs are hedged using the Electricity Price Area Differentials (EPAD), formerly known as Contract for Difference (CfD) contracts. The EPAD provides a hedge for the difference between system price and the electricity price from a specific area due to constraints in transmission (ECA 2015).

Geographical power flows and trade statistics

The geographical power flows in between the Nordic countries have daily and seasonal patterns which are heavily dependent on the availability of the renewable energy sources in the region. When there is lots of rain, Norway and northern Sweden have excess cheap hydropower which is exported to neighboring countries. During drier years, southern Sweden and Finland provide stable thermal baseload power exporting it to Norway and Sweden. Denmark obtains a lot of wind power from its large offshore capacity which is shared with its neighbors.

The annual market report for the year 2014 provides some statistics for cross-border power trade between Norway, Sweden, Finland and Denmark. The data is shown in Figure 27. The

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highest trade volumes in 2013 were recorded between Norway and Sweden, followed by Sweden and Finland.



Figure 27. Cross-border power trade between Norway, Sweden, Finland and Denmark

From (NordREG 2014)

Nord Pool has multiple interconnectors with other European countries with the total capacity of over 6,000 MW (Nord Pool Spot 2016). As shown in Figure 28, the Nordic market generally has been a net exporter of electricity to other parts of Europe over the past three years.

Figure 29 shows the cross-border electricity exchange as a percentage of the national consumption (ACER 2015). These percentages should be interpreted carefully, since the national consumption at Latvia, Estonia, and Denmark are much smaller than Sweden and Norway. It is also worth noting that a lot of power transferred from Estonia and Latvia could be just wheeled through from other regions.

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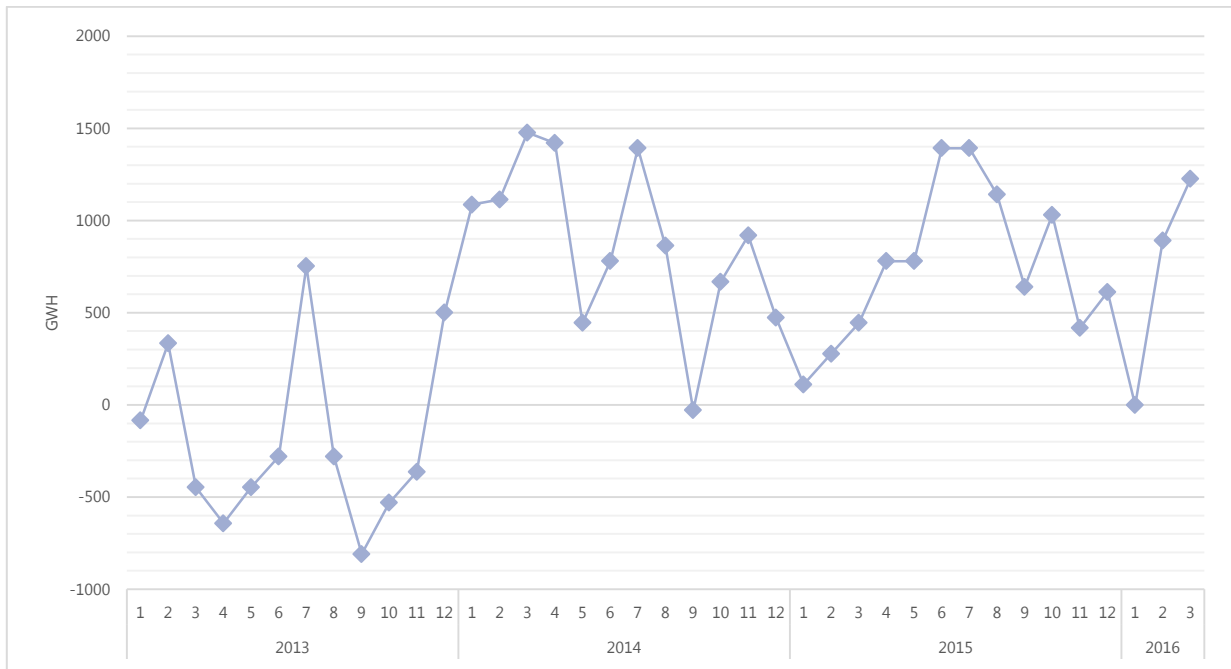


Figure 28. Yearly exports to from Nord Pool to the rest of Europe

Adapted from (EC 2016b)

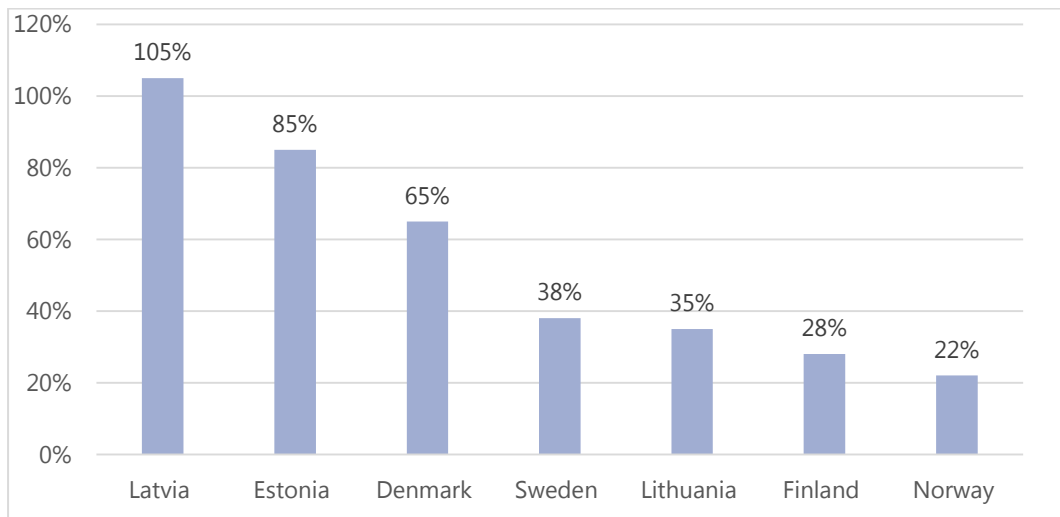


Figure 29. Cross-border electricity exchange as a percentage of the national consumption in Nord Pool countries

From (NordREG 2014)

Electricity prices

Figure 30 highlights the comparison of wholesale electricity prices in Nord Pool and other European markets. Nord Pool has been consistently the lowest price benchmark in whole Europe which is intuitive considering a large amount of hydropower and wind energy generation in the region. Overall price decline is also due to falling fossil fuel prices and generation overcapacity in Europe. The recent quarterly market report suggest a high influence of weather on the wholesale price development in Nord Pool (EC 2016b). The information on zonal price development is provided in the European markets section of this report.

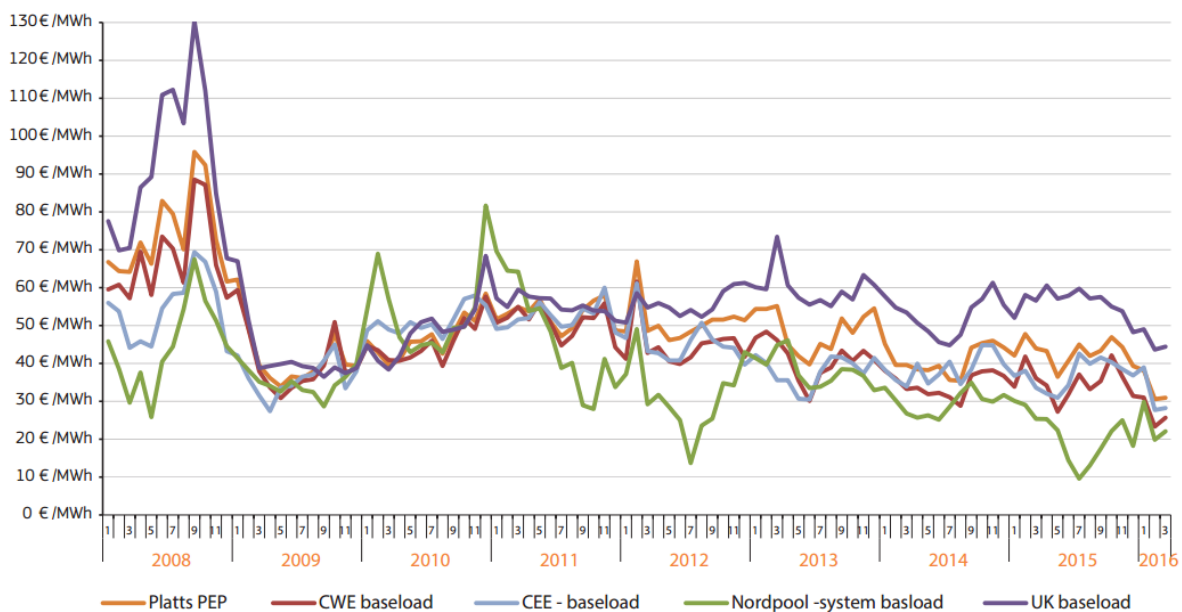


Figure 30. Comparison of monthly wholesale prices across European power markets

From (EC 2016b)

Transmission pricing and allocation

Nord Pool consists of 16 interconnected pricing areas or bidding zones. Transmission pricing in the Nordic market is done through zonal market splitting and implicit capacity allocation

which is now also common in many parts of Europe. The market splitting mechanism allows transmission costs to be priced implicitly into the electricity pricing. The congestion charge is determined as a difference between the area price and the system price.

The Nordic market is partitioned into separate bidding areas that can become separate price areas if the contractual flow between bidding areas exceeds the capacity allocated by TSOs for spot contracts. If there are no such capacity constraints, the spot system price is also the spot price throughout the entire Nordic Power Exchange Area. Price differences occur when there is not enough transmission capacity available between two different bidding areas to equate prices.

One potential shortcoming of this mechanism is the since the transmission service operator retains the congestion earnings, there may be lack of incentives for investment in grid infrastructure, the issue that has been already mentioned in TYNDP section of the European markets chapter.

Ownership structure

Nord Pool is owned by the national TSOs who also have the ownership of the physical transmission infrastructure in the member states. This is intuitive because the market relies on the information input and scheduling by the TSOs. The actual ownership of Nord Pool Spot is shown in Figure 40 below:

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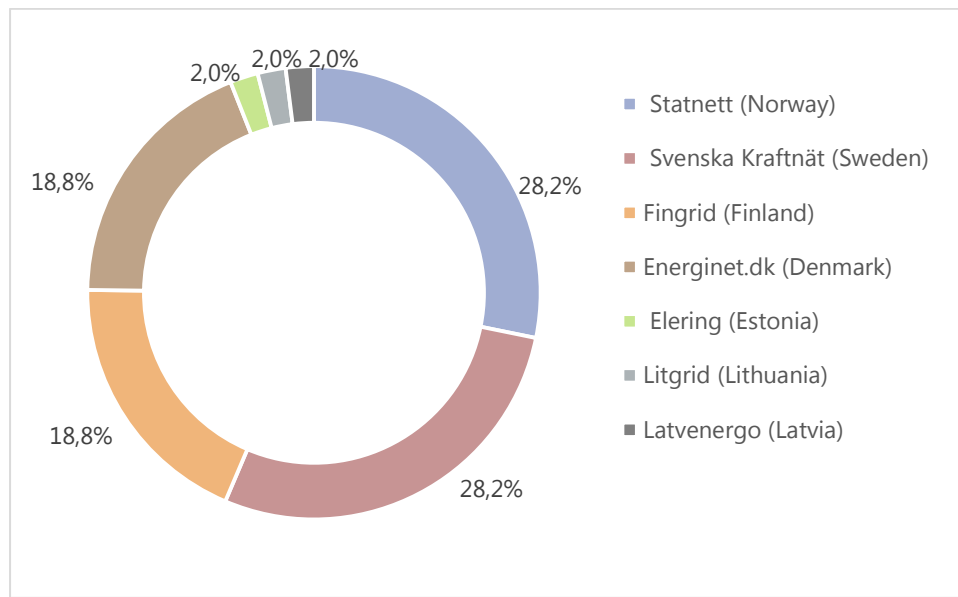


Figure 31. Nord Pool shareholders

Adapted from (AEMI 2016)

Distribution of ownership is reflection of how Nord Pool has evolved. Norway and Sweden were the founding members with the equal ownership majority. Finland and Denmark joined at relatively the same time later and received the smaller share because the market grew since its establishment. Finally, the Baltic states joined much more recently.

Early success in the derivatives market had significantly boosted the value of Nord Pool by the time Finland and Denmark were going to become owners. To lower the cost of ownership, Nord Pool was split into the physical market (owned by all TSOs) and the financial market (originally owned by Statnett and Svenska Kraftnät). However, the split created challenges in managing two different entities: Nord Pool Spot (physical market) and Nord Pool ASA (financial market). Eventually, Nord Pool ASA was sold to NASDAQ in 2008 (AEMI 2016).

NordREG

Nord Pool has set up NordREG, a regional cooperative body between the Nordic energy regulatory authorities, which oversees the institutional and legal frameworks within the Nordic electricity market. On the European level, NordREG works in a close cooperation with ACER

and CEER, while most Nordic regulators except for Norway share memberships in all three entities.

The establishment of NordREG was a result of a traditionally close cooperation on energy between the Nordic countries. The regulatory role of NordREG covers the wholesale, retail and transmission aspects of the electricity market. Specifically, NordREG works towards creating a liberalized retail market, an efficient wholesale market and ensuring reliable transmission and distribution of electricity throughout the electricity market as their priority objectives. To that end, NordREG holds public consultations, commissions research reports and releases various publications every on pertinent issues to achieve their strategic objectives. Beyond ensuring efficiency of the electricity market, NordREG is also responsible for maintaining the efficiency of the financial market (AEMI 2016, Nord Pool Spot 2016).

Current state of supply and demand

The Nordic states had a total installed capacity of 102 GW. Roughly 50 GW of this capacity is hydropower located mainly in Norway and Sweden (Fortum Energy Review 2015). Other important sources by capacity are wind and nuclear energy, with both having roughly 12 GW.

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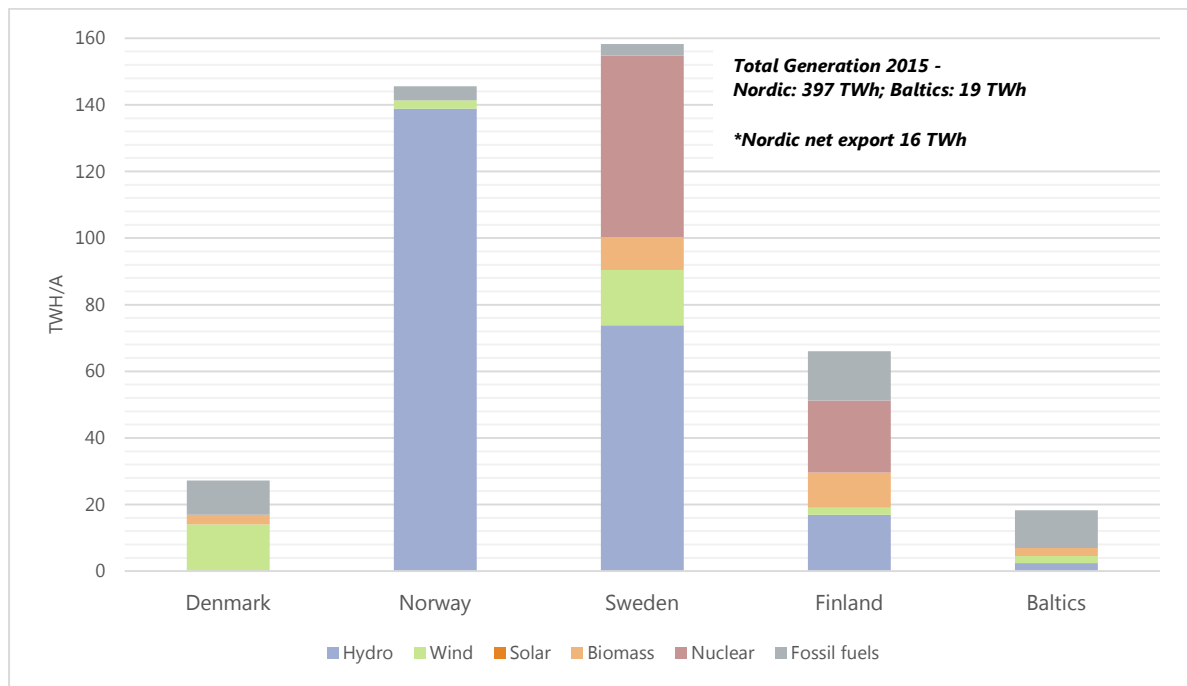


Figure 32. Electricity supply mix in Nordic and Baltic countries in 2015

Adapted from (Fortum Energy Review 2015)

Figure 32 shows electricity supply mix for the Nordic and the Baltic states in 2015. Over 50% of the total electricity supplied in the Nordic states from hydropower, given ample water resources in that year. However, the annual hydropower generation in Norway and Sweden can vary by +/-20% based on the weather conditions. Another 20% of the electricity supply was covered by nuclear power, while 14% and 7% were respectively contributed by CHP and fossil fuel generators. With increasing wind generation and low marginal cost of production for wind, around 7% of the electricity demand was supplied by wind. The Baltic states are much more reliant on the fossil fuel generation which contributed 66% of the total electricity supply there.

Seasonal and temperature changes are the main determinants of electricity demand patterns in the Nordic countries, with colder winters registering highest electricity consumption.

The total electricity demand in the Nordic countries was approximately 400 TWh in 2015, of which industry, households and services consumes around 41%, 28% and 21% respectively. The remaining 10% are accounted for by agriculture use (2%), traffic use (1%) and network losses (7%) (NordREG 2014). Similarly, to the rest of Europe, the electricity demand in the Nordic states recently rebounded after a decline period caused by the economic crisis of 2008 (Nord Pool Spot 2015).

Market transparency

The success of the Nord Pool scheme is largely due to its high transparency, reflecting that equal information access for all participants improve trust and efficiency. Nord Pool provides a large database of market information in the open access on its website. It is also a part of the Regulation on Energy Market Integrity and Transparency (REMIT) initiative by the EU. This initiative requires market participants to provide ACER with timely records of their wholesale energy market transactions through a selected Registered Reporting Mechanisms. Norway is also a voluntary participant in this scheme, even though Norway is not a member of the EU.

Other examples which must be reported to REMIT include changes in planned power outages or any other information that can affect market prices significantly. Information must be disclosed to the market or the player must be suspended from trading during the relevant time period. The Nord Pool Spot's Market Surveillance Team follows up on them as well.

Functional linkage with European markets

Nord Pool becomes increasingly connected with other European electricity markets. Important projects with relevance for the Nordic electricity market are going on in cooperation between the EU Commission, ACER, CEER and system operators (ENTSO-E). The EU's Energy Strategy has been widely endorsed and adopted by the Nordic countries.

The most significant achievement in market integration between the Nord Pool and the European markets is the price coupling of day-ahead markets. Nordic member states are also part of the XBID initiative to achieve intraday market coupling across Europe.

Furthermore, the Nordic TSOs actively participate in the development of Ten Year and Projects of Common Interest as a part of ENTSO-E functions. The Nordic Regulators have taken actively part in the writing of Framework Guidelines and in the drafting the Opinions of ACER on proposed Network Codes. Finally, Nord Pool provides consulting services to other electricity markets within and outside of Europe.

Conclusions

The Nord Pool market between Norway, Sweden, Finland and Denmark is arguably the most successful international power market in the world. The market has a well-developed physical and financial electricity markets with a high liquidity in both sections. The 2015 market progress reports by ACER highlights that Nord Pool spot exchange had the second highest aMoUnt of traded electricity in Europe in 2013 after European Spot Exchange EPEX Spot. This is despite Nordic countries generate and consume significantly less electricity per annum compared to the Western Europe. Even though Nord Pool is exposed to weather-related uncertainties in renewable energy output as well as to the uncertainty with natural gas imports from Russia (Finland), the electricity prices between the Nordic and the Baltic states have been converging, indicating the benefits of their interconnection. Following the activation of the NordBalt Lithuania-Sweden electricity connection, the electricity exchange price in Latvia and Lithuania fell significantly in February 2016, coming close to Estonian price level (Elering 2016). The interconnection has also resulted in falling carbon dioxide emissions in the Baltic region.

Nord Pool's trading system is being constantly upgraded with new features focusing on efficiency, easy terms of use in order to deliver an efficient trading for Nord Pool customers regardless of their size or geographic location.



Nord Pool has pioneered the concept of cross-border electricity market coupling and coupling of balancing markets in Europe. This expertise puts Nord Pool in a position to implement and test systems for establishing day-ahead markets in other countries with Bulgaria and Croatia being the most notable examples.

An interesting evidence from Nord Pool is that the scheme had multilateral cross border trading before establishing the Nord Pool spot market. Thus, reforming power sector by separating of generation and transmission sectors is not a necessarily requirement for a multilateral market which is also evident from the SAPP's experience. Nevertheless, unbundling played a crucial role in the later success of Nord Pool, particularly in terms of competition and efficiency. As the market became more and more established, more players realized the benefits of having an integrated electricity market, spurring higher trading volumes. In order to promote liquidity in the spot market, all available transmission capacity between different areas was given to the market. Furthermore, regardless of their size, all market participants were required to source a minimum amount of electricity from the exchange.

Current challenges for Nord Pool include the ongoing integration with the European electricity markets, particularly with the Western Europe and transferring of its operational standards to the Baltic States. Other issues include common Nordic (and European) grid planning, provision of balancing services for renewable energy integration and alignment of interests between international TSOs. The greatest challenge regarding transmission system planning concerns the uncertainty of future developments, particularly in renewable energy and energy storage.

Chapter 5: Power interconnection in the ASEAN region

Case for energy cooperation in ASEAN

ASEAN has ten member countries including Brunei Darussalam, Myanmar, Cambodia, Indonesia, Lao PDR, Malaysia, Philippines, Singapore, Thailand, and Vietnam. These countries are widely diverse in geographical, economic and cultural terms. Table 7 shows some key statistics of the ASEAN member states. If those were combined into a single country, it would be the seventh-largest economy in the world, with a combined GDP of US\$2.4 trillion in 2013. In absolute terms, Indonesia, Thailand and Malaysia have highest GDPs in the region, while its value per capita is highest in Singapore, Brunei and Malaysia. The general notion about the ASEAN region is that it is expected to rapidly grow in the next decades and potentially become the fourth-largest economy in 2050.

Table 7: Key Statistics in ASEAN

Country	PPP GDP (million2005 USD) ¹	Population (‘1,000) ²	PPP GDP/capita (2005 USD/capita) ¹	Urbanization Rate (%)	Area (‘1,000km ²) ³
Brunei Darussalam	25,873	418	61,929	77	5.8
Cambodia	39,732	15,135	2,625	20	181.0
Indonesia	2,061,232	249,866	8,249	52	1860.4
Lao PDR	28,114	6,770	4,153	36	236.8
Malaysia	597,494	29,717	20,106	73	330.3
Myanmar	164,260	63,259	3,084	33	676.6
The Philippines	554,714	98,394	5,638	45	300.0
Singapore	366,915	5,399	67,957	100	0.7
Thailand	832,188	67,011	12,419	18	513.1
Viet Nam	409,798	89,709	4,568	32	331.0
ASEAN	5,080,319	615,676	8,252	46	4435.6

From (ACE 2015a)

Power Interconnection in ASEAN Region

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In 2013, ASEAN accounted for about 8.5% of the world population, consumed about 4.5% of world's primary energy and produced 5.7% of the total global energy. The total electricity consumption in ASEAN has increased from roughly 180 TWh in 1990 to over 800 TWh in 2013 (ACE 2015a). Two factors behind this trend are the ongoing population and economic growth as well as the increased energy consumption per capita (IEA 2015a). As the region's economies continue to grow, its per capita consumption and electricity access are still below worldwide average, creating a threat of even higher pace of growth in demand, both for the individual countries and the region as a whole. Forecasts by ACE, shown in Figure 33, demonstrate that region's electricity consumption could increase between two and three times between 2013 and 2035, depending on the policy scenario chosen.

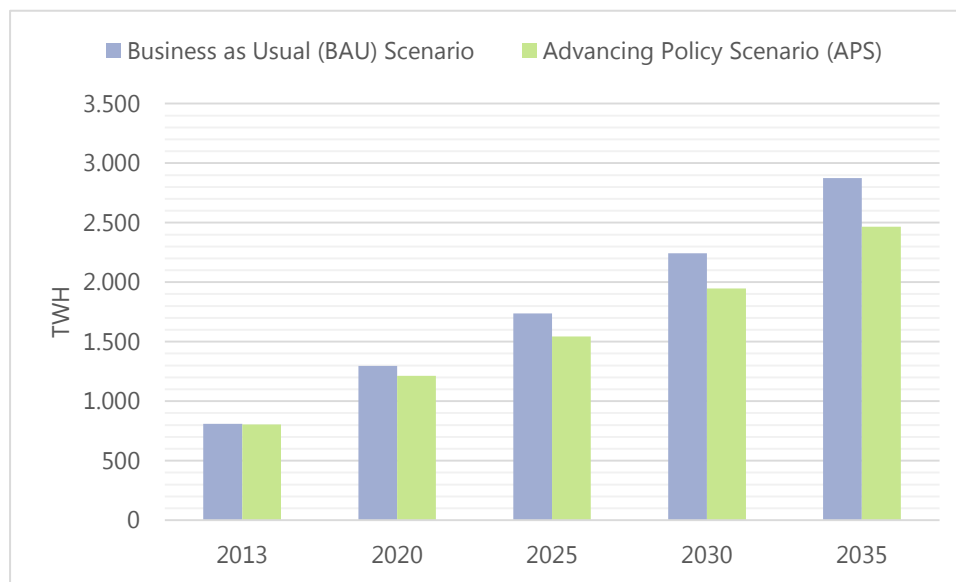


Figure 33. Projected electricity demand in ASEAN

From (ACE 2016a)

Fortunately, ASEAN member states have abundant primary energy resources to address these needs (see Figure 34). In the North, Lao PDR, Myanmar, Cambodia and Vietnam possess large hydropower potential, potentially more than they require domestically, while Indonesia, Malaysia and Brunei have rich fossil fuel reserves. Virtually all countries have significant wind and solar potentials. However, utilising these reserves may be a challenging task, because not all of these reserves are located near the consumption centres or can be easily extracted. Gas-

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fired generation can be developed quickly, it is relatively clean and efficient, however expensive. Coal-fired power generation is affordable, but carries risks of air pollution and greenhouse gas emissions. Hydropower has a big cost advantage over other sources, however it requires large capital investments in the initial stage and exposes its users to seasonal droughts. It can also cause severe political and social tensions around water supply and use. Furthermore, countries may be willing to have a diversified portfolio of fuel sources for security reasons. All these arguments present a compelling cause for ASEAN to coordinate utilisation of available resources and integrate energy systems between the member states.



Country	Oil	Gas	Coal	Hydro	Geothermal	Wood
Myanmar	3.1 BBI	12.1 TCF	-	108,000 MW	-	129,935 Kton
Thailand	0.156 BBI	12.2 TCF	1,240 MMT	-	-	67,130 Kton
Malaysia	3.42 BBI	84.4 TCF	1,024.5 MMT	25,000 MW	-	137,301 Kton
Vietnam	5 BBI	19.2 TCF	4,500 MMT	68,500 MW	-	48,960 Kton
Brunei	6 BBI	34.8 TCF	-	-	-	-
Philippines	0.285 BBI	4.6 TCF	346 MMT	9,150 MW	2,047 MW	89,267 Kton
Lao PDR	-	3.60 TCF	600 MMT	26,500 MW	-	46,006 Kton
Cambodia	-	9.89 TCF	-	10,000 MW	-	81,565 Kton
Singapore	No Energy Resources					
Indonesia	10 BBI	169.5 TCF	38,000 MMT	75,625 MW	19,658 MW	439,049 Kton

Figure 34. Energy resources in ASEAN

Adapted from (AEMI 2016) and (ERIA 2015)

History of regional cooperation in energy

The energy cooperation in the region began in 1966, when an agreement was signed between Thailand and Lao PDR. This was one year before ASEAN was established as an entity by five founding members: Indonesia, Malaysia, the Philippines, Singapore, and Thailand. The interconnection project between Thailand and Lao PDR was built in order to supply Thailand's growing energy needs and to boost cooperation between two countries. The next major milestone in regional energy cooperation took place only fifteen years later, after the military conflicts in Indochinese Peninsula have ceased. In 1981, the Heads of ASEAN Power Utilities/Authorities (HAPUA) was established to work on blueprint of electricity interconnection in ASEAN. The ASEAN Energy Cooperation Agreement, signed in 1986, outlined main areas of energy cooperation and proposed an ASEAN-wide electricity network. However, very few concrete steps were achieved in progressing the regional interconnection until mid-1990s (AEMI 2016, ERIA 2013).

Since 1995, the key initiatives in energy cooperation of the ASEAN member states have been formalized the ASEAN Plan of Action on Energy Cooperation (APAEC) which were released every five years.

APG and TAGP

In 1997 ASEAN leaders have agreed on the "ASEAN Vision 2020" which aligned interests of the member countries under one common vision for ASEAN. One of the areas emphasized in the document was establishing of energy networks, spanning across all ASEAN member states and consisting of two main components: the ASEAN Power Grid (APG) and the Trans-ASEAN Gas Pipeline (TAGP). Since publishing of the ASEAN Vision 2020, both components have become de-facto main strategic areas of regional energy cooperation and had been included in all subsequent APAECs and AEC Blueprint. Although the ASEAN Vision 2020 identifies main

strategic goals for market integration in the region, it does not specify a particular market model for the regional electricity market.

The ASEAN Power Grid (APG) is an initiative to link the member states in a single network in order to enhance the electricity trade, provide means to address the growing electricity demand in the region, to enhance the use of clean energy, and to provide electricity access to populations across the region (ACE 2016, AEMI 2016).

The Memorandum of Understanding (MOU) on the APG was signed between the ASEAN member states in 2007. This MOU recommended the member states to cooperate in assessing common policy, regulatory and technical standards for cross-border interconnection and trade. The cooperation was promoted on bilateral or multilateral basis and had to comply with national laws of each member country. The areas of work include review and assessment of national and regional legal and institutional frameworks for power interconnection and trade, commercial and economic feasibility of interconnectors, construction, financing, operation, and maintenance of the APG (APG 2007). However, this MOU did not contain any concrete milestones to be achieved or information about the targeted market integration model (AEMI 2013, ERIA 2013).

Parties responsible for implementation of APG are the Working Group Two (APG/Transmission) of HAPUA and the ASEAN Power Grid Consultative Committee (APGCC). The harmonisation of regulatory practices and technical standards is undertaken by the ASEAN Energy Regulators' Network (AERN), established in 2012. The implementation of MoU is reported by the HAPUA Council through periodic reports, submitted to the senior energy officials in the ASEAN.

Implementation and current status

The development of physical interconnection capacity follows recommendations outlined in ASEAN Interconnection Master Plan Studies (AIMS). These documents help to design an optimal interconnected system by achieving lowest total system costs, subject to technical,

policy and resource constraints of the member states. The detailed methodology can be found in any of the AIMS. AIMS are prepared by HAPUA and regional experts. Before the first AIMS was conducted in 2003, HAPUA had planned to build APG from 14 bilateral and multilateral interconnection projects which included existing interconnections of Thailand–Lao PDR PDR and Peninsular Malaysia – Singapore. However, the AIMS I, completed in 2003, concluded that it was uneconomic to create a single ASEAN grid, and recommend instead 11 bilateral interconnectors to be constructed by 2019.

Following the re-organisation of HAPUA in 2004, its Working Group 4 embarked on a second study (AIMS II) which was published in 2010. Unlike AIMS I, AIMS II concluded and ASEAN-wide power grid was economically viable. However, it suggested first to create three geographically separate interconnection sub-systems before integrating them into one APG. In addition to the five interconnections that already existed at that time, the report listed another 12 projects that were classified as “committed” and another 17 as “generic” (AIMS Working Group 2010).

Following recommendations outlined in AIMS II, HAPUA developed an integration strategy that starts from developing bilateral and multilateral interconnections between single member states.

These interconnections are then gradually expanded to a sub-regional basis and finally to a fully integrated Southeast Asian power grid (see Figure 35). Both AIMS and AIMS II suggest three sub-systems as intermediate steps to APG.

- System A (Upper West System), consisting of ASEAN countries under the Greater Mekong Sub-region (GMS) including Cambodia, Lao PDR PDR, Myanmar, Thailand and Vietnam;
- System B (Lower West System), consisting of countries under the IMT (Indonesia, Malaysia and Thailand) and IMS Growth Triangle Sub-region, Indonesia (Sumatra, Batam), Malaysia (Peninsular and Singapore);

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- System C (East System), consisting of countries under the BIMP/EAGA Sub-region, including Brunei, Malaysia (Sabah, Sarawak), Indonesia (West Kalimantan), and the Philippines.

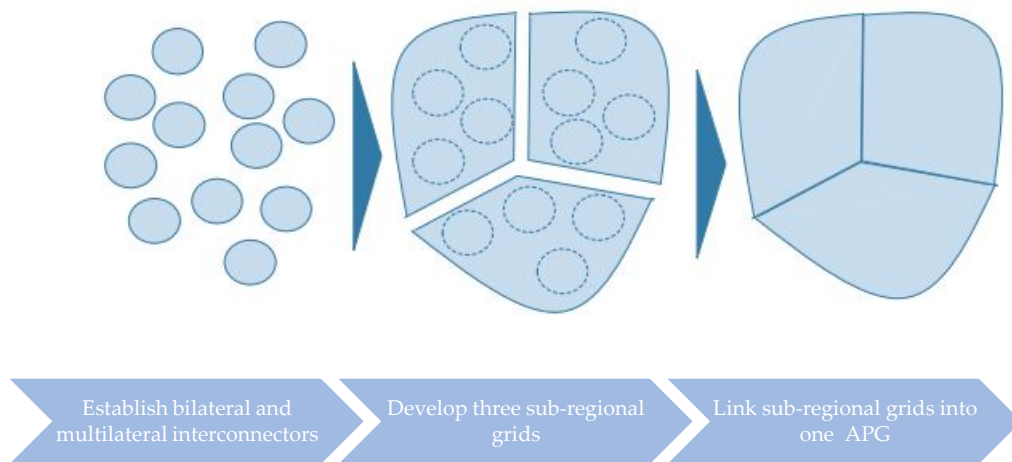


Figure 35. Strategy of developing APG by HAPUA

The geographical coverage of these systems and list of priority projects are shown in Figure 36.

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Interconnection capacity development

By the end of 2014, 11 interconnections between 6 pairs of countries were in commercial operation, with a total capacity of nearly 3,500 MW, as shown in Table 8. Most of these interconnectors are concentrated in the Indochinese Peninsula under the Greater Mekong Subregion (GMS) initiative, between Lao PDR, Thailand, Vietnam, Cambodia and China's Yunnan Province.

Table 8: Cross-border interconnectors in ASEAN as of 2016

Project	System	Type	Original COD	Current COD	MW
P.Malaysia - Singapore					
Plentong-Woodlands	HVAC: 230 kV	EE	-	1958	450
Thailand - P.Malaysia					
Sadao-Chuping	HVAC: 132/115 kV	EE	-	1980	80
Khlong Ngae - Gurun	HVDC: 300kV	EE	-	2002	300
Thailand - Lao PDR					
Nakhon Phanom-Thakhek-Theun Hinboun	HVAC: 230 kV	PP: La->Th	-	1998	220
Ubon Ratchathani 2 - Houay Ho	HVAC: 230 kV	PP: La->Th	-	1999	126
Roi Et 2 - Nam Theun 2	HVAC: 230 kV	PP: La->Th	-	2010	948
Udon Thani 3 - Na Bong - Nam Ngum 2	HVAC: 500 kV	PP: La->Th	-	2011	597
Nakhon Phanom 2 - Thakhek - Theun Hinboun (Expansion)	HVAC: 230 kV	PP: La->Th	2012	2012	220
Lao PDR - Vietnam					
Xekaman 3 - Thanhmy	HVAC: 230 kV	PP: La->Th	-	2013	248
Vietnam - Cambodia					
Chau Doc - Takeo - Phnom Penh	HVAC: 230 kV	PP: La->Th	-	2009	200
Thailand - Cambodia					
Aranyaprathet - Banteay Meanchey	HVAC: 115 kV	PP: La->Th	-	2007	100
Total:					3,489

From (AEMI 2016)

Table 4 summarizes other 13 projects identified in the AIMS II report which are expected to be completed by 2020. Large capacities will be constructed in the Mekong region. There is also a proposed link between Sumatra and Peninsular Malaysia. Most of these projects are currently

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two years or more behind the original schedule and may not be completed by 2020 (AEMI 2016).

Table 9: Planned interconnector projects by 2020

Project	System	Type	Original COD	Current COD	MW
Thailand - P.Malaysia					
Su-ngai Kolok - Rantau Panjang	HVAC: 132/115 kV	EE	2014	TBC	100
P.Malaysia - Sumatra					
Melaka - Pekan Baru	HVDC: TBA kV	PP: SM -> PM & EE	2015	2020	600
Sarawak - W.Kalimantan					
Sarawak - Sabah - Brunei	HVAC: 275 kV	EE	2012	2015	230
Sarawak - Brunei	HVAC: 275 kV	EE	2012-16	2018	2x100
Thailand - Lao PDR					
Mae Moh 3 - Nan 2 - Hong Sa	HVAC: 500 kV	PP: La->Th	2015	2015	1473
Udon thani 3 - Na Bong - Nam Ngeip 1	HVAC: 500 kV	PP: La->Th	2017	2019	269
Ubon Ratchathani 3 - Pakse - Xe Namnoi	HVAC: 500 kV	PP: La->Th	2018	2019	390
Khon Kaen 4 - Loei 2 - Xayaburi	HVAC: 500 kV	PP: La->Th	2019	2019	1220
Lao PDR - Vietnam					
Xekaman 1 - Ban Hat San - Pleiku	HVAC: 500 kV	PP: La->Vn	2011-16	2016	1000
Nam Mo - Ban Ve	HVAC: 230 kV	PP: La->Vn	2011-16		TBC
Luang Prabang - Nho Quan	HVAC: 500 kV	PP: La->Vn	2011-16	2020	1410
Lao PDR - Cambodia					
Ban Hat - Stung Treng	HVAC: 230 kV	PP: La->Kh	2011	2017	300
Total					7,192

Table 10: Planned interconnection projects beyond 2020

Project	Type	Original COD	Current COD	MW
P.Malaysia - Singapore	PP: PM->Sg	2018	Post - 2020	600
Thailand - P.Malaysia	EE	2016	TBC	300
Sarawak - P.Malaysia	PP: Sw->PM	2015-21	2025	4 x 800
Batam - Singapore	PP: Bt->Sg	2015-17	2020	3 x 200
Phillippines - Sabah	EE	2020	2020	500
Sarawak - Sabah - Brunei	PP: Sw->Sb	2020	2020	100
Thailand - Lao PDR	PP: La->Th (+EE)	2015-23	2019 - 23 ->	1000 +
Lao PDR - Vietnam	PP: La->Vn	2011-16	TBC	TBC
Thailand - Myanmar	PP: Mm->Th	2016-25	2016 - 26 ->	13000 +
Vietnam - Cambodia	PP	2016	TBC	TBC
Thailand - Cambodia	PP: Kh->Th	2015-17	Post - 2020	2,200
E.Sabah - E.Kalimantan	EE		Post - 2020	TBC
Singapore - Sumatra	PP: Sm->Sg	2020	Post - 2020	600

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Total:	22,274 - 25,424
	From (AEMI 2016)

The vision beyond 2020 has over 20,000 MW of interconnectors, where the links between Thailand and Myanmar take more than 60%.

Trade volumes

Figure 37 shows the development of traded electricity volumes in ASEAN in past 25 years. Overall, there is an increasing trend in volumes of traded power. The major share in the total volume is exchanged between GMS members. Lao PDR grew into a major net exporter of hydropower over the last 25 years, increasing electricity exports from 2.8 TWh in 2000 to 12.5 TWh in 2013. While Lao PDR exports to most neighbouring countries, currently almost 80% of these exports go to Thailand. Over the same time period, the economic growth in Thailand turned the country into a major electricity importer. Thailand's imports grew nearly four times between 2000 and 2013. Electricity trade between Lao PDR and Thailand has rapidly expanded in 2010 with the start of commercial operation of the Nam Theun 2 Hydropower station (IEA 2015a). Malaysia was a net electricity exporter in the 2000s, but now imports power to meet growing demand as well as providing back-up capacity in the case of potential power emergencies. Southeast Asia as a whole is a net electricity importing region, with the imports coming from China (IEA 2015a).

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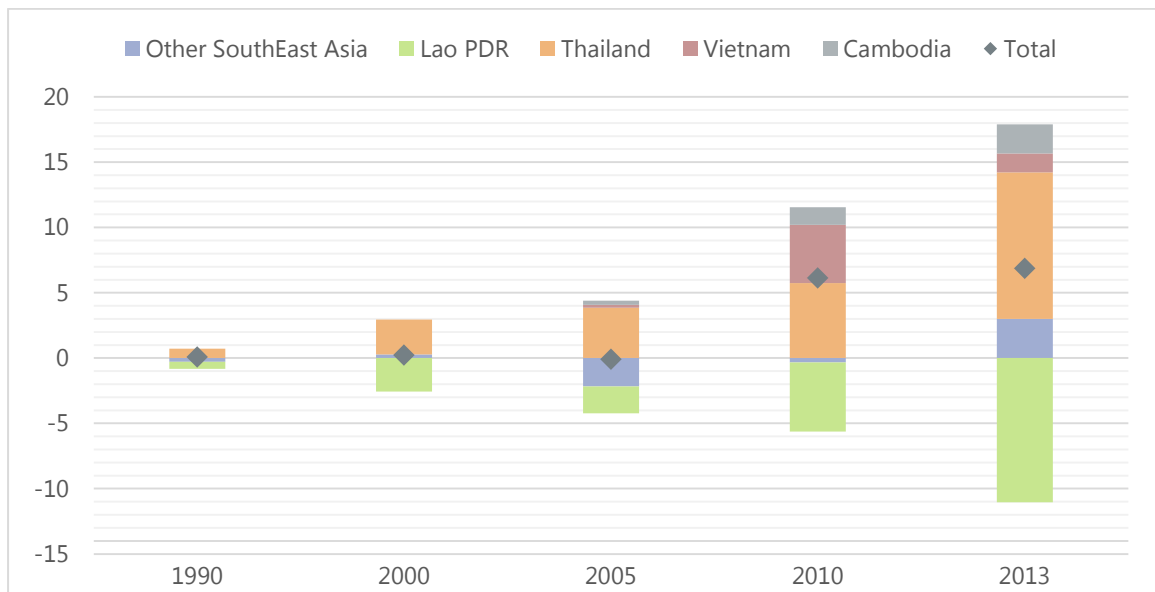


Figure 37: Electricity trade in Southeast Asia in 1990-2013

From (IEA 2015a)

Implications

At its current stage, APG is mainly focused on the development of the physical interconnection capacity between single member states. There has not been much progress in other areas, such as development of complementary institutional, legal and commercial frameworks for an integrated electricity market. Some regional experts argue that this is because there is no clear vision about the fully developed APG. A deeply integrated APG could, for example, include a competitive electricity market open for all participants (such as the EU market). Such a model would require ASEAN countries to develop comprehensive institutional, regulatory and market arrangements which in turn require a very high level of cooperation and trust between the member states. A shallow version of APG could be a physical interconnection scheme with a limited or even absent market framework which links several heterogeneous grids and markets in the region (such as the power pools in Africa).

Despite the slow historical progress in establishing the APG, especially in the areas other than infrastructure development, following steps have been successful:

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- adoption of the AIMS and the updated AIMS II, which serves as a reference guide for the implementation of the ASEAN interconnection projects;
- signing of a Memorandum of Understanding on the ASEAN Power Grid (MOU on the APG)⁴ to serve as a reference document for the coordination and facilitation of programmes to implement the APG;
- restructuring of HAPUA to streamline operations and the establishment of a permanent HAPUA Secretariat, which rotates every three years; and
- establishment of the APGCC to oversee the overall development and implementation of APG projects

As a result, in 2015, the ASEAN region had following links established between the countries' electricity systems:

- Cambodia imports electricity from Thailand, Vietnam and Lao PDR;
- Indonesia (West Kalimantan) imports electricity from Malaysia (Sarawak⁶);
- Lao PDR imports from and exports to Thailand and Vietnam;
- Malaysia imports from and exports to Thailand;
- Singapore is interconnected with Peninsula Malaysia but only for purposes of energy security;
- Thailand imports from and exports to Lao PDR and Malaysia, while only exporting electricity to Cambodia; and
- Vietnam imports electricity from Lao PDR and China, and exports electricity to Cambodia and Lao PDR.

⁶ Project commenced in 2015

Benefits to participating countries

General benefits

The benefits of creating an ASEAN-wide interconnection systems range from cost and fuel savings to enhanced energy security of the countries and environmental benefits for the region. The increased geographical coverage and integration of a common grid allow to take advantage of a variety of available resources. A very often cited example in the context of ASEAN is development of hydropower resources in Mekong region and sharing them with the neighbouring countries in the South. Displacing the use of hydrocarbons with cheaper hydropower could benefit the growing economics with reduced electricity costs and lower greenhouse gas emissions.

A recent study by the Economic Research Institute for ASEAN and East Asia (ERIA) which is also cited in the latest IEA's World Energy Outlook for Southeast Asia gives a broad perspective of the potential benefits if the projects presently under construction and planned are realised. The results are summarized in Figure 38.

The same figure also shows potential trends in supply and demand centres across ASEAN with expanded cross-border transmission capacity. Intuitively, countries with large hydropower potential such as Myanmar, Lao PDR and Cambodia would be major exporters while Thailand, Malaysia, Vietnam and Singapore would be the main importers. The view on Singapore is not without contention, because the country has currently about 50% of overcapacity in the generation sector. Thailand is expected to emerge as a trading hub, importing electricity from Myanmar, Lao PDR and Cambodia and exporting it to Malaysia. A mutually complementary relationship could be established between Malaysia and Indonesia, with Peninsula Malaysia importing electricity from Indonesia and Sarawak exporting electricity to Indonesia.

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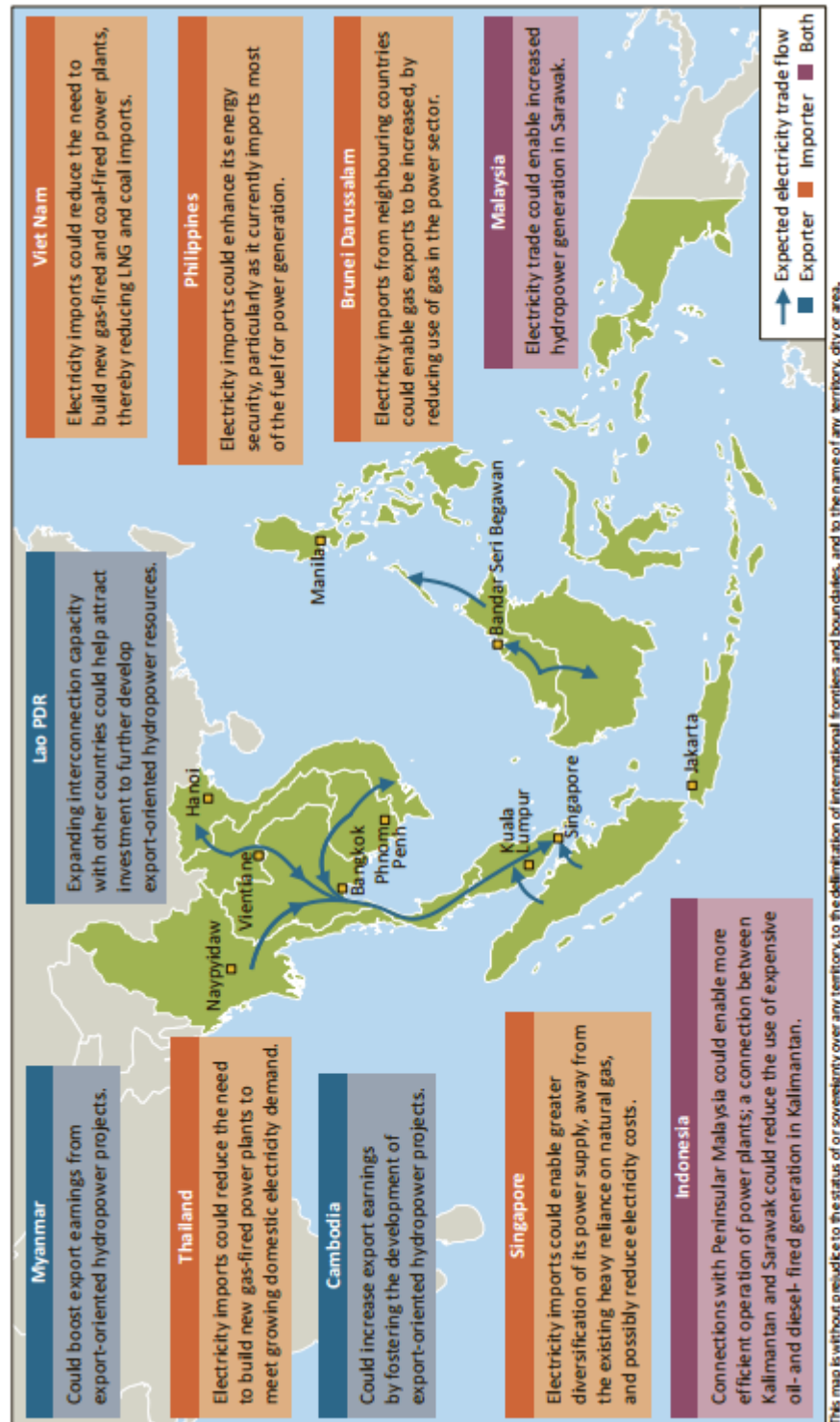


Figure 38. Benefits of APG for ASEAN member states

From (IEA 2015b)

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Quantified benefits

The analysis done by AIMS II compared systems with and without interconnections which were identified as a part of the AIMS list. The results are shown in Table 11. New interconnections could save a total of US\$ 1.87 billion, of which US\$ 1.72 billion would be capacity costs and US\$ 154 million would be fuel costs.

Table 11: Cost savings of interconnection projects identified in AIMS II

	Total expenses (mUSD)		Savings
	Without interconnection	With interconnection	
Costs structure	83,699	81,980	1,719
Capacity costs	253,025	252,871	154
Fuel costs	336,724	334,851	1,873

From (AIMS Working Group 2010)

Challenges for interconnection projects

A range of obstacles delay the progress in integration of electricity sectors in ASEAN. ASEAN countries vary greatly in their size, landscape, levels of economic development and national energy resources. Countries like Indonesia and Philippines are archipelagos, separated by large water bodies, while Mountain ranges in Indochina, Sumatra and Borneo create immense technical and economic challenges for infrastructure development. ASEAN member countries also vary considerably in power sector regulations, market structure and technical characteristics. All this creates barriers for an effective regional energy cooperation which are explained in more detail in the following paragraphs.

Coordination of infrastructure development

In theory, large interconnected systems need less reserve capacity for the same level of system reliability compared to disconnected power systems. In the case of power shortage, interconnected region can draw supply from other regions instead of relying on the domestic generation capacity. This ability reduces required investments in the power sector

infrastructure and creates economic benefits in a form of cost savings. In order to reap these benefits, countries would need to give up a certain degree of self-sufficiency in domestic supply and rely on power exchange instead.

This is a logical step of a market integration that has been achieved in many other parts of the world, but not yet in ASEAN. As of today, the most national power development plans in the ASEAN countries give priority to domestic power generation when planning for the future. The existing cross-border transmission lines are constructed at project-to-project basis and there is no coordinated operation and management guidelines that are systematic for the entire region (ERIA 2013).

A relevant example would be the Greater Mekong Subregion (GMS) trading scheme described in the case study below. Even though power trading is growing in the GMS region, the contracts are signed purely on bilateral terms and often involve creating separate infrastructure retained only for these contracts. Power generation projects are often locked from selling power to entities other than the contracted party either through physical transmission lines or through power purchase agreements⁷.

Different technical standards

Different technical standards of power system operations between ASEAN member states is another limiting factor. Although countries have common technical standards for all national utilities, these standards can greatly vary between them. Currently, there is still no set of common technical standards for ASEAN. The existing example of power interconnection have not dealt with these issues properly. For example, the power exports in GMS are mainly from generators separated from the national grids of domestic countries and exporting power through separate lines. The technical standards can be relatively easily aligned for these cases because power flows are small and go in one direction. However, with developing power systems, there will be a necessity for regional coordination of technical standards. Technical

⁷ One of the interviewed experts called this “energy colonialism”

failures would have a much more pronounced impact in large interconnected systems compared to small-scale lines (ERIA 2013).

Access to financing

Access to financing remains another important challenge. Future power system investment needs are significant compared to the existing ASEAN asset stock and to the global investment needs. According to IEA, the ASEAN region would need to spend US\$618 billion in generation and US\$ 690 billion in the transmission and distribution sectors. Compared to that, the cost of APG in its current state is estimated to be “only” US\$20 billion (IEA 2015b, ERIA 2015).

It is still unclear how the financing for all these projects is going to be sourced from. The completion of some interconnections is more realistic because of existing funding from multilateral development banks, bilateral agencies and the private sector. However, other APG projects lack economic viability although they have regional benefits and can be seen as a regional public good.

Institutional differences

Institutional and administrative features of power systems in different countries are also likely to differ in many ways, hindering technical and operational dimensions of an interconnection. Even if funding is available, electricity grid interconnections are complex to develop and manage. Table 12 shows that Brunei, Cambodia, Lao PDR, and Myanmar have traditional vertically integrated, state-owned power utilities, while Indonesia, Malaysia, Thailand, and Viet Nam have private IPPs operating together with state-owned utilities. Only the Philippines and Singapore have unbundled with separated generation and transmission sectors.

The ASEAN’s tendency to implement reforms from within a given country rather than between countries has been a major barrier in achieving closer cooperation. One example could be national regulations on interconnections that make it difficult to justify an interconnection with another country (ERIA 2015).

Power Interconnection in ASEAN Region



Table 12. Power sector structure in ASEAN

Country	Regulator	Regulator Independence	Market Structure
Brunei Darussalam	Dept. of Electrical Service	Under the Ministry of Energy	Single buyer
Cambodia	Electricity Authority of Cambodia	Independent	Single buyer
Indonesia	Dept. of Energy and Mineral Resources	Under the Ministry of Energy and Mineral Resources	Single buyer
Lao PDR	Dept. of Electricity	Under the Ministry of Energy and Mines	Single buyer
Malaysia	Energy Commission	Independent	Single buyer
Myanmar	Ministry of Electric Power	Under the Ministries of Electric Power	Single buyer
Philippines	Energy Regulatory Commission	Independent	Price pool
Singapore	Energy Market Authority	Under the Ministry of Trade and Industry	Price pool
Thailand	Energy Regulatory Commission	Independent	Single buyer
Vietnam	Electricity Regulatory Authority	Under the Ministry of Industry	Cost-based pool

Adapted from (IEA 2015b)

Energy security concerns of individual countries' place emphasis on self-sufficiency rather than cooperation. Power tariffs and electricity subsidies also differ markedly among ASEAN countries and so do the taxation rules and the sequence of approval procedures. Such trade and investment barriers do not promote a secure investment environment, particularly for private investors.

Market design

Market design is a broad concept covering several areas such as: allocation of costs, revenues, and rights to use the cross-border transmission lines; transmission pricing and allocation: balancing and congestion management; market clearing and dispatch rules in an interconnected market; and other regulations on renewables and taxation. The market design should be able to give correct price signals for investment in both power generation capacities and cross-border transmission infrastructure which is a challenging task even in mature markets such as Nord Pool. These issues are very difficult to resolve without establishing

institutions promoting cooperation between transmission system operators and regulators which are still missing in ASEAN.

Case Study: Greater Mekong Subregion(GMS)

The Greater Mekong Subregion (GMS) is a natural economic area in the Mekong River basin, covering 2.6 million square kilometres and a combined population of around 326 million. The area is well-endowed with various energy resources which have been explored to a different extent. The GMS power interconnection is the most significant scheme of bilateral power trade agreements in ASEAN. Although it has not yet moved beyond the initial phase, the GMS scheme provides a relevant expertise for future projects in ASEAN to compare and learn from as it develops. It is particularly relevant to analyse the involvement of Lao PDR and Thailand which are also involved in LTMS.

Motivation and context for trade

The significant potential for trade in the GMS region had been known for many years. The rapid economic growth of Thailand, together with the ending of various regional conflicts, led to renewed interest in tapping on the rich hydro potential of Lao PDR and Myanmar as a means of meeting growing electricity demand at low cost and allowing diversification of the generation mix. In early 2000s Vietnam has emerged as a potential importer to meet demand growth which, in recent years, has averaged 12% annually. Cambodia's interest in power trade is reduction of the current reliance on expensive and polluting oil-fired generation. In the longer term, Cambodia may become an exporter of power from its own hydro schemes. China and Lao PDR are currently net exporters of electricity, seeking to boost foreign revenues through sales of hydropower.

External agencies, notably the Asian Development Bank (ADB), World Bank and ESMAP, have supported a number of studies looking at the potential gains from increased regional power trade and major barriers to achieving this. Estimates by ADB show that the present value of

electricity costs across the GMS over the period 2005–2025 would be some US\$213 billion lower if the regional energy market was to be fully integrated, representing a reduction of around 15% in costs. This reduction owes to following factors:

- Cross border interconnections can be more cost efficient than connecting the locality via the national grid from domestic plants far away. Proof of this are the many low voltage cross border connections for the purpose of rural electrification. Similarly on a grander scale, it is far cheaper to generate and send power from southern Lao PDR into southern Vietnam than to do it from the northern Vietnam.
- Due to advantages in natural resources, some countries can produce electricity easier than others. One clear example is the geographic endowment of Lao PDR enabling it to tap into its massive hydro reserve, exporting power to Thailand, Myanmar, and Yunnan Province in PRC.
- Using differences in peak load profile, it is possible to smoothen the overall load on the regional grid among Vietnam, Thailand, Myanmar, and Yunnan Province in PRC. Using seasonal peak load variations, it is possible to balance out differences between Thailand and Vietnam during winter. The trading of electricity between areas balancing out load centres can help better utilize existing plants and postpone the construction of new generating capacity.

The analysis demonstrated that US\$585 billion of investment will be needed during the period if infrastructure availability is not to be a constraint on economic growth (ECA 2010, ADB 2013).

Historical development

The significant infrastructure development began after stabilisation of political situation in the GMS in early 1990s. Constructing transmission interconnection projects were implemented with private sector participation and ADB help. Prior to this, the only significant transmission links in the subregion were those between the Lao PDR and Thailand (ADB 2013a). Collaboration focused on building trust and frameworks among countries through different

studies and consultations. ADB published the first GMS energy study in 1994 identifying the opportunities and mechanisms in energy cooperation among GMS members. The study led to an establishment of the annual Electric Power Forum (EPF) in April 1995. The EPF facilitated the adoption of a policy statement on regional power trade in the GMS in 1999, which then led to the formulation of an intergovernmental agreement to implement the policy statement.

In 2000, the Regional Indicative Master Plan on Power Connection was initiated with the help of ADB. Completed in 2002, this document contained projected regional electricity demand in 2020 and identified key points for interconnection between the participants. In 2004 the GMS governments signed an inter-governmental agreement establishing the Regional Power Trade and Coordinating Committee (RPTCC). The RPTCC's major role is the completion of the initial Regional Power Trade Operating Agreement, which is a set of technical and commercial guidelines to support the establishment of a regional power market in the GMS. The MoU was signed in 2007 (ECA 2010).

Stages of market integration

Owing to differences in technical and regulatory standards among GMS participants, the MoU contained the roadmap of the market development in 4 stages outlined below:

- **Stage 1 (current stage).** In stage 1, the power trade is almost entirely conducted under bilateral agreements between the PPA member (which can be national utilities or IPP) selling power to the national utility of the importing country. This definition also provides scope for opportunity trades between national utilities, using any excess interconnection capacity developed for these PPAs.
- **Stage 2.** This stage foresees some transit trade between any pair of GMS countries, using transmission facilities of a third member country. However, this capacity must be surplus capacity of lines linked to PPAs mentioned in Stage 1.
- **Stage 3.** Further development of interconnectors and granting trade access to third parties other than national power utilities.

- **Stage 4.** Establishment of a regional competitive power pool market with multiple sellers and buyers within and across the member countries. A precondition for this would be the establishment of the national competitive markets.

The second Memorandum of Understanding was signed at the 3rd GMS Summit on March 2008 in Lao PDR. The purpose of second MoU is to clarify the timelines up to 2012 in preparation for the Stage 2. The associated key activities were defined in a road map titled “Indicative Regional Master Plan on Power Interconnection in the GMS” published in 2010.

To establish a more permanent institution to coordinate the trade of power within the region, GMS members agreed on reforming the RPTCC into the Regional Power Coordinating Center (RPCC) in 2012. RPCC’s functions would include monitoring national transmission system operators, utilities, and other relevant national agencies to ensure that common rules are followed and merging planning of the transmission grid. Financing would be provided by contributions from member states. However, as of early 2016, there is still no consensus about which country should host RPCC (ADB 2016).

GMS participants

GMS is comprised of six member countries including Thailand, Cambodia, Lao PDR, Vietnam, Myanmar, and the People’s Republic of China. China is represented by two provinces Yunnan and Guangxi. Figure 39 provides the map and the estimated energy resources in the region which are heavily dominated by hydropower.

Power sectors of the member states remain dominated by state-owned utilities, although there is a large number of IPPs in all countries except Vietnam. Generation, transmission and distribution are vertically integrated in Cambodia, Lao PDR and Vietnam. In Thailand, generation and transmission are vertically integrated while in Myanmar, transmission and distribution are integrated (ECA 2010). Vietnam has launched a pilot initiative to develop a competitive electricity market, but the development has been slow so far (ADB 2016). The

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current members who signed the MoU are: Electricité du Cambodge (EDC), Electricité du Lao PDR (EDL), Electricity Generating Authority of Thailand (EGAT), Electricity of Vietnam, China Southern Power Grid (CSG) and the Government of Myanmar who controls the power sector domestically. National regulatory agencies (NRAs) have been established in Cambodia, China, Thailand and Vietnam. The independence and powers of these regulators varies significantly.

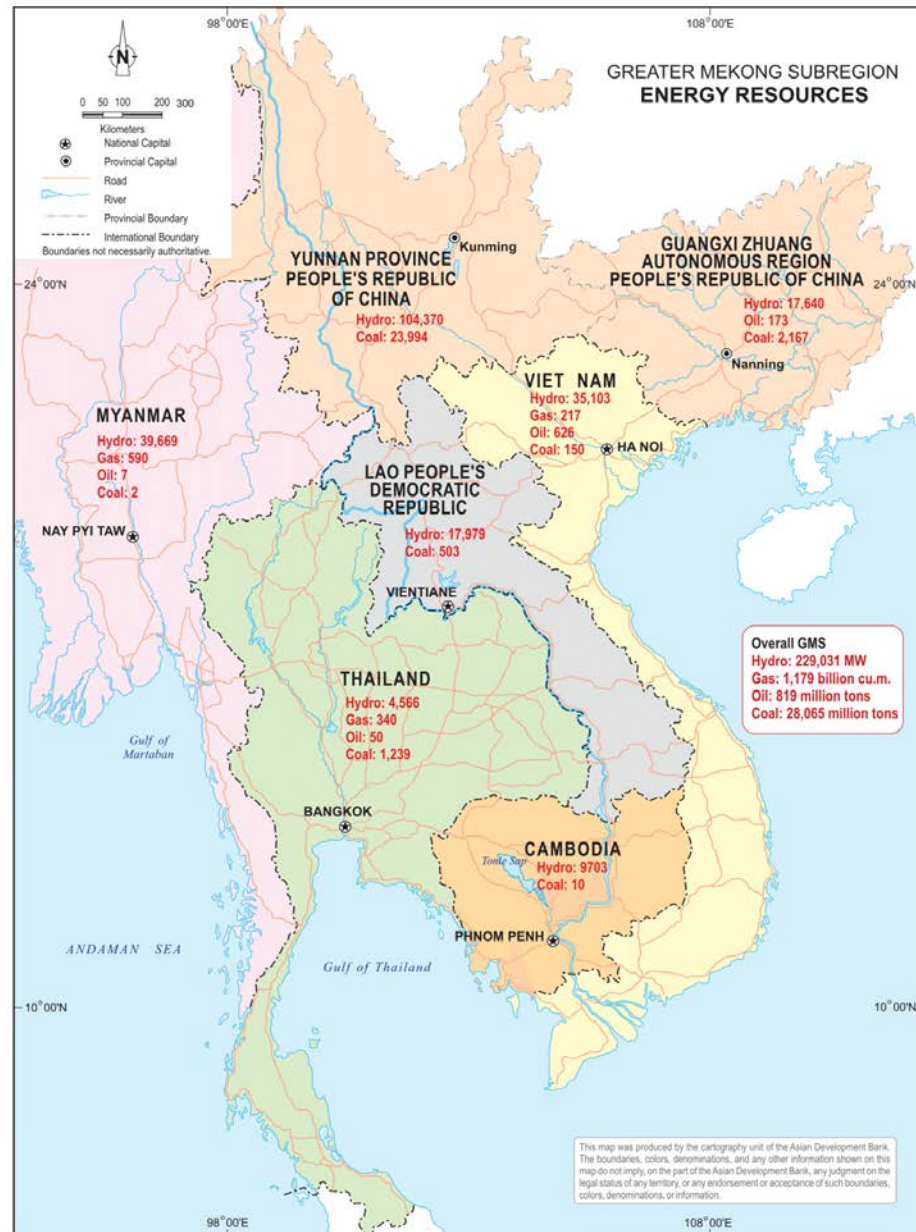


Figure 39. GMS participants and energy resources

From (ADB 2012)

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It is important to note that some of the IPPs involved in cross-border trade are partially owned by the same state-owned enterprise which is purchasing and importing the power into the country. This is particularly the case in Lao PDR where plants exporting power exclusively into Thailand are partially owned by EGAT.

Cross-border power trade

Figure 40 shows the important interconnection lines in the GMS region. In capacity terms, the largest interconnections are two lines between Lao PDR and Thailand with 1,500 MW and 1,000 MW, as well as one 600 MW line from Myanmar to China. The total interconnection capacity in GMS in 2015 was roughly 5,000 MW with almost 75% of capacity serving between Lao PDR and Thailand. In 2010, GMS electricity traded was estimated at 34.1 TWh. This is roughly 20% of Thailand's annual electricity consumption which was 149 TWh in 2011.

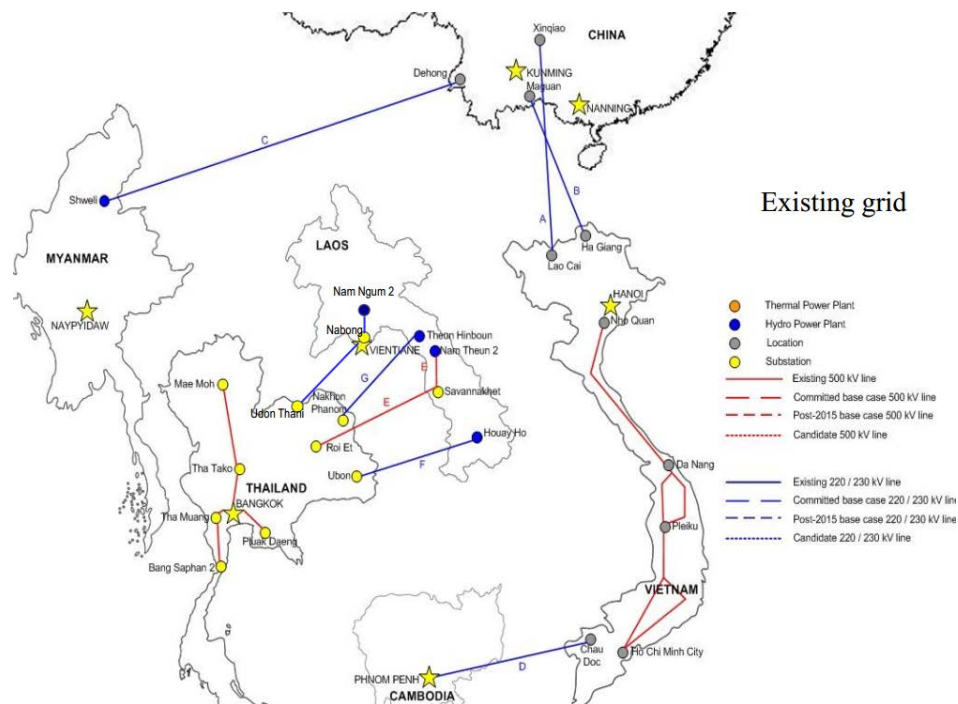


Figure 40. Existing major GMS cross-border connections

From (ADB 2015a)

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The breakdown of electricity trade data is shown in Table 13. The data is from year 2010 which is the most recent data source. The largest percentage of trade turnover is between Thailand and Lao PDR, occupying almost 50%, which is intuitive considering the distribution of interconnection lines. China and Vietnam are the next large trade participants while the shares of Myanmar and Cambodia are several times smaller. Besides that, data in Figure 37 highlights that the total amount of trade in GMS has grown significantly since 2000. Overall, Thailand and Vietnam are two countries with the greatest interest in importing power in the GMS market as they have the greatest need for new generation capacity and have most exploited their existing low-cost hydro resources. Thailand is particularly interested to reduce the need of expensive LNG imports in the future.

Table 13. GMS power trade and imports in 2010

Country	Imports	Exports	Total Trade	Net Imports
Cambodia	1,546	-	1,546	1,546
Lao PDR	1,265	6,944	8,210	- 5,679
Myanmar	-	1,720	1,720	- 1,720
Thailand	6,938	1,427	8,366	5,511
Vietnam	5,599	1,318	6,917	4,281
People's Republic of China	1,720	5,659	7,379	- 3,939
Total	17,069	17,069	34,139	-

Notes: - = nil, All Values in GWh = gigawatt-hour

From (ADB 2010)

Electricity prices

At present, prices for bilateral cross-border trade are set under negotiated PPAs on a case-by-case basis. Some of the associated bilateral contracts and trade terms can be obtained from (ECA 2010). Overall, there is little publicly available information about power prices associated with each PPA. The available prices varied between USc 5 and USc 8 per KWh in 2010 price terms which is lower than the average electricity tariffs in importing countries (ECA 2010). It is likely that the contracts have been renegotiated during the period of high oil prices and while countries like Thailand are progressively rolling back domestic energy subsidies.

State of supply and demand

No recent forecast for the supply & demand situation is available for the GMS region as a whole. According to ADB, a forecast study has been conducted by the ASEAN Center for Energy in 2011 (ACE) with assistance of the Institute of Energy Economics, Japan (IEEJ) and expert teams from each of the member countries (ADB 2013a). However, this study does not include energy forecasts for Yunnan and Guangxi which are part of the GMS. The more recent 4th ASEAN Energy Outlook does not provide disaggregated information for the member states but only for the region as a whole (IEA 2015b). The report by ECA, published in 2010, estimated potential capacity additions in GMS countries derived from the official documents. Given that this data was collected more than 6 years ago, these values, displayed in Figure 41 should serve only as a proxy. Nevertheless, one can see the significant projected growth in generating capacity which comes mainly from hydropower, coal and gas power.

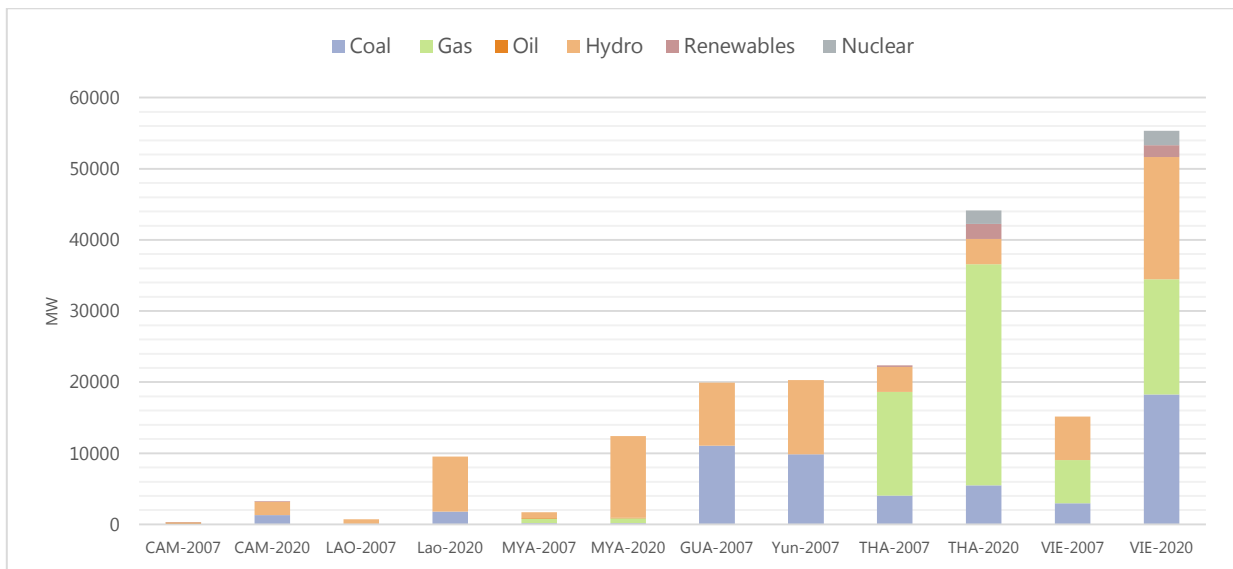


Figure 41. Comparison of installed capacity in GMS region in 2007 and in 2020 (projected)

From (ECA 2010)

Moreover, ADB published estimated of peak load demand for the GMS region which can serve as a proxy for projected demand situation. Notably, due to economic and population growth, the peak electricity demand increases by more than 3 times between 2010 and 2025, reaching

277 MW. The most significant growth is anticipated in Vietnam, Chinese provinces and Thailand.

Table 14. GMS Peak Load Demand Profile in MW

Year	GMS	Cambodia	Lao PDR	Myanmar	Thailand	Vietnam	Guangxi Zhuang AutonoMoUs Region, PRC	Yunnan Province, PRC
2000	26,126	114	167	780	14,918	4,890	n.a	5,257
2010	83,259	467	618	1,573	23,936	16,165	16,300	16,400
2015	148,371	1,008	1,911	2,533	31,734	30,084	31,600	30,100
2020	212,005	1,640	2,665	3,898	42,024	47,608	41,800	39,000
2025	277,220	2,401	2,696	5,596	54,588	71,280	50,290	47,970

From (ADB 2013a)

Institutional arrangements

The GMS Program does not have a formal secretariat or developed regional institutions. Instead, the emphasis is placed on the government agencies and national utilities of participating countries. Many support functions are carried out by ADB which facilitates and coordinates meetings and activities, and provides technical, financial, administrative and logistical support to the GMS institutions. Development of interconnection facilities does not follow any comprehensive regional planning initiative but is a part of the long-term power development planning of all GMS member countries. The ASEAN Interconnection Master Plan Studies provide reference about prioritized projects, however the member countries are not obliged to follow it.

Interconnector facilities are generally owned by the transmission utilities in which they are located, with the exception of transmission lines in Lao PDR, which are owned by the related project development company. Financing is undertaken by a mix of national utilities, international developers, commercial banks and development agencies.

Despite existing bilateral power supply agreements between the countries, there is no overarching regulator across the GMS. Due to the different national circumstances of each

country, national regulators have also different levels of independence from the government, although none can be described as fully independent and empowered. Lao PDR and Myanmar have no national regulators. Some cooperation was achieved between regulators in Thailand and Vietnam who have stated the need to revise their national grid codes to conform to regional GMS performance standards (ECA 2010).

Conclusions

International Energy Agency states that according to ADB estimates the GMS power interconnection has resulted in US\$ 14.3 billion in savings, coming mainly from the substitution of fossil fuel generation with hydropower (IEA 2015b). Despite this achievement, ADB notes that despite some progress, the regional power market is no closer than when the intergovernmental agreement (IGA) was signed in 2002 (ADB 2013a). The main obstacles for the GMS market to transition to the Stage 2 are different technical standards and regulatory arrangements between the member states. It is difficult to see how the intergovernmental MOU can be implemented without a degree of reform in national markets which is still a long way ahead. The lack of adequate transmission network across the whole GMS region is another important constraint. Furthermore, it is unclear who will be financing new transmission lines given asymmetric distribution of benefits and varying levels of economic affluence in the area.

Independent power producers (IPPs) create additional obstacles in that they forbid third-party access (TPA) to their dedicated transmission lines. Many major cross-border transmission lines are privately owned by the IPPs who are unwilling to allow third party electricity flow through the line. In other cases, the line has no sufficient extension to be connected to other sources outside of the existing PPA. Thus, the associated power purchase agreements (PPAs) will need to be revised if the public–private partnerships (PPPs) are to participate in a regional market.

The issues are further exacerbated by growing tensions between different members of ASEAN and the People's Republic of China due to various territorial disputes and the use of water in the region. Hydropower development undertaken by China in the upper Mekong River region

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can restrict the flow of water downstream to Vietnam and Lao PDR which is critically needed to generate and sell power there. Any kind of instability in one member country can also have adverse effects on neighbours who are dependent on either importing the energy for power or exporting the electricity for foreign currency. A more detailed list of challenges and opportunities of GMS can be found in (ADB 2013a).

Chapter 6: Lao PDR-Thailand-Malaysia-Singapore (LTMS) Interconnection

Introduction

The Lao PDR-Thailand-Malaysia-Singapore interconnection is the initiative to establish the first multilateral power interconnection project in ASEAN. This project was initiated during the Special Senior Official Meeting on Energy (SOME) convened on 9 – 11 December 2013 in Manado, Indonesia. In September 2014, the countries agreed on the pilot project entitled to study cross border power trade from Lao PDR to Singapore via the existing interconnections between the transit countries. The LTMS would take into account each country's national development plan with the existing interconnection among the countries as well as associated laws and regulations (ACE 2015b).

The member states set up a working group to study the technical feasibility of a pilot project up to 100 MW from Lao PDR to Singapore using existing interconnections. In this pilot agreement, Thailand and Malaysia would serve as the transit countries. The working group consisted of representatives from utilities, regulators and government agencies of the four involved countries. The task of the group was with setting up a conceptual framework for the project, by examining relevant technical, regulatory, political and commercial issues that need to be resolved before trade can happen (Leesombatpiboon 2015).

In September 2016, the MoU was signed between Lao PDR, Thailand and Malaysia while Singapore did not sign the document. Under the agreement, Malaysia will buy up to 100 MW of power from Lao PDR, to be transmitted through Thailand's national power grid. The project could potentially be extended to Singapore in the future. No reasons were given why Singapore chose not to participate in the MoU, although it should be noted that the country is vastly different from other project participants in terms of energy landscape and market structure (Asiaone 2016).

Case for LTMS

The LTMS project has been identified by ERIA as the most promising multilateral power trade scheme connecting Lao PDR in Singapore. The associated economic net benefit could be US\$25.5 billion (ERIA 2015). However, the scope of impacts caused by the interconnection is does not include environmental and socioeconomic risks. Particularly the ecosystem of the Mekong river basin is vulnerable to the construction of hydropower dams and new transmission lines that would be necessary for growing power exports from Lao PDR. So far, the LTM(S) pilot project mentioned above does not foresee any new infrastructure investments, as it caters only up to 100 MW of capacity between the countries.

Regional motivation for power trade can be understood easier after reading the detailed review of participating countries in the Annex. Figure 42 shows the map of LTMS countries with national power sector characteristics.

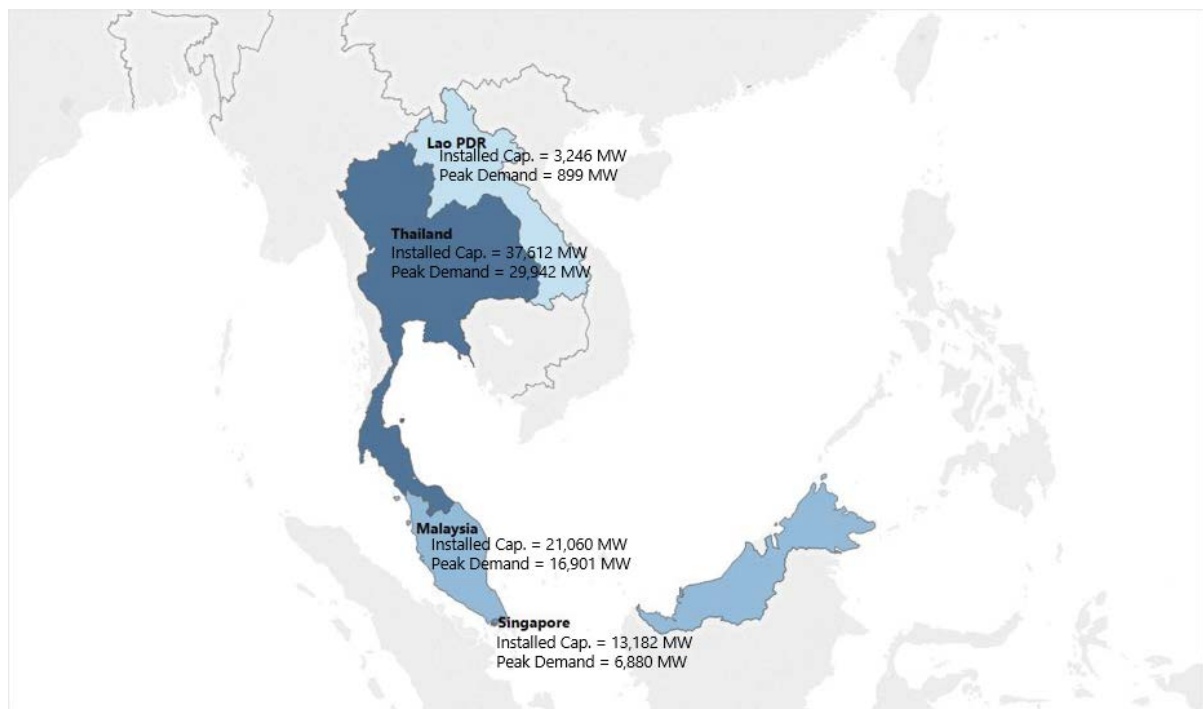


Figure 42. Map and power sector summary of LTMS countries

Adapted from (Leesombatipoon 2015)

Lao PDR has roughly 18 GW of hydropower potential which can be utilized as a relative easy source of foreign currency revenues in the country, although Lao PDR also carries a large burden of environmental damage that has not been accounted in cost-benefit studies. Thailand and Malaysia have the largest peak demand and annual consumption in the region, and are particularly interested in hydropower imports from Lao PDR. Considering that the electricity demand in Thailand and Malaysia is projected to rapidly increase in the next decades, Thailand's motivation is to fuel this growth without necessarily relying on natural gas imports. Malaysia has a somewhat similar motivation, although it has advantages compared to Thailand which are larger domestic oil and gas reserves and potential electricity imports from Sarawak located on the Borneo Island.

For Singapore, the motivation is a combination of benefits and drawbacks. The country has currently a 40% overcapacity in the generation sector and a low projected electricity demand growth. Importing hydropower into the domestic market which is entirely natural gas-based will further reduce the wholesale price. This benefits larger consumer categories (industry), but negatively impacts the domestic power generation companies. Hydropower imports, on the other side, create security benefits by reducing Singapore's dependence on natural gas imports.

Lessons from international experiences

The development of LTMS project resembles in many ways many other example in energy cooperation in ASEAN such as APG, TAGP and LTMS. Paved with many negotiations and delays, the actual progress is moving ahead slowly. This is mainly due to numerous barriers for cross-border power trade in ASEAN discussed in Chapter 4, which need to be resolved before the actual power exchange can take place. In this section, we compare the situation in LTMS (and potentially other regional interconnection initiatives) with the situation in SAPP, European market and Nord Pool and derive relevant experiences from those markets for the LTMS project. An examination of the experience in energy market integration in different regions of

the world shows that common elements have emerged. Broadly, these are: (a) binding agreements; (b) physical infrastructure; (c) standardized or harmonized rules of operation; and (d) governing or coordinating institutions.

Physical infrastructure

New capacity development

The physical interconnection capacity between LTMS countries has currently the limit of 300 MW which is more than enough to support the LTMS pilot project of 100 MW capacity. However, additional facilities will be needed if the level of integration between the countries is planned to increase. This includes generation transmission lines that either connect existing infrastructure networks in neighbouring countries or create new networks across countries. Coordination of infrastructure investments is an important task between LTMS countries which can draw from experiences from Europe and Nord Pool. In Europe, ENTSO-E and ACER prepare Ten-Year Network Development Plans (TYNDP), a co-ordinated planning initiative for pan-European transmission plan which is agreed on by all European TSOs and regulators. The Nordic countries did not have an institutional counterpart to ENTSO-E – instead this task was carried out by the planning committee of Nordel⁸, made up of the representatives of Nordic TSOs.

Furthermore, network development plans should adopt the same planning horizon for each country and undertake demand forecasts consistent with national and regional policy targets. Finally, the plans should be aligned with regards to project financing and implementation timelines. The experience from SAPP shows that developing a regional infrastructure development plan without considering these aspects may not lead to an effective project implementation.

Cost-benefit analysis is the common tool when prioritizing new projects. However, project selection should not only focus on minimizing costs but also reflect a balance between the national security interests and environmental and socioeconomic factors. TYNDP include

⁸ In 2009 this task was transferred to ENTSO-E as Nordel was wound up

environmental impact assessment that should also be considered for the LTMS initiative, particularly in the Mekong region.

To what extent should TSOs be involved in interconnection capacity development is an open question. Clearly, TSOs (and merchant interconnectors) are the main operators of transmission lines who cannot be excluded from the planning exercise. However, the experience from TYNDP highlighted the possible conflict of interests between the TSOs who benefit from the congestion rent and at the same time undertake capacity planning and prioritisation.

Operation of existing networks

The physical infrastructure between LTMS member states is developed enough to allow some basic power exchange, but neither is it synchronised nor operates according to a common standard. Although, international power markets studied in this report demonstrated that it is unnecessary to have a single system operator, power markets do require a harmonised set of rules on operation. These rules are known as the network codes and can be divided into grid connection codes, system operation codes and market codes. The first two categories deal with the access and operations of the physical system and contain a range of topics such as requirements for obtaining grid access, operation security, operational planning and scheduling load frequency control and high-voltage direct current (HVDC) connections. These rules are legally binding for all network participants. Network codes are drawn up nationally or even sub-nationally in many countries. However, as interconnected area grows in size and complexity, such arrangement must become supra-national in order to achieve the desired level of reliability.

The experiences from SAPP and GMS show that cross-border power exchange can happen even without a comprehensive alignment of these standards. However, there is a need for these codes to be harmonised, i.e. the codes implemented in different countries should not interfere. The absence of harmonised grid codes is viewed as a limiting factor for both SAPP and GMS which also causes frequent technical breakdowns in both systems (IRENA 2013, ADB 2013). In Europe, network codes are developed by European Commission, ENTSO-E and ACER

which also cooperate with Nord Pool. Prior to that, Nordel's operational committee was responsible for developing these standards across for the Nordic states. LTMS countries can harmonise grid codes in stages, first bilaterally and then multilaterally.

Another challenge related to power systems is that some of the existing transmission lines, particularly between Lao PDR and Thailand have been "locked" by PPA agreements with IPPs and therefore cannot be used to transfer power between entities other than the contractual parties. Renegotiating of these agreements may be required to obtain full access to transmission lines.

Financing

The financing arrangements for cross-border power infrastructure is another important issue. According to ERIA estimates, the cost of proposed future interconnectors on the LTMS route, listed under AIMS II, is US\$ 2 billion (ERIA 2015). Project financing is typically undertaken by beneficiaries of the interconnectors which are national utility companies, independent TSOs or third-party investors. For example in SAPP, interconnectors are financed by the utilities involved or by special-purpose companies set up to execute the projects. In Europe and in Nord Pool, it is TSOs and third-party investors who carry the main financial burden while the involvement of national governments and the EU is low⁹. Access to financing and favourable financing terms is a challenge in all three markets, but most notably in Africa. Some of the key projects there were financed through international development agencies and donors due to urgent socioeconomic conditions and lack of viable alternatives. The financing in GMS is a mixture of public and private sources with a lot of support from ADB and World Bank.

Financing for LTMS will likely be a mixture of public and private sources, coming from national utilities, IPPs and third-party investors. Given a relatively high per capita income of countries other than Lao PDR and high expected benefits of the interconnection, obtaining direct funding from development agencies would be difficult. On the other hand, private investors come with a perception that transmission business is risky and unattractive even in more

⁹ It is easier to obtain public financing if the project is of common interest (PCI)

mature markets, such as EU while small IPPs may not have enough funds available (TYNDP 2014, ERIA 2015). Achieving stable returns and investor-friendly conditions and instruments is therefore paramount for access to sources other than domestic financing. Nevertheless, the involvement of dominant state-owned utilities in LTMS and Singapore's strong credit rating could improve the perception of transmission system investments in this scheme. Credit guarantees from international development agencies could be another way to attract investment.

Market design and operations

Choice of market design

There is a variety of models of cross-border power trade with different degrees of market integration (IEA 2015). A model with low level of integration would be the "old" Nordic scheme, which relied on a system of bilateral contracts between state-owned utilities trading excess power. Roughly the same scheme was adopted by SAPP in its early years. Both markets have since then adopted multi-seller multi-buyer spot markets, albeit to a different degree of success. One of the important drivers for the market reform was the mismatch between supply and generation capacities in the long-run. Whereas excess supply, like in early 1990s in Norway, primarily affects power plant owners and investors, the impact is much more dramatic if the supply capacity is not sufficient, like it is the case in SAPP today. SAPP's experience also shows that a market can initially have an oversupply problem that later turns into a supply gap when power sector expansion cannot keep pace with the rapid growth in electricity demand.

While power exchanges or spot markets provide flexibility and competition benefits compared to a purely long-term market, they also cannot not fully address the issues of long-term capacity planning. As wholesale electricity prices become more and more volatile, European and Nordic electricity sectors turned to various support policies and market mechanisms, such as feed-in-tariffs, contracts for differences and capacity markets which all aim to provide sufficient planning horizon for new investments. However, it is questionable that such advanced mechanisms can be implemented in early stages of market integration. Given that

ASEAN countries have a much higher demand for new capacity and investments than Europe, the choice of market design must address this issue very clearly.

The existence of a functional spot market does not necessarily mean that it will be prioritized for electricity trading. Two key lessons can be derived from SAPP on this issue. Firstly, in an interconnected system with frequent generation and transmission bottlenecks, parties prefer long-term contracts, allowing sides to agree on delivery terms in advance, as compared to trading in the spot market. Secondly, spot market is an open trading platform which requires participants to disclose information about price, volume and time of delivery to the market operator, regulator and other participants. Bilateral trading does not have such requirements. Naturally, there is an incentive for existing players to continue trading via long-term contract, especially if the market concentration is high. The large difference in liquidity ratios of the spot markets in Europe implies the same problem. Nord Pool, which has the highest share of spot trading in Europe, tackled this problem by mandating large utilities to keep a certain share of trading in the spot market.

Choosing market design is particularly different for the LTMS project due to existence of competitive electricity markets in Singapore. Foreign participants could be in principle granted limited access to Singapore's market, trading power on pre-arranged terms. However, agreeing on such terms would be difficult, given that hydropower will undermine the competitiveness of non-subsidized gas-fired generators in Singapore.

Reforming existing power sector structures

An important question in the regional context is to what extent existing power sector structures are suitable for cross-border electricity trade. Between LTMS countries, Lao PDR, Thailand and Malaysia operate under single buyer models with IPPs, while Singapore has liberalized power market markets with unbundled generation and transmission. Technically, none of the countries has structural barriers in place that would prevent cross-border power trade. The scheme can be established between Lao PDR, Thailand and Malaysia linked by multilateral agreements, similarly to the SAPP. The Nordic market prior to 1990 could be

another example, although the Nordic states were historically more competitive compared to SAPP.

Including Singapore in the LTMS arrangement would be more challenging, because the power sector structure is more advanced in Singapore. Singapore allows only private generation companies to participate in generation and trading of electricity, while the government's participation is not allowed due to its exclusive transmission system rights. Therefore, Singapore does not have an institutional counterpart to join the inter-utility agreement in LTMS.

Another important question is whether unbundling and privatization of single buyer utilities is important for cross-border power markets to evolve further. SAPP achieved a basic cross-border power trade without unbundling or privatization, albeit the former reform is recommended for SAPP. Nord Pool became a successful power market with unbundling and no privatization. Many European power markets have both successful unbundling and privatization.

We see unbundling as a more important priority for the market development than privatization. In cross-border power markets, unbundling will give all generators equal access to transmission systems and ensure that the single buyer utility cannot easily abuse its transmission rights to prevent third-party from network access. Unbundling would also prevent cross-subsidies between generation, transmission and distribution arms owned by the same entity which will also raise the level of trust in the market and improve its liquidity. It may be realized as unbundling of accounts, legal unbundling and ownership unbundling. Depending on the level of transparency and trust, not all of unbundling forms may be required. Currently, only Singapore has successfully adopted unbundling of generation and transmission among LTMS members.

Harmonization of market codes

Market codes is a sub-category of network codes which deals with electricity market rules. The codes govern spot market trading, transmission capacity allocation, definition of bidding zones

and provision of balancing services. In general, same rules apply here as mentioned for other network codes: the codes do not have to be identical, but they have to be harmonised to the extent enabling smooth market operations. Most electricity markets contain a set of market rules and codes, some of which are mandatory while some can be negotiated between operating members.

Some market codes will have to be created specifically for the LTMS scheme, such as definition of bidding zones or nodes, allocation and pricing of interconnection capacity, and provision of balancing services. The proposed mechanism under the LTMS pilot project adopts a MW-km transit charge for pricing of transmission capacity which is similar to the method in SAPP. Balancing would be provided by national system operators while the cost of balancing is entailed in the wheeling charge. This model may serve well for the initial phase of market operations with a limited cross-border trading. However, the expansion of the pool may will require adding transmission lines between the countries and more efficient methods of transmission capacity allocation.

Setting up a market operator

Markets in advanced stages of multilateral cross-border trading involving power exchanges require an independent market operator. The operator would be in charge of the monitoring and management of electricity trade between countries and would act as a platform for connecting buyers and sellers. It would also provide inputs for national system operators for allocation of dispatch orders, physical transmission capacity and provision of balancing services. Market operators have been established in all studied international power markets. Among LTMS countries only Singapore has an independent power market operator which is EMC (Energy Market Company). Although EMC operates solely within Singapore's borders, it is theoretically possible to extend it to Lao PDR, Thailand and Malaysia which would be a technically challenging task. An important issue here is to ensure that EMC would be seen as a truly independent market operator by countries other than Singapore. This can be achieved by strict surveillance and disclosure practices that became prevalent in Europe and Nord Pool.

Institutional arrangements

The basic model for cross-border power trade can function on a purely bilateral basis, as it was shown by the Nordic countries in 1970s and 1980s. Relevant negotiations, harmonisation of standards and market operations can be carried out jointly by the state-owned utilities of the participating countries. However, more advanced stages of market integration naturally require inter-regional institutions driving integrated planning, harmonisation of codes and coordination of development efforts among many participants. The Nordic countries delegated these functions to various committees of Nordel, while cooperation of regulators realized under NordREG. SAPP has a similar arrangement with SAPP committees and RERA. In Europe, these functions are carried out by separate institutions which are European Commission, ENTSO-E and ACER. Considering that LTMS and ASEAN countries envisage full market integration at some point in time, there will be a need for a region-wide institution(s) with additional powers and responsibilities.

An important question in this context is how much authority should be given to such institutions. The EU member states collaboratively develop new standards, but become bound by them once they are called into force by the European Commission. In Scandinavia, Nordel's recommendations formed the basis of the technical regulations for generation and grid operations. However, it is difficult to find much relevance for the ASEAN countries, given that geopolitical and socioeconomic conditions are vastly different in ASEAN. The lessons from SAPP provide a more immediate example where prioritising of the national interests over regional goals and lack of empowered inter-regional bodies curbed the progress in market integration.

Even though the ASEAN community has already established some inter-regional institutions related to the development of APG¹⁰, none of them has binding authority. Furthermore, some

¹⁰ Heads of ASEAN Power Utilities/Authorities, HAPUA (promoting of regional interconnection), ASEAN Center for Energy, ACE (project prioritization, harmonisation of technical codes for APG), ASEAN Energy Regulatory Network, AERN (alignment of regulatory and legal framework for APG)

experts argue that it may not be practical for ASEAN to uniformly formulate rules due to the large differences in the national circumstances of the member states.

Given slow progress in development of APG and the recent withdrawal of Singapore from the LTMS MoU, we suggest first creating an institution with a limited intervention authority that serves as information exchange and capacity building platform. This would allow member states to build more trust without compromising national interests. Over time, this institution should ideally evolve into a more empowered functional body that can produce binding regulations and drive project implementation.

Harmonising national regulations

In interconnected markets, national regulators have a challenging task of balancing national priorities and the requirements of inter-regional collaboration. Power sector regulations do not have to be identical between interconnected markets, but they should be harmonised to the extent preventing them from conflicting developments in other countries. Among LTMS countries, particularly large differences are between Singapore and other three countries due to inherent differences between a competitive market and a single buyer scheme. For example, the independence of national regulators in Lao PDR, Thailand and Malaysia can be questioned, because public sectors in all three countries are involved in generation transmission and regulation functions. In Singapore, public sector is involved only in transmission and regulation functions. At the same time, no domestic power company in Singapore is mandated to import power, either by itself or through foreign representatives, while the government is not allowed to participate in electricity trading.

Lao PDR, Thailand and Malaysia have a variety of regulatory support schemes in the electricity sector such as direct producer subsidies, feed-in-tariffs and tax breaks. All these subsidies may distort the real price of electricity when it is traded in a competitive market, undermining the competitiveness of non-subsidised participants such power companies from Singapore.

Environmental, social and security concerns

The role of hydropower potential in the Mekong basin is crucial in the current vision of ASEAN electricity market integration. Countries in the region and outside of it see it as means to offset expensive fossil fuel use and cut greenhouse gas emissions. However, intensive damming required for electricity generation will create profound environmental and socioeconomic impacts for the region, many of which have not been properly understood. The magnitude of these impacts will grow disproportionately as increased interconnection will give the opportunity to purchase hydroelectricity to more and more countries.

Virtually none of the regional studies prepared by experts in the energy field analyse the environmental and social impacts of increased hydropower development in the Mekong basin. In contrast, the 2010 study by International Centre for Environmental Management (ICEM) notes a range of potential consequences including:

- LMB mainstream hydropower present very significant economic benefits for the regional power sector, most of which (70%) would fall to Lao PDR (US\$ 3-4 billion per annum);
- The losses experienced by the fisheries and agriculture sectors due to the mainstream dams are an order of magnitude greater than the realistic benefits to those sectors;
- The LMB mainstream projects would induce significant additional basin-wide effects on the Mekong river-dependent ecosystems, the majority of which are unavoidable if the projects go ahead;
- Even with mitigation measures conventionally associated with hydropower projects in the region, LMB mainstream projects would likely contribute to a growing inequality and a short to medium term worsening of LMB poverty in LMB countries;
- The mainstream projects would lead to irreversible losses in aquatic and terrestrial biodiversity of global importance;

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- By 2030, if 11 mainstream dams were built, the protein at risk of being lost annually would be the equivalent of 110% the current annual livestock production of Cambodia and Lao PDR; and
- Risks and losses incurred by the Mekong terrestrial and aquatic ecosystems will result in increasing food insecurity for millions of people.

The final conclusion of report team is to defer any construction of mainstream dams for a period of ten years (ICEM 2010).

Conclusions and way forward

In the review of the experiences of selected regional electricity markets around the world, we identify some key elements of integration that emerged independently as those markets evolved. These are coordinated physical infrastructure development, standardized or harmonized rules of operation, some form of market competition and empowered governing or coordinating institutions. Prioritization of these elements and the sequence of steps to achieve them the steps are not straightforward and depend on the regional market's environment and history. Moreover in many regions this process is still ongoing.

Market integration in Europe adopted a more top-down integration approach, capitalising on the legal system of the European Union. In contrast, Nordic and Southern African markets developed on incremental and voluntary basis, driven by the utilities themselves. Given diverse regional circumstances in ASEAN and absence of an overarching legal system like in the EU, we believe that the latter approach is more suitable for ASEAN.

The importance of coordinated infrastructure development is particularly important in markets with growing electricity demand, such as SAPP and ASEAN. Insufficient generation and transmission infrastructure in Southern Africa seriously limit the progress of the otherwise successful market. Frequent power outages and failures to deliver contractual obligations reduce the trust in the benefits of electricity market integration. Poor infrastructure development is driven by non-cost reflective tariffs and weak protection of third party investors. These aspects deserve consideration by ASEAN where the required generation capacity is expected to double by 2040.

Another important point is whether particular ASEAN countries should maintain vertical structures in electricity industry. While this is matter for national policy in each sovereign country, we note that such structures do not preclude cross-border interconnection and power trade until a fairly advanced stage. Nevertheless in order to move market to more competitive schemes, separation of generation and transmission industries is highly recommended.

Tapping on hydropower potential in the Mekong basin is the crucial aspect in the current vision of ASEAN electricity market integration. We note that virtually all existing regional interconnection studies do not sufficiently analyse profound environmental and socioeconomic impacts that come with planned damming of Mekong and its tributaries. These impacts are: loss of biodiversity of global importance, increased food insecurity for millions of people and increased international tensions that could outweigh the collaborative push resulting from electricity market integration. All these aspects should be considered by policy makers in ASEAN when designing a vision of a common resource use.

Given the commitment of ASEAN member countries to increase cross-border interconnection and power trade, we suggest below three market design options and required steps to achieve them. In setting out these options, we have sought to incorporate important lessons derived from international experiences analysed in this study.

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Option 1 Multilateral trade of excess power via long-term contracts	Option 2 Multilateral trade with spot exchange	Option 3 Fully competitive power markets
<u>Closest analogue:</u> Nordic countries before 1990	<u>Closest analogue:</u> Southern African Power Pool	<u>Closest analogue:</u> Nord Pool, some European countries
<u>Steps required:</u> <ul style="list-style-type: none"> - Formulation of institutional and contractual arrangements for cross-border power trade - Some harmonisation of technical and regulatory standards - Coordination of system operation between countries for electricity transfers - Signing of contracts between state-owned utilities on pre-arranged terms - Setting up separate entity to trade power in country with competitive markets (e.g. Singapore) on pre-arranged terms - Transit charge is optional, although desired 	<u>Steps required:</u> <ul style="list-style-type: none"> - Formalising the market institution with relevant committees - Setting up independent and empowered association of energy regulators - Agreement on coordinated infrastructure development plans - Development and adoption of comprehensive network codes including grid connection codes, system operation codes and market codes - Deeper harmonisation of existing national standards with grid codes - Setting up market operator and legal market entity - Phasing out energy supply subsidies 	<u>Steps required:</u> <ul style="list-style-type: none"> - All steps under Option 2 plus: - Vertical unbundling of state-owned utilities - Full independence of TSOs from electricity production - Unrestricted and non-discriminatory grid access to all participants - High market transparency and access to information for all market players - Sophisticated methods of system balancing and transmission capacity allocation
<u>Pros:</u> <ul style="list-style-type: none"> - Easy to implement - Does not require power sector reforms - Provides mutual benefits in system security 	<u>Pros:</u> <ul style="list-style-type: none"> - More efficient than Option 1 - Provides greater benefits to all efficient participants - Can react to market signals - Creates pathway for Option 3 	<u>Pros:</u> <ul style="list-style-type: none"> - Most efficient of all options - Reduces wholesale electricity prices - Provides greater benefits to all efficient participants - Increased market liquidity - Attracts private sector investments
<u>Cons:</u> <ul style="list-style-type: none"> - Inefficient - Low flexibility as market signals are missing - Retains non-competitive practices - Infrastructure investments are difficult, particularly in transmission - Low private sector participation 	<u>Cons:</u> <ul style="list-style-type: none"> - Presence of unbundled state-owned utilities deters private sector participation - Information asymmetry - Transmission system operators are not independent 	<u>Cons:</u> <ul style="list-style-type: none"> - Requires difficult domestic reforms - Requires high level of technical sophistication and experience in operating power markets - Requires stable political climate with high protection of participants' rights

Annex: Overview of LTMS participants

Lao PDR

Country profile

The Lao People's Democratic Republic (Lao PDR) is a one-party socialist republic, which shares borders with Cambodia, China, Myanmar, Thailand, and Vietnam. The Mekong river, which accounts for a large portion of its border with Thailand, is an important source of hydropower resource for the country, which aims to be the "battery of Southeast Asia" through exporting its hydroelectricity. While Lao PDR is an authoritarian state with a one-party system, the country operated under a planned economy for mere eleven years. Battered down by severe economic hardship and foreign exchange woes, Lao PDR introduced the New Economic Mechanism (NEM) in 1986, which opened doors for trade and market liberalisation.

Currently, Lao PDR is considered to be one of the fastest growing economies in the East Asia region, and has successfully graduated from its least developed country status to be classified as a lower-middle income economy by the World Bank. Lao PDR's strong growth rate is primarily supported by its power and mining sectors, which were identified to be fundamental drivers of its national economy (World Bank 2016a).

Lao PDR is well-endowed with domestic energy resources, both fossil fuel based and renewable sources. Although it has no proven oil and gas resources¹¹ and thus imports all its petrol and diesel needs, Lao PDR has sufficient lignite reserves for about 2GW of installed capacity and 500MW installed capacity for bituminous and anthracite coal (Vongsay 2013). While the solar, wind and geothermal potential for power generation is limited, biomass and hydropower are very attractive options (Vongsay 2013). Traditional biomass (mainly in the form of wood fuel) remains a primary energy source, accounting for close to 70% of total

¹¹ Lao PDR also has no petroleum refineries, therefore it imports all its petroleum products.

energy consumption (World Bank 2012). Recently these traditional energy sources are increasingly being replaced by petroleum and electricity. Hydropower remains the most exploitable resource for Lao PDR. The total estimated hydroelectric generation potential stands at 18-20 GW, of which only 1.28% were utilized as generating capacity as of 2011. Taking into account current hydropower under construction, it is expected that by 2020, 40% will be exploited, of which over 30% of the technically viable resources will be for export (ADB 2013b). As of 2010, majority of the final energy consumption is from the residential sector. Keeping in line with the GDP growth estimates, it is expected that the commercial and industry demand for energy will increase accordingly.

Energy subsidies and other incentives

The pricing of some energy-related commodities are regulated in Lao PDR. The Ministry of Industry and Commerce regulated gasoline and diesel prices by region. However, regular revisions of the prices may also indicate alignment with market price movements. Moreover, with a tight fiscal condition and various development needs, the relevant agencies may find it hard to maintain fiscal spending on energy subsidies. Despite speculations, due to the lack of transparency on price composition and pricing mechanism, it remains difficult to accurately ascertain the presence or absence of energy subsidies.

Lao PDR levies historically heavy subsidies on electricity tariffs. However, in recent years, there is gradual alignment of tariffs and the real cost of electricity production and distribution, as seen from the recent upward revisions of tariffs. Table 15 below presents the trends in electricity tariffs in Lao PDR. There has been a general increase in tariffs, although the rate is different for different sectors. The current levels of tariffs suggest cross-subsidy among different consumer groups. Specifically, the residential sector, particularly those who consume the least electricity, is subsidized by the sectors who are better able to afford higher electricity tariffs, such as the embassies and international organizations.

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Table 15. Trends in Electricity Tariffs in Lao PDR

ELECTRICITY TARIFF										
<i>*Unit: Kip/kWh</i>										
Category of Consumers	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Residential										
0 - 25 kip/kWh	133	154	177	203	234	269	321	328	334	341
26 - 150 kip/kWh	276	284	293	301	310	320	382	390	398	405
> 150 kip/kWh	773	773	773	773	773	773	923	941	960	979
Non-Residential (Low Voltage) 0.4 kV										
Embassy & International Organization	1,077	1,077	1,077	1,077	1,077	1,077	1,286	1,312	1,338	1,365
Commercial	835	835	835	835	835	835	997	1,017	1,037	1,058
Education and Sports Business							783	799	815	831
Entertainment	1,106	1,106	1,106	1,106	1,106	1,106	1,321	1,347	1,374	1,401
Government Office	703	694	684	674	665	565	783	799	815	831
Irrigation	313	329	345	362	380	399	476	486	496	506
Industry	634	625	616	607	599	591	706	720	734	749
Medium Voltage Consumers 22-35 kV										
Commercial	709	709	709	709	709	709	847	865	881	898
Education and Sports Business							665	678	692	706
Entertainment							1,255	1,280	1,305	1,331
Government Office	539	531	524	516	509	557	665	678	692	706
Irrigation	266	279	293	308	323	340	406	414	422	431
Industry < 5 MW	539	531	524	516	509	502	599	611	624	636
Industry > 5 MW							647	660	673	687
High Voltage Consumers 115 kV										
High Voltage							647	673	660	673

From (Laos Ministry of Energy and Mines 2014)

Electricity sector outlook

The power sector is one of Lao PDR' strategic growth sectors. Currently, government directives governing power sector development centres on three main objectives:

- Increase domestic electrification ratio to 90% by 2020 through the expansion of generation, transmission, distribution networks, as well as through off-grid installations;
- Promote public-private partnership development in hydropower projects as a way of increasing export revenues as well as honouring export commitments with neighbouring countries; and

- Promote high voltage (500 kV) grid development as a pathway to power systems integration in the Greater Mekong Subregion (GMS).

The total installed capacity in Lao in 2012 is around 3,000 MW, with numbers ranging from 2,978MW to 3,205MW. The majority of the generated electricity is exported to other countries through a series of bilateral contracts (IEA 2015a) while domestic consumption remains low. With economic and population growth, it is forecasted that the domestic electricity demand will face rapid growth in the coming decade (Figure 54). The growth in electricity demand could be traced back to two fundamental causes: increasing electrification of the population and rapid industrial growth in future years.

There has been remarkable growth in the national electrification rate in Lao PDR in recent years, with access to electricity increasing from 15% in 1995 to 69% in 2009 (World Bank, 2012). The Government of Lao PDR has ambitious plans to increase the residential electrification rate to 90% by 2020 (ADB, 2010) and which is equivalent of electrifying an additional 450,000 household from 2009 levels. Furthermore, with a focus on economic growth, the government engaged in an ambitious campaign to encourage investment in mining, commercial and industrial enterprises.

Overall, electricity demand is expected to increase from 8.45TWh in 2010 to 68.82TWh in 2035, representing an overall annual growth rate of 8.8% throughout the period 2010 to 2035 (Kimura, 2013). ADB, on the other hand, estimates higher annual growth rate for domestic electricity demand of 15%-18% (ADB, 2013).

Currently, Lao's Power Development Plan details two alternative resources to meet growing domestic demand: (1) expansion of the national utility, Electricité du Lao PDR (EDL)'s, generation capacity and (2) support the development of both domestic and export-based Independent Power Producers (IPPs). Despite EDL's plans to increase its generation capacity by close to 600MW by 2016, a substantial portion of the increased demand would still have to be met by IPPs, some of which EDL is investing in (ADB, 2013). The Laotian government is seen to

be actively promoting the participation of IPPs in the electricity sector, particularly in the hydropower sector (World Bank, 2012). The Electricity Law, first introduced in 1997, thereafter revised in 2008 and 2011 respectively, promotes private participation in the electricity sector by encourage private investment through public-private partnership arrangements, or a fully private mode. As such most of the capacity developed in recent years is held by Independent Power Producers (IPPs) (Lao PDR, 2014).

To support the government's ambitious rural electrification and economic development plans, there needs to an accompanying increase in transmission and distribution capacities. As of 2013, rural villages not yet connected to the EDL grid are supplied by some 85 diesel based or small hydropower mini-grids maintained by provincial entities and medium-voltage connections to neighbouring grids. While rural electrification is likely to still require electricity exports due to cost benefits of importing electricity when compared to extensive grid extension, the need to meet strong industrial demand in the south demands high quality grid transmission infrastructure (ADB 2013b).

Prior to 2009, Lao PDR had four independent regional sub-grids, namely Northern Grid, Central Grid 1, Central Grid 2, and Southern Grid, with 115 kilovolt (kV) and lower-voltage lines and substations(ADB, 2010, 2013). The four sub-grids are not interconnected, which gives rise to forced power shedding and poor quality of electricity. There are ongoing plans to integrate regional grids into a single national grid to ensure high quality power supply in the national grid (World Bank, 2012). From 2009 to 2011, Central 1 and 2 grids have been combined, and mainly serves the Vientiane Capital and Luang Prabang (ADB 2013b). Going into the future, EDL has plans to integrate remaining sub-grids with high-voltage lines (115kV, 230kV, and 500kV) by 2020 (World Bank, 2012).

Expansions in the transmission and distribution infrastructure is likely to be financed by EDL, with parallel participation of private sectors, following a pattern observed in the past decade. ADB estimates that EDL contributed 3,922 km out of the overall 5,500 km expansions in transmission infrastructure between 2011 and 2015 (ADB 2013b).

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At the same time, exports are expected to increase disproportionately in order to maintain the economic growth targets set by the government. Despite abundant hydropower resources, Lao PDR imports electricity from other countries. This is due needs to support domestic demand during dry seasons to maintain grid stability. One key area of concern is the cross-subsidies between import and export prices for electricity.

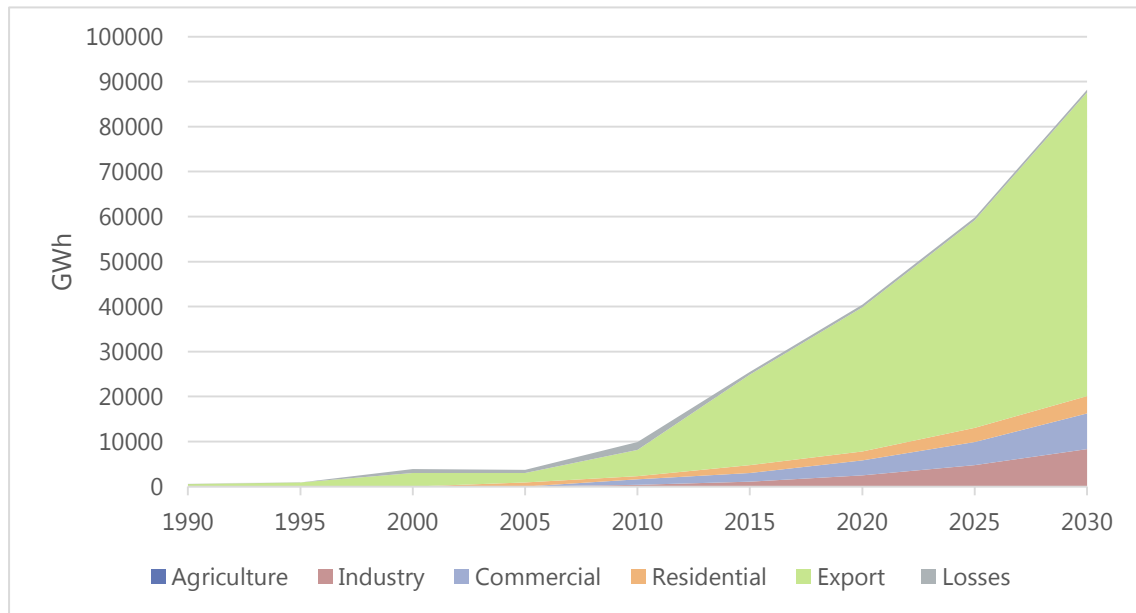


Figure 43. Electricity consumption (inclusive of export and losses)

From (Jyrki et al. 2012)

The generation mix in Lao PDR is dominated by large hydropower, with minimal solar energy used in solar home systems in rural areas and biomass gasification in specific uses in the industrial sector.

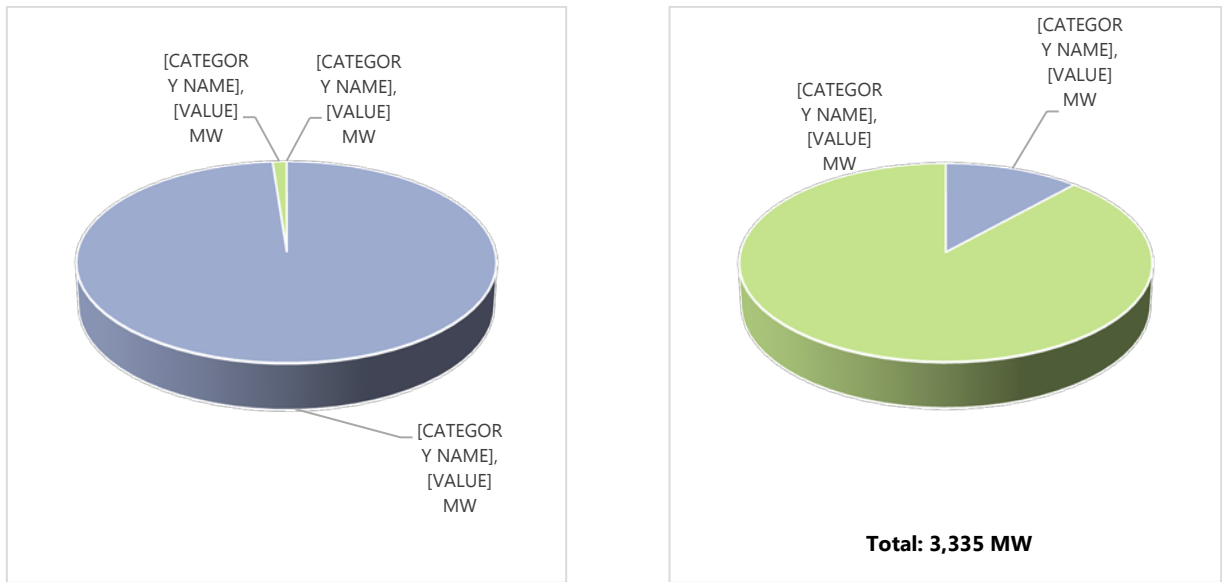


Figure 44. Electricity fuel mix and capacity ownership in Lao PDR

From (Laos Ministry of Energy and Mines 2014)

Lao PDR also has a renewable energy target to increase the share of renewable energy to 30% in the total energy mix by 2025 (ADB 2013b). The renewable target are to be met with three broad strategies: (1) increase the share of bio-fuel in the transport sector (2) the introduction of wind generation in the fuel mix and (3) increased share of thermal energy from renewable sources.

Summarizing future developments of Lao PDR' electricity sector, we conclude:

- **Domestic electricity demand will continue expanding rapidly, placing increasing stress on the undersupplied domestic electricity markets.**

With higher electrification rates and economic growth, particularly in the industrial sector, Lao PDR will experience a surge in electricity demand which may place stress on the domestic electricity markets. With most capacity additions serving foreign markets, more emphasis has to be placed in expanding power generation capabilities serving the local markets. Moreover, the current situation of exporting electricity will most likely persist, due to the cost benefits associated and the lack of grid expansion, especially to remote areas.

- **Demand for high quality transmission and distribution systems are required to accompany growth in the industry sector and ambitious rural electrification plans.**

The government's rural electrification program will in itself require substantial investment in distribution and transmission capacity. More significantly, the economic development plans in the mining sector is also expected to contribute to increase in domestic electricity demand. Further compounding the challenges is the need to transport electricity supply centres in the Northern and Southern grids to the key demand centre in the Central Grid, a feat that requires not only expansion of the transmission capacity, but also interconnection of the four separate sub-grids (ADB, 2013).

- **There shall remain a focus on export-oriented hydropower projects that are facilitated by increasing bilateral interconnections.**

With the electricity export being a strong support for the local economy, the dominance of export-oriented projects are expected to maintain (at around 90% of new capacity). While the state-owned utility, EDL, is likely to invest in domestic capabilities, private sector players are likely to remain more interested in export-oriented until the issue of domestic electricity price subsidies are resolved.

- **Renewables (ex-hydropower) shall play an increasing role in Lao PDR' electricity market, although the overall impact remains low.**

With a stated emphasis on alternative renewable sources, such as wind and solar, it is expected that the generation capacities of these technologies rise. However, the overall impact of these generation resources are likely to be limited, given that the wind generation projects that are being explored are at a nascent stage, whereas solar generation is currently limited to solar home systems. This leaves the electricity generation mix vulnerable to seasonality and the need for interconnection to maintain stability.

Development and organization of electricity sector

The Department of Electricity (DOE) is responsible for the national energy policy, formulating key policies for the power sector in areas of generation, transmission, distribution, rural electrification, while also holding the role as the o the regulator of the electricity market in Lao PDR (ADB 2013b).

The electricity market operates under a single buyer model, with EDL purchasing all the electricity and distributing them to end-users through various provincial branches. EDL is one of the three state-owned enterprises under the Ministry of Energy and Mines (MEM) under the Prime Minister's Office (IEA 2015b). Lao Holding State Enterprise (LHSE), a special purpose vehicle that is intended to maintain the government's share in export-oriented independent power projects, and the Electrical Construction and Installation Company, the company tasked with the construction of EDL's transmission and distribution networks, are also under MEM. However, it was noted that EDL has "a wide operational scope", "despite its de jure agent status", thus potentially indicating a relative degree of autonomy in making commercial decisions in a market setting.

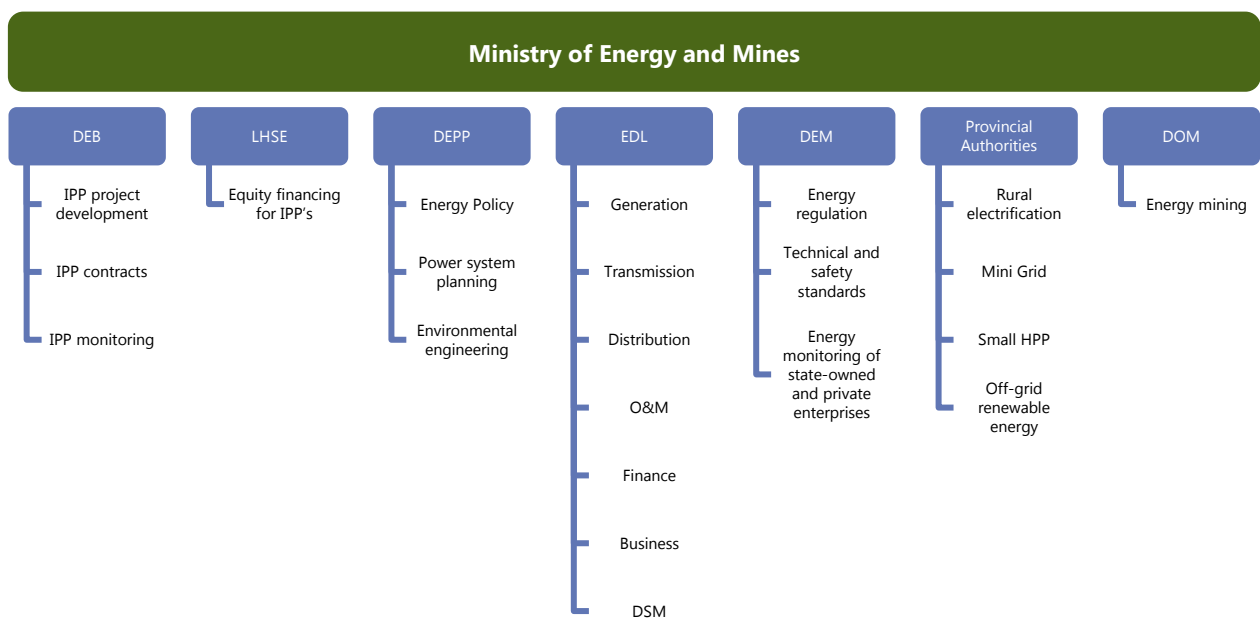
EDL is a vertically state-owned integrated company that is responsible for a broad range of operations in the domestic power market, from generation, transmission to distribution. While at the moment EDL still owns some generation assets, it seems to be increasingly shedding those assets to its daughter company - EDL-Generation (EDL-Gen) Company. EDL-Gen is a public company that is listed on the Lao Securities Exchange, who raises private sector capital to purchase generation assets from EDL, as well as take over the equity holdings held by EDL in IPP projects.

To meet domestic electricity demand, EDL also undertakes off-taker contracts from generation capacity operated by independent power producers (IPPs). It is interesting to note that the projects typically adopt a build-operate-transfer (BOT) or a build-operate-own-transfer (BOOT) mode, after which the project will be operated by Lao Holding State Enterprise.

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EDL has various payment settlement mechanism with the various independent power projects. The tariff for sale of electricity from IPPs to EDL is negotiated on a case-by-case basis, with the final tariff approved by MEM. For independent power projects with a mix of domestic and export capacities, the projects have bilateral power purchase agreements (PPAs) with both the cross-border offtakers and EDL. Recalling that EDL is also responsible for electricity imports and exports, it also has payment settlement mechanisms with the utilities in Thailand and Viet Nam (ADB 2013, World Bank 2012).



DEB= Department of Energy Business. DEM = Department of Energy Management. DEPP = Department of Energy Policy and Planning. DOM = Department of Mines. DSM = demand-side management. EDL = Electricité du Laos. EDL-GEN = EDL Generation Public Company. HPP = hydropower plant. IPP = independent power producer. IREP = Institute of Renewable Energy Promotion. LHSE = Lao Holding State Enterprise. O&M = operation and maintenance. Source: Ministry of Energy and Mines.

Figure 45. Lao PDR power system governance

From (ADB 2013b)

The distribution of electricity is undertaken by EDL, also EDL-Gen which are also tasked with the construction of transmission lines and substations, as well as operations and maintenance services to other power generation projects in Lao PDR. In recent years, segments of electricity distributions are being undertaken by private sector companies (see discussions above). In order to achieve the 90% electrification target by 2020, provincial governments are seen to

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have engaged private sector expand the local grid services, especially in remote and rural areas (see discussions above). These are typically Build-Operate-Transfer projects, whereby the infrastructure is bought over by the government at investment cost plus a reasonable return at the end of five years of operation by the private player (World Bank 2012). However, policy-wise, there remains a strong preference for public grid expansion due to the potential to leverage on subsidized electricity prices. As such, it is unlikely that public sector dominance in the electricity market be diminished in the medium term.

Role of electricity exports

Over the past decades, Lao PDR became the major net exporter of electricity in ASEAN, with total exports far outstripping its domestic consumption. Cross border hydropower sales have been a major source for the government revenue and access to foreign credit but also contributed to the environmental and social impacts in Lao PDR and countries downstream the Mekong river. The above-mentioned rapid acceleration in access to electricity was partially funded through foreign credit provided by Thailand and China in exchange for electricity exports.

Table 16 below illustrates the hydropower generation, supply as well as electricity import and export in Lao PDR.

Table 16: Hydroelectric generation, supply, export and import in Lao PDR

Year	Generation (GWh)	Domestic Supply (GWh)	Export (GWh)	Import (GWh)
2001	3,653.7	710.3	2,871.4	183.8
2008	3,717.0	1,915.7	2,315.4	844.5
2011	8,449.0	2,440.7	6,646.5	1,209.7
2012	12,979.5	2,555.7	10,668.4	904.3

From (Vongsay 2013)

The significant hydropower potential in the country has attracted interest from various international developers and investors, which was supported by the revised Electricity Law by the National Assembly introduced in 2008 which facilitated private sector participation in

export-centric hydropower development. However, the process is not without controversy. Firstly, the development of large hydropower projects is shown to adversely impact the environment, as well as cause negative social impacts such as displacement of local communities (Ulrich 2015). While there is a national development plan to address the environmental sustainability of hydropower developments and some success stories, application is patchy to say the least (Ulrich 2015). Secondly, the government has been criticised on the lack of transparency with regards to the awarding of concessions to hydropower developers (ADB 2013b). Furthermore, corruption remains rampant in Lao PDR, with Transparency International ranking Lao PDR as one of the most corrupt countries in the world. This has created issues with foreign direct investment (FDI), particularly in its infrastructure, due to the government's inability to enforce rule of law, business contracts among others.

Correspondingly, the government has acknowledged the need to manage the environmental and social impacts, as well as enhance the screening, negotiation and tendering process for hydropower projects developers. The Water Resources and Environment Administration (WREA) was set up to be the primary agency for the environmental management, responsible for "certifying the environmental and social impact assessments for hydropower projects, as well as working on broader assessments such as cumulative impact assessments, integrated water resource management, and strategic environmental assessments" (World Bank, 2012). The Department of Energy Promotion and Development (DEPD) was set up to be the government's main communication channel with prospective hydropower developers and investors, with the added responsibility of negotiating key hydropower deals with relevant stakeholders. An additional layer of accountability was added with the Ministry of Planning and Investment, who eventually signs on the projects agreements with the developers and/or investors (World Bank 2012).

Projections indicate that Lao PDR' electricity exports will increase in the future at a higher pace than the domestic consumption. This will make Lao PDR the target of competing electricity demands from the neighbouring countries and increase their reliance on Lao PDR (at least in

the Northern region). The regional over-reliance on hydropower which is subject to seasonal weather patterns, could create domestic and international tensions in the case of water shortage as it has been the case in Southern Africa and Latin America. Although Lao PDR has power co-operation agreements with neighbouring countries, such as Thailand and Vietnam, to meet domestic demand during hydroelectric-supply shortages in the dry season, it cannot give a full guarantee considering the rapid growth of the regional electricity demand.

Malaysia

Country profile

Malaysia is a federative state with three federal territories and 13 provinces consisting of two regions, the Peninsular Malaysia and the Eastern Malaysia, separated by the South China Sea. The Peninsular Malaysia is located on the Malay Peninsula. The Eastern Malaysia, consisting of two provinces Sabah and Sarawak, is separated by some 1000 km of the water area from the peninsular part. In our analysis, we look only at the peninsular part of the country and henceforth refer to it with the term "Malaysia".

Malaysia is an upper-middle income economy with one of the highest GDP per capita in the ASEAN region. World Bank projects Malaysian GDP to grow between 4% and 5% per annum till 2020. The population of the Peninsular Malaysia was 22.5 Million in 2013 comprising 80% of the total country's population.

Malaysia's domestic fossil fuel resources include large reserves of oil, gas and coal. The Malaysian economy was historically dominated by agriculture and resources, but it has become much more diversified in the past 20 years due to rapid growth in the manufacturing and services industries. The energy sector remains a critical sector for the growth of the domestic economy contributing almost 20% of the GDP. The proved oil reserves in Malaysia in 2014 totalled 4 billion barrels which are the fourth-highest oil reserves in Asia-Pacific after China, India, and Vietnam. The proven gas reserves in Malaysia totalled 83 trillion cubic feet

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(Tcf) (EIA 2014) which made the country the third-largest natural gas reserve holder in the Asia-Pacific region. The majority of oil and gas reserves are located in offshore fields. Malaysia has some coal resources located in the Eastern Malaysia. However, the majority of it lies in environmentally sensitive areas and are hard to extract. Currently, Malaysia imports about 90% of its consumed coal (IEA 2015b).

Table 17: Malaysia's energy statistics

	Unit	2000	2013	CAAGR 2000-2013
Population	million	23	30	1.8%
GDP (PPP) per capita	\$2,014	16,269	23,680	2.9%
Energy demand	Mtoe	50	89	4.5%
Energy demand/capita	toe/capita	2.13	2.98	2.6%
Electricity demand	TWh	61	124	5.6%
Electricity demand/capita	kWh/capita	2,720	4	3.7%
Energy intensity	toe per \$ 100 (\$2014, PPP)	0.131	0.126	-0.3%
Net Oil exports	mb/d	0.310	- 0.040	-185.0%
Net natural gas exports	bcm	21	25	1.4%
CO₂ emissions	Mt	118	211	4.6%

*Negative values indicate net imports. ** In 2013, Malaysia's net gas pipeline imports accounted to almost 13 bcm, while it exported around 34 bcm of LNG. *** Excludes emissions from land use, land-use change and forestry

Notes: CAAGR = Compound average annual growth rate; PPP = purchasing power parity; Mtoe = million tonnes of oil equivalent; toe = tonnes of oil equivalent; TWh = terawatt-hour; kWh = kilowatt-hour; mb/d = million barrels per day; bcm = billion cubic meters; Mt = million tonnes

From (IEA 2015b)

Although Malaysia was historically an exporter of oil and gas, growing local demand for carbohydrates declining production made Malaysia a net oil importer in 2013. In the gas sector, imports of natural gas grew over the past years alongside with LNG exports (IAE 2015b). Malaysia has a significant potential for renewable energy sources in form of biomass, solar and wind. In 2001, the Fifth Fuel Policy was introduced which includes renewable energy as the fifth fuel in the energy mix with natural gas, oil, hydro and coal. However, so far the development of renewable energy capacity has lagged behind mainly due to application quotas set by the government.

Energy subsidies

Malaysia has various energy and non-energy subsidies in place. Most of the energy subsidies fall on petroleum products, liquefied petroleum gas (LPG), natural gas and electricity. Malaysia has also various tax and investment incentives targeted to promote oil and natural gas exploration and development in the country's offshore fields as well as promote energy efficiency and renewable energy sources (EIA 2014).

Reduction of energy subsidies one of Malaysia's key policy directives in recent years. The government paid large amounts on fossil fuel subsidies during the period of soaring oil prices. During the same time, the national oil conglomerate PETRONAS recorded a high amount of foregone revenue because of the widening gap in domestic and international fossil fuel prices. Combined with other factors, this has led to a policy shift on energy subsidies in Malaysia starting in 2011. Malaysia raised electricity and gas tariffs in June 2011 and tied electricity prices to fossil fuel price fluctuations. In 2014 the government increased natural gas prices paid to the domestic producers by the power sector and industry. Furthermore, subsidies were completely removed for specific types of gasoline and diesel. As of January 2016, the regulated price of piped gas was increased to RM 18.20/mmBtu from RM 16.70/mmBtu. However, this regulated price is still below the market price of MFO at RM 25/mmBtu and the government still bears a form of subsidy to the power sector at 30% (Energy Commission of Malaysia 2016).

Electricity sector outlook

Growing energy demand is the main challenge faced by Malaysia. Coupled with economic and population growth, Malaysia's total primary energy demand increased by almost 80% from 2000 to 2013. In 2015, Malaysia had the third-largest energy demand in the region after Indonesia and Thailand (IAE 2015). The electricity demand in Malaysia has grown even at a higher rate than the energy demand. Electricity demand and generation have doubled between 2002 and 2012, landing at 140 GWh in 2014. The main consumer of electricity in 2014 was the industrial sector (46%), followed by commercial (33%) and residential (21%) sectors.

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Transportation and agriculture sectors contributed less than 1% of the electricity demand. The electricity access is almost universal throughout the country.

Malaysia's electricity sector is heavily reliant on fossil fuels. The fuel mix consists of coal (48%), natural gas (42%), large-scale hydro and renewables (10%). The total installed capacity in Peninsular Malaysia was about 21 GW in 2014. Its breakdown by generation type is shown in Table 18. Over the past 30 years, the fuel mix became more inclined towards gas and coal, while the share of oil has decreased.

Table 18: Installed generation capacity in Peninsular Malaysia by end of 2014

Type	Fuel	Capacity (MW)
Conventional Thermal	Coal	8,066.0
Combined Cycle Gas Turbine (CCGT)	Gas	8,030.0
Conventional Thermal	Gas	564.0
Open Cycle Gas Turbine (OCGT)	Gas	1,900.4
Hydroelectric	Hydro	2,149.1
Total Capacity (MW)		20,709.5
From (Energy Commission of Malaysia 2015)		

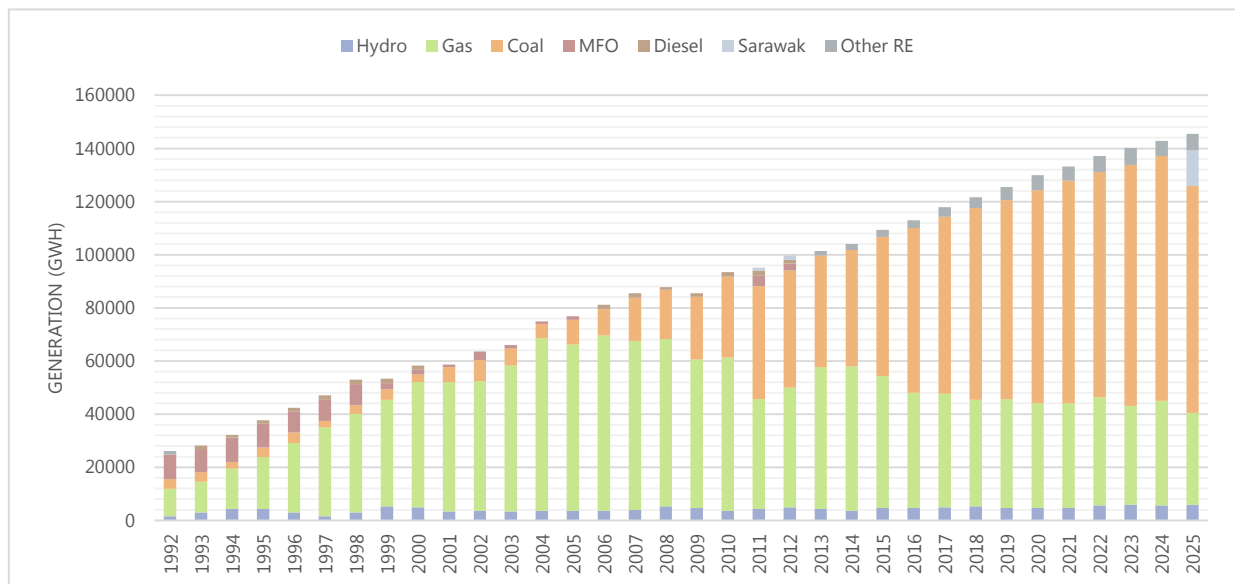


Figure 46. Historical and projected electricity fuel mix in Peninsular Malaysia

From (IEA 2015b)

studies by international agencies anticipate that primary energy and electricity demand in Malaysia will continue to grow at a rate between 2% and 3% per year in the next decades (IEA 2015b, EIA 2016). Projections displayed in Figure 46 indicate that coal will become the dominant fuel in the electricity mix, followed by gas and large-scale hydro.

The challenge of growing demand has been reflected in several policy directives seeking to provide means to sustain this growth. Policies such as the Fifth Fuel Policy, National Biofuels Policy, and National Renewable Energy Policy and Action Plan promote energy efficiency and use of renewable energy sources in order to decrease consumption of oil and gas and alleviate pressure on domestic producers.

In 2001, Malaysia enacted the Five Fuel Policy in their 8th Malaysia Plan. The Five Fuel Policy defined renewable energy as one of the main fuels alongside oil, gas, coal and hydro. Initially, companies were given fiscal incentives as a way to encourage the use of renewable energy in the private sector. Feed-In-Tariffs (FIT) for renewable energy producers were introduced in 2011. The tariffs are financed through the Renewable Energy Fund. The fund is financed through retail customers with monthly consumption above 300 kWh who pay an associated premium of 1.6% on their electricity bills. However it remains unclear, whether these scheme could support the fund in the long-term, as renewable capacity will grow and more money will be required for FiTs. Addressing the last point, the government has imposed quotas on capacities receiving FiTs and is considering to curb FiTs for solar in 2017. Malaysia's policies also promote energy efficiency and conservation. Households are offered rebates of 5%-7% on energy efficient appliances. Furthermore, minimum-energy performance standards for products were implemented.

Summarizing the initiatives outlined in the aforementioned policy documents, we present three conclusions for the future development of the electricity sector in the peninsular Malaysia:

- **Coal will overtake gas as the dominant fuel for power generation**

Projections by the Malaysian authorities and international institutions indicate that coal-fired generation will cover the large part of the future electricity demand. At the same time, the proportion of the natural gas in the fuel mix will decrease. Coal has a cost-competitive advantage over natural gas which will become even more pronounced with the gradual removal of fossil fuel subsidies. Some of the new coal-fired generation capacity will utilise the ultra-supercritical technology in order to achieve lower CO₂ emissions.

- **Growing renewables will still be small market player**

The development of renewable energy will accelerate, although renewables will not play a pivotal role in the fuel mix for at least another 10-15 years. One of the limiting factors is the existing cap on renewable energy capacity and the unclear long-term policy direction on FiTs. Nevertheless, the cost-competitiveness of renewables vis-à-vis gas will increase with declining costs and gradual removal of fossil fuel subsidies.

- **Inter-regional power transfer will play a more important role**

Malaysia is planning to increase its power interconnection capacity by establishing links between Peninsular Malaysia and Sarawak, Peninsular Malaysia and Sumatra and expanding the existing capacities in the North with Thailand and in the South with Singapore. Specifically, official sources mention "on the ASEAN front, the Lao PDR–Thailand–Malaysia–Singapore Power Integration Project which is at an advance negotiation stage, will be a significant milestone in the ASEAN agenda, paving the way for future interconnection between ASEAN countries towards realising an ASEAN power grid¹²". Meanwhile, the inter-regional power flow from Sarawak will be delayed until 2025.

¹² See Peninsular Malaysia Electricity Supply Industry Outlook 2016 p.9

Development and organization of electricity sector

The current model in the Malaysian electricity sector is a single-buyer model with monopolies in transmission and distribution sectors and some form of competition in the generation sector. Each of the Malaysian states including Peninsular Malaysia, Sabah and Sarawak have its own dominant utility company acting as a monopolist. In the Peninsular Malaysia it is Tenaga Nasional Berhad (TNB) which owns the National Grid (transmission), majority of distribution assets and some generation capacity (ERIA 2015). Market regulation is done by the regulatory body Energy Commission which was established in 2001 and regulates both electricity and gas industries. Energy policy is overseen by the Energy Section of the Economic Planning Unit, one of the organizations under the direct jurisdiction of the Prime Minister's Department, country's decision making body with the highest authority.

Malaysia has traditionally been a complete vertically-integrated monopoly in the electricity sector. Reforms have begun with the Electricity Supply Act passed in 1990. Electricity Supply Act authorized private investment to enter the generation business as a means to respond to rapidly increasing electricity demand. Shortly after that, the first electricity purchase agreement with an IPP was signed in 1993. As of 2014, there were 14 IPPs in the Peninsular of Malaysia selling electricity to TNB at a fixed rate based on the signed Power Purchase Agreements (PPAs). A PPA is signed for the duration of 21 years between TNB and IPPs (Ngadiron et al. 2014)

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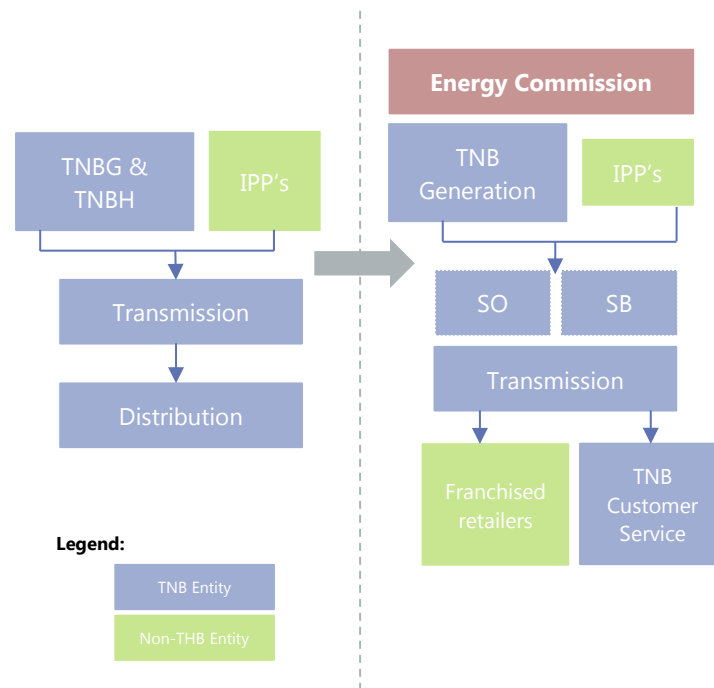


Figure 47. Proposed reform of single buyer model in Malaysia

From (Ngadiron et al. 2014)

After the introduction of IPPs, the Malaysian Government had the intention to further liberalize the electricity sector by introducing an Independent Grid System Operator (IGSO) in early 2000s. The role of the grid operator is to schedule dispatch of power plants in a liberalized electricity market. However, this plan has been never realized due to a conflict of interests of the proposed scheme with TNB. Not much development in the electricity sector reform has happened in 10 years after that (ISIS 2014). Starting from 2012, some attempt of unbundling was introduced to the single buyer model. Prior to that, TNB was responsible for long-term capacity planning, energy contracts and dispatch schedules as one entity. As a next step in market evolution, it was proposed to separate operations within TNB's Single Buyer unit by creating four independent entities: Power and Resource Planning, Power Contract Management, Enterprise Management and Technical Advisory and Industry. The Power and Resource Planning would be responsible for load forecasting, long-term capacity planning and day-ahead generation scheduling. The entity would also oversee fuel mix and security planning, development and management of gas supply contracts and medium term capacity scheduling

for fuel and outage planning. The Power Contract Management unit would be responsible for power contracts and cross-border power trade. The Technical Advisory and Industry Development unit would provide technical advisory related to generation, transmission and distributor to the regulator (Ngadiron et al. 2014).

Thailand

Country profile

Thailand is bordered by Lao PDR to its east and north and by Malaysia to its south. The country has an area of 513,000 km² and a population of about 70 million inhabitants. World Bank ranks Thailand's GDP per capita at US\$5,930. In terms of geographic area and GDP per capita, it occupies the fourth rank in the region. Thailand is an upper middle income economy and its GDP is expected to grow at the rates between 2.5 % and 3% by 2020 (World Bank 2016b).

The oil and gas reserves in Thailand are in steady decline while the domestic energy consumption increases. Gas reserves have declined to 7.75 Tcf, as of end 2014 from 12.7 Tcf back in 2000, while crude oil reserves have fallen to 222 million barrels from 272 million barrels over the same period¹³. Thailand has also some 2 Gt of lignite reserves located in Northern Thailand, and there are currently limited or no reserves of hard coal. It is estimated that 1,400 Mt of it is economically recoverable (IEA 2015b).

Thailand is a major energy producer and importer. According to IEA, 36.3% of production falls on gas, 31.5% on biofuels and waste, 24.8% on oil and 6.5% on coal. Alternative energy sources including hydro, solar and wind take less than 0.8% combined. Over the past decade, the growth in production happened primarily in the oil and gas sector, while the production of coal declined. Thailand is highly dependent on energy imports. Increasing domestic production of oil and natural gas, which will be depleted over the next 8-12 years unless new reserves are discovered, is difficult (IEA 2016b). Consequently, Thailand imported a total of

¹³ <http://www.dmf.go.th/>

70.7 Mtoe of energy in 2013, consisting of crude oil (64.0%), coal (16.7%), natural gas (13.4%), oil products (4.2%), and electricity (1.5%) (IEA 2016b).

Energy sector subsidies

Similarly, with many other Asian economies, Thailand has a variety of subsidies in energy and electricity sectors. ADB notes that the largest amount of subsidies was given in a form of tax breaks for diesel and market price support for LPG and natural gas vehicles (ADB 2013a). Relevant for the electricity sector, Thailand subsidises the price of natural gas for domestic gas consumers. However, there is an information gap about the exact differences in domestic price levels compared to the world market price. Besides that, tax incentives can be found for machinery imports used for oil and gas exploration, processing and transport.

Two subsidy types are present in the Thai electricity sector. The first is free electricity supply to low-income households whose electricity consumption does not exceed 50 kWh per month, which is funded through a cross-subsidy from electricity consumers in other sectors (primarily industry). The second subsidy is provided to EGAT in form of subsidising prices of lignite and natural gas for power generation. The total amount spent on fuel subsidies is unclear, owing to the lack of information disclosure about contract details (ADB 2015b). Receiving fuel at subsidised rates, however, put an obligation on EGAT to maintain electricity tariffs for the consumers beyond a certain level. If EGAT wants to change the tariff structure, let's say due to changes in fossil fuel prices, it must first seek approval from the regulatory agency. The regulator makes the ultimate decision to grant increases or decreases, taking into account EGAT's costs, among other things. Besides having own generation capacity, EGAT procures electricity from IPPs at the market rate and distributes it to the consumers at the approved tariffs. In this situation, the interaction between the tariff subsidy and the cost of purchasing power from IPPs determines the financial situation of EGAT and its ability to invest in new projects and ventures.

Renewable energy sector in Thailand receives subsidies in form of FiTs. The rates vary depending on fuel type (solar PV, wind, waste or biomass) and the size of installed projects (ADB 2015b).

Electricity sector outlook

Like most ASEAN countries, Thailand is expecting future growth in energy and electricity demand. Currently, Thailand has the second largest energy and electricity demand in the region. The total primary energy supply has almost doubled between 2000 and 2015. Electricity demand grew by more than 80% between 2000 and 2014, landing at 181 GWh (EPPO 2015). The main consumers of electricity in 2014 were the industry (44%), residential (23%) and commercial (19%) sectors. The electricity access is almost universal throughout the country.

Figure 48 highlights the main components of the electricity fuel in 2014, which consist of natural gas (66%), coal/lignite (21%) and electricity imports (7%). Thailand imports power from projects in Lao PDR and Myanmar named in the previous chapters. These projects are directly connected to the Thai grid and are generally isolated from their domestic markets. The power is supplied under PPAs under a bilateral contractual form.

The total installed capacity was about 34.5 GW, some of which was located in neighbouring Lao PDR. Over the past 30 years, the fuel mix became more inclined towards gas and coal, while the share of oil has decreased (IEA 2016b).

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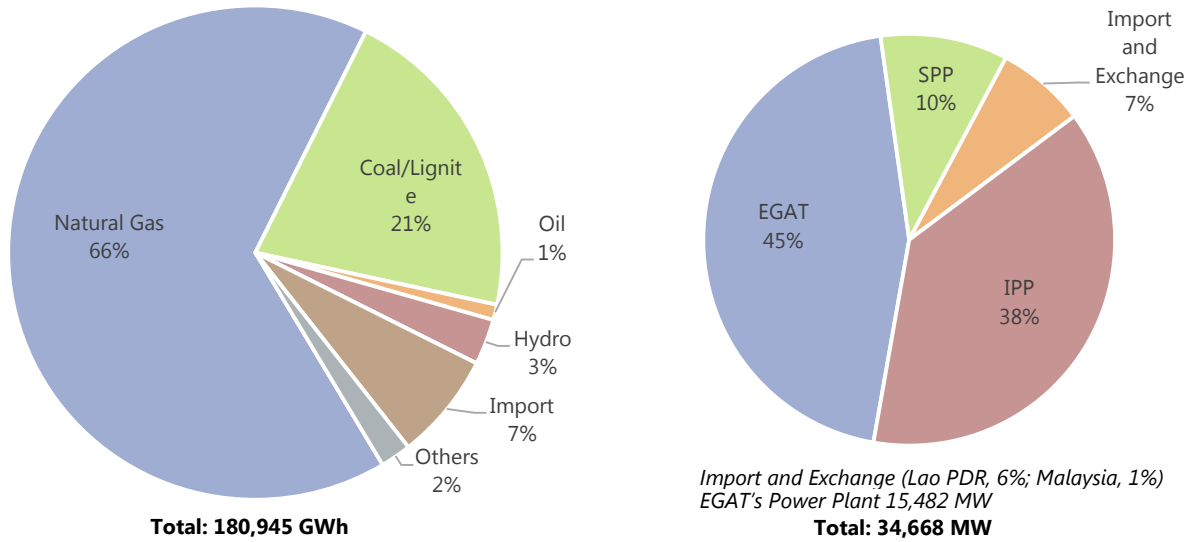


Figure 48: Electricity fuel mix and production breakdown in Thailand

From (EPPO 2015)

The historical trend of electricity supply mix shown in Figure 49 highlights that the power generation mix has been gradually shifting towards gas- and coal-fired technologies substituting the share of oil.

Power Interconnection in ASEAN Region

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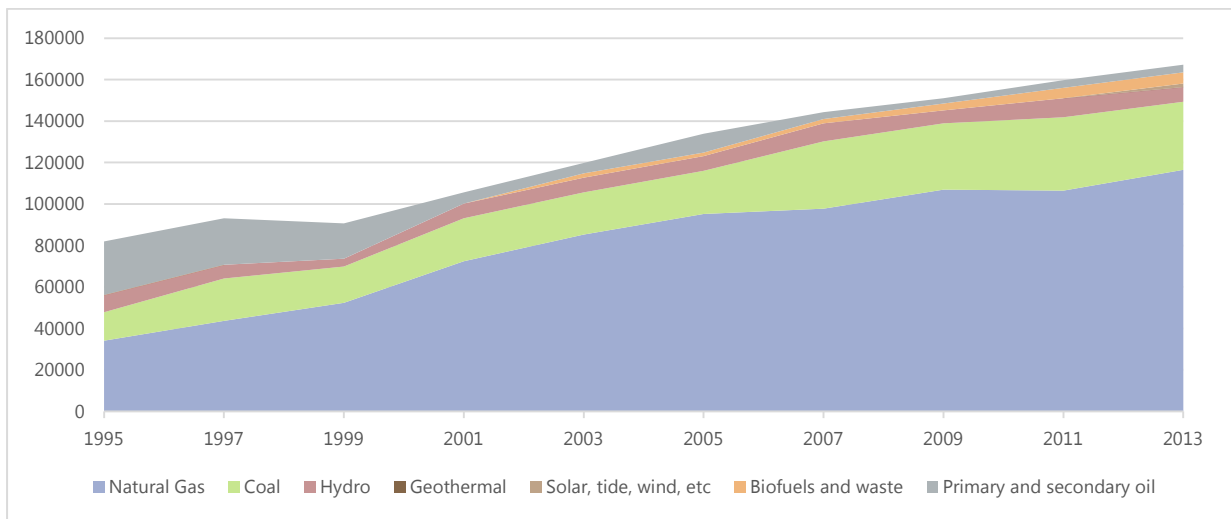


Figure 49. Historical electricity fuel mix in Thailand

From (IEA 2016b)

The recent power development plan, released by EGAT in 2015, anticipates further growth of the domestic electricity demand. The power development plan takes into account energy efficiency and alternative energy measures outlined in other policy directives. According to the document, electricity demand would grow 2.67% annually from year 2014 to 2036. In year 2036, the expected electricity demand would be 326 GWh or 80% more compared to 2014.

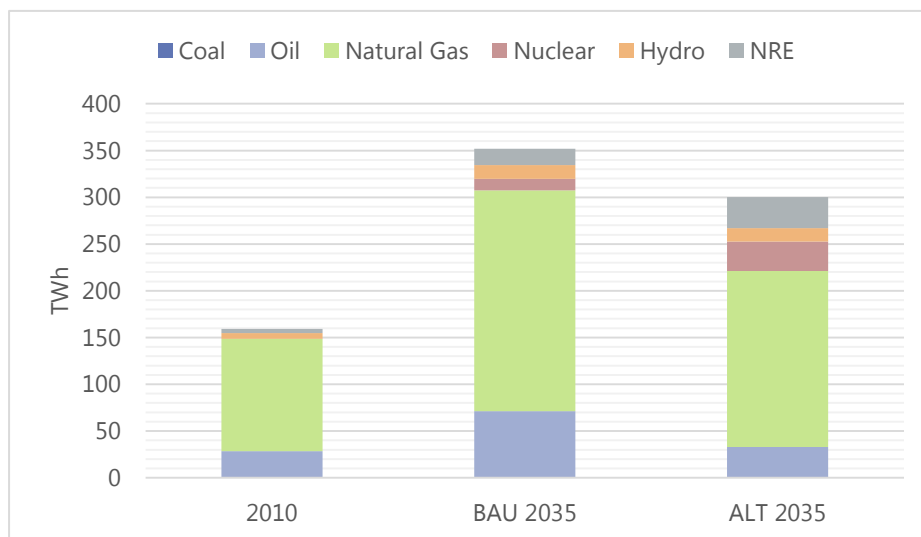


Figure 50. ADB's projections of the fuel mix in Thailand

From (ADB 2013c)

In response to depleting domestic oil and gas resources, Thailand is likely to diversify energy supply sources through imports, coal nuclear and renewable energy. Fuel diversification is also one of the main topics in the new power development plan. The document foresees an expansion of the domestic installed capacity from 34.7 GW to 70 GW, out of which main additions fall on renewables (21.5 GW) and natural gas (17.5 GW). Roughly 11 GW of capacity would be providing electricity imports from the neighbouring countries to Thailand (EPPO 2015).

Summarizing future developments of the Thailand's electricity sector, we conclude:

- **Role of natural gas will decrease but remain important**

Heavy reliance on natural gas for electricity generation and lack of domestic gas resources create potential threats for Thailand. The diversification of the fuel mix is one of the main goals outlined in the official policy documents. Even if the diversification attempts will be successful, the role of natural gas will still be high, as it is outlined in the official policy documents and projections by ADB. This could create a potential conflict of interest between subsidizing fuel electricity and growing gas import needs.

- **Main capacity additions will come from renewables including solar and biomass**

Thailand has already the leading role in development of renewable energy in the region. Although the largest renewable energy capacity is currently hydro, hydro resources in Thailand are almost fully maximised. The main capacity additions will come from solar power in biomass which are already growing rapidly. Thailand has both an abundant sunlight and the developed agricultural sector capable of providing fuels for biomass facilities.

- **Role of electricity imports will increase**

About 2.4 GW of power generation capacity supplying power to Thailand is located the neighbouring countries. Another 11 GW of mainly renewable (hydro) capacity would be added over the next 20 years. Electricity imports allow Thailand to substitute the share of natural gas imports with electricity.

Development and organization of electricity sector

Thailand has a single-buyer model with liberalised generation sector and monopolies in transmission and distribution. Electricity Generation Authority of Thailand (EGAT) owns and operates a significant portion of the generation fleet, the whole transmission network, and a portion of the distribution sector (see Figure 51).

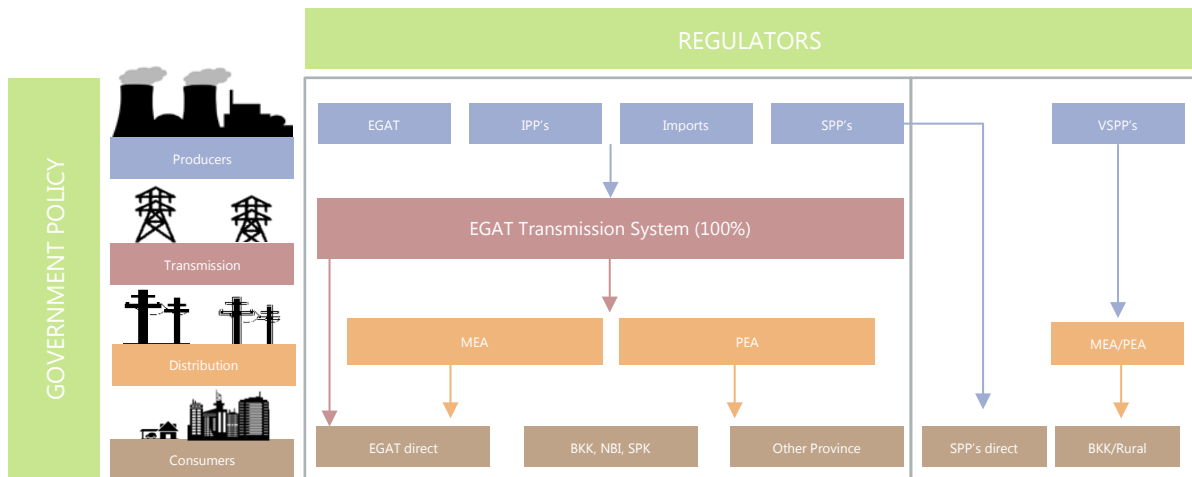


Figure 51: Organization of Thailand's electricity sector

Adapted from (EPPO 2015)

EGAT also purchases electricity from IPPs, small power producers (SPPs), and imports from other countries (which are generally structured as IPPs). Overall, EGAT owns approximately 45% of the generation fleet in Thailand, while independent power producers (IPPs) own approximately 38% (excluding imports). It should also be mentioned that EGAT holds shares in the country's two largest IPPs which are in charge of the 25% share in country-wide power supply (EPPO 2015).

In addition to owning and operating its own generation fleet and transmission network, EGAT is responsible for system operations, including dispatch of the generating fleet. In order to ensure that IPPs are dispatched equally with EGAT-owned generation, the activities of the market operator are ring-fenced from the rest of the company. At the same time, legislation does not provide an adequate mechanism for the market regulator to prevent the misuse of dispatch monopoly by EGAT.

The distribution sector is shared by EGAT and two other companies, Municipal Electricity Agency (MEA) and Provincial Electricity Agency (PEA). MEA is responsible for the distribution of electricity in the metropolitan areas of Bangkok, Nonthaburi, and Samut Prakarn provinces, which together account for two-thirds of Thailand's electricity demand. MEA is not involved in power generation and has to purchase power either from EGAT or directly from Very Small Power Producers (VSPPs). PEA is responsible for generation, procurement, distribution and sale of electricity on the provincial level, outside of the municipal zones (IAE 2016). PEA does not own or control any of the high-voltage lines within its service territory. Real-time co-ordination between EGAT, MEA and PEA is managed through various regional dispatch control centres, as well as a single national control centre. EGAT has also an almost exclusive right of supplying power to MEA and PEA.

While large customers may purchase power directly from EGAT, smaller commercial and residential consumers purchase power from MEA and PEA. SPPs can also choose to electricity directly to consumers. IPP rights have been awarded to both international and domestic developers. Foreign investors come mainly from Asia and include J-Power (Japan), SPC Power Corporation (the Philippines), China Light and Power (Hong Kong, China), Mitsubishi (Japan), Tokyo Electric Power (Japan), Marubeni (Japan) and GDF Suez (France).

VSPPs are mainly local companies sell electricity directly to MEA and PEA. A lot of VSPPs generate renewable energy and are considered as non-dispatchable which means that they and do not have to follow the dispatch schedule by EGAT. Instead, PEA and MEA provide data

on VSPP production to the Energy Regulatory Commission (ERC), which in turn passes that information on to EGAT.

The regulatory framework of the Thai electricity and gas sectors is formally defined by the Energy Industry Act. Energy development plans for single energy sub-sectors come under one set of documents, the Energy Master Plan. It includes the Power Development Plan, the Energy Efficiency Plan, the Alternative Energy Development Plan, the Gas Plan and the Oil Plan. Of these, the Power Development Plan, the Energy Efficiency Plan and the Alternative Energy Development Plan are also key components of Thailand's Intended Nationally Determined Contribution (INDC). As highlighted before, the strategic direction on power sector development and interconnection is contained in the Power Development Plan.

Policies for both electricity and gas sectors are developed in Thailand by the National Energy Policy Council (NEPC) with the Ministry of Energy (MoEN) as a key participant. The MoEN is responsible for overseeing the activities of EGAT and setting the proportion of the country-wide capacity owned by EGAT. Three departments and two offices within MoEN are responsible for actual policy design and energy development plans.

The regulator functions are assumed by Energy Regulatory Commission (ERC), established in 2008 under the Energy Industry Act of 2007. Although it operates separately from the MoEN and other government departments, ERC cannot be considered a fully independent regulatory authority because MoEN retains some key authorities over ERC (IEA 2016b). All electricity-related investment decisions must also be approved by the Ministry of Finance (MoF).

Singapore

Country profile

The Republic of Singapore is a former British colony which merged with the Federation of Malaya, for two years in early 1960s, before it was expelled and granted independence.

Singapore is a city state, located on one main island surrounded by many small islets. Land reclamations have increased the country's total land area from 581.5km² in the 1960s to 719.1km² in 2015.

Singapore has a developed albeit small economy. Its population of 5.6 million has one of the highest GDP per capita in the world. The economy initially grew as a refining hub for the Indonesian crude oil and a petrochemical trading hub. Complemented by the country's advantageous geographic position in the Strait of Malacca, it helped Singapore to become a hub for Middle East oil exports and goods going out and to Asia.

Singapore does not have any domestic energy resources except for some solar energy potential. Its entire electricity sector relies on natural gas imports. Traditionally, most of Singapore's supply of natural gas comes from pipelines that connect from Indonesia and Malaysia. However, with the opening of an LNG terminal in 2013, a share of the Singapore's imports is now in form of LNG. The uptake of the LNG sector has been stimulated by imposed controls on pipe gas imports for all new generation capacity. This policy is due to a revision in 2018 (EMA 2016).

Electricity sector tariffs

Singapore has bands of electricity tariffs for different consumer types. In general, these tariffs are cost-reflective and depend on the price of natural gas imports. Contestable consumers (industry and commercial) can either buy electricity from the power exchange which is liberalized in Singapore, or through a retailer whose rates will be reflective of market prices. Non-contestable consumers (residential) pay a fixed tariff which is adjusted every quarter based on the average forward fuel oil price over the past three months (EMA 2016). Electricity price for non-contestable consumers was around US\$ 15 per KWh.

Singapore does not have energy subsidies, however it provides vouchers for population groups with low income, which can be used to offset utility bills. Compared to subsidizing the cost of electricity directly, this approach presents all consumers with the true cost of electricity,

incentivising them to save and be efficient. It also does not compromise the cost-reflective pricing of electricity by the generation companies. The electricity access rate is universal.

Electricity sector outlook

Singapore's total electricity consumption rose by 2.4% to 48 TWh in 2015. This was largely driven by industrial-related consumption which comprised 42% of total electricity consumption in 2015. This was followed by the commerce & services-related sector and households which constituted 37% and 15% of the remaining consumption (EMA 2016). Future electricity demand projections are not published in the official statistics, however it is unlikely that demand will grow much in the next five years.

Singapore's total installed capacity was about 13 GW in 2015 (EMA 2016). This is almost double of the recorded peak electricity demand which is 6.8 GW and well above the indicative reserve margin of 30%. This capacity almost entirely consists of natural gas combined-cycle turbines. Figure 63 show that the share of natural gas in the total fuel mix is 95%. Waste combustion petroleum products, mainly in the form of diesel and fuel oil, and a coal-biomass project contribute remaining 4%. The total installed capacity of solar was 46 MW in 2015. Singapore does not provide feed-in-tariff or equivalent schemes for solar.

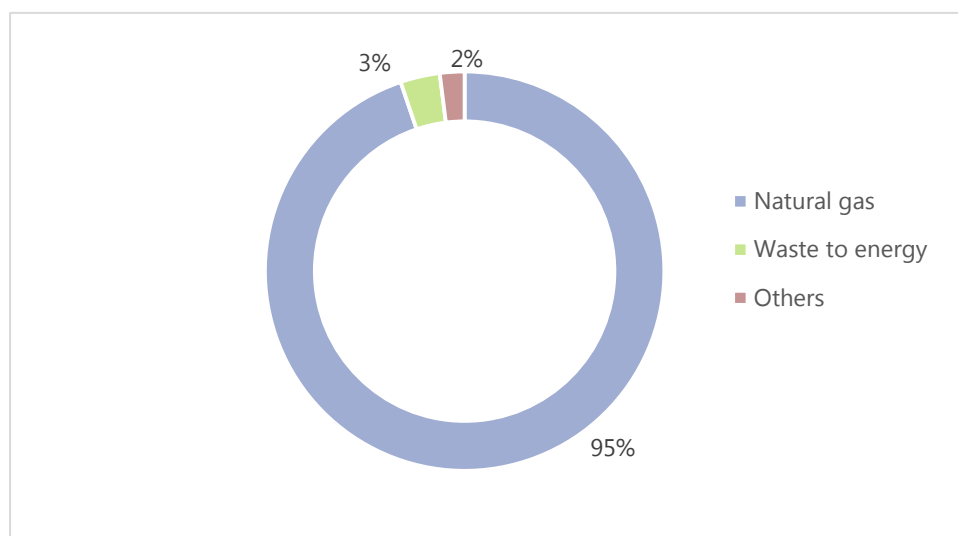


Figure 52. Electricity fuel mix in Singapore

In comparison to most ASEAN states except for Philippines, Singapore has a liberalized power sector with separated generation and transmission sectors. The generation sector is an oligopoly of private sector companies with three large players occupying 75% of the market (EMA 2016). The transmission sector is owned by the government through SP Power Grid which manages and operates transmission and distribution network. Since the transmission system is a natural monopoly, SP Power Assets is subject to price regulation.

In order to avoid any conflict of interest, the operations of the high voltage network are delegated to the Energy Market Authority (EMA) while SP Power Assets will simply to own, operate and maintain the complete transmission system.

Summarizing the initiatives outlined, we present three major factors for future development of the electricity sector in Singapore:

- **The role of natural gas will stay dominant**

Due to Singapore's position as LNG hub and the large domestic gas-fired capacity base which has been developed recently, natural gas will remain as the main component of Singapore's fuel mix for at least another decade. Given the lack of other viable options, gas will maintain its dominant position

- **Renewables will continue to be a small market player**

Given the country's large energy consumption relative to its tiny land area, solar and other renewables will be limited to mitigating and reducing peak loads rather than providing stable baseload power for residential, commercial, and industrial uses.

- **Energy security plays a crucial role for Singapore**

The over-reliance on natural gas, even from a diversity of sources, makes the issue of energy security an important topic for Singapore. The country has little strategic reserves to deal with interruptions in gas supply. Electricity imports can potentially

can help address this problem, especially if they come at the cheaper price. However, in this case Singapore has conflicting interests of the domestic power industry.

Development and organization of electricity sector

The electricity sector in Singapore is regulated by the Energy Market Authority, a statutory board under the Ministry of Trade and Industry (MTI) which is also regulating the natural gas markets. In the electricity sector, EMA is responsible approving technical and market standards,

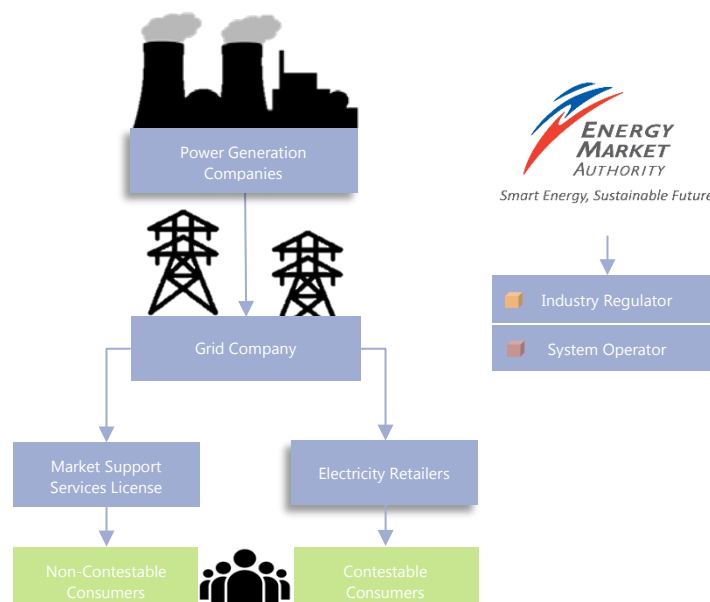


Figure 53: Singapore's electricity industry

Adapted from (EMA 2016)

issuing market licenses and protecting consumers' interests. The energy policy is set by the Energy Division of MTI with the aim of supporting economic growth, addressing energy security, economic competitiveness, and the environmental sustainability (EMA 2016).

Singapore's electricity market

The National Electricity Market of Singapore (NEMS) is a power exchange similar to other competitive electricity markets described in this report. The associated financial market is run

by the Singapore Exchange (SGX). The market has been progressively liberalized starting from late 1990s and today and OTC (vesting contracts) and power exchange sections.

The power exchange uses a form of auction pricing to settle transactions in the market. Every half-hour the spot market determines:

- The dispatch quantity that each generation facility is to produce;
- The reserve and regulation capacity required to be maintained by each facility; and
- The corresponding wholesale spot market prices for energy, reserve and regulation.

These quantities and prices are based on price-quantity offers made by generators and load forecasts prepared by the market operator EMC. The market is cleared for a system of nodes across the island which provide a better resolution for congestion management compared to zonal pricing, although the price differential between different nodes is very small in Singapore.

Full liberalization of the energy market is expected in 2018. Currently, only commercial and industrial customers with monthly consumption of more than 2 MWh are considered contestable. This limit was lowered from 4 MWh in July 2015. Once full liberalization is in place, residential consumers will be free to select and purchase power directly from the generators through packages in the same way each household has a cable, telephone, or internet package (EMC 2016).

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