FUTURE GRID EXPANSION PLANNING TOWARDS COST EFFECTIVE AND SUSTAINABLE ASEAN POWER GRID DEVELOPMENT

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ABSTRACT

The efficient utilization of clean energy resources to meet increasing electricity demand is imposing the integration of the electricity market and the construction of secure transmission mechanisms around the globe. Accordingly, the Association of Southeast Asian Nations (ASEAN) is integrating its large geographical power transmission infrastructure via the ASEAN power grid (APG). Transmission expansion planning (TEP) is a complex and multidimensional because of a high number of uncertainties and influencing parameters. Therefore, it is very difficult to get a unique optimal transmission grid plan which maximizes the benefit and minimize the investment risks by satisfying all the technical, economic, social, and environmental constraints. During TEP process, assessing various scenarios like electricity generation capacity from renewable sources and fossil fuels, electricity demand, market prices, technological, social and environmental aspects are important to identify the uncertainties and minimize the risks. This study provides the building blocks of a TEP optimization methodology towards efficient APG development. Therefore, this study develops an optimal power flow, a minimum-cost power generation model, in MATLAB/MATPOWER simulation platform for simulating ASEAN energy market to evaluate the optimal development of APG infrastructure for 2030 generation and demand scenarios. Publicly available data are taken for the evolution of optimal cross-border power flows through the interconnections. An annual cost is used as the output matrix for to evaluate the feasibility of high voltage AC (HVAC) and high voltage DC (HVDC) transmission option for the cross-border interconnections links. Finally, a net market benefit framework to evaluate the benefit of APG establishment is developed by considering emission benefit of renewable generation. Developed net market benefit model also consider consumers, producers and transmission owner benefit. Results demonstrate that APG can enhance power generation from countries with abundant renewable resources to meet the growing demand at load centers in the ASEAN member nations. Moreover, transmission technology analysis results reveal that in some interconnections, implementing HVDC link instead of currently planned HVAC could be economically beneficial for the APG. Furthermore, benefit-cost evaluation reveals that APG transmission infrastructure with optimal cross-border transmission capacity is beneficial than APG with cross-border transmission capacity mentioned by ASEAN Center for Energy (ACE). Additionally, HVDC transmission options need overall less Yearly Required Revenue (YRR) than HVAC during APG establishment. Finally, the findings in this research would serve as valuable references for the power utilities and APG planners.

Keywords: ASEAN Power Grid, Cross-border power transmission, HVAC and HVDC, Net Market benefit, Power system economics.

[PERANCANGAN MASA HADAPAN PENGEMBANGAN GRID KE ARAH PEMBANGUNAN GRID KUASA ASEAN YANG CEKAP DAN MAMPAN]

ABSTRAK

Penggunaan sumber tenaga bersih dengan cekap adalah bertujuan untuk memenuhi permintaan elektrik yang semakin meningkat, sekaligus memaksimumkan integrasi pasaran elektrik dan pembinaan mekanisme penghantaran dengan selamat di seluruh dunia. Sehubungan itu, Persatuan Bangsa-bangsa Bersatu Asia Tenggara (ASEAN) mengintegrasikan infrastruktur penghantaran kuasa meliputi geografi yang besar melalui grid kuasa ASEAN (APG). Perancangan pengembangan transmisi (TEP) bersifat kompleks dan pelbagai dimensi kerana bilangan ketidakpastian yang tinggi serta pengaruh parameter. Oleh itu, adalah amat sukar untuk mendapatkan pelan grid transmisi optimum yang unik serta memaksimumkan manfaat dan meminimumkan risiko pelaburan dengan memuaskan semua kekurangan teknikal, ekonomi, sosial dan alam sekitar. Semasa proses TEP, penilaian pelbagai senario seperti kapasiti penjanaan elektrik dari sumber boleh diperbaharui dan bahan api fosil, permintaan elektrik, harga pasaran, aspek teknologi, sosial dan alam sekitar adalah penting untuk mengenal pasti ketidakpastian dan mengurangkan risiko. Kajian ini menyediakan pembangunan blok metodologi optimum TEP ke arah pembangunan APG yang cekap. Oleh itu, penyelidikan merangkumi pembangunan sistem pengawasan untuk menganggarkan dan meramalkan prestasi yang tepat. MATLAB/MATPOWER digunakan untuk mensimulasikan pasaran tenaga ASEAN untuk menilai pembangunan infrastruktur APG yang optimum untuk generasi 2030 dan scenario permintaan. Data yang tersedia secara umum diambil untuk evolusi aliran kuasa merentas sempadan optimum melalui rangkaian penyambungan. Kos tahunan digunakan sebagai matriks output untuk menilai kemungkinan keluaran AC voltan tinggi (HVAC) dan voltan tinggi DC (HVDC) untuk rangkaian hubungan rentas sempadan. Akhir sekali, rangka kerja faedah bersih pasaran untuk menilai manfaat penubuhan APG yang dibangunkan dengan mempertimbangkan manfaat pelepasan

generasi yang boleh diperbaharui. Model faedah pasaran bersih yang dibangunkan juga mengambil kira manfaat pengguna, pengeluar dan penghantaran. Keputusan menunjukkan bahawa APG dapat meningkatkan penjanaan kuasa dari negara-negara dengan sumber yang boleh diperbaharui yang banyak untuk memenuhi permintaan yang semakin meningkat di pusat beban di negara anggota ASEAN. Selain itu, hasil analisis teknologi penghantaran menunjukkan bahawa dalam beberapa perhubungan, pelaksanaan rangkaian HVDC dan bukannya HVAC yang digunakan kini dapat memberi manfaat ekonomi kepada APG. Di samping itu, penilaian kos manfaat mendedahkan bahawa infrastruktur penghantaran APG dengan kapasiti penghantaran merentas sempadan yang optimum adalah berfaedah daripada APG dengan kapasiti penghantaran rentas sempadan yang disebut oleh Pusat Asean (ACE) ASEAN. Di samping itu, pemilihan penghantaran keperluan HVDC secara keseluruhan adalah kurang daripada Pendapatan Tahunan yang Diperlukan (ARR) daripada HVAC semasa penubuhan APG. Akhirnya, penemuan dalam kajian ini akan digunakan sebagai rujukan bernilai bagi utiliti kuasa dan perancang APG.

Kata Kunci: Grid Kuasa ASEAN; Penghantaran kuasa merentas sempadan; HVAC dan HVDC; Keuntungan Bersih Pasaran, Ekonomi sistem kuasa.

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AC	:	Alternating current
ACSR	:	Aluminium conductor steel-reinforced cable
ASEAN	:	Association of Southeast Asian Nations
APG	:	ASEAN Power Grid
ACE	:	ASEAN Center for Energy
ARR	:	Annual Required Revenue
BBl	:	Billion barrels
CAISO	:	California Independent System Operator
CF	:	Capacity factor
CRF	:	Capital recovery factor
DC	:	Direct current
DC OPF	:	Direct current optimal power flow
EC-JRC	:	European Commission Joint Research Centre
ENTSO-E	:	European network of transmission system operators for electricity
FiTs	:	Feed-in tariffs
GDP	:	Gross domestic product
Gt	:	Gigatonnes
GW	:	Gigawatt
HAPUA	:	Heads of ASEAN Power Utilities / Authorities
HVAC	:	High-voltage alternating current
HVDC	:	High-voltage direct current
kWh	:	Kilowatt-hour
LMP	:	Locational marginal price
LNG	:	Liquefied natural gas

MMT	:	Million tons
Mt	:	Million tonnes
Mtoe	:	Million ton of oil equivalent
MW	:	Megawatt
M$	:	Million United States Dollars
NEM	:	Net Energy Metering
NTC	:	Net transfer capacity
OPF	:	Optimal power flow
O&M	:	Operation and Maintenance costs
PV	:	Photovoltaic
PVGIS	:	Photovoltaic Geographic Information System
RES	:	Renewable energy source
STATCOM	:	Static Synchronous Compensator
TCF	:	Trillion cubic feet
TEP	:	Transmission expansion planning
TEAM	:	Transmission Economic Assessment Methodology
TSO	:	Transmission system operator
TWh	:	Terawatt-hour
VSC	:	Voltage source converter
VRES	:	Variable renewable energy sources
XLPE	:	Cross-linked polyethylene insulation
YRR	:	Yearly required revenue

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CHAPTER 1: INTRODUCTION

1.1 Background and motivation

Association of Southeast Asian Nations (ASEAN) consists of 10-member countries which include Thailand, Vietnam, Laos, Indonesia, Philippines, Myanmar, Brunei, Malaysia, Singapore, and Cambodia. ASEAN comprises the world's third fastest-growing economy (IEA, 2015a). The projected incremental rate of ASEAN countries gross domestic product (GDP) would be 4.6% until 2040 and could contribute to global GDP increment from 5.9% to 7.7% within this period (IEA, 2013, 2015e). Due to the fast economic growth of the ASEAN region, the energy demand increases significantly compared to other regions of Asia. It has been reported that the primary energy consumption of the ASEAN region would increase from 556.28 (Million ton of oil equivalent) Mtoe to 1,414 Mtoe from 2012 to 2030 (ACE, 2015a; EIA, 2015d). From the primary energy consumption, electricity demand has the highest growth rate at 6.4% per annum (ACE, 2015a; Purwanto et al., 2015; Vithayasrichareon, MacGill, & Nakawiro, 2012). Meeting this growth rate in a techno-economic and sustainable way is challenging for the ASEAN nations (Chang & Li, 2015; IEA, 2015a). Also, electricity access in this region varies greatly from country-to-country. For example, Brunei Darussalam, Malaysia, Thailand, and Singapore are capable of providing adequate electricity to their respective nations, meanwhile, 50% population in Myanmar and Cambodia have access to electricity (IEA, 2013). ASEAN countries have an abundance of renewable resources throughout its geographical region. However, the distribution is far from uniform; regions such as Cambodia, Myanmar, and Lao PDR are rife with hydropower resources, whereas Indonesia and the Philippines possess many geothermal sources. This geographical distribution of renewable energy sources (RESs) limits its eventual utilization (Chang & Li, 2015; Taggart, James, Dong, & Russell, 2012). Also, the utilization of these renewables energy in generating electricity is not appreciable, due to high capital investment costs and the lack of financial means, as well as inadequate knowledge transfer (Das & Ahlgren, 2010; Panwar, Kaushik, & Kothari, 2011). Furthermore, unbalanced economic development prevents the development of renewable energy based generation (Atchatavivan, 2006). Therefore, most of the electricity in this region is generated from fossil fuels, which in turns increase the CO_2 emissions of the region (IEA, 2009a, 2009b). Geographically distributed renewable power generation can be promoted by integrating the ASEAN energy market to expedite cross-border trade and free movement of green electricity within the ASEAN region. Cross-border trade in integrated energy market enhances the electricity trade from countries with abundant RESs to countries with less renewable sources, and the developed countries will encourage investments in the renewable sources to developing or least developed countries, which will, in turn, enhance knowledge and technology transfer between these countries (Lim & Lee, 2011).

To meet the growing demand for electricity, the ASEAN power grid (APG) is being implemented among ASEAN countries via ASEAN Heads of States/Governments, under the ASEAN Vision 2020 (ACE, 2015b; Ibrahim, 2014). The primary aim of APG is to ensure regional energy security by promoting the effective utilization and sharing of resources for the common regional benefit. It also aims to enhance cross-border electricity trade by interconnecting the national power grid with reliable, efficient, and economic operations; sharing of surplus generated electricity for improving system security via the reduction of system cost amongst member countries. APG will contribute to the creation of the provision for future energy trade and mutually exploit the abundant energy resources within ASEAN and reduce the dependency on fuel imports from other regions (Ibrahim, 2014). Also, introducing carbon pricing after the establishment of cross-border trade facility through APG may eventually shift the dependency of base load power from coal, natural gas, and hydro, to renewables (Taggart et al., 2012).

It is important to perform a comprehensive analysis of the technical, economic, and environmental issues related to the integration of remotely located renewable generation into APG from the transmission expansion planning paradigm perspective. Moreover, pointing out the major barriers and limitations for the establishment of APG is also important for enhancing the establishment of APG in the Southeast Asian region. This study aims to present the issues towards the development of a transmission structure to exchange clean and sustainable energy in the ASEAN region, and the future research direction to enhance APG development by overcoming barriers and limitations.

1.1.1 Decarbonization of the power sector

At present, ASEAN countries are generating power by prioritizing the affordability and availability of fuel types rather than their environmental sustainability. As a result, conventional energy sources, mainly oil, coal, and gas, are the dominant fuel mix, which contributed 82% of electricity generation in 2013 (IEA, 2015d). Therefore, the dependency of fossil fuels in generating electricity making it the largest contributor to CO_2 emissions in the region (IEA, 2009a, 2009b). The amount of CO2 emission for primary energy consumption would increase from 1.354 gigatonnes (Gt) to 1.962Gt from 2015 to 2030, due to fossil fuel dependency in meeting the primary energy demand as opposed to carbon-free sources, such as renewable energies (Azam, Khan, Bakhtyar, & Emirullah, 2015; IEA, 2013, 2015b, 2015e).

ASEAN region is very vulnerable to climate change and for this ASEAN member states have announced voluntary CO_2 emissions reduction targets (ASEAN Cooperation on Environment, 2017; IEA, 2013). To achieve a low carbon economy, electricity has to play an important role. It is possible to reduce CO_2 emissions from the electricity sector by integrating more generation from renewable energy resources (RESs) because 1 MWh of RE electricity generation could avoid 0.63 tonnes of CO_2 (IEA, 2010). The RESs of this region can be utilized for electricity generation which could save CO_2 and outdoor air pollution from the power sector of ASEAN equivalent to 5 Billion USD/year (IRENA, 2016). However, utilizing the geographical distributed RESs will require substantial investment in every segment of the power sector, starting from power generation to transmission and distribution as well as consumption.

Recently, individual ASEAN countries are promoting electricity generation from renewables via the implementation of different policies such as feed-in tariffs (FiTs), Net Energy Metering (NEM), and tax exemptions (Ismail, Ramirez-Iniguez, Asif, Munk, & Muhammad-Sukki, 2015; SEDA, 2016; Solangi, Islam, Saidur, Rahim, & Fayaz, 2011). Which in turns increasing electricity generation capacity from RESs throughout the ASEAN jurisdiction. The ASEAN Center for Energy (ACE) and International Renewable Energy Agency (IRENA) expects that renewable energy share in power generation will reach 39% in 2030 (IRENA, 2016). Together with hydropower, geothermal, and biomass, solar PV and onshore wind energy are the two main RESs. The primary challenge arising from the expected large penetration of RESs is the variability and unpredictability of variable RESs, mainly wind speed and solar radiation. It will be very challenging to maintain the stability of the grid while a high share of variable renewable power in a power system. Thus, increasing penetration of energy from RESs create demand for building stronger power transmission grid to transfer and deliver low-cost electricity it requires the power system to be flexible, which, can be done by integrating regional power market through APG.

1.1.2 Challenges from renewable energy integration

Power system network faces several challenges from RES integration. Structural characteristics of the power system network must experience fundamental changes due to accommodate RES in the power system network. The traditional power system structure is changing by introducing RES electricity generators at a lower voltage level and widely distributed locations. Electricity consumers may become electricity producers' due to this change depending upon the RES generators output at a given moment of time. On the other hand, integration of a large number of RES generators affects the generation adequacy. Conventional generators are characterized by specific availability factors which may depend on several aspects, such as maintenance time, overhaul, reserves and potential unplanned interruptions. However, for RES generators availability factor is unpredictable due to its intermittent nature.

The liberalization of the cross-border electricity markets and high penetration of RESs introduce new challenges to transmission system operators. This is happening mainly due to complexity in technical, regulatory, social or legal frameworks increment in the power systems. Moreover, the unpredictable nature of RESs makes them hard to integrate into traditional power system which is mostly built with predictable loads. This unpredictable nature cannot be ignored for the power system with a high penetration of RESs because this in turns leads to a mismatch between regional demand and generation of electricity. Therefore, detail system planning along with accurate resource and demand forecasting across ASEAN is very much necessary for the electricity network of ASEAN countries.

1.1.3 The demand for transmission network capacity

Transmission of electrical power is an enabling technology that can be used to minimize the challenges from the RES to electricity supply of ASEAN. Several studies show that electrical transmission development including cross-border interconnections of individual isolated ASEAN electricity network is necessary to enhance RES integration for decarbonization of the ASEAN power sector; to manage the variability of RES generations; and to enable free movement of green electricity within the ASEAN region (Das & Ahlgren, 2010; Huber, Roger, & Hamacher, 2015; IRENA, 2016; Sambodo, 2013). ASEAN power market integration through cross-border transmission does not only increase the RES integration but also to transfer power from low-cost generating stations to high demand load centers throughout ASEAN (Chang & Li, 2015; Ibrahim, 2014). However, cross-border transmission network capacities are very much important to utilize the advantages of ASEAN energy market integration using APG establishment. Lack of sufficient transmission capacities could limit the power transfer from countries with abundant RES as well as low-cost generation to countries with high demand load centers. Therefore, detail evaluation of cross-border transmission needs is very much necessary during APG establishment.

1.1.4 Transmission network technology and investment optimization

Increasing penetration of energy from RES and power system interconnection creates demand for building stronger power transmission grid. This power transmission can be done through either high-voltage alternating current (HVAC) or high-voltage direct current (HVDC) transmission technology (Bresesti, Kling, Hendriks, & Vailati, 2007; Wu, Lee, & Shu, 2011). Selecting the transmission technology (i.e., HVAC and HVDC) is the most critical because a huge investment is associated with commissioning the long-distance regional transmission line. More advanced and robust planning of transmission grids is necessary for the justification of the investments and the efficient grid design during practical implementation (Ergun, Van Hertem, & Belmans, 2012; Torbaghan, Gibescu, Rawn, & Van Der Meijden, 2015).

HVDC transmission technology is becoming more attractive over AC technology because of the bulk power transferring capability from both onshore and offshore locations (ADB, 2014; Bahrman & Johnson, 2007). Nonetheless, HVDC has some advantages such as cost-effectiveness, reduced size and weight, low power loss due to the use of two cables, reactive power management, and harmonics. However, HVDC transmission options are commonly preferred for transmission systems above a certain distance. Nevertheless, the evaluation of the detailed cost and benefit when choosing transmission options is necessary because the distance is not only the factor in selecting transmission options (Van Eeckhout, Van Hertem, Reza, Srivastava, & Belmans, 2010; Wang, Tang, & He, 2008).

Consequently, huge investment is required for interconnecting the long distance regional transmission line which is also the constraints for realistic development. These investment costs should have been justified through the expected benefit in ASEAN electricity market environment. Detail investigation of the net market benefit of the development of large transmission grid is necessary (CAISO, 2004; Ergun et al., 2012; Torbaghan et al., 2015). As a result, more advanced and robust planning of the APG is necessary for the justification of the investments and efficient grid design during practical implementation.

In the coming decades, ASEAN electricity networks will be facing several challenges. Economic risks (investment; transmission topology and technology to meet rising electricity demand) are very much critical among the challenges. Therefore, detail evaluation of cross-border transmission technology options along with a cost-benefit evaluation for the point-to-point transmission interconnections toward the development of APG for the 2030 generation and demand scenarios is important.

1.2 Problem statement

The planning and implementation of the individual ASEAN power system combining RESs and the transmission infrastructure to interconnect them require major engineering and computing effort. Implementation of ASEAN power grid would be step by step. The time horizon to implement APG can reach several years. Such long-time horizons make infrastructure projects subject to a large number of uncertainties. Therefore, it is important to analyze a various number of scenarios in order to minimize the risks. These scenarios include, estimating optimal cross-border transmission links capacity to transmit electrical power from the geographically distributed energy sources to meet the demand; selecting optimal transmission technology of the cross-border transmission links; cost-benefit analysis to optimize and justify the transmission investment for the ASEAN by considering the environmental impact.

To investigate optimal cross-border electricity transmission links capacity, technology, and investment, it is important first to understand and explore if and why there is a need for such capacity, technology, and investment optimization in ASEAN. For this, modeling the ASEAN interconnected power system is necessary to analyze the impacts of cross-border transmission capacity expansion. These impacts should be investigated by using optimization techniques which aims to minimize variable generation cost and increase the total social welfare as well as minimize the investment risks. Moreover, the cost-benefit study is also important to justify the investment and minimize the risks. In order to evaluate the economic study in the form of cost-benefit of ASEAN power market integration, a net market benefit framework modeling is necessary. The net market benefit of APG integration should be investigated by considering the environmental impacts of power generation (CO_2 emissions).

1.3 Objectives

This study aims to present the building blocks of a methodology towards the optimal development of ASEAN power grid transmission infrastructure to exchange clean and sustainable energy in the ASEAN region. Independent system planners and transmission system operators can analyze different future scenarios of ASEAN power sectors by utilizing the optimal ASEAN transmission grid architecture. These scenarios include generation, demand, cross-border transmission needs, transmission system topology and technology, equipment prices and net market benefit under different assumptions. The following objectives will achieve the aim of this study:

i. To identify the key challenges of developing large geographical APG through interconnecting individual isolated ASEAN power markets.

ii. To design an optimal power flow based APG model, a minimum cost ASEAN power generation model to evaluate the development of APG for the 2030 generation and demand scenarios.

iii. To investigate optimal cross-border transmission links capacity and technology (HVAC or HVDC) for 2030 scenario.

iv. To evaluate the cost-benefit of establishing APG by developing a net market benefit framework with the inclusion of emission pricing.

1.4 Assumption and limitations

This study considers some realistic assumptions in different Chapters with proper justifications and references. Some of them are given next:

- The individual power transmission networks of APG are considered as a single node; the internal network constraints are not considered due to lack of publicly available data (e.g., transmission line capacity, electricity consumption, and generation time series)
- Steady state operating conditions are considered only in this study. Also, this study considers that the geographically distributed power systems are dynamically secure
- This study considers that conventional generators have to pay penalty for CO_2 emission during modeling of net market benefit framework for ASEAN as ASEAN member states have announced voluntary CO_2 emissions reduction targets (ASEAN Cooperation on Environment, 2017; IEA, 2013). Carbon pricing is taken from (Chang & Li, 2015). However, the change in government

decision and political situation of respective countries may change the decision and emission pricing scheme.

1.5 Organization of the thesis

The thesis is organized as follows:

Chapter 2 presents the comprehensive literature review related to the development of a transmission structure to exchange clean and sustainable energy in the ASEAN region. The chapter provides the status of energy resources (ie., fossil fuels and renewables), current utilization, and future projection of energy resources, electricity export import scenarios. The chapter also provides the literature study to assess the transmission expansion planning practices in ASEAN countries for promoting renewable generation. Additionally, the major barriers and the technical challenges for establishing ASEAN grid have been analyzed briefly.

Chapter 3 provides the detail model description of ASEAN Power Grid, including its mathematical formulation. An optimal power flow, a minimum-cost power generation model of APG, is developed in the MATLAB/MATPOWER simulation platform which has been used to conduct various studies presented in Chapter 4 and 5. In addition, Chapter 3 provides an overview of the common scenario data used in the studies in Chapter 4 and 5.

Chapter 4 shows the energy market simulation to evaluate the maximum requirements of cross-border transmission needs in ASEAN by 2030. The chapter also shows the economic details of calculating investment costs and operation and maintenance costs related to HVDC and HVAC transmission options. The chapter also analyzes the results to evaluate the best possible transmission technology for the transmission links. In addition, the Chapter also presents the sensitivity analysis of choosing transmission technology by varying the transmission link distances.

Chapter 5 presents an economic study in the form of cost-benefit analysis of APG integration. The chapter presents the net market benefit framework by considering consumer, producer, transmission owner and environmental benefit for APG interconnection. The Chapter also presents the comparison of the benefit of APG interconnection for two different scenarios of cross-border transmission limit.

Chapter 6 consists of the concluding remarks and future work.

CHAPTER 2: LITERATURE REVIEW

2.1 Introduction

This Chapter aims to present the issues towards the development of a transmission structure to exchange clean and sustainable energy in the ASEAN region. Therefore, this study extensively reviews the energy resources (i.e. fossil fuels and renewables), current utilization, and future projection of energy resources for ASEAN development. Electricity export import scenarios and renewable generation based transmission expansion planning practices in ASEAN countries are also critically reviewed in this chapter. Additionally, the major barriers and the technical challenges for establishing ASEAN grid have been analyzed briefly.

The Chapter is organized as follows: Large-scale renewable power generation potential, including energy status, primary energy demand as well as electricity demand, generation and import and export scenarios of the ASEAN countries are briefly described in Section 2.2. Section 2.2 also contains present renewable electricity generation potentials and future targets taken by the ASEAN countries followed by transmission expansion planning practices by the ASEAN countries for renewable power generation in Section 2.3. The present research and development status of ASEAN power grid is presented in Section 2.4, and major barriers and technical challenges of establishing ASEAN grid are discussed in Section 2.5. At last, Section 2.6 includes the summary drawn from all the above-discussed section.

2.2 Large-Scale Renewable Power Generation Potential

2.2.1 Energy status of ASEAN countries

Energy resources, including fossil fuels and renewables, are abundant throughout the geographical region of ASEAN. The summary of energy resources of ASEAN countries is shown in Table 2.1 (ADB, 2012, 2015b; Aroonrat & Wongwises, 2015; Bakhtyar, Sopian, Sulaiman, & Ahmad, 2013; Chimklai, March 14, 2013; EIA, 2015c; HAPUA, 2013a; Hasan, Mahlia, & Nur, 2012; Lidula, Mithulananthan, Ongsakul, Widjaya, & Henson, 2007; Olz & Beerepoot, 2010; Prasertsan & Sajjakulnukit, 2006; Sarraf, Rismanchi, Saidur, Ping, & Rahim, 2013; Sawangphol & Pharino, 2011; Sovacool & Bulan, 2012). Reported oil reserves in the ASEAN region is 27.96 billion barrels (BBl). Indonesia is the largest oil producer, corresponding to its possession of the largest oil reserve in the region. Brunei has the second largest oil reserve, followed by Vietnam, Malaysia, and Myanmar. However, Brunei and Malaysia are the only net oil exporter in the region (IEA, 2013). Natural gas reserves of 350.29 trillion cubic feet (TCF) are reported for ASEAN region, where Indonesia, Malaysia, and Brunei stand in the top three of natural gas reserves. Thailand and Singapore are the net liquefied natural gas (LNG) importer in this region, while Brunei, Malaysia, and Indonesia are net exporters of LNG.

Coal is the most abundant fossil fuel in the region, with 80 years of reserve to production ratio, with its highest amount being 45,710.5 million tons (MMT). Indonesia, Thailand, Malaysia, and Vietnam have the highest amount of coal reserves, respectively. Indonesia is the world largest steam coal exporters, while Vietnam is the second largest coal producer in ASEAN, whereas Thailand, Malaysia, and the Philippines are importers of steam coal (IEA, 2013). The ASEAN region has an abundance of hydropower resources, including large, mini, micro, and pico hydropower plants, totaling to about 344GW. Mini, micro, and pico hydropower stations can be crucial to the rural electrification of ASEAN, as 134 million people lack access to electricity (IEA, 2013). Myanmar, Indonesia, Vietnam, Malaysia, and Lao PDR have massive potentials for hydropower, and it was found that countries in the Mekong basin i.e., Cambodia, Lao PDR, and Myanmar have hydropower resources that could exceed the respective countries demand (Matsuo et al., 2015). Moreover, the Philippines and Thailand possess great resources for hydropower generation, and this sector is being actively developed by its government (Bakhtyar et al., 2013; Ministry of Energy, 2015).

Table 2.1: Energy Resources in ASEAN countries

Country	Oil (BBl)	Gas (TCF)	Coal (MMT)	Hydro (MW)	Biomass (MW)	Geothermal (MW)	Solar (MW)	Onshore Wind (MW)	Offshore Wind (2030) (TWh)
Brunei	6.0	34.8	-	-	-	-	10	-	-
Cambodia	-	9.89	-	15,000	1,712	-	875	1,300	-
Indonesia	10	169.5	38,000	75,625	49,810	29,000	551	9,300	21.34
Lao PDR	-	3.60	600	26,500	730	-	33	24,000	-
Malaysia	3.42	84.4	1,024.5	29,500	29,000	-	1412	2,599	13.39
Myanmar	3.1	12.1	-	108,000	6,849	-	12,967	1600	-
Philippines	0.285	4.6	346	13,107	20	2,047	350	7,400 - 76,000	6.96
Singapore	-	-	-	-	-	-	-	-	0.22
Thailand	0.156	12.2	1,240	16,655	22,831	-	3,000	190,000	19.42
Vietnam	5	19.2	4,500	68,500	9,688	-	3,111	642,000	15
Total	27.961	350.29	45,710.5	352,887	120,640	21,705	22,309	946,799	76.33
- = Data not available / No resource									

Sources: (ADB, 2012, 2015b; Aroonrat & Wongwises, 2015; Bakhtyar et al., 2013; Chimklai, March 14, 2013; EIA, 2015c; HAPUA, 2013a; Hasan et al., 2012; Lidula et al., 2007; Olz & Beerepoot, 2010; Prasertsan & Sajjakulnukit, 2006; Sarraf et al., 2013; Sawangphol & Pharino, 2011; Sovacool & Bulan, 2012)

ASEAN region has a great potential for non-hydro based renewable generation. A Significant supply of biomass energy is available in ASEAN, from agricultural residues of rice husks, rice straw, corn cobs, sugarcane trash, cassava stalks, bagasse, as well as coconut and palm oil. Indonesia, Malaysia, and Thailand are the top three countries that have the highest theoretical biomass energy reserve, respectively, as Indonesia and Malaysia are the highest palm oil producers in the world and 40% of the Thai populations are actively depend on agriculture sector for livelihood (ADB, 2015b; Ahmad, Ab Kadir, & Shafie, 2011; Hasan et al., 2012; Shafie, Mahlia, Masjuki, & Ahmad-Yazid, 2012). Vietnam, Myanmar, Cambodia, and Laos also possess some moderate theoretical reserve of biomass energy, and the total biomass energy potential in the ASEAN region for generating electricity is equivalent to 120.64 GW. However, the technical and economic potential of biomass energy is much less due to the difficulty of collecting these residues from its distributed geographic territory. The Philippines and Indonesia are the second and third largest geothermal power generators in the world, respectively (EIA, 2015c), having a total geothermal energy reserve of 31.05 GW. The rest of ASEAN have not exploited their respective geothermal energy resources potential as of yet.

Solar is one of the most important and usable clean energy sources in the world, and due to the fact that ASEAN countries are generally tropical, the region has the highest solar irradiation, at an average of 4.5 kWh/m^2, encompassing a significant area. Solar PV prospects and utilization of individual ASEAN countries has been reviewed in (Ismail et al., 2015) and shows that ASEAN countries have annual solar insolation level ranging from 1460 to 1892 kWh/m2 per year. Consequently, Cambodia, Malaysia, Myanmar, Thailand, and Vietnam, are significantly advantaged when it comes to solar energy. With the exception of Singapore, most ASEAN countries have great potentials for onshore wind energy potentials, equivalent to 947 GW of electric power. Vietnam, Thailand, Philippines, and Laos have the highest theoretical wind energy potentials in the ASEAN region respectively. Furthermore, ASEAN countries are generally located in coastal areas; hence, there is a great possibility for offshore wind energy generation. It is necessary to exploit the offshore wind potentials for this region, and currently, it is found that Indonesia, Malaysia, Philippines, Thailand, and Vietnam have offshore wind energy potentials equivalent to 76 TWh. The geographical distribution of the energy resources of the ASEAN region is illustrated in Figure 2.1, and it can be summarized that the integration of the energy market could enhance the utilization of the energy resources of the region.

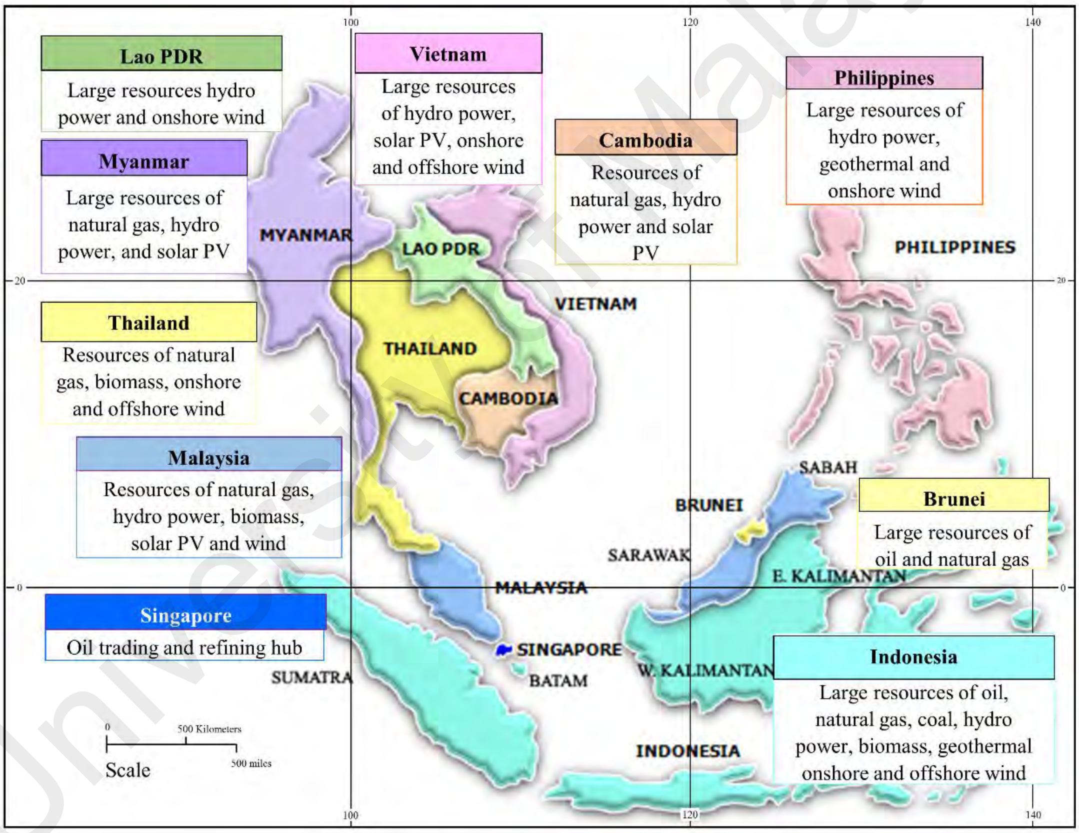


Figure 2.1: Geographical distribution of energy resources of ASEAN countries (IEA, 2013).

In addition to the distribution of energy resources, it is obvious that there are mismatches between countries with high potential energy resources and countries with high electricity demand. Moreover, the economic development of ASEAN is not uniform, which in turn make it difficult in utilizing sustainable energy resources to meet high electricity demands. Furthermore, fossil fuels reserves are decreasing day after day, so it is important to build an interconnected power system for this region by utilizing the distributed energy resources and reduce dependency on fossil fuels. This interconnection can be realized via APG, where resources can be shared via common interests, creating investment opportunities for countries with high power demand that have fewer resources to countries with high potential resources. This will also enable countries to work together in creating a sustainable power system.

2.2.2 Primary energy demand scenarios of ASEAN countries

The projection of individual primary energy demands is depicted in Figure 2.2. It can be observed from Figure 2.2 that the primary energy demand of ASEAN would increase in 2015 – 2040, from 647 Mtoe to 1070 Mtoe, which is a 65% increment. It can also be observed from these figures that this region will remain heavily dependent on fossil fuels, despite the huge potentials of renewables, with fossil fuels dependency projected to increase from 74% in 2015 to 79% in 2040. It should also be pointed out that the demand for oil would increase from 227 Mtoe to 309 Mtoe, whereas the demand for coal would increase to more than double, from 114 Mtoe to 309 Mtoe during the projection period, and in 2040, coal will become the largest energy mix with oil, overtaking natural gas, mostly due to their availability and lower prices. As a result of this, the contribution of oil in the primary energy mix would decrease from 35% in 2015 to 29% in 2040, while, the contribution from coal would increase from 18% to 29%. On the contrary, demand for natural gas would increase by 72% from 139 Mtoe to 240 Mtoe, with a continuous contribution of 21% to the primary energy mix within the projection period. Currently, nuclear power has no contribution to the ASEAN energy mix; however, nuclear power will contribute 1% to the energy mix in the ASEAN region after 2020, as Vietnam and Thailand are planning to install nuclear power plants. Moreover, Indonesia, Malaysia, and the Philippines intend to construct nuclear power plant after 2020 as well (ACE, 2015a).

The demand for hydropower would double, from 10 Mtoe to 22 Mtoe, during the projection period; however, it will only make up 2% of the primary energy mix in 2040. Bioenergy, including traditional biomass demand, rises from 128 Mtoe to 134 Mtoe, but its contribution to the primary energy mix would decrease from 20% to 13% from 2015 to 2040, due to the decreased usage of traditional biomass energy. Furthermore, other renewables, namely solar, wind, and geothermal, would double from 29 Mtoe to 67 Mtoe between 2015 - 2040 in the primary energy demand, and their contribution to the primary energy mix would increase from 4% to 6%, due to their availability economic viability, advanced in technology, and the awareness for reducing fossil fuels dependency.

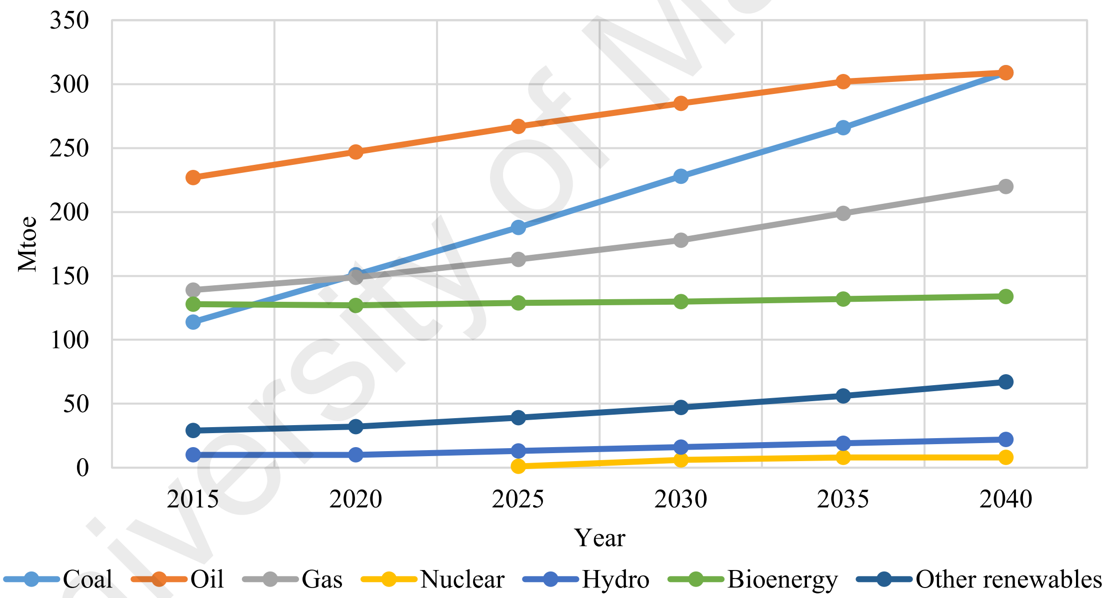


Figure 2.2: Primary energy demand of the ASEAN countries (IEA, 2015d).

2.2.3 Electricity demand, generation capacity, importing and exporting scenarios of ASEAN countries

The primary energy demand of ASEAN is dominated by electricity, making up 52% of total primary energy demand, mostly due to rapid economic development (IEA, 2013, 2015d). The projection of electricity demand from 2015 - 2040 in terms of Mtoe is shown in Figure 2.3. It can be seen from this figure that electricity demand would increase from

199 Mtoe to 463 Mtoe from 2015 to 2040, and would mostly be fossil fuel dependent. Among fossil fuels, coal would contribute 53% of the energy mix in 2040, while its demand would increase from 38% in 2015 to 53% in 2040. On the other hand, the contribution of oil and natural gas to the electricity demand energy mix would decrease during 2015 to 2040, from 6% in 2015, to 1% in 2040, and 35% in 2015, to 20% in 2040, respectively. Furthermore, the contribution from nuclear, hydro, biomass, and other renewables, such as solar, wind, and geothermal to the electricity demand energy mix projection would increase from 22% in 2015 to 26% in 2040.

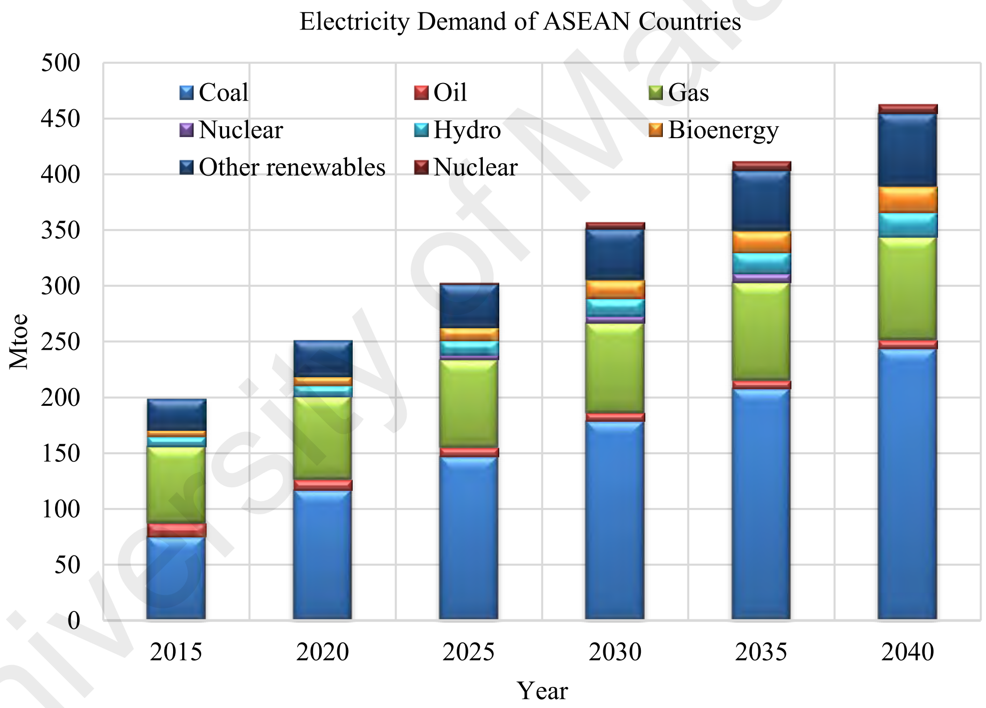


Figure 2.3: Projection of electricity demand of ASEAN countries (IEA, 2013, 2015d).

Individual ASEAN countries have estimated their respective electricity demand until 2020, and Figure 2.4 shows the projected electricity demand. It can be seen from Figure 2.4 that ASEAN countries need to generate around 200 GW of electricity to meet demands in 2020, which is 37% more than the generation capacity in 2015. Electricity demand increment is dissimilar across ASEAN. It can be noted that the electricity demand of Indonesia would be the highest in 2020 in terms of GW power demand, followed by Vietnam, Thailand, and Malaysia, respectively, while the percentage of electricity demand increment would be highest for Myanmar, followed by Cambodia, Vietnam, and Indonesia, and these demand increment would be 85%, 78%, 59%, and 47%, respectively, compared to the demand in 2015, mostly due to rapid urbanization, rural electrification initiatives from the governments, and industrialization from foreign investments (HAPUA, 2013a).

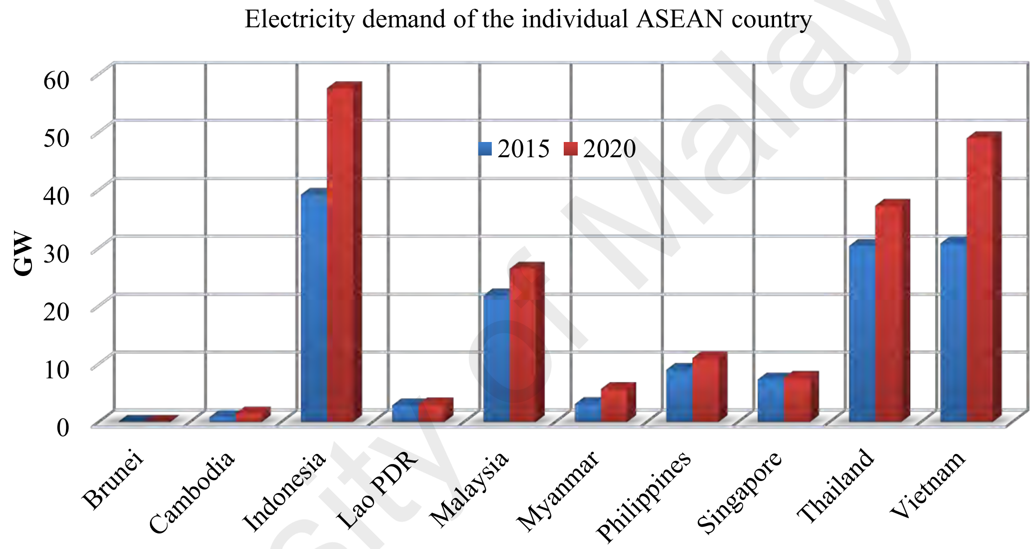


Figure 2.4: Projection of electricity demand of the individual ASEAN countries (HAPUA, 2013a).

The electricity generation capacity of ASEAN would also increase steadily, in line with the demand and projection of the generation capacity from 2015 to 2040 is shown in Figure 2.5**.**

It illustrates that the generation capacity would increase from 218 GW in 2015, to 549 GW in 2040, where coal would dominate the capacity addition energy mix, followed by natural gas and hydro power, at 37%, 29%, and 16%, respectively, in 2040. The oil dependent capacity addition would decrease due to high fuel costs. The addition of hydropower based renewable energy capacity would be highest, from 37 GW in 2015, to

90 GW in 2040. Also, a significant amount of biomass energy and other renewables of solar, wind, geothermal would contribute to the capacity addition at 9GW and 57GW, respectively. The percentage of energy mix shows that fossil fuel dependency would have been decreased from 77% in 2015 to 69% in 2040, although it remains as the dominant source for electricity generation.

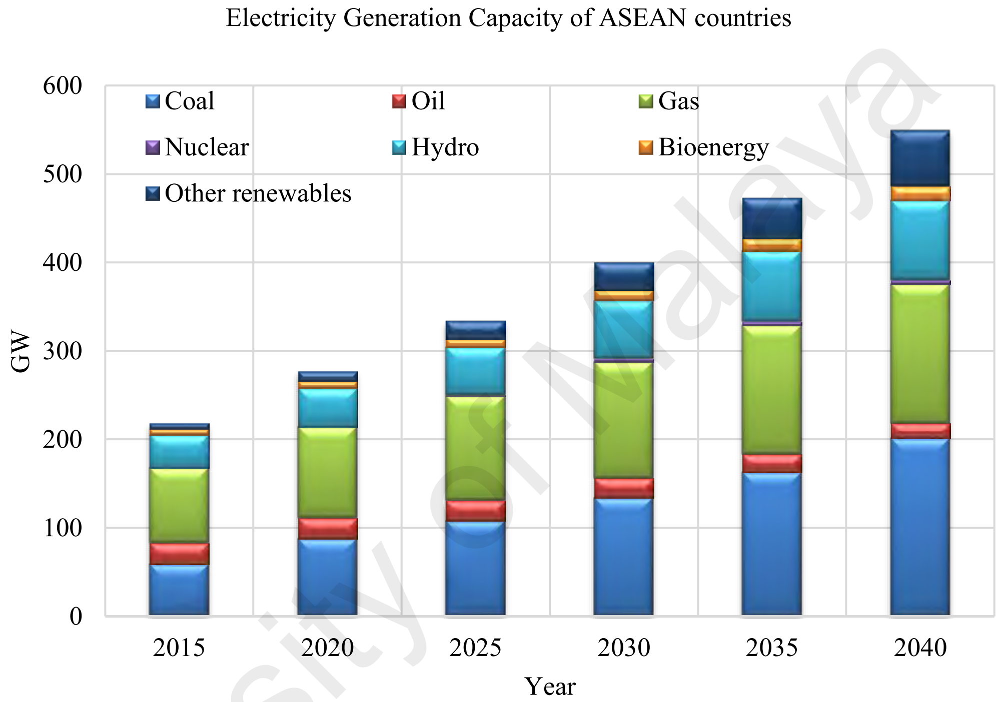
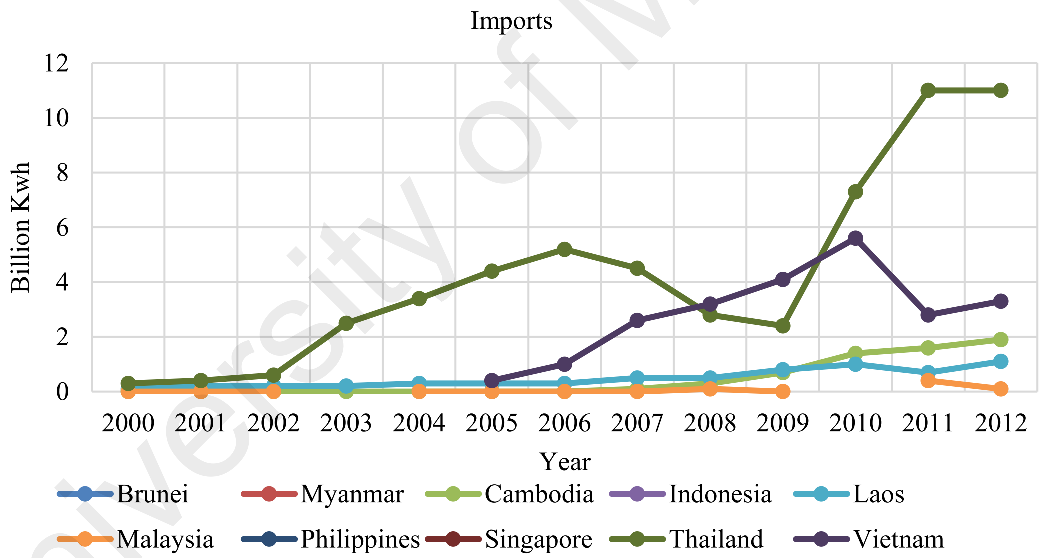


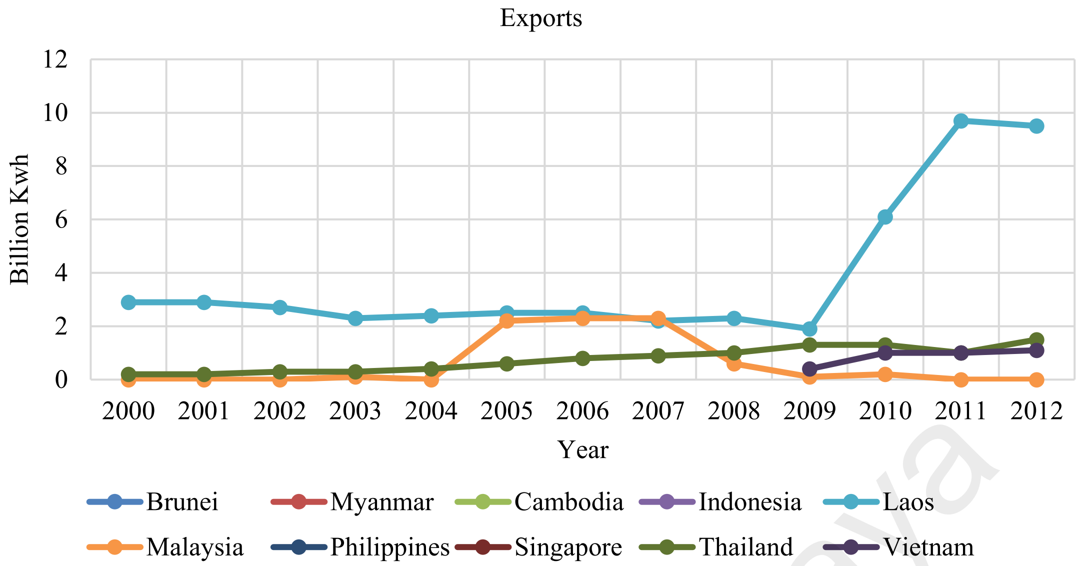
Figure 2.5: Projection of electricity generation capacity of ASEAN countries (IEA, 2013, 2015d).

ASEAN countries are involved with electricity imports and exports within and beyond its borders (EIA, 2015b). Figure 2.6(a), (b), (c) represent the electricity imports, exports, and net imports scenarios of ASEAN countries from 2000 - 2012. It can be seen from Figure 2.6(a) that electricity imports by ASEAN countries increase steadily to meet electricity demand, from 0.4 billion kWh to 17.4 billion kWh from 2000 to 2012, while Thailand and Vietnam are actively involved with electricity imports, whereas Cambodia, Laos, and Malaysia import moderate amounts of electricity. Figure 2.6(b) shows the export scenario of the region, from the figure it can be seen that that electricity exports increased in large amounts in the region, from 3.1 billion kWh in 2000, to 12.2 billion kWh in 2012. Laos, Thailand, Vietnam, and Malaysia export their electricity to neighboring countries. Figure 2.6(c) shows the net import scenario of electricity, and from the figure, it can be seen that Thailand is a net importer of electricity, followed by Vietnam and Cambodia. Laos is a net exporter of electricity in this region, due to increased investments in their hydropower reserves from China (EIA, 2015b). Malaysia was also a net electricity exporter until 2010, but in 2011, it became a net electricity importing country. It is necessary to link the power system network of ASEAN countries by building cross-border interconnections that will enhance electricity imports and exports amongst these countries.

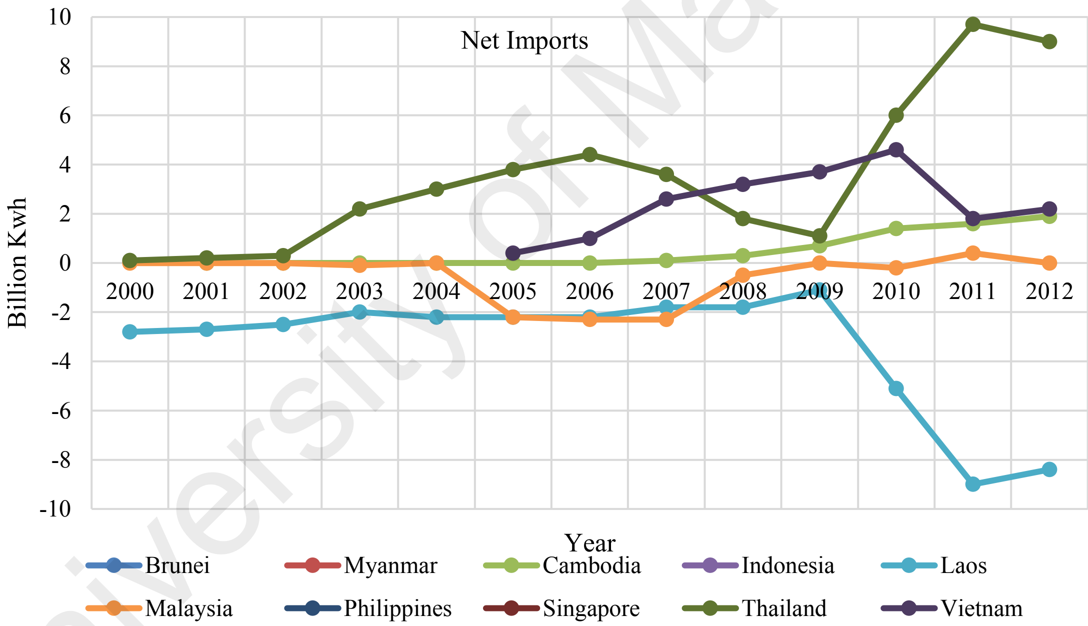


(a)

Figure 2.6: (a) Electricity imports, (b) Electricity exports, (c) Net imports by the ASEAN countries (EIA, 2015b).



(b)

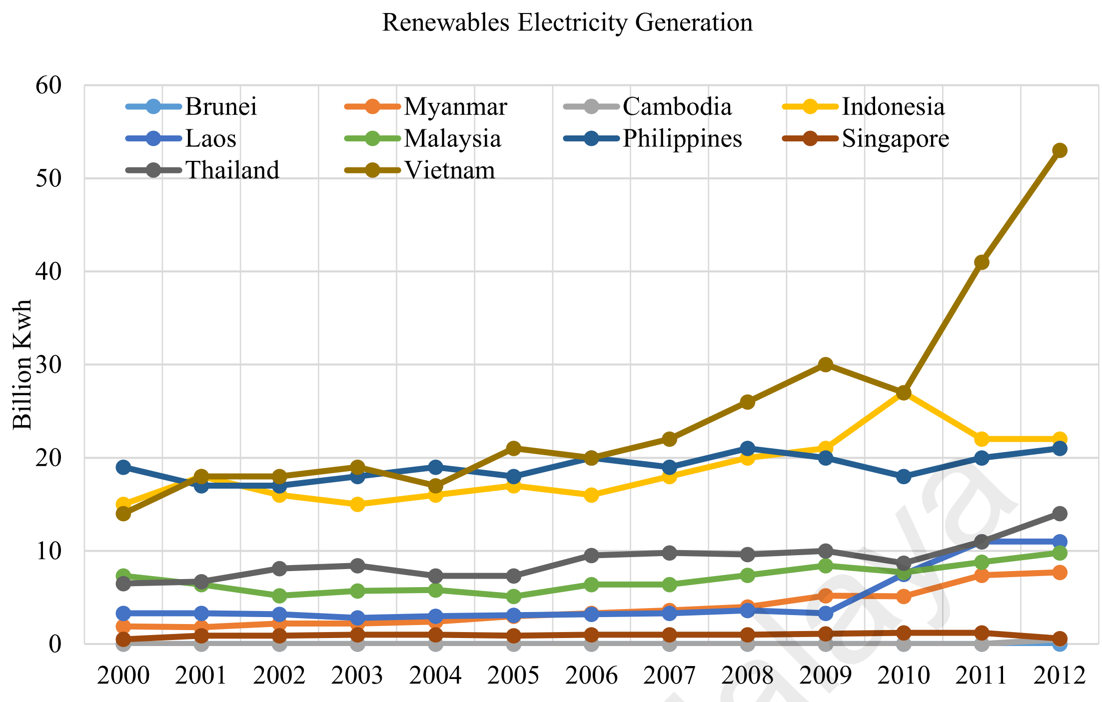


(c)

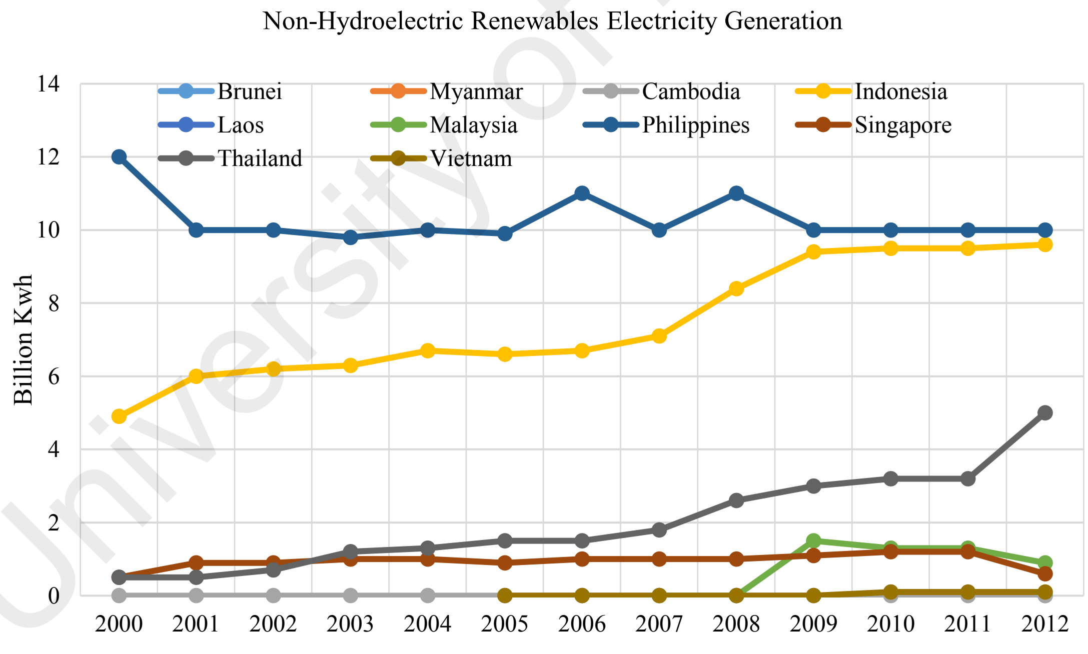
Figure 2.6, Continued.

2.2.4 Present scenario and future targets of renewable power generation

It has been mentioned earlier that the ASEAN countries have abundant renewables-based electricity generation potentials. Renewables power generation scenario, including hydroelectricity and non-hydroelectricity of ASEAN from 2000 to 2012 are shown in Figure 2.7(a), (b) (EIA, 2015b). From the statistics shown in Figure 2.7(a), (b), it can be seen that the renewable electricity generation, including hydroelectricity, increased from 67.5 billion kWh to 139.6 billion kWh, whereas non-hydroelectric renewables electricity generation increased from 17.9 billion kWh to 26.2 billion kWh from 2000 to 2012, which means that hydroelectricity is an abundant source of renewable power and could be utilized for electricity generation in ASEAN. It should also be noted that Vietnam is the largest renewable electricity producer in ASEAN, followed by Indonesia, Philippines, and Thailand, while on the other hand, the Philippines is the largest non-hydroelectric renewable energy producer, followed by Indonesia and Thailand. Most non-hydroelectric electricity of ASEAN are generated from geothermal and biomass energies. Moreover, renewable electricity generation scenarios of Singapore, Cambodia, and Brunei are negligible compared to other ASEAN countries. Singapore generates small amounts of renewable electricity from biomass and solid waste management. Cambodia also has a negligible renewable energy electricity generation sector, due to the lack of renewable energy action plan, as well as high capital investment, and in 2012, the amount was 0.5 billion kWh, which is far beyond what others are generating. Furthermore, energy generation from renewables in Brunei is also negligible, due to their highly developed oil and gas sector.



(a)



(b)

Figure 2.7: ASEAN countries (a) Renewables electricity generation, (b) Non-hydroelectric renewables electricity generation (EIA, 2015b).

For increasing energy mix from renewables, individual ASEAN countries are promoting electricity generation from renewables via the implementation of different policies such as feed-in tariffs (FiTs), Net Energy Metering (NEM), and tax exemptions (Ismail et al., 2015; SEDA, 2016; Solangi et al., 2011). Indonesia, Malaysia, the Philippines, and Thailand have introduced feed-in tariffs (FIT), feed-in tariffs (FiTs), Net Energy Metering (NEM), and tax exemptions to the generation of electricity from renewable resources. Despite the renewable potentials and policies are undertaken by ASEAN, the current power generation from renewable energy is non-significant compared to the present power generation capacities of ASEAN. Along with the policies, ASEAN countries should also set their respective targets to increase electricity generation from renewables. The present status of renewable power installed capacity and future target are tabulated in Table 2.2 (ACE, 2015a; ADB, 2015a; ARES, 2015; HAPUA, 2013a; IRENA, 2014; Ismail et al., 2015; Khaing, 2015; Shafie, Mahlia, Masjuki, & Andriyana, 2011; Unkovic, 2011). Here, the present installed capacity only includes a small hydroelectricity generation. It is seen from Table 2.2 that ASEAN countries have less amount of installed capacity from renewables at present, with Indonesia has the largest renewable generators installed capacity in this region, followed by Thailand and Philippines in 2013. Table 2.2 also shows the future target of renewable generation, including hydroelectric, and it can be seen from the statistics that, all countries have set their respective targets for enhancing renewable generation in their electricity generation energy mix.

Table 2.2: Scenarios of renewable power generation by the ASEAN countries

Country	Renewable Power Installed Capacity (MW)	Future Plan of Renewable Power Generation
Brunei	1.2	10% of electricity consumption by 2035 Offshore wind projects with total capacity of between 18 and 20 MW
Cambodia	5.72	Renewable energy development in Cambodia is very negligible. More research and funds are required for exploring the renewable energy potentials.
Indonesia	1,353	17% of total primary energy consumption in 2025 25.9% in 2025.
Lao PDR	46	30% share of renewable energy share in 2025
Malaysia	129	Target RE Generation of 985 MW by 2015 (~5.5% of energy mix), 2080MW by 2020 and 4000MW by 2030
Myanmar	26.9	15-20% share of renewable in the total power installed capacity by 2020; 34,452MW generation from RE is expected in 2030
The Philippines	171	15234.3MW by 2030
Singapore	10	5% of peak electricity demand supplied from RE sources by 2020, 4% of total generated electricity from RE sources by 2030.
Thailand	984	13701MW; 25% share of RE is expected in 2021
Vietnam	31	4.5% by 2020

Sources: (ACE, 2015a; ADB, 2015a; ARES, 2015; HAPUA, 2013a; IRENA, 2014; Ismail et al., 2015; Khaing, 2015; Shafie et al., 2011; Unkovic, 2011)

The percentages of energy mix of the present renewable power installed capacity for the year 2015 is shown in Figure 2.8, and it shows that most countries are utilizing their abundant renewable sources to generate the maximum amount of clean electricity, such as Brunei utilizing solar PV, Indonesia utilizing geothermal energy, Laos with its small hydro, Malaysia and Myanmar utilizing biomass, the Philippines utilizing geothermal and wind, and Thailand utilizing solar PV. Renewable generation mix of various clean sources for future targets are presented in Figure 2.9, and it is seen that hydroelectricity is the most promising source of renewable energy when setting targets by ASEAN countries. Hydroelectricity will contribute 69.54 GW of electricity for future renewables installed capacity target, lead by Myanmar, followed by Vietnam, the Philippines, Thailand, Indonesia, Malaysia, and Laos. Moreover, geothermal is the second largest contributor of renewable power capacity addition for Indonesia and the Philippines, with the amount being 7.5 GW, followed by biomass including biogas, which contributes 7.19 GW of renewable electricity generation for Thailand, Malaysia, Philippines, Indonesia, and Laos. Wind is the fourth largest source, which contributes 5.22 GW of electric power to future renewable generation target, lead by the Philippines, and followed by Thailand, Vietnam, Myanmar, Indonesia, Laos, and Brunei. Solar PV contributes 6.54 GW of electric power, mostly in Myanmar, Thailand, Malaysia, Philippines, and Indonesia, as well as small amounts in Laos and Brunei. Also, electricity generation from waste management also contributes to the future targeted amount of 1.07GW for Malaysia, Singapore, Thailand, and Laos. In addition, sea wave contributes small amounts of electricity for a future target of 72MW for the Philippines and Thailand.

The present generation and future target of renewable generation of ASEAN are insignificant compared to their available renewables resources, as well as present and future electricity generation capacity (Das & Ahlgren, 2010). As mentioned earlier, uneven distribution is also another important reason behind the lower utilization of renewables. Power market integration via the establishment of cross-border power trade through APG could be the solution to overcoming the barriers of the utilization of renewables in the region.

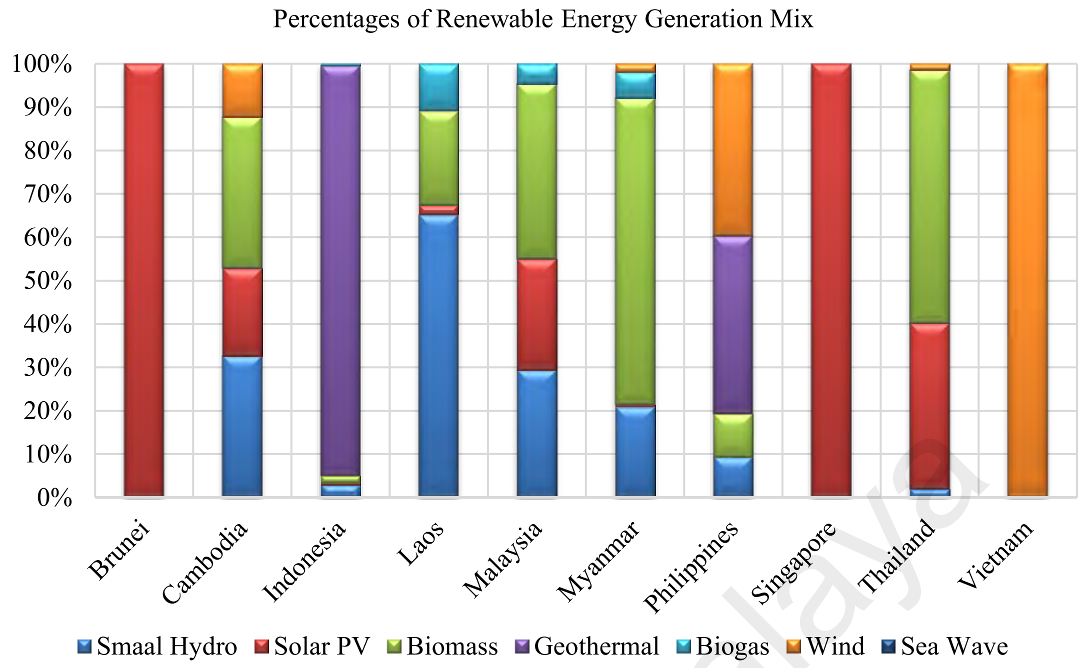


Figure 2.8: Energy mix of present renewables electricity generation for 2015.

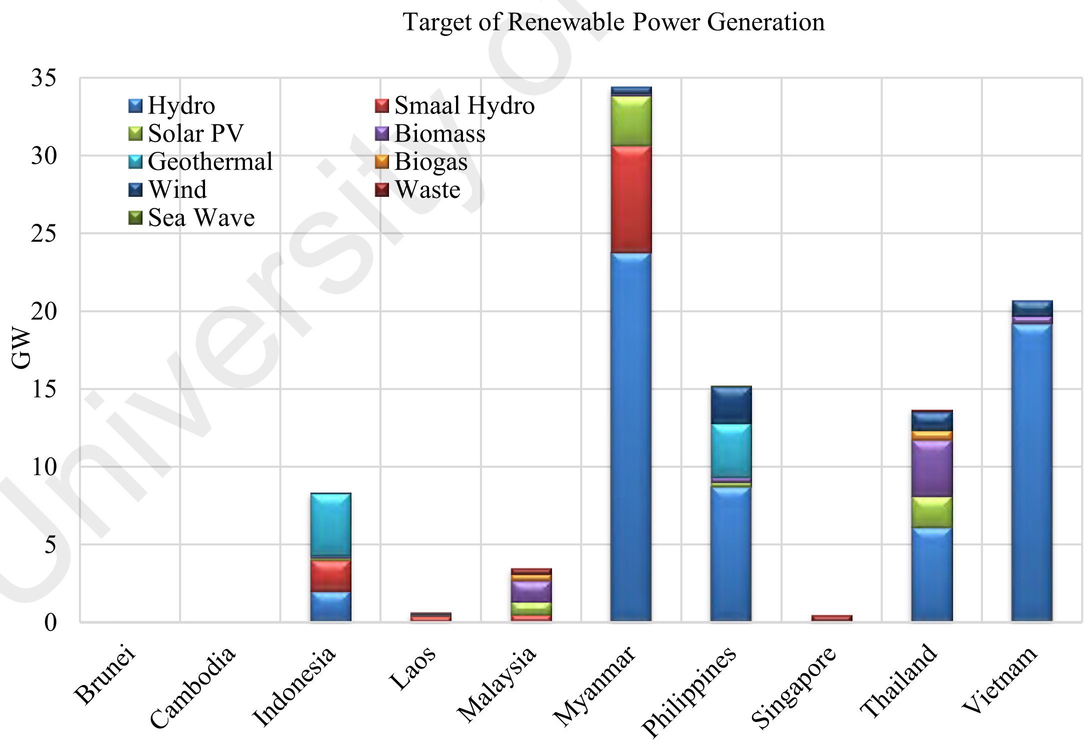


Figure 2.9: Renewable energy generation target by the ASEAN countries.

2.3 Transmission expansion planning practices for renewable generators of ASEAN countries

Transmission expansion planning (TEP) traditionally focuses on expanding the existing transmission system for serving load centers by taking into account various economic and technical constraints (Quintero, Zhang, Chakhchoukh, Vittal, & Heydt, 2014). The lack of transmission system facilities and capacity for transferring generated power is problematic for any generation system. However, the lack of transmission facilities can greatly influence renewable power generation. Most large-scale renewable generators are located far from existing load centers, and for transmitting the generated power from renewables, it is necessary to have a transmission network infrastructure covering a large geographical area. Building such a transmission infrastructure requires more time with compared to renewable generation facilities development. Larger transmission infrastructure and proliferation of renewable generations force the traditional TEP process to account for new challenges, such as economic impacts and uncertainties in a deregulated electricity market (Torre, Conejo, & Contreras, 2008; Silva, Rider, Romero, & Murari, 2006). Also, the variable and intermittent nature of renewable generators influence the TEP process. Some renewable generations have a low capacity factor, which in turns results in the lesser utilization of the developed transmission line capacity. Therefore, the TEP for integrating renewables into the existing grid have to account for different comparison with traditional TEP process to speed up renewable generations via the provision of adequate transmission network infrastructure facilities.

Large investment cost is associated with this transmission infrastructure development and pricing methodology is very complex. Transmission infrastructure can be broadly categorized under connection and network assets (Madrigal & Stoft, 2012). Assets such as transformer and substations, which are required for interconnecting generators with existing transmission network, are known as connection assets. System extensions, such as building long-distance transmission lines and high voltage transmission facilities for interconnecting generators and substations with the existing grid, are also viewed as connection assets. In contrast, network assets, or reinforcements, are assets required for upgrading the transmission network to accommodate new generators. This reinforcement is required when the existing transmission facilities are unable to transmit additional injected power, and the reinforcements might include upgrading existing transmission lines and substation capacity. Incorporating these network and connection assets is responsible for transmission expansion costs, and these costs can be broadly divided into two types, namely connection costs and network infrastructure costs (Hasan, Saha, Chattopadhyay, & Eghbal, 2014; Madrigal & Stoft, 2012; Zhao, Dong, Lindsay, & Wong, 2009). Both these connection costs and network costs allocation procedures have great influence upon renewables generation, which are described in the following subsections.

2.3.1 Connection costs

Renewable energy generations face a problem related to high transmission network connection cost for new renewable generators. Often the expense of transmission cost is totally assigned to the project developer, and stakeholders share this cost. Unlike conventional power generation, bearing transmission connection costs by renewable generators have a great impact, because renewable generators are located far from load centers, such as offshore wind farms. Various transmission cost allocation policies are being practiced by different jurisdictions, and these policies are the cost allocation boundary between the transmission system operator (TSO) and renewable generator. These transmission connection costs allocation policies can be broadly categorized into four types; (i) super shallow, (ii) semi-shallow, (iii) shallow, and (iv) deep shallow (Scott, 2007). Figure 2.10 shows the connection cost allocation methods for renewable generators. In super shallow connection cost policy, renewable generators are not responsible for bearing any connection cost, and all the network interconnection or upgrade costs are borne by the TSO, which is, in turn, shared amongst network users. Consequently, in semi-shallow connection cost policy, the network integration cost is divided between the generators and consumers, and a portion of the cost shared by the generators is determined via negotiation between TSO and generators. A super-shallow cost allocation policy is excellent for renewable generators, since it shares less amount of connection cost with an existing network (Madrigal & Stoft, 2012). On the contrary, in the shallow connection cost policy, renewable generators are solely responsible for providing the connection cost of the generation unit to existing load centers. This cost allocation policy imposes significant upfront investment cost to renewable generators, especially for remotely located solar or offshore wind generators. In contrast, in deep shallow pricing policy, the renewable generators are solely responsible for network interconnection and network up-gradation cost, along with the generation cost. Deep shallow connection cost policy imposes huge upfront transmission interconnection costs to renewable generators, which might discourage renewable developers, rendering renewable projects economically impractical. It can be surmised that these four types of connection cost policies have a great impact on renewable generations from economic and financial perspectives, while, among these cost policies semi-shallow connection cost allocation policy is economically viable for renewable generators (Scott, 2007).

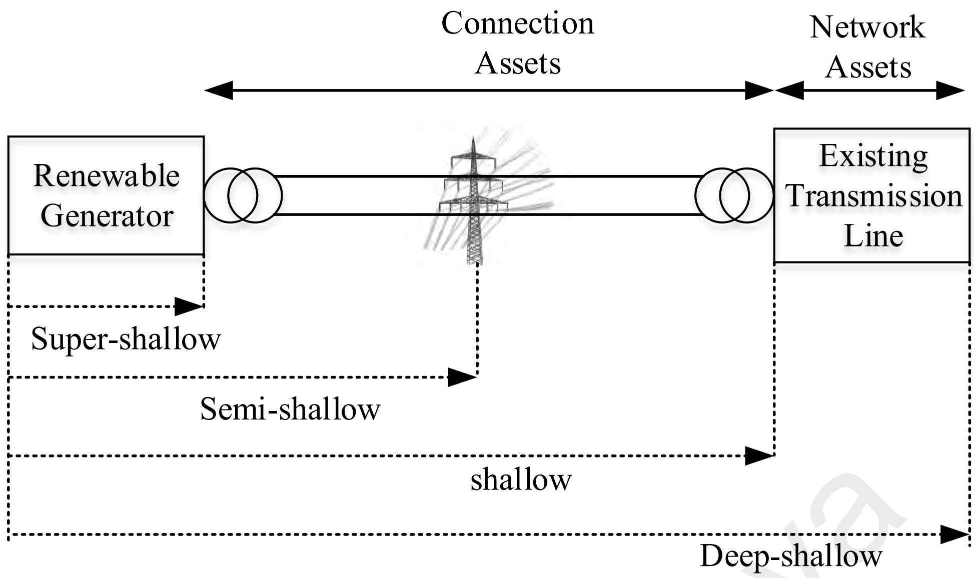


Figure 2.10. Connection costs allocation process for renewable generators (Madrigal & Stoft, 2012).

2.3.2 Network infrastructure costs

The cost associated with network infrastructure is made up of operation and maintenance costs of the shared transmission network, including losses and congestions (Hasan, Saha, Chattopadhyay, et al., 2014; Madrigal & Stoft, 2012). Moreover, ancillary services and system operators cost might also be included in network costs. The regulated yearly revenues in most regulatory regimes cover these costs, and imposing tariffs to network users collects these regulated revenues. These tariffs are called the use of system (UoS) tariffs. UoS tariffs are less compared to the total costs of the consumers, depending upon the transmission system pricing methodology, however, these UoS charges have a great impact on remotely located and offshore renewable energy generators (Madrigal & Stoft, 2012). There is no best solution to this transmission system regulation and pricing methodology. This transmission system revenue could be collected from generation or load consumers, or from both parties. This is very important when selecting a transmission-pricing design. Generation and demand (distribution utilities and consumers) are the main users of the transmission system network, and the prices of the transmission system can be collected from either of these two, or shared, but it is appreciable not to select transmission network prices from renewable generators, since the transmission prices are finally collected from the consumers. Network infrastructure cost methods can be broadly categorized into two types, namely postage stamp and usage based method. The network infrastructure cost methods are briefly described below.

2.3.2.1 Postage stamp

Postage stamp methods can be defined as when all the transmission network users bear similar average charges based on the amount of energy transmitted or injected on the network, irrespective of cost or benefit derived by the users from using the transmission network (Hempling; Stoft, Webber, & Wiser, 1997). Transmission network prices are recovered in a simple and effective way via postage stamp. The postage stamp methods do not account for the distance of generators, users or network congestion conditions (Krause, 2003; Lima, Padilha-Feltrin, & Contreras, 2009). Postage stamp method can be defined primarily two categories like pure postage stamp pricing and residual postage stamp pricing methods, where, for the former, all the transmission users are charge average irrespective of their locations (Bell, Green, Kockar, Ault, & McDonald, 2011). The average charge of the postage stamp methods can be collected by either energy consumption (MWh) or peak load (MW). Postage stamp transmission pricing based on energy consumption (MWh) can be defined as total transmission cost multiplied by the ratio of extracted or injected MWh by an individual transmission system user to total annual transmitted MWh by the transmission system. On the contrary, peak load (MW) based transmission pricing is total transmission cost multiplied by the ratio of extracted or injected MW by an individual transmission system user to total annual peak load (MW) of the transmission system. In the postage stamp methods, imposing average charge in per-MW rather than MWh might be disadvantageous for renewable energy generators, due to low capacity factor of renewable generators for their intermittent nature and the high prices of the network. Residual postage stamp charging is a part of a transmission tariff and, when a cost based transmission tariff fails to recover the transmission investment then residual transmission investment can be recovered by applying postage stamp transmission system and for this reason it is called residual postage stamp transmission system (Bell et al., 2011; Jansen et al., 2015). Since, postage stamp method considers the full utilization of transmission network, but, practically full capacity is not utilized especially when local load presents in the transmission system and for renewable generators. Delivered power by generator or load to the transmission system will be reduced with the existence of local load at buses because some parts of the supplied power will directly flow to the local load. As a matter of this fact, postage stamp coverage method has been introduced in (Radzi, Bansal, Dong, Hassan, & Wong, 2013) where the unused capacity cost will be shared among the generators. But, this method also does not consider the presence of local load. However, this method might not be beneficial for renewable generators as more transmission price need to share by the generators due to capacity factor limitations. Another modification of postage stamp coverage method by considering the presence of local load namely tracing based postage stamp coverage method has been presented in (Radzi, Bansal, Dong, & Hassan, 2011) where, transmission pricing for individual generators are charged based on tracing the actual power injection to the transmission line. Though transmission costs need to be shared by the generators, but it might be suitable for remote renewable generators because it needs to share only the actual usage of transmission lines system whether transmission system consists local load case or not (Radzi, Bansal, & Dong, 2015). From the aforementioned discussion, it can be said that postage stamp charging method based on peak load (MW) based pricing method might be suitable for renewable generators as it only considers the MW supplied by the generators irrespective of any of the abovementioned transmission conditions.

2.3.2.2 Usage based

Usage based network costs allocation method is defined as when all the transmission network users are charged based on their use of the transmission network (Madrigal & Stoft, 2012). Usage based methods can be categorized into two types, namely flow based and distance based MW mile charging, where the former is more burdensome on long distance energy travel. UoS tariffs based on usage based methods might be disadvantageous for long distance renewables generators, because in the pricing methods, all connection costs are charged to the generators (Madrigal & Stoft, 2012).

A summary of the connection and network infrastructure costs is shown in Figure 2.11. It can be surmised that these costs can be distributed to generation and load. Also, super shallow connection cost policy is less impactful upon renewable generations, whereas for long distance renewable generators usage based network infrastructure, the pricing technique is more impactful.

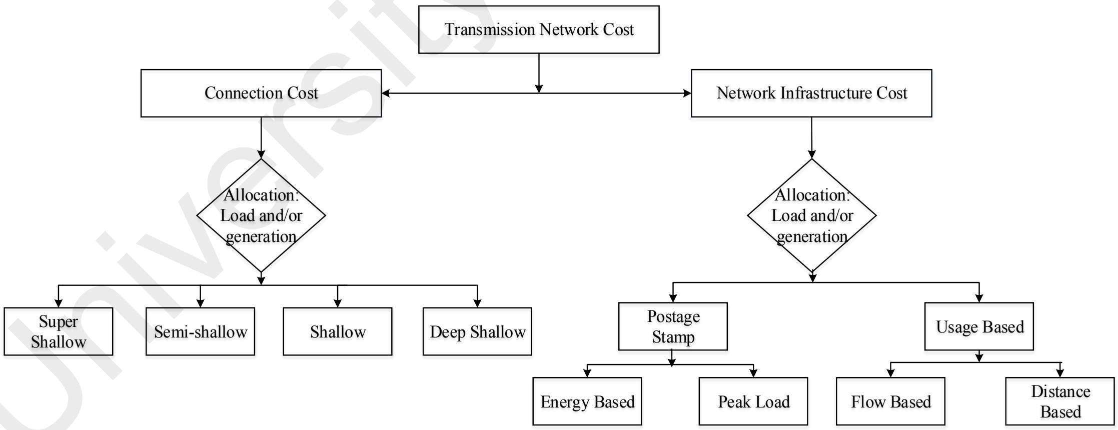


Figure 2.11: Allocation and pricing of transmission network cost (Madrigal & Stoft, 2012).

Taking into account the aforementioned TEP considerations for the enhancement of the renewable energy generations, ASEAN countries are far behind in their respective policies in expediting renewable generation to meet their renewable energy targets, as shown in Table 2.2. Among ASEAN countries, only the Philippines is adopting transmission expansion planning practices that advance generation from renewable energy. For facilitating and advancing renewable energy growth, as well as decrease the fossil fuel dependency and increasing the energy security, the Congress of the Philippines has approved the Renewable Energy Resources Act (Congress of the Philippines, 2008), which provides the guideline and institutional framework to enhance the development and utilization of renewable energy. This act introduces planning and connecting, as well as financing and interconnection building of the renewable energy projects, all of which will be carried out by the transmission company (TRANSCO) of the Philippines. It also mentions that the system extension investment costs should be recouped through monthly installments by the generators. Besides the Renewable Energy Act, a technical group for addressing the aspects of renewable energy planning has been formed by the National Renewable Energy Board (NREB), the Energy Regulatory Commission (ERC) in the Philippines, and the transmission company. This group organizes and plans the transmission development according to interconnecting requests from the different renewable energy generation zones, which in turns reduces the significant transmission investment needs of the renewable generations and speed up the interconnection process.

Presently, the Philippines has incorporated semi-shallow connection costs allocation policy instead of the previous shallow connection cost policy to enhance electricity generation from renewable resources (Madrigal & Stoft, 2012). For network infrastructure cost, the Philippines utilizes the postage stamp pricing policy to similar amounts of generations and consumptions on the basis of MWh methodology. Also, the system extension costs are initially given from the TSO, and these costs are later recouped from the generators. Summary of the connection, network, and UoS services costs are tabulated in Table 2.3.

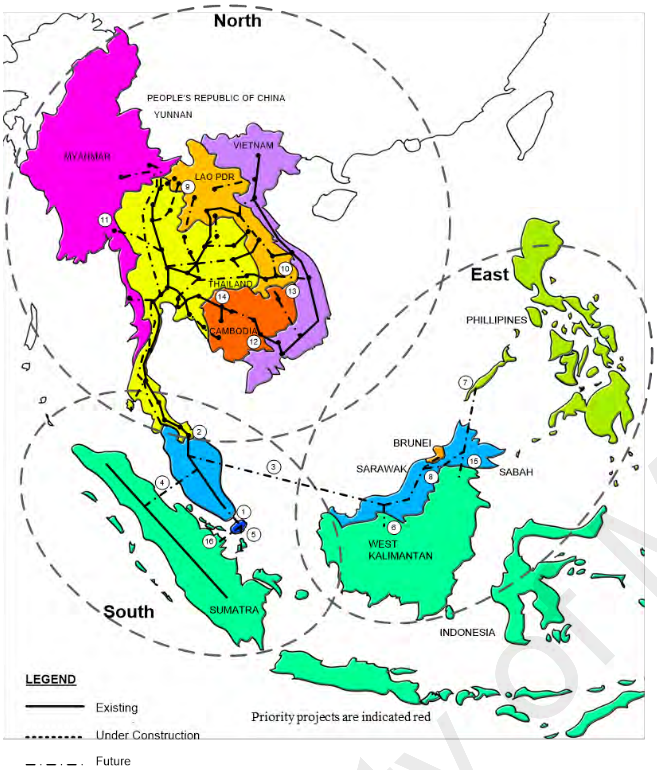
Table 2.3: Costs allocation policy (Madrigal & Stoft, 2012)

Country	Connec-tion cost allocate-ion policy	Cost Provider			Network infrastructure cost allocation policy	Transmission pricing cost allocation (%)	
		Gener-ation	System Extens-ion	Network Updates		Gener-ator	Load
The Philippines	Semi-shallow	G	G	TSO	Postage stamp	50	50

2.4 Present research and development status of ASEAN power grid

ASEAN interconnection master plan (AIMS) working group was established in the year 2000 for developing the ASEAN grid (ACE, 2015b; Atchatavivan, 2006). AIMS focuses on the basics of APG by concentrating the long run energy demand of the ASEAN countries. Optimization study of AIMS completed in 2003 and AIMS selected 15 potential power grid interconnection projects within 2015 based on the study. This interconnection is mainly based on first, bilateral cross-border, followed by gradual expansion to sub-regional basis, and a fully integrated ASEAN power grid. Estimation has been made for the investment to establish APG, which amounted to USD 5.9 billion, with a net benefit of USD 662 million from APG interconnections projects (ACE, 2015b; Atchatavivan, 2006). For updating the master plan of APG, AIMS-II was adopted in 2006, and began working for 16-year (2009-2025) periods, with its final report submitted in 2011 (ACE, 2015c). AIMS-II identified 16 feasible interconnection projects under APG. AIMS-II also estimated that 19,596 MW of cross-border power trade and 3,000 MW of cross-border power exchange will be established by 2025, which results in USD 788 million of savings and a reduction of 2,013 MW installed capacity (Chimklai, March 14, 2013; Ibrahim, 2014). APG have been divided into three regions, namely Eastern, Northern, and Southern regions, while the geographical view of this inter connection project is shown in Figure 2.12 (Takapong, 2016). It can be observed from Figure 2.12

that among these 16 interconnection projects, some interconnection projects are already in operation, some are on-going, and rests of the interconnection projects will be established in future.



		Earliest COD
1)	P.Malaysia - Singapore (New)	post 2020
•	Plentong - Woodlands	Existing
•	P. Malaysia – Singapore (2nd link Plentong - Woodlands)	post 2020
2)	Thailand - P.Malaysia	
•	Sadao - Bukit Keteri	Existing
•	Khlong Ngae - Gurun	Existing
•	Su Ngai Kolok - Rantau Panjang	Future
•	Khlong Ngae – Gurun (2nd Phase, 300MW)	Future
3)	Sarawak - P. Malaysia	2025
4)	P.Malaysia - Sumatra	2020
5)	Batam - Singapore	2020
6)	Sarawak - West Kalimantan	Existing
7)	Philippines - Sabah	2020
8)	Sarawak - Sabah – Brunei	
•	Sarawak –Sabah	2020
•	Sarawak – Brunei	2019
9)	Thailand - Lao PDR	
•	Roi Et 2 - Nam Theun 2	Existing
•	Sakon Nakhon 2 – Thakhek – Then Hinboun (Exp.)	Existing
•	Mae Moh 3 - Nan - Hong Sa	Existing
•	Udon Thani 3- Nabong (converted to 500KV)	2019
•	Ubon Ratchathani 3 – Pakse – Xe Pian Xe Namnoy	2019
•	Khon Kaen 4 – Loei 2 – Xayaburi	2019
•	Nakhon Phanom – Thakhek	2015
•	Thailand – Lao PDR (New)	2019-2023
10)	Lao PDR - Vietnam	2016-2020
•	Xekaman 3 - Tranhmy	Existing
•	Xekaman 1 – Pleiku 2	2016
11)	Thailand - Myanmar	2018-2026
12)	Vietnam - Cambodia (New)	
•	Chau Doc – Takeo – Phnom Penh	Existing
•	Tay ninh – Stung Treng	Future
13)	Lao PDR - Cambodia	Post 2018
14)	Thailand - Cambodia (New)	post 2020
•	Aranyaprathet – Banteay Meanchey	Existing
15)	East Sabah - East Kalimantan	post 2020
16)	Singapore – Sumatra	post 2020

Figure 2.12: Geographical Map of APG Interconnections (Takapong, 2016).

The status of existing, on-going and future projects are given in Table 2.4, Table 2.5, Table 2.6, respectively according to updates from Heads of ASEAN Power Utilities / Authorities (HAPUA) secretariat (ARES, 2016; ERIA, 2016; HAPUA, 2015; Ibrahim, 2014; Takapong, 2016). Table 2.4 shows that 7 projects of APG are in operation with cross-border power transfer of 5,032-5,192 MW, while, Table 2.6 illustrates that 5 projects of APG are in under construction which will allow 5,589 MW of cross-border power transfer. From Table 2.6 it can be seen that, another 12 projects of APG are in the planning stage with a capacity of 24,829 - 27,979 MW cross-border power transfer.

Table 2.4: Updates on APG Existing Projects

No.	Project	System	Type	Capacity (MW)
1	**P. Malaysia – Singapore** • Plentong – Woodlands	HVAC: 230 kV	EE	450
2	**Thailand - P.Malaysia** • Sadao - Bukit Keteri • Khlong Ngae - Gurun	HVAC:132/115 kV HVDC: 300 kV	EE EE	80 300
6	**Sarawak – West Kalimantan** Mambong – Bengkayang	HVAC: 275 kV	EE	70 - 230
9	**Thailand – Lao PDR** • Nakhon Phanom – Thakhek – Then Hinboun • Ubon Ratchathani 2 – Houay Ho • Roi Et 2 - Nam Theun 2 • Udon Thani 3 – Na Bong – Nam Ngum 2 • Nakhon Phanom 2 – Thakhek – Theun Hinboun (Expansion) • Mae Moh 3 – Nan 2 – Hong Sa # 1, 2, 3	HVAC: 230 kV HVAC: 230 kV HVAC: 230 kV HVAC: 500 kV HVAC: 230 kV HVAC: 500kV	PP: La->Th PP: La->Th PP: La->Th PP: La->Th PP: La->Th PP: La->Th	220 126 948 597 220 1473
10	**Lao PDR – Vietnam** • Xekaman 3 - Thanhmy	HVAC: kV	PP: La->Vn	248
12	**Vietnam – Cambodia** • Chau Doc – Takeo – Phnom Penh	HVAC: 230 kV	PP: Vn->Kh	200
14	**Thailand – Cambodia** • Aranyaprathet – Bantey Meanchey	HVAC: 115 kV	PP: Th->Kh	100
Total Capacity				5,032-5,192
EE: Energy Exchange; PP: Power Purchase				

Sources: (ARES, 2016; ERIA, 2016; HAPUA, 2015; Ibrahim, 2014; Takapong, 2016)

Table 2.5: Updates on APG On-Going Projects

No.	Project	System	Type	Capacity (MW)
2	**Thailand - P.Malaysia** • Su – ngai kolok – Rantau Panjang	HVAC: 132/115 kV	EE	100
4	**P. Malaysia – Sumatra** • Melaka - Pekan Baru	HVDC: kV	PP: SM->PM & EE	600
8	**Sarawak – Sabah – Brunei** • Sarawak – Brunei	HVAC: 275 kV	EE	2x100
9	**Thailand – Lao PDR** • Udon Thani 3 – Na Bong – Nam Ngiep 1 • Ubon Ratchathani 3 – Pakse – Xe Pien Xe Namnoi • Khon Kaen 4 – Loei 2 - Xayaburi	HVAC: 500 kV HVAC: 500 kV HVAC: 500 kV	PP: La->Th PP: La->Th PP: La->Th	269 390 1220
10	**Lao PDR – Vietnam** • Xekaman 1 - Ban Hat San - Pleiku • Nam Mo - Ban Ve • Luang Prabang - Nho Quan	HVAC: 500 kV HVAC: 230 kV HVAC: 500 kV	PP: La->Vn PP: La->Vn PP: La->Vn	1000 100 1410
13	**Lao PDR – Cambodia** • Ban Hat – Stung Treng	HVAC: 230 kV	PP: La->Kh	300
Total Capacity				5,589
EE: Energy Exchange; PP: Power Purchase				

Sources: (ARES, 2016; ERIA, 2016; HAPUA, 2015; Ibrahim, 2014; Takapong, 2016)

Table 2.6: Updates on APG Status: Future Projects

No.	Project	System	Type	Capacity (MW)
1	**P. Malaysia – Singapore** • Plentong – Woodlands (2nd link)	HVDC: kV	PP:PM->Sg	600
2	**Thailand – P. Malaysia** • Khlong Mgae – Gurun (Addition)	HVDC: 300 kV	EE	300
3	**Sarawak – P. Malaysia** • Sarawak – P. Malaysia	HVDC: kV	PP: Sw->PM	4x800
5	**Batam – Singapore** • Batam – Singapore	HVAC: kV	PP: Bt->Sg	3x200
7	**Philippines – Sabah** • Philippines - Sabah	HVDC: kV	EE	500
8	**Sarawak – Sabah – Brunei** • Sarawak – Sabah	HVAC: 275 kV	PP: Sw->Sb	100
9	**Thailand – Lao PDR** • Nong Khai – Khoksa-at • Nakhon Phanom – Thakhek • Thoeng – Bo Keo • Udon Thani 3 – Na Bong • Ubon Ratchathani 3 – Pakse • Nan 2 – Tha Wang Pha – Nam Ou	HVAC: 230 kV HVAC: 230 kV HVAC: 230 kV HVAC: 500 kV HVAC: 500 kV HVAC: 500 kV	EE EE EE PP: La->Th PP: La->Th PP: La->Th	 600 510 315 1040
10	**Lao PDR – Vietnam** • Xekaman 1 - Pleiku 2 • Luang Prabang – Nho Quan • Nam Mo - Ban Ve	HVAC: 230 kV HVAC: 500 kV HVAC: 230 kV	PP: La->Vn PP: La->Vn PP: La->Vn	290 1600
11	**Thailand – Myanmar** • Mai Khot – Mae Chan – Chiang Rai • Hutgyi – Phitsanulok 3 • Mong Ton – Sai Noi 2 • Myanmar – Thailand	HVAC: 230 kV HVAC: 500 kV HVDC: 500-800 kV HVAC: 500 kV	PP: Mm->Th PP: Mm->Th PP: Mm->Th PP: Mm->Th	369 1190 3150-6300 7000
12	**Vietnam - Cambodia** • Tay Ninh- Strung Treng	HVAC: 230 kV	PP: Vn->Kh	465
14	**Thailand – Cambodia** • Battambang – Prachin Buri 2 • Stung Meteuk (Mnum) – Trat 2 • Koh Kong - Thailand	HVAC: 230 kV HVAC: 230 kV HVAC: 500 kV	EE PP: Kh->Th PP: Kh->Th	300 100 1800
15	**E. Sabah – E. Kalimantan** • Sipitang – East Kalimantan	HVAC	EE	200
16	**Singapore – Sumatra** • Sumatra – Singapore	HVDC	PP: Sm->Sg	600
Total Capacity				24,829-27,979
EE: Energy Exchange; PP: Power Purchase				

Sources: (ARES, 2016; ERIA, 2016; HAPUA, 2015; Ibrahim, 2014; Takapong, 2016)

Limited research on transmission expansion planning has been reported for the ASEAN context, in particular for APG establishment. Developing optimal power generation to meet the growing power demand of ASEAN countries by prioritizing renewable generation integration was presented by Y. Chang & Li, (2013). The benefits of different amounts of cross-border electricity transmission by considering the macroeconomic data of power generation and transmission, as well as the cost of losses and emission pricing, were also discussed by Y. Chang & Li, (2013). However, the availability of renewable sources (e.g., solar and wind) and the feasibility of transmission options are not considered by Y. Chang & Li, (2013). The financial sustainability of interconnecting cross-border power system for the ASEAN+2 (China and India) was presented in the study of (Y. Li & Chang, 2014), where the benefits of different amounts of cross-border power transmission were analyzed. Matsuo et al. (2015) conducted a quantitative assessment of a future APG (ASEAN + Yunnan Province of China + North East India) interconnection based on the optimum power generation planning model and the supply reliable evaluation model for 2010–2035. This study considered maximum peak power demand, power generation cost, transmission loss, and transmission cost for optimal design of APG. The cost and benefit of various interconnection routes interconnecting Vietnam, Lao PDR, and Thailand were analyzed in this study. However, this study only considered hydropower as a potential candidate for power exchange instead of optimal generation. Huber et al. (2015) proposed an optimal sustainable power system development for the ASEAN by considering all the possible renewable generation resources. Cost-benefit analysis for three specific routes of APG was conducted by Fukasawa, Kutani, and Li (2015). However, the comparison between HVAC and HVDC transmission options for the selected routes was not presented by Fukasawa et al. (2015). Operation and maintenance costs were also not considered here during cost calculation. Another evaluation study was conducted by ADB (2014) for the Borneo and Mindanao power systems. ADB (2014) concluded that the HVDC transmission options are suitable for certain routes for this part of the APG; however, more evaluation studies are required.

2.5 Major barriers and technical challenges in establishing the ASEAN grid

The establishment of APG brings the regional power industry into a common platform through interconnecting the multiple power transmission networks originating from multiple TSOs. This vertical interconnected power system may offer several economical, technical and environmental benefits like, security of supply through the integration of large numbers of generating stations, sharing of spinning reserve, improvement of load factor and load diversity, and generation investment reduction through sharing the generating facility. Interconnection also allows the utilization of most economical power sources: solar and hydro from remote areas, nuclear from special locations and large offshore wind firm connections (Sarmiento & Rosales, 2010; Sitnikov, Povh, Retzmann, & Teltsch, 2003). However, this interconnection increases a new set of challenges or uncertainties in the regional integrated power transmission network. These uncertainties include voltage and frequency deviation due to non-dispatchable production (intermittent power), congestion, blackouts as well as demand supply management for long distance power transmission network (Brancucci Martínez-Anido, 2013; Papaemmanouil, 2011). These uncertainties could act as barriers to the establishment of APG. Addressing these barriers technically is important for the enhancement of APG development. The barriers and technical challenges are highlighted and discussed in the following:

2.5.1 Energy yield

ASEAN region has a very high penetration of renewable energy sources (RESs) and ASEAN countries are also upgrading their policies to increase the generation penetration from RESs throughout its region. However, these RESs especially solar PV and wind are intermittent in nature and it can be seen that ASEAN countries aim to increase the significant amount of generation contribution from solar PV and wind. Power generation of solar PV and wind is highly depending upon geographical location and weather conditions. Therefore, it is important to have a simple and suitable monitoring system to estimate and predict the accurate performances of these variable renewable energy sources (RES) (Mason, 2016; Shah, Mithulananthan, Bansal, & Ramachandaramurthy, 2015). In addition, it can be seen that ASEAN countries have similar resource potential of solar PV and most of the countries are expecting more contributions from solar PV in the coming years (ADB, 2012; EIA, 2015c; HAPUA, 2013a; Ismail et al., 2015; Olz & Beerepoot, 2010; Prasertsan & Sajjakulnukit, 2006). Therefore, estimation and prediction of the accurate performances of these installed solar PV are very much necessary (Shah et al., 2015). Energy yield is one of the key performance indicators for solar PV which can give the true performance of the installed capacity (Mason, 2016). Precise and reliable solar PV yield can give immediate calculation of annual electricity generation from the present installed solar PV, which in-turns important for the power system planning and operation perspectives as the transmission system operators (TSOs) can predict the generation scenarios of intermittent solar PV generators (Graditi, Ferlito, Adinolfi, Tina, & Ventura, 2016).

Average yield can be calculated by dividing the PV generated energy by the PV installed capacity (kWh/kWp). However, annual yield calculation requires both the appropriate information regarding annual solar PV power generation and installed capacity throughout its geographical area. It is also necessary to have the correct information about the tilt and orientation (azimuth) as well as performance of PV plants. Various methods are presented for estimating solar PV generation, such as analytical methods (Omar, Hussin, Shaari, & Sopian, 2014; Torres-Ramírez, Nofuentes, Silva, Silvestre, & Muñoz, 2014; Yan, Saha, Meredith, & Goodwin, 2013), combination of numerical and analytical methods (Navabi, Abedi, Hosseinian, & Pal, 2015), combination of physical approach and modern techniques like neural-network(Graditi et al., 2016) and others. Web-based system has been developed for the estimation of solar PV generation for Europe and Asia by the European Commission Joint Research Centre (EC-JRC) (Huld, Müller, & Gambardella, 2012).

2.5.2 Coordination and information sharing among TSO's

APG aim to link regional power markets and share individual resources for common interests. Different TSOs control different regional power markets. Interconnection of the individual power system via APG will create a power system that is a composition of different regional interconnected power system, operated by different regional TSOs. Multi-TSOs will share the network for transmitting power, and it is important to prepare a guideline for sharing the network resources by individual TSOs. The lack of interconnection could be a hindrance to realizing significant improvements to the quality and efficiency of its operation, and could create major disturbances, leading to blackouts in the interconnected power system (Zhang, Li, Liu, & Yang, 2012). It was found that the lack of co-ordination among TSOs resulted in blackouts in the US, Italy, and European transmission grids (Bialek, 2003; UCTE, 2007). Moreover, the lack of co-ordination amongst TSOs might increase the cost of network constraints in the short term, and investment might become unproductive in the long run. Moreover, cross-border investors (TSOs) do not take into account the needs of regional networks when investing (Strbac et al., 2014). Furthermore, information sharing among TSOs is important in a multi-TSOs network, because the lack of information sharing might create unnecessary complications to the TSO. If the operation limits of one reached its maximum point with saturated control limit, then accessibility to the neighboring TSOs information is necessary to maintain stable operation of the interconnected power system networks (Corsi, 2009b). Therefore, co-ordination amongst multiple TSOs and sharing of information between neighboring TSOs are very important during the development of APG, in order to enhance system security, reliability, and the efficiency of the large geographically distributed power network.

2.5.3 Critical ancillary services control

TSOs consider voltage and reactive power control services as critical ancillary services in a deregulated power market, where multiple TSOs are involved in the integrated power system network (Mousavi & Cherkaoui, 2013). In long-distance transmission system, supplying reactive power is a great challenge, due to the leading nature of additional active and reactive power losses. Therefore, reactive power management system is developed by individual TSOs within their own respective area locally, and for this reason, the voltage and reactive power management for interconnected power system draw less consideration from the TSOs (Mousavi & Cherkaoui, 2013). However, voltage and reactive power control are needed throughout the system. Although voltage control is primarily a local problem, the widespread blackouts in recent decade have demonstrated that the voltage instability and collapse as the major cause of global power outages around the world (Lu, Bésanger, Zamaï, & Radu, 2006). Reducing active power losses in one TSO region may increase the loss of another region (Mousavi & Cherkaoui, 2013). As a result of this, it is important to develop mutual voltage and reactive power control methodologies inside different TSO areas, as well as between control paradigms to mitigate the problem of voltage and reactive power control. Moreover, it can be seen from recommendations of the European network of transmission system operators for electricity (ENTSO-E) that within the interconnected network, multi-TSOs should harmonize their voltage control mechanisms and maintain acceptable voltage range at individual interconnection links (Corsi, 2009a; Phulpin, Begovic, & Ernst, 2010). So, maintaining critical ancillary services is very challenging for the interconnected multi-TSOs power network, and it is important to pay attention to this and maintain critical ancillary services during the development of APG to enhance its robustness and reliability.

2.5.4 Inter-TSO compensations

Generators from multiple producers, along with a large number of consumers, are being interconnected in a modern power system network. This network contains sufficient transmission and distribution facilities to provide the necessary electrical energy demand to consumers. This interconnection, in turn, links several TSOs within an integrated network. Similar to this, the development of APG will bring multiple TSOs into one interconnected network and enhance the cross-border trade among ASEAN countries, or different TSOs within ASEAN countries. This interconnection aims to transmit electrical power, meaning that power can be transferred from one country to another using a third country's network infrastructure. Cross-border trade, as well as hosting cross-border trade or transit, increase power flow and losses. Presently, Lao PDR, Thailand, Malaysia, Singapore (LTMS) Power Integration Project (LTMS-PIP) is the first multilateral cross-border power trade in ASEAN, which is going to be established in the following manner as shown Figure 2.13 (APGCC, 2015). It can be surmised from Figure 2.13 that multilateral cross-border power trade will take place from Lao PDR to Singapore via the usage of existing transmission network connection of Thailand and Malaysia. For this case, Thailand and Malaysia will host the cross-border power trade between Lao PDR and Singapore. It is necessary to consider the transmission losses and congestion of existing networks of Thailand and Malaysia.

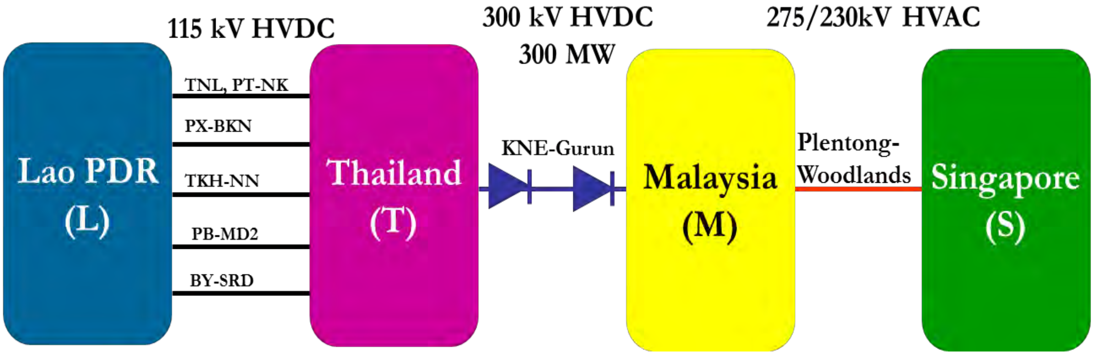


Figure 2.13. Block diagram of LTMS-PIP (APGCC, 2015).

On the contrary, the integration of large-scale renewable energy sources from ASEAN countries is the aim of APG, and this integration, in APG, challenges the existing transmission system due to increased congestion and cross-border flows. ASEAN countries have taken various variable renewable energy integration targets, and most of these sources are located in remote areas, far from load centers. These remotely located variable generations will result in internal congestion and cross-border trades. For example, the Greater Mekong sub-region (GMS) countries, such as Cambodia, Lao People's Democratic Republic (Lao PDR), Myanmar, Thailand, and Vietnam possess abundant resources relative to their respective electricity demand, and for this reason, it is expected that cross-border flows will increase from countries of the GMS region towards others. This cross-border flow will increase congestion in the existing network, and the transmission networks from different countries might be utilized to facilitate cross-border trade from the GMS region. As a result of this, more investment for transmission network extension, or congestion management costs, are required for the TSOs of the GMS region. Congestion management can be realized via efficient control of existing network, as well as transmission capacity enhancement through transmission grid extension, which involves high capital and optimal planning via concentration of long-term electricity generation and highly uncertain load forecasts (Fursch et al., 2013; Munoz, Hobbs, Ho, & Kasina, 2014). In integrated power networks in Europe, an individual country's network congestion is managed by re-dispatching (Oggioni, Murphy, & Smeers, 2014). Managing congestion for increased cross-border flow due to the addition of large-scale variable generation is a great challenge for ASEAN countries in the course of the establishment of APG.

The previous discussion showed that it is important to allocate costs and revenues between the participating TSOs, and for this reason, inter-TSO compensations are crucial (Androcec, Krajcar, & Wangensteen, 2011; Olmos & Perez-Arriaga, 2007). Inefficient methods of pricing may create obstacles to the development of a regional grid. Several methods for inter TSOs compensations are reported in (Camacho & Perez-Arriaga, 2007; Daxhelet & Smeers, 2005; SAGUAN, AHNER, DE HAUTECLOCQUE, & GLACHANT, 2011; Stoilov, Dimitrov, & Francois, 2011; Stoilov & Stoilov, 2013) for pan-European transmission grids. These inter TSO compensation methods are mostly based on With-and-Without Transits (WWT), marginal participation (MP), average participations (AP), grid losses in WWT, and cross-border flows hosting via infrastructural compensation. During the establishment of APG, the experience of inter-TSOs compensations for the European transmission grid can be considered when designing inter-TSOs compensations for APG to mitigate the pricing problems, as well as take back the capital and operational expenses from different TSOs.

2.5.5 Formation of offshore grid-its control and operation

ASEAN countries have great potential for offshore wind energy, and the establishment of APG will create the opportunity to utilize them in fulfilling the energy demand. Moreover, linking ASEAN countries can be done efficiently via the construction of an offshore transmission grid. This long-distance offshore power transmission can be done through either high-voltage alternating current (HVAC) or high-voltage direct current (HVDC) transmission technologies (Bresesti et al., 2007; Wu et al., 2011). However, high voltage AC cables have high capacitance, which in turns limit the active power transmission over certain distances through the HVAC transmission system (Henry, Denis, & Panciatici, 2010). As a result of this, HVDC transmission system is becoming an attractive solution for transferring high power from the large capacity offshore wind farms, due to the advantages of HVDC technology, such as cost effectiveness, smaller size and weight, low power losses due to two cables, reactive power management, and harmonics (Lu & Ooi, 2003; Meyer, Hoing, Peterson, & De Doncker, 2007; Mura, Meyer, & De Doncker, 2010). Two types of HVDC transmission technologies are present; one is current source converter (CSC) based classical HVDC transmission system called line commutated converter (LCC), while the other is a self-commutated voltage source converter (VSC) based HVDC transmission system (Nikolas Flourentzou, Vassilios G Agelidis, & Georgios D Demetriades, 2009; R. S. Li, Bozhko, & Asher, 2008). LCC-HVDC contains naturally commutated thyristor valves, and these converters need a relatively strong synchronous voltage source to assist the communication of thyristor valves, as well as reactive power during the conversion process. Also, LCC-HVDC system does not provide independent control of active and reactive powers (Bahrman & Johnson, 2007). On the contrary, VSC-HVDC transmission configuration is becoming a more appropriate technology, due to higher capabilities in delivering bulk power, self-commutated, and dynamic voltage control features. Furthermore, VSC-HVDC system utilizes insulated gate bipolar transistors (IGBTs), as it does not require active communication voltage and higher switching frequency for usage, which in turns results in harmonic contents minimization and filter size reduction. In addition, active and reactive power can be controlled independently in VSC-HVDC transmission technology (N. Flourentzou, V. G. Agelidis, & G. D. Demetriades, 2009; Knaak, 2011). However, the VSC-HVDC system results in higher losses compared to the LCC-HVDC, due to the higher switching frequency of IGBT (Nandlal Popat, 2013). So, it is important that this be taken into account during the offshore grid design. Additionally, the HVDC system configuration may be point-to-point or multi-terminal HVDC (MTDC) system, where MTDC is more advantageous compared to point-to-point HVDC system such as increment of the reliability of power transmission by increasing its transmission path, as well as connecting several power markets to facilitate power trade. Furthermore, the MTDC system can either be connected in series or parallel to the MTDC system. Both have their respective advantages and disadvantages, such as losses and insulation requirement in point-to-point MTDC system being higher compared to the parallel connected MTDC system; the parallel MTDC system improve the reliability of the system; the high response DC circuit breaker for isolating fault lines arrangement is very difficult for parallel MTDC, since the clearing time for parallel MTDC system is 4ms, which is not commercially available (Callavik, Blomberg, Häfner, & Jacobson, 2012). Moreover, offshore grids can be connected in radial and mesh connection configurations, and various complicated control arrangements are required to maintain normal operation of the different types of offshore grid systems (Dierckxsens et al., 2012; Kalcon, Adam, Anaya-Lara, Lo, & Uhlen, 2012). Consequently, it is seen that the formation of the offshore grid, with necessary configuration and control system, is a very challenging task, and might be a hindrance in the course of the establishment of APG.

2.5.6 Identification of future generation investment zone and probabilistic evaluation of reserve margin for the system

The reliability of the generation system is very important for the large interconnected power system because it shows the need of supply in the context of demand (Papaemmanouil, 2011). To supply the incremental demand of the electric power, it is necessary to identify the potential generation investment zones, which in turn help identifying the future generation investments for utilizing accessible generation sources, especially, renewable generation sources to meet clean energy developments (Mishra, Ledwich, Ghosh, & George, 2012). Thus, member countries should work together to develop future power infrastructure zone strategically like identification of generation zone near the border area, so that, could contribute both the regional and cross-border power demand (Wu, 2013). Strategical identification of future renewable generation investment zone through integrated resource planning could reduce the dependency on imported fossil fuel based power generation and inadequacy of supply resources for this region as well as could reduce the installed capacity of power to meet the demand (Pagnarith & Limmeechokchai, 2015a, 2015b). Lack of identification of future investment zone could limit the sustainable power infrastructure development and reduce the benefit of APG.

On the other hand, reliability or adequacy of the generation system can also be measured via its reserve margin. Generation capacity is reserved for maintaining load demand in case of outage of the generators due to fault or maintenance. Reserve margin can be set via two ways: deterministic and probabilistic (Diewvilai, Nidhiritdhikrai, & Eua-arporn, 2011). A fixed percentage of maximum peak load demand is considered as a reserve margin in deterministic reserve margin approach, whereas the reserve margin is set by considering a reliability index, namely Loss of Load Expectation (LOLE) in the probabilistic approach (Nitikitpaiboon & Eua-arporn, 2010). The deterministic method does not consider generation failure and demand forecast uncertainties, however, the probabilistic method accounted for these uncertainties during the reserve margin calculation. This is important during calculating the reserve margin, as not accounting for it might result in over or under estimation. Overestimation reserve margin will result in high electricity price to the consumers, while lower reserve margin results in shortage of electricity to consumers. Therefore, future generation investment and probabilistic evaluation of the reserve margin is important towards enhancing the performance and system security of the large geographical APG.

2.5.7 Integrated transmission and generation planning

Electricity demand is increasing, and in order to meet this demand via sustainable development, it is necessary to plan a power system expansion so that the future generation can meet the electrical power demand in an economical, reliable, and environmentally friendly manner (Moghaddam, Javidi, Moghaddam, & Buygi, 2013). The power system expansion problem contains transmission expansion planning, generation, expansion planning, and the coordination of both transmission and generation expansion planning (Aghaei, Akbari, Roosta, Gitizadeh, & Niknam, 2012; de la Torre et al., 2008; Khodaei, Shahidehpour, Wu, & Li, 2012; Pozo, Sauma, & Contreras, 2013). In a deregulated market, the transmission system, which is operated by different TSOs, are responsible for assessing the transmission expansion investments that are needed in accordance with economics and reliability. On the contrary, generation system planners decide on their investments, while transmission system planners have no involvement in that. Despite the fact that transmission and generation are completely different, their interactions and interrelationships are important. Coordination and centralization between the generation developer and the transmission planner are important within a competitive electricity market, because the generation developer wants to exploit the market opportunities, while the transmission planner focuses on developing an operating a system in an efficient and reliable manner. Therefore, the centralization and coordination between transmission generation and planning are required, otherwise, it might results in a hazardous, incomplete, and irregular system design (Bresesti, Gallanti, & Lucarella, 2003). Also, a deregulated integrated planning process can decide the best expansion plan for the region, state, or country (Cedeño & Arora, 2013). Furthermore, the effect to the environment is a matter of concern to many people, and for this reason, the effect of power system planning on the environment needs to be carefully analyzed (Shu, Wu, Zhang, & Han, 2015). Consequently, the ASEAN region requires the coordinated transmission and generation planning for economic management of future demands by developing a sustainable power system. Lack of coordinated transmission and generation planning could limit the development and maximum utilization of interconnected transmission system benefit and increase the system cost with the unbalanced generation and transmission development and might transfer negative information to the investors (Papaemmanouil, 2011; Singh, Frei, Chokani, & Abhari, 2016). Consequently, it is seen that coordinated transmission and generation planning is a very challenging task, and might be a hindrance in the course of the establishment of APG.

2.5.8 Benefit-cost analysis

It is very important to evaluate the techno-economic evolution of the designed transmission system. Conducting this benefit-cost analysis is important for comparing and assessing various transmission alternatives. The transmission grid which shows the highest difference between benefit and cost are chosen as the best transmission configuration. Literature shows that operation cost, investment cost, maintenance cost and possible dismantling cost are the prime factors during cost calculation. Whereas, grid congestion relief, CO_2 emission reduction, network loss reduction, reduction of generation cost, improvement of system adequacy to enhance demand and operation security, higher integration of RES to the power system network, and avoided investment are the main factors during benefit evaluation (ENTSO-E, 2013; Westermann et al., 2010).

Investment cost related to the cost refers to the costs of construction and infrastructure development of the transmission grid. Therefore, the costs related to investment cost are transmission line development cost, compensation, stations, operation and maintenance cost, system and line losses. Nevertheless, investment costs are greatly influenced by environmental, technical and socio-economical aspects of the project. Therefore, these must be considered during calculation of investment cost. In contrary, variable costs are related to functional costs like reactive power control, damping control, network start up, and frequency control. But, for HVDC the variable costs are mostly dependent on the structure of the transmission network (ENTSO-E, 2013; Westermann et al., 2010).

Transmission expansion planning in any jurisdiction requires a huge amount of investment. It is necessary that this transmission investment must be justified through the comprehensive economic analysis in a market environment and the economic analysis of the transmission planning can be conducted in the form of cost-benefit analysis (Ergun et al., 2012; Hasan, Saha, Chattopadhyay, et al., 2014; Torbaghan et al., 2015). Therefore, net market benefit analysis of the ASEAN power grid is necessary to justify the investment as well as to identify the future transmission investment zone during establishing APG.

2.6 Summary

An overview of the ASEAN energy market is presented in this chapter highlighting the rational of the project described in this research. Subsequently, the energy resources status of ASEAN including fossil fuels and renewables as well as present and future energy demand are discussed. Electricity generation, demand, export-import scenarios along with transmission planning by giving priority to renewable generation are discussed also. In addition, this chapter identifies the major barriers and the technical challenges for establishing ASEAN grid. The next chapter shows the modeling details of ASEAN Power Grid (APG) in MATLAB/MATPOWER simulation environment for various analysis. The results obtained from the developed APG model could contribute establishing APG in secure and sustainable way.

CHAPTER 3: MODELING OF ASEAN POWER GRID

3.1 Introduction

In recent years, growing concern for clean energy to reduce emissions and minimize the reliance on fossil fuels have led to the worldwide integration of renewable energy generation. For overcoming the challenges associated with the large-scale deployment of renewable energy, countries around the world are upgrading their policies to increase the contribution from renewable energy (RE) to their energy mix. The previous chapter shows that the ASEAN region has abundant RESs generating potential and ASEAN is expecting increasing contribution from RESs in the electricity generation mix due to APG interconnections and policy upgradations by ASEAN countries.

This chapter presents and describes the details of the APG model, a minimum-cost power generation model for the ASEAN electricity market. APG model has been developed in MATLAB/MATPOWER simulation environment for analyzing the ASEAN electricity transmission network and the benefit of interconnecting ASEAN electricity market. In addition, developed APG model has been utilized to investigate the future needs of additional cross-border transmission needs in ASEAN for a low-cost generation by considering the available power generation options of individual countries. The developed model has been used for the study carried out in chapters 4 and 5.

The rest of the chapter is organized as follows: Section 3.2 contains detail descriptions of the APG model. Section 3.3 shows the modeling considerations of APG network followed by modeling of generation in Section 3.4. Section 3.5 and Section 3.6 show the demand and generation cost respectively. Section 3.7 briefly illustrates the scenario data. Section 3.8 shows the cross-border transmission capacity from ACE. The mathematical formulation is presented in Section 3.9 followed by a summary in Section 3.10.

3.2 Description of the APG model

The APG model is developed to analyze the impact of the changes in the transmission network portfolio of independent transmission system operators (TSOs) in ASEAN countries through cross-border interconnections. It also analyzes the impact of changes in the electricity generation portfolio upon cross-border electricity flows to meet the demand. Consequently, the develop APG model also estimates cross-border transmission needs to meet the demand for 2030 ASEAN electricity market scenarios from low-cost generation options. In addition, the develop APG model also analyze the economic characteristics of HVAC and HVDC connection options for all cross-border interconnections by considering the maximum requirements for the cross-border transmission capacity under 2030 scenarios. Accordingly, all types of generation portfolios and maximum peak demands of 10 ASEAN countries are considered. The variable generation costs of each type of generation are considered during the calculation of the optimal cross-border power flows among the interconnections. However, the model does not consider optimal cross-border transmission routes toward APG establishment.

APG model focuses on minimum-cost power generation options to meet the growing electricity demand. To calculate the realistic cross-border transmission requirement of the ASEAN countries for the 2030 scenario, energy market simulation is incorporated into this model. The market simulation model is designed for the minimum cost of the ASEAN power generation model for the APG. Energy market simulation is conducted as an optimization problem. DC OPF can be calculated by using MATPOWER (Zimmerman, Murillo-Sanchez, & Thomas, 2011) and Gurobi Optimizer, a high-performance mathematical programming solver (Gurobi, 2017). The developed APG energy market optimization model has been coded in MATPOWER and Gurobi Optimizer. MATLAB is used to perform input/output data processing.

The objective function of this model is to maximize social welfare or minimizing the variable generation costs of electricity for the ASEAN countries by giving priority to cross-border transmission. Variable generation costs of electricity are different for the individual power plant. Variable generation costs include all kinds of operation and maintenance cost and fuel costs. In addition, emission costs (CO_2) are not included within variable electricity generation costs during optimization, however, emission costs (CO_2) are considered during analyzing the net market benefit of establishing APG interconnection. Variable generation costs of electricity may vary depending on the scope of the analysis and the time horizon of the scenario to be modeled. This variation of variable generation costs is due to changes of fuel prices, efficiencies of the power plant and emission prices. Neither feed-in-tariffs (FiT) nor renewable portfolio standard (RPS) is considered for RESs. Details of the variable generation costs are shown in Section 3.6. Investment costs for electricity generation and transmission are not considered in the optimization model. However, electricity generation and transmission investment costs are considered during investigating the economic characteristics of HVAC and HVDC connection options for all cross-border interconnections and analyzing the net market benefit of establishing APG interconnection.

The individual power transmission networks of APG are considered as a single node; the internal network constraints are not considered. The reasons for this consideration are the lack of publicly available data (e.g., transmission line capacity, electricity consumption, and generation time series) on the entire ASEAN transmission network and the computational complexity considering with a large geographic transmission network. In addition, demand and generation data are not available at a high geographical order than only for per node. The unavailability of detailed demand and generation data for ASEAN countries compels the representation of large geographical countries, such as Myanmar, Thailand, Vietnam, and Laos, by only one single region in this model.

Nevertheless, the results could give the idea about the future cross-border power transmission scenario for the ASEAN region to the investors and policy makers.

Major limitation of considering a simplified single node network for analyzing cross-border transmission is that internal network congestion is not considered. Internal network congestion is sometimes more critical than congestion in cross-border. During considering the results from APG, it should be considered that internal network congestion and flows are not considered during modeling. However, transmission assumptions considered here in this thesis do not affect the purpose of this study and the meaning and validity of the results. The main goal of designing the APG is to model the cross-border interconnection in the ASEAN region. Within this scope, the benefit of ASEAN energy market integration and the future needs of cross-border power transmission as well as the suitable technology of the cross-border transmission link are analyzed by modeling the evolution of the system and by comparing various economic appraisal of the designed system.

3.3 APG network

The APG model is represented by 15 nodes because of the presence of 15 isolated TSOs in the interconnection projects. Myanmar, Thailand, Laos, Cambodia, Vietnam, Singapore, Brunei, and Philippines (Luzon grid) are represented by a single node. Malaysia is represented by three nodes, namely, Peninsular Malaysia, Sarawak, and Sabah. Indonesia is represented by four nodes, namely, Sumatra, Batam, W. Kalimantan, and E. Kalimantan. These 15 nodes are interconnected by cross-border transmission links as APG aims to transfer power among these 15 isolated TSOs (ACE, 2015b; Ibrahim, 2014).

The transmission network is parameterized by publicly available data for the given transmission voltage level for the power flow and optimal power flow (OPF) modeling.

The typical single-circuit reactance value used in the model is 0.31 ohm/km for 380 kV lines at 50 Hz during the DCOPF modeling (Say, 1973). Resistance and shunt admittance have been ignored in the DC power flow model for simplicity (Zhou & Bialek, 2005). In modeling the APG network, only distances of the cross-border interconnections are considered (ADB, 2014; Energy Commission, 2016; Fukasawa et al., 2015). In countries where more than one cross-border interconnection takes place, the longest distances among these interconnections are considered in the model. Table 3.1 presents the individual cross-border interconnections distance which are considered during the modeling of APG network in this study.

Table 3.1: Distances between the individual interconnecting nodes (ADB, 2014; Energy Commission, 2016; Fukasawa et al., 2015)

From	To	Distances (km)	
		Overhead	Underground
Myanmar	Thailand	250	0
Thailand	Laos	270	0
Thailand	Cambodia	300	0
Laos	Cambodia	50	0
Laos	Vietnam	203	0
Cambodia	Vietnam	50	0
Thailand	Peninsular Malaysia	110	0
Peninsular Malaysia	Singapore	12	4
Peninsular Malaysia	Sumatra	189	83
Peninsular Malaysia	Sarawak	800	850
Singapore	Sumatra	180	90
Singapore	Batam	40	0
Sarawak	West Kalimantan	128	0
Sarawak	Brunei	13	0
Sarawak	Sabah	13	0
Sabah	East Kalimantan	130	0
Sabah	The Philippines (Luzon)	400	400

The single-line diagram of the APG is shown in Figure 3.1. The base KV and MVA of this network are considered 380kV and 100MVA respectively. The total active power demand and the power generation of the APG network are 262453.4 MW and 318323.1 MW respectively. The detail specifications of the network are given in Appendix A.

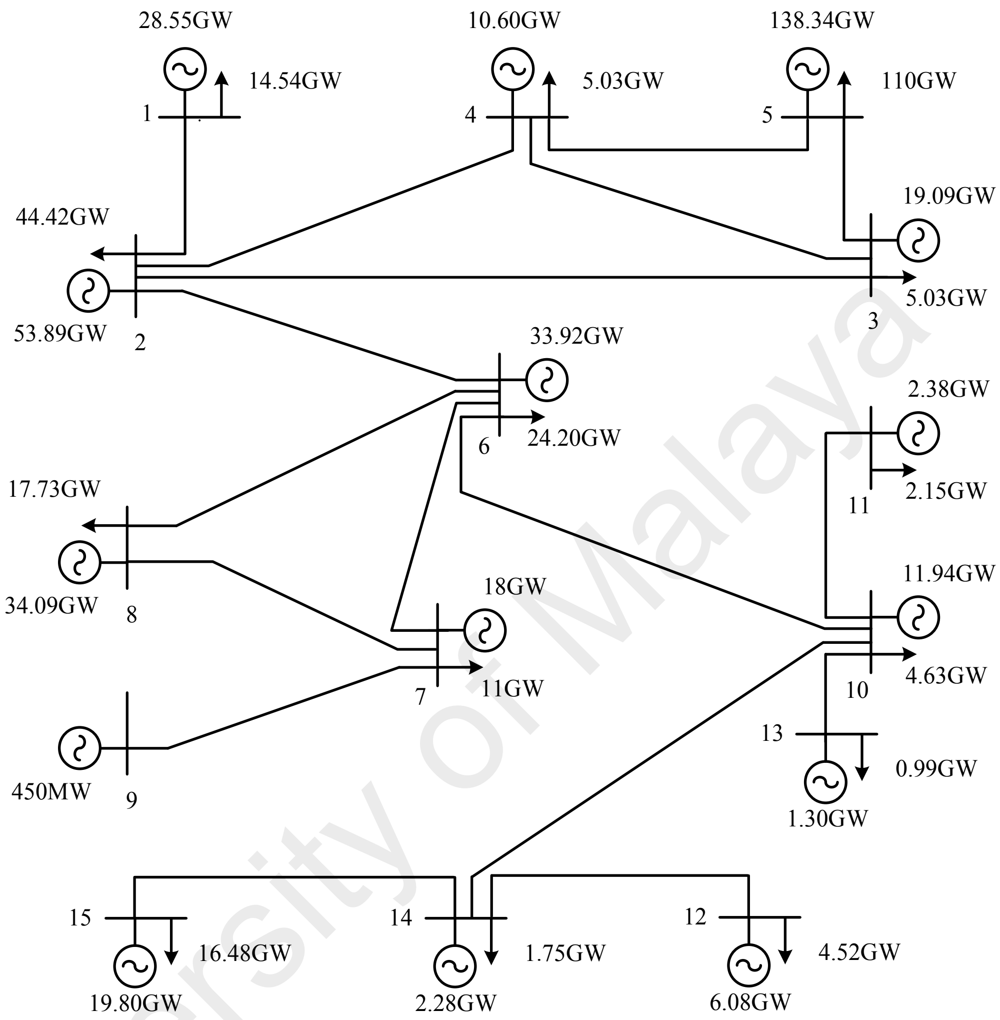


Figure 3.1: Single-line diagram of ASEAN Power grid.

The develop APG model requires the following inputs:

- Net electricity generation capacities for each of the individual power plant at each node
- Load demands at each node
- Variable generation costs for individual power plant
- Cross-border transmission limits

The detail descriptions are provided in the following sections. The main outputs of the develop APG model are:

- Generation of each individual power plant at each node
- Cross-border electricity flows
- Electricity generation related CO_2 emissions
- Locational marginal prices (LMPs) of individual node

3.4 Modeling of generation

Power generation from all types of conventional and non-conventional energy sources is considered. Each type of source (coal, natural gas, oil, nuclear, hydro, solar, wind, biomass and geothermal) is represented by a virtual power plant with the total net installed capacity of the respective node. However, the model divides the total installed capacity of all energy sources, except for oil-based power generation plants, in a node into a single unit with a maximum rated capacity of 1000 MW. The rated capacity of 400 MW is considered for oil-based power plants. The reserve margins of each node are not modeled individually but are partly considered when setting up the minimum and maximum power output levels of individual generating units. Various operational constraints of the individual generating units have been considered following the studies of (Hewes, Altschaeffl, Boiarchuk, & Witzmann, 2016; Martinez-Anido et al., 2013; Zhou & Bialek, 2005). These operational constraints are explained in the following sections.

3.4.1 Conventional generation

Coal is the largest contributor to the fuel mix because of its availability and low cost. Coal will contribute roughly 35.67% of the total installed capacity in 2030. A coal power plant has a high capital cost and low fuel cost. It is considered as a base–load in the power plant in this model, and its output can vary at 70%–100% of its available rated power. Natural gas is the second largest contributor to the fuel mix, and it will contribute roughly 25.63% of the total installed capacity in 2030. Its power output is limited to 40%–100% of its available capacity. By contrast, because of its high operating cost, an oil-based power plant is considered as a peak-load in the power plant. Its output can vary between the minimum and maximum available capacities. The outputs of individual power plants are corrected by the availability factor of the respective type of power plant (Chang & Li, 2015). It should be noted that Vietnam plans to introduce a nuclear power plant. Given its high capital cost and low operational cost, a nuclear power plant is also considered a base–load in the power plant. Its output can vary at 70%–100% of its available rated power. The availability factor of nuclear energy is taken from the World Nuclear Association (WNA, 2016). Table 3.2 summarizes the operational constraints of the individual power plants.

Table 3.2: Operating considerations of individual power plants

Fuel	Type	Maximum Availability	Operating Range
Coal	Base Load	0.85	70%–100%
Natural Gas	Combination	0.85	40%–100%
oil	Peaking	0.85	0%–100%
Nuclear	Base Load	0.85	70%–100%

3.4.2 Renewable generation

Hydropower is the most abundant and reliable renewable energy source in the ASEAN region, and it will contribute to about 26.63% of the installed capacity in 2030. Both large and small hydropower generators can have varying generation levels at 0%–100% of the available generation capacity. Despite the high potential of solar and wind, ASEAN countries will have a small contribution to power generation from these sources, with a combined contribution of 4.66% of the installed capacity. This model considers that solar and wind can generate a maximum of 25% and 50% of its installed capacity, respectively, because of the weather dependency of these sources. Geothermal energy sources have a high potential in the Philippines and Indonesia. These countries are taking initiatives to enhance the generation from this source. Power output from a geothermal power plant is considered here to vary between the minimum and maximum available capacities. In addition, ASEAN countries have a great biomass potential. Biomass power plant output is constrained by the maximum available capacity in the model. Although biomass is cheaper than natural gas, it is not considered a base load because of the limitations of its supply chain.

3.5 Modeling of demand

The load demand of each node has a significant effect on DC optimal power flow (DC-OPF) during developing APG model. Unfortunately, no publicly available data about the demand of each individual zone are available. Therefore, peak electricity demand of each node is considered as the load demand for this model. Individual node peak electricity demands are taken from publicly available sources, mostly from the power development plans of TSOs.

3.6 Modeling of the variable generation cost

The objective function of this model is to maximize the social welfare or minimize the variable generation costs for the ASEAN countries by giving priority to cross-border transmission. Variable generation costs are the sum of the operation and maintenance costs and the fuel costs for individual electricity generation sources. The levelized variable generation cost of electricity for 2030 is calculated based on (Chang & Li, 2015; EIA, 2015a; Huber et al., 2015; IEA, 2015e; NREL, 2016; Short, Packey, & Holt, 1995), in which all assumptions are in 2014 US dollars. As mentioned earlier, variable generation cost depends upon the fuel prices and coal price is considered USD 80/tonne and gas price is considered USD10/MBtu during calculating levelized variable generation cost.

Operation and maintenance costs, lifetime, and capacity factor of the various power plants for the ASEAN region are presented in Table 3.3.

Table 3.3: Levelized O&M cost for ASEAN countries

Generation Technologies	Total O&M cost (USD/MWh)	Lifetime (Years)	Capacity Factor (%)
Coal CCS	41.13	30	75
Coal	34.84	30	75
Gas CC	70.60	25	60
Gas OC	64.77	25	75
Oil	212.88	30	75
Advanced Nuclear	24.00	30	90
Hydro	29.05	35	33
Small Hydro	31.47	35	33
PV	21.10	20	17.5
Wind	21.74	20	27
Geothermal	16.92	20	75
Biomass	26.75	30	75

Sources: (Chang & Li, 2015; EIA, 2015a; Huber et al., 2015; IEA, 2015e; NREL, 2016; Short et al., 1995)

3.7 Scenario data

Electricity generation and demand data for the 2030 scenario are taken from publicly available sources, mostly from the power development plans of TSOs. Scenarios with key considerations on the assumptions for the electricity installed capacity and demand of individual nodes are given in Table 3.4. Electricity installed capacity and demand data is presented in Table 3.5 by considering the scenarios in Table 3.4.

Table 3.4: Scenarios of electricity generation and demand for the ASEAN

Node	Key Considerations	References
Myanmar	• Least cost generation scenario.	(JICA, 2015; Nam, Cham, & Halili, 2015)
Thailand	-	(Ministry of Energy, 2015)
Lao PDR	-	(EDL, 2013; Phonekeo, 2015)
Cambodia	• The annual average power demand increment rate for 2025–2030 will be same as that for 2021–2024.	(Electricity Authority of Cambodia, 2015; ERIA, 2013; Ritouch, 2011)
Vietnam	-	(Hung, 2014; MOIT/GIZ, 2016)
Peninsular Malaysia	• The coal and natural gas-based power generation increment rate for 2026–2030 will be the same as that for 2015–2025. • Less hydro and more solar and biomass will be developed due to low hydro potentials.	(ARES, 2015; Energy Commission, 2016; IRENA, 2014)
Sabah	• Power generation will depend on gas, and an insignificant amount of power will be produced from oil.	(Energy Commission, 2016)
Sarawak	-	(Energy Commission, 2016; HAPUA, 2013b; Sarawak Energy, 2016; Shirley & Kammen, 2015; TNB, 2014)
Singapore	-	(APERC, 2013)

Table 3.4, Continued

Node	Key Considerations	References
Sumatra, Batam, West Kalimantan, East Kalimantan	• The annual average generation and demand increment rate for 2025–2030 will be same as that for 2015–2024. • Geothermal power development will be prioritized. • About 70% of oil generation and 10% of gas generation will be decommissioned because of the aging issue. • East, Central, South, and North Kalimantan are considered a single node called East Kalimantan because they will be interconnected by 2018.	(RUPTL, 2015)
Brunei	• The single-cycle gas power plant will be converted to combined cycle with an efficiency of 45%. • Renewable generation will be 5%.	(APERC, 2012; ERIA, 2015)
The Philippines (Luzon)	• Renewable generation will be prioritized.	(APERC, 2013; Asirit, 2012; Department of Energy, 2012)

Table 3.5: Installed generation capacity and demand of ASEAN countries for 2030

Nodes	Coal (GW)	GAS CC (GW)	GAS OC (GW)	Oil (GW)	Nuclear (GW)	Hydro (GW)	Small Hydro (GW)	PV (GW)	Wind (GW)	Geothermal (GW)	Biomass (GW)	Total Installed Capacity (GW)	Peak Demand (GW)
Myanmar	5.03	-	2.48	-	-	12.15	6.89	0.22	1.70	0.08	-	28.55	14.54
Thailand	4.76	24.21	6.72	0.32	-	5.55	0.26	4.89	1.99	0.00	5.20	53.89	44.42
Laos	1.80	-	-	-	-	17.00	-	-	0.25	-	0.04	19.09	5.03
Cambodia	2.50	-	-	-	-	8.10	-	-	-	-	-	10.60	5.03
Vietnam	75.00	6.00	11.30	-	10.7	22.11	5.04	-	6.20	-	2.00	138.34	110.00
P. Malaysia	15.60	8.36	4.49	-	-	3.92	-	1.40	-	-	0.15	33.92	24.20
Singapore	-	16.38	-	1.08	-	-	-	-	-	-	0.54	18.00	11.00
Sumatra	14.97	0.25	7.10	0.16	-	7.05	0.35	-	-	4.20	0.02	34.09	17.73
Batam	-	-	-	-	-	0.50	-	-	-	-	-	0.50	0.00
Sarawak	1.98	-	0.88	0.14	-	8.84	-	0.05	-	-	0.05	11.94	4.63
W. Kalimantan	2.02	-	0.32	0.04	-	-	-	-	-	-	-	2.38	2.15
E. Kalimantan	4.30	-	1.47	0.08	-	0.22	-	-	-	-	-	6.08	4.52
Brunei	-	1.29	-	-	-	-	-	-	-	-	0.01	1.30	0.99
Sabah	-	1.66	-	0.04	-	0.49	-	-	-	0.03	0.06	2.28	1.75
The Philippines (Luzon)	7.88	0.65	4.03	0.91	-	2.90	0.02	0.07	0.97	2.18	0.19	19.80	16.48

Sources: (APERC, 2012, 2013; ARES, 2015; Asirit, 2012; Department of Energy, 2012; EDL, 2013; Electricity Authority of Cambodia, 2015; Energy Commission, 2016; ERIA, 2013, 2015; HAPUA, 2013b; Hung, 2014; IRENA, 2014; Ministry of Energy, 2015; MOIT/GIZ, 2016; Nam et al., 2015; Phonekeo, 2015; Ritouch, 2011; RUPTL, 2015; Sarawak Energy, 2016; Shirley & Kammen, 2015; TNB, 2014)

3.8 Cross-border transmission capacities

In the develop APG model, each of the 15 isolated TSOs are represented by a single node. These 15 nodes are interconnected by cross-border transmission links with specific transmission capacity. The cross-border transfer capacity between two individual nodes is defined as the net transfer capacity (NTC) of the respective transmission link of APG. NTC values of individual transmission links are taken from the updates on APG existing, on-going and future projects from Heads of ASEAN Power Utilities / Authorities (HAPUA) secretariat (ARES, 2016; ERIA, 2016; HAPUA, 2015; Ibrahim, 2014; Takapong, 2016). NTC of individual cross-border transmission links are calculated by summing the existing, on-going and future transfer capacity of all the projects as the APG in this study is developed for 2030 scenario. Table 3.6 shows the NTC values of individual transmission links of APG.

Table 3.6: Net transmission capacities of individual cross-border transmission links

No.	From	To	NTC (MW)
1	Myanmar	Thailand	14859
2	Lao PDR	Thailand	7928
3	Cambodia	Thailand	2300
4	Lao PDR	Cambodia	300
5	Lao PDR	Vietnam	4648
6	Cambodia	Vietnam	665
7	Peninsular Malaysia	Thailand	1080
8	Peninsular Malaysia	Singapore	1050
9	Sumatra	Peninsular Malaysia	600
10	Sarawak	Peninsular Malaysia	3200
11	Sumatra	Singapore	600
12	Batam	Singapore	600

Table 3.6, Continued

No.	From	To	NTC (MW)
13	Sarawak	West Kalimantan	230
14	Sarawak	Brunei	200
15	Sarawak	Sabah	100
16	Sabah	East Kalimantan	200
17	Sabah	The Philippines (Luzon)	500

Sources: (ARES, 2016; ERIA, 2016; HAPUA, 2015; Ibrahim, 2014; Takapong, 2016)

3.9 Formulation of optimal power flow for energy market simulation

Mathematical modeling of energy market simulation of APG is presented in this section. To calculate the realistic cross-border transmission requirement of the ASEAN countries for 2030 scenario, energy market simulation is incorporated into this model. Energy market simulation is conducted as an optimization problem and for this optimal power flow (OPF) calculations are used to determine the optimal cross-border transmission minimizing a given objective function. The objective function might be anything; however, the objective is to minimize the operational costs which include generation costs, cost of losses and costs of energy not served in most of the applications. The market simulation model is designed for the minimum cost of the ASEAN power generation model for the APG. Equation (3.1) shows the basic objective of the OPF of the APG market simulation model, where, the objective is to minimize the costs subject to physical and technical constraints of transmission and generation are shown in (3.2) to (3.4).

$$\text{Minimize } f(x) \tag{3.1}$$

Subject to

$$g_p(x) \le 0 \tag{3.2}$$

$$h(x) \le 0 \tag{3.3}$$

$$x_{\min} \le x \le x_{\max} \tag{3.4}$$

Where; (3.1) is the total active power generation cost, and (3.2), (3.3), and (3.4) are the power balance equation, line power flow constraints, and optimization variable constraints respectively.

The power flow equations (3.1) to (3.4) can be linearized by assuming equal voltage magnitudes for all the branches and approximated the sign of voltage angle differences by the angle differences (Ergun, 2015; Oeding & Oswald, 2004). This linearized power flow is called DC power flow calculation. For simplicity, this optimization model is considered a DC OPF model, the optimization variables are reduced to (3.5) according to (Zimmerman et al., 2011).

$$x = \begin{bmatrix} \theta \\ P_g \end{bmatrix} \tag{3.5}$$

In (3.5), θ and P_g are the voltage angle and generator real power injection, respectively. Based on the above discussion, the objective function of the OPF considers the polynomial cost functions of real power injections for each generator. Total active power generation cost in (3.1) can be written as shown in (3.6).

$$\min \sum_{i \in n_g} f_p^i(p_g^i) = \min \sum_{i \in n_g} (a_i p_g^{i^2} + b_i p_g^i + c_i) \tag{3.6}$$

In (3.6), n_g is the number of generators in the system, $f_p^i(p_g^i)$ is the active power generation cost of generator i, p_g is the active power injection, and a_i, b_i, c_i are the cost coefficient of generator i.

The optimization is subject to the load balance in each node. So, power balance equality constraints of (3.2) can be presented as in (3.7).

$$g_p(\theta, P_g) = P_{bus}(\theta) + P_d - P_g = 0 \quad (3.7)$$

In (3.7), $P_{bus}(\theta)$ is the sum of the active power flows, P_d is the reactive power demand, and P_g is the sum of active power injections in each node. Line power flow limits are the inequality constraints in the optimization. Line power flow constraints of (3.3) can be written as (3.8) and (3.9).

$$F_{\min} \leq F_f(\theta) \leq F_{\max} \quad (3.8)$$

$$F_{\min} \leq F_t(\theta) \leq F_{\max} \quad (3.9)$$

In (3.8) and (3.9), $F_{\min}$ and $F_{\max}$ are the upper and lower power flow limits, and F_f (θ) and F_t (θ) are the power flows in both positive and negative directions respectively. Optimization variable constraints of (3.4) can be represented as (3.10) and (3.11).

$$\theta_i^{i,\min} \leq \theta_i \leq \theta_i^{i,\max} \quad (3.10)$$

$$P_g^{i,\min} \leq P_g^i \leq P_g^{i,\max} \quad (3.11)$$

In (3.10) and (3.11), $\theta_i^{i,\min}$ and $\theta_i^{i,\max}$ are the upper and lower phase angle limits, θ_i is the actual phase angle, $P_g^{i,\min}$ and $P_g^{i,\max}$ are the maximum and minimum allowable active power generation of generator *i*, and P_g^i is the actual active power generation of generator *i*.

The energy market simulation results obtained from OPF calculation shows the cross-border power transmission to meet the demand in the ASEAN electricity market. OPF utilizes thermal line limit constraint (3.8) and (3.9), and for this line overloads will not occur if the OPF calculation converges. As a result, branch flows represent the realistic cross-border power transmission among the ASEAN countries. However, no thermal line limit is considered during calculating optimal cross-border transmission needs to meet the demand from low-cost generation for 2030 scenario. In addition, OPF results can be used to calculate the net market benefit of interconnecting ASEAN electricity market.

3.10 Validation

Developed APG model is validated by comparing its results with publicly available statistics from the Heads of ASEAN Power Utilities / Authorities (HAPUA) secretariat (ARES, 2016; ERIA, 2016; HAPUA, 2015; Ibrahim, 2014; Takapong, 2016). The model outputs used for the validation are the outcome of a power grid model representing the ASEAN Power Grid network infrastructure in 2030 based on the load demand, net generation capacities and NTC values from HAPUA. Estimating cross-border transmission needs is one of the main model outputs. Therefore, the validation is carried out by comparing the net cross-border transmission capacity of each individual transmission links with actual statistics (ARES, 2016; ERIA, 2016; HAPUA, 2015; Ibrahim, 2014; Takapong, 2016). Figure 3.2 shows the single line diagram of APG which shows the amount of NTC and direction of cross-border power flow among the nodes as well as the actual generation of individual nodes. Figure 3.3 shows the NTC of individual cross-border transmission links for 2030 from HAPUA statistics and the model simulation results.

It can be seen that net cross-border power transmission through the individual transmission links are mostly similar for HAPUA statistics and in the simulation results. However, cross-border power transmission from Myanmar to Thailand; from Lao PDR to Thailand; and from Lao PDR to Vietnam have some differences between HAPUA statistics and in the model results. For Myanmar to Thailand, this difference is due to the consideration of transmission link capacity, like, HAPUA mention a range of transmission limit for the future power trade between Myanmar and Thailand, however, this study considers the maximum value of the mention transmission limit. Also, least-cost power generation scenario is considered for Myanmar during scenario data which might be different from the considered scenario of HAPUA during calculation of transmission link capacity. As a result, the NTC value from Myanmar to Thailand is about to similar but slightly lower in the simulation results. Additionally, Figure 3.3 shows that NTC values from Lao PDR to Thailand and from Lao PDR to Vietnam are slightly lower in the model results than in reality. These differences are also due to power generation scenario considerations of Lao PDR. This study considers publicly available installed generation capacity data; however, this publicly available data might have some differences than the real installed generation capacity which is considered by HAPUA. Nevertheless, it can be seen also from Figure 3.3 that power flow directions among the individual nodes are identical for both the HAPUA statistics and simulation results of the model.

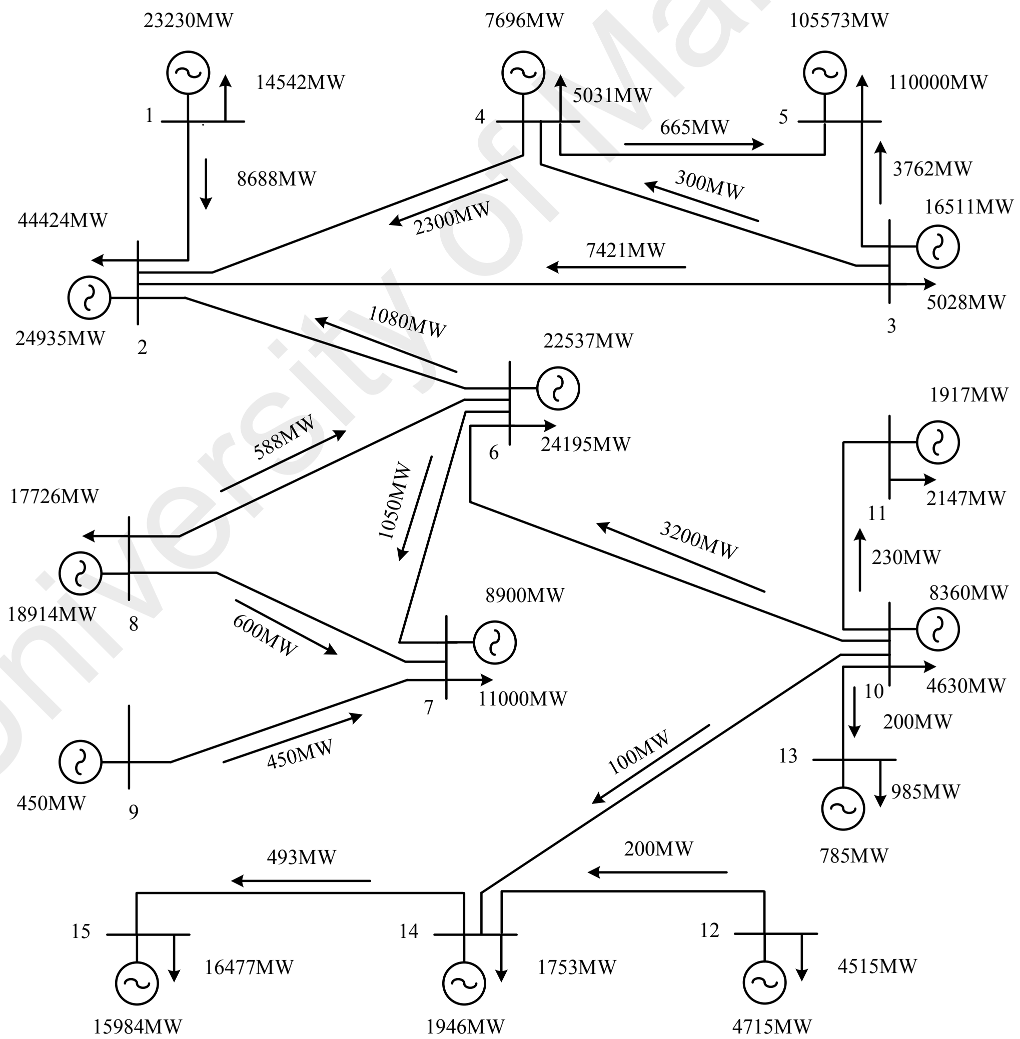


Figure 3.2: Single line diagram of the developed APG model with individual nodes generation and cross-border power transmission.

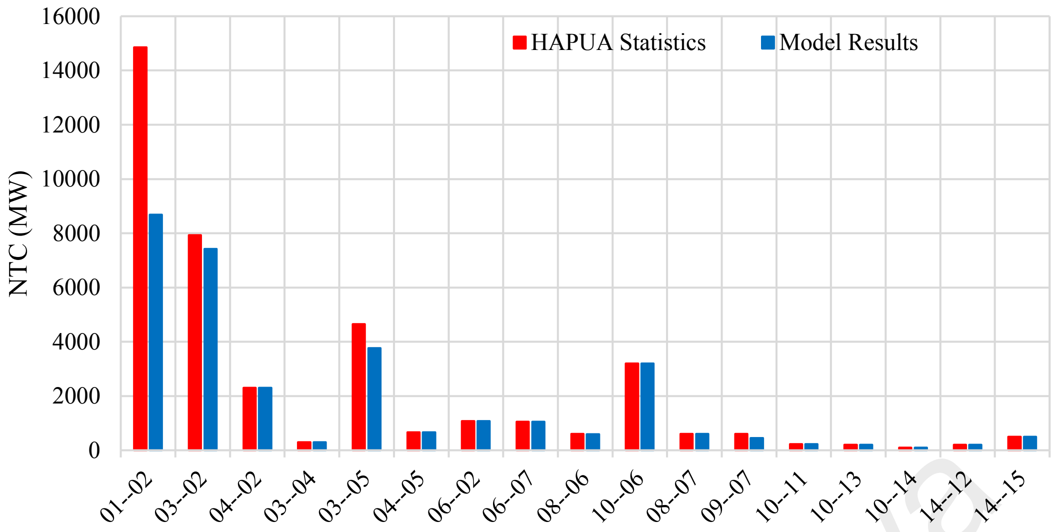


Figure 3.3: NTC of individual cross-border transmission link (HAPUA statistics & Model results).

3.11 Summary

This chapter presents and discusses the detail modeling technique of APG. Various assumptions and considerations are discussed during modeling APG model in this chapter. Cross-border power transmission needs among the 15 isolated TSOs of ASEAN countries can be obtained from OPF results of ASEAN energy market. These results of cross-border power transmission are used as input parameters for analyzing the transmission options. In additions, the OPF results are also used to calculate net market benefit analysis of interconnecting regional energy markets through APG. All these are elaborated in the following chapters.

CHAPTER 4: THE FUTURE NEEDS OF CROSS-BORDER TRANSMISSION CAPACITY AND TECHNOLOGY FOR ASEAN

4.1 Introduction

ASEAN power grid (APG) aims to enable the more economic power transfer from power surplus region to the power deficit region through the cross-border transmission. The APG model has been developed in the previous chapter to analyze the maximum requirements of cross-border transmission capacity for the 2030 scenario to meet the demand. The developed APG model also analyze economic characteristics of HVAC and HVDC connection options for all the cross-border interconnections by considering maximum requirements of cross-border transmission capacity for the 2030 scenario.

The aim of this chapter is to explore the maximum requirements of cross-border transmission in ASEAN by 2030 to meet the electricity demand by giving priority to low cost generating options. The impact of cross-border transmission links capacity on selecting the transmission technology is also investigated in this chapter through the economic analysis. In addition, a sensitivity analysis is carried out to investigate the impact of transmission links distance on selecting transmission technology. The study is performed with the APG model presented in Chapter 3.

The rest of the chapter is organized as follows: Section 4.2 shows the energy market simulation results of ASEAN power market. Economic appraisal of HVDC and HVAC technology is presented in Section 4.3. Section 4.5 details the results of the economic comparisons between the HVDC and HVAC transmission options for the individual interconnection links. Sensitivity analysis is carried out in Section 4.6 followed by a summary of the chapter in Section 4.7.

4.2 Energy market simulation results in optimal condition

Optimal cross-border power transmission for ASEAN region to meet the demand has been calculated from the energy market simulation by using the APG model in Chapter 3. During calculating optimal cross-border transmission for ASEAN no capacity limits of the cross-border transmission links are considered. Optimal cross-border power transmission for ASEAN region is shown in Figure 4.1. Figure 4.1 also shows the optimal cross-border power flowing through the APG system. In Figure 4.1, the arrows indicate the dominant power flow directions between the nodes. Power mainly flows from the nodes with a large generation capacity and low generation cost, and demand toward the nodes with a high generation cost and demand. From the figure, Myanmar, Lao PDR, Cambodia, Sumatra (Indonesia), Batam (Indonesia), and Sarawak (Malaysia) can be identified as the net exporter of electricity to the neighboring nodes because of the availability of low-cost generating resources (hydropower and geothermal generations) compared with the load demand of the respective nodes. On the other hand, Thailand, Vietnam, P. Malaysia, Singapore, W. Kalimantan (Indonesia), E. Kalimantan, Brunei, Sabah (Malaysia), and Luzon (Philippines) are identified as the net importers of electricity given their lack of sufficient low-cost power generation sources to meet the load demand. Thailand, P. Malaysia, Sarawak, and Sabah can become electricity transportation hubs by transmitting electricity from low-cost-generating nodes to high-cost-generating nodes to meet the electricity demand through the APG system.

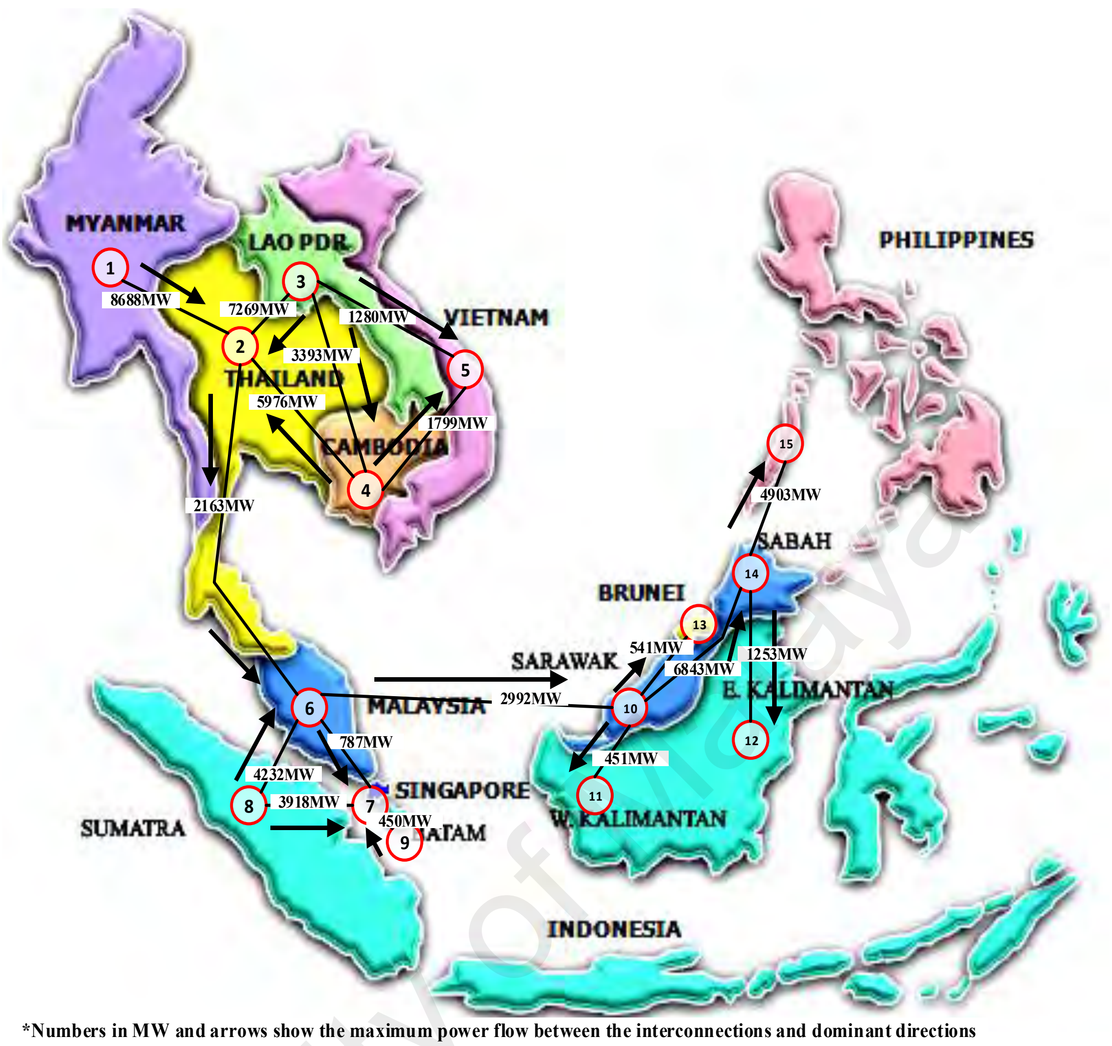


Figure 4.1: Optimal cross-border power transmission for the ASEAN region.

4.3 Economic appraisal to compare the HVDC and HVAC options

The comparison between HVDC and HVAC can be completed regarding the capital expenditure, including reactive compensation requirement and costs associated with maintenance and loss.

4.3.1 Capital costs

Capital costs of HVAC transmission systems include transmission line costs and substation costs for either end of the interconnection, including all the necessary components and transformers. Also, the reactive compensation required by an HVAC transmission system to facilitate sufficient active power transmission. This reactive compensation has significant capital costs and usually considered for every 160 km-line length (Fukasawa et al., 2015).

The capital costs of HVDC systems are the AC–DC converters cost at either end of the interconnections and transmission line costs. The HVDC transmission system can be arranged either by a monopole or a bipole. A monopole requires only one AC–DC converter at each end with two cables: positive and negative conductors. Conversely, a bipole configuration requires two converters at each end. It consists of three cables, namely, positive, negative, and metallic earth return, which all create the voltage difference between the positive and negative terminals by doubling the power transfer (FSWG, 2012). The capital cost assumptions for HVAC and HVDC transmission systems are given in Table 4.1 and Table 4.2, respectively, which are based on the values published in (Fukasawa et al., 2015). From the Table 4.1 and Table 4.2, it can be seen that the transmission line costs are higher for HVAC comparing to HVDC transmission systems and AC – DC converter costs are higher for HVDC comparing with the substation costs of HVAC transmission system. However, the costs of the equipment depend upon market conditions, in particular, the price of the copper and semiconductor devices.

Table 4.1: Presumed capital cost for HVAC connections (Fukasawa et al., 2015)

Component	Cost (Million USD)	Notes
500 kV overhead cable transmission lines	0.45/km/circuit	Maximum capacity 1.8 GW/circuit
500 kV submarine cable transmission lines	5/km/circuit	Maximum capacity 1.8 GW/circuit
Substations		Required for either side of the transmission line
Substations land, civic, buildings, common facilities	20/location	
Substations equipment	10/circuit	
Existing substations extension	10/circuit	
Substations for reactive compensation		Required for each 160 km-line

Table 4.2: Presumed capital cost for HVDC connections (Fukasawa et al., 2015)

Component	Cost (Million USD)	Notes
± 300 kV overhead cable transmission lines	0.30/km/circuit	Maximum capacity 3.0 GW/circuit
± 300 kV submarine cable transmission lines	3.75/km/circuit	Maximum capacity 3.0 GW/circuit
AC–DC converters including AC switchgear	150/GW/location	Either end of the interconnection requires 2 VSCs for giving ± 300 kV

4.3.2 Operation and maintenance costs

The lifetime cost of a transmission link contains a significant contribution from operational costs: energy losses in the system and maintenance costs. Energy losses in the AC transmission system primarily occur in cables, although losses also occur in substations. These losses are compensated for by using additional generators. The cost associated with this is referred to as operational costs.

HVAC transmission system losses have two components: 1) losses due to active power transmission through the cables and 2) losses due to reactive power production from the cable capacitance. Both losses depend upon the resistance of the transmission cable, which depends on the length of the cable, skin and proximity effects, and temperature (Van Eeckhout, 2008).

Both the active and reactive components of the cable are considered during cable loss calculation. Transmission cable capacitance is evenly distributed throughout the transmission line. It produces a specific amount of reactive power for each unit of length (Elliott et al., 2016). Although, each unit of length have different reactive power flow because of the accumulation of reactive power throughout the cable length. As a result, sending end of the interconnecting cable have less reactive power and receiving end has the largest reactive power. Placement of reactive compensation has a significant effect on this reactive power flow of the cable. Therefore, this also needs to be considered during cable loss calculation. Cable losses associated with active power transmission are calculated using cable resistance and the current for maximum power transmission. Transformer and reactive compensators also have losses that vary between 0.2% of the nominal power flow for the no-load condition and 0.6% of the nominal power flow for load-dependent elements (Brakelmann, 2003). The typical cable parameters considered in this study are the 500 kV ACSR cable (0.1275 ohm/km resistance, 0.0018 μF/km capacitance, and 0.17A/km charging current) for the overhead lines and the 500 kV XLPE cable (0.0441 ohm/km resistance, 0.19 μF/km capacitance, and 17.6 A/km charging current) for the underground lines (ABB, 2010a; ACSR, 2013).

Losses in the HVDC transmission system depend on cable losses and AC–DC conversion losses. Cable losses are related to cable resistance and active power transmission. AC–DC conversion losses have fixed no-load components and proportional power flow components. The typical cable parameters considered in this study are the 320 kV ACSR cable (0.0266 ohms/km resistance) for overhead lines and the 320 kV

XLPE cable (0.009 ohm/km resistance) for underground lines (ABB, 2010b; ACSR, 2013). The no-load components of the AC–DC conversion losses are considered 0.16% of the nominal power flow, and it can increase to 1.1% of the full load conditions for VSC–HVDC converters (Elliott et al., 2016; Torbaghan et al., 2015).

Maintenance costs also have a significant contribution to the lifetime operational cost of a transmission system. Therefore, maintenance costs are considered in calculating the operational cost through a lifetime. For both the HVAC and HVDC transmission lines, 1% of the annualized investment cost is considered the maintenance cost (Ergun et al., 2012). In addition, substations' maintenance costs also have a significant contribution to the operational costs. For the AC substation, 0.4% of the annualized investment cost is considered the maintenance cost; for the HVDC case, 0.5% of the annualized investment cost is considered the maintenance cost (Bresesti et al., 2007).

4.4 Formulation of Economic appraisal to compare the HVDC and HVAC options

Mathematical formulation to calculate the total annual equivalent costs for both the HVDC and HVAC transmission system is shown in this section by considering the scenarios presented in Section 4.3.

4.4.1 HVDC

Annual costs for the cross-border interconnections with HVDC transmission technology can be calculated from (4.1).

$$\begin{aligned}&Total\ annual\ equivalent\ costs = Total\ annual\ equivalent\ investment\\&costs + Total\ Energy\ Loss\ costs / year + Maintenance\ costs / year\end{aligned} \tag{4.1}$$

Total annual equivalent investment costs of cross-border interconnections will be the total investment costs of individual cross-border interconnection (TI) multiplied with capital recovery factor (CRF) which can be represented as (4.2).

$$Total\ annual\ equivalent\ investment\ cost = \sum_{i \in n_b} TI\ x\ CRF \tag{4.2}$$

Where,

$$TI = invT + invC \tag{4.3}$$

$$CRF = \frac{r.(1+r)^n}{(1+r)^n - 1} \tag{4.4}$$

In (4.2), (4.3), and (4.4) n_b is the number of cross-border transmission link among the individual TSOs, *invT* is the total investment costs of individual cross-border transmission link, *invC* is the total investment costs of AC-DC convertor station of individual cross-border transmission link, *r* is the discount rate, and n is the lifetime (number of years).

Each part of (4.3) can be expressed as the following equations.

$$invT = \sum_{i \in n_b} n_{r,p_r}^{cap}.KI_{r,n_b}.N_c.L_T \tag{4.5}$$

$$invC = \sum_{i \in n_b} f_{p,n_p}^{cap}.n_{r,p_r}^{cap}.N_l.KI_{c,n_b} \tag{4.6}$$

In (4.5), and (4.6), n_b is the number of cross-border transmission link among the individual TSOs, n_{r,p_r}^{cap} is the number of transmission route to transfer the power from one node to another, KI_{r,n_b} specific investment cost/km of transmission line, N_c is the number of circuit, L_T is the distances of cross-border transmission link, f_{p,n_p}^{cap} is the total amount of power transfer through each transmission route, n_{r,p_r}^{cap} is the number of transmission route to transfer the power from one node to another, N_l is the number of location of AC-DC converter station, and KI_{c,n_b} is the specific investment cost/GW/location of transmission line.

Total annual energy loss costs have significant contribution in the total annual equivalent costs of HVDC transmission system. Total annual energy loss costs can be calculated from (4.7).

$$Total\ Energy\ Loss\ costs\,/\,year = 8760 * GC_{MWh} * (P_{Trans} + P_{AC-DC}) \tag{4.7}$$

In (4.7), GC_{MWh} is the MWh energy generation cost of the designed APG model, P_{Trans} is the power loss in individual cross-border interconnection link, and P_{AC-DC} is the power loss in AC-DC converter station.

P_{Trans} of (4.7) can be expressed as the following equations.

$$P_{Trans} = \sum_{i \in n_b} 2 * n_{r,p_r}^{cap} . i^2 . R . N_{con} . L_T \tag{4.8}$$

Where,

$$i = \frac{f_{p,n_p}^{cap}}{V . N_{con} . N_r} \tag{4.9}$$

In (4.8), and (4.9), n_b is the number of cross-border transmission link among the individual TSOs, n_{r,p_r}^{cap} is the number of transmission route to transfer the power from one node to another, i is the line/phase current per route of bipolar HVDC transmission system, R is the transmission line resistance per km, N_{con} is the number of conductor per line/phase, L_T is the distances of cross-border transmission link, f_{p,n_p}^{cap} is the total amount of power to be transferred through the individual cross-border transmission link, V is the transmission voltage (kV), and N_r is the number of transmission route.

P_{AC-DC} of (4.7) can be expressed as the following equations.

$$P_{AC-DC} = \sum_{i \in n_b} K_{np} . f_{p,n_r}^{cap} . n_{r,p_r}^{cap} . N_l \tag{4.10}$$

In (4.10), n_b is the number of cross-border transmission link among the individual TSOs, K_{np} is the AC-DC convert loss multiplying factor which is 0.16% of the nominal power flow for the no-load condition and 1.1% of the nominal power flow for full load conditions, f_{p,n_r}^{cap} is the total amount of power transfer through each transmission route, n_{r,p_r}^{cap} is the number of transmission route to transfer the power from one node to another, and N_l is the number of location of AC-DC converter station.

Maintenance costs also have a significant contribution to the total annual equivalent costs of HVDC transmission system. Maintenance costs can be calculated from (4.11)

$$Maintenance\ Costs = MC_{Tran} + MC_{AC-DC} \tag{4.11}$$

Where,

$$MC_{Tran} = \sum_{i \in n_b} .01 * TI \tag{4.12}$$

$$MC_{AC-DC} = \sum_{i \in n_b} .005 * TI \tag{4.13}$$

In (4.11), (4.12), and (4.13), n_b is the number of cross-border transmission link among the individual TSOs, MC_{Tran} is the maintenance costs for the transmission system, MC_{AC-DC} is the maintenance costs for AC-DC converter stations, and TI is the total investment costs of individual cross-border interconnection.

4.4.2 HVAC

Annual costs for the cross-border interconnections with HVAC transmission technology can be calculated from (4.14).

$$\begin{aligned} &Total\ annual\ equivalent\ costs = Total\ annual\ equivalent\ investment \\ &costs + Total\ Energy\ Loss\ costs / year + Maintenance\ costs / year \end{aligned} \tag{4.14}$$

Total annual equivalent investment costs of cross-border interconnections will be the total investment costs of individual cross-border interconnection (TI) multiplied with (capital recovery factor) CRF which can be represented like (4.15).

$$Total\ annual\ equivalent\ investment\ cost = \sum_{i \in n_b} TI\ x\ CRF \tag{4.15}$$

Where,

$$TI = invT + invS + invR \tag{4.16}$$

$$CRF = \frac{r.(1+r)^n}{(1+r)^n - 1} \tag{4.17}$$

In (4.15), (4.16), and (4.17), n_b is the number of cross-border transmission link among the individual TSOs, *invT* is the total investment costs of individual cross-border transmission link, *invS* is the total investment costs of substation of individual cross-border transmission link, *invR* is the total investment costs of reactive compensation of individual cross-border transmission link, *r* is the discount rate, and n is the lifetime (number of years).

Each part of (4.16) can be expressed as the following equations.

$$invT = \sum_{i \in n_b} n_{r,p_r}^{cap} .KI_{r,n_b} .N_c .L_T \tag{4.18}$$

$$invS = \sum_{i \in n_b} n_{r,p_r}^{cap} .N_s .KI_{s,n_b} .N_c \tag{4.19}$$

$$invR = \sum_{i \in n_b} n_{r,p_r}^{cap} .N_{rs} .KI_{s,n_b} .N_c \tag{4.20}$$

In (4.18), (4.19), and (4.20), n_b is the number of cross-border transmission link among the individual TSOs, n_{r,p_r}^{cap} is the number of transmission route to transfer the power from one node to another, KI_{r,n_b} specific investment cost/km of transmission line, N_c is the number of circuits, L_T is the distances of cross-border transmission link, N_s is the number of substations required for individual route, KI_{s,n_b} specific investment cost substation, N_{rs} is the number of substation for reactive compensation, and KI_{s,n_b} is the specific investment cost of substation for reactive compensation.

Total annual energy loss costs have significant contribution to the total annual equivalent costs. Total annual energy loss costs can be calculated from (4.21).

$$Total\ Energy\ Loss\ costs\ /\ year = 8760 * \sum_{i \in n_b} GC_{MWh} * (P_{Trans} + P_{Sub} + P_{\mathrm{RC}}) \tag{4.21}$$

In (4.21), n_b is the number of cross-border transmission link among the individual TSOs, GC_{MWh} is the MWh energy generation cost of the designed APG model, P_{Trans} is the power loss in individual cross-border interconnection link, P_{Sub} is the power loss in the substation, and P_{RC} is the power loss in reactive compensation substation.

P_{Trans} of (4.21) can be expressed as the following equations.

$$P_{Trans} = \sum_{i \in n_b} 3 * n_{r,p_r}^{cap} .i^2 .R.N_{con} .L_T \tag{4.22}$$

Where,

$$i = \sqrt{(i_{phase})^2 + (i_{charging})^2} \tag{4.23}$$

$$i_{phase} = \frac{f^{cap}_{p,n_p}}{\sqrt{3}.V.\cos\theta.N_{con}.N_r} \tag{4.24}$$

$$i_{charging} = i_{c,charging} * L_T \tag{4.25}$$

In (4.22), (4.23), (4.24), and (4.25), n_b is the number of cross-border transmission link among the individual TSOs, n^{cap}_{r,p_r} is the number of transmission route to transfer the power from one node to another, i is the line/phase current per route, R is the transmission line resistance per km, N_{con} is the number of conductor per line/phase, L_T is the distances of cross-border transmission link, i_{phase} is the phase current per conductor, $i_{charging}$ is the charging current of the conductor, f^{cap}_{p,n_p} is the total amount of power to be transferred through the individual cross-border transmission link, N_r is the number of transmission route, and $i_{c,charging}$ is the charging current of conductor per unit length (A/km).

P_{Sub} and P_{RC} of (4.21) can be expressed as the following equations.

$$P_{Sub} = \sum_{i \in n_b} K_{sp}.f^{cap}_{p,n_r}.n^{cap}_{r,p_r}.N_s \tag{4.26}$$

$$P_{RC} = \sum_{i \in n_b} K_{rcp}.f^{cap}_{p,n_r}.n^{cap}_{r,p_r}.N_{rs} \tag{4.27}$$

In (4.26), and (4.27), n_b is the number of cross-border transmission link among the individual TSOs, K_{sp} is the substation loss multiplying factor which is 0.2% of the nominal power flow for the no-load condition and 0.6% of the nominal power flow for load-dependent elements, f^{cap}_{p,n_r} is the total amount of power transfer through each transmission route, n^{cap}_{r,p_r} is the number of transmission route to transfer the power from one node to another, N_s is the number of substations required for individual route, K_{rcp} is the reactive compensation substation loss multiplying factor which is 0.2% of the nominal power flow for the no-load condition and 0.6% of the nominal power flow for load-dependent elements, and N_{rs} is the number of reactive compensation substation required for each 160km-line.

Maintenance costs also have a significant contribution to the total annual equivalent costs of HVAC transmission system. Maintenance costs can be calculated from (4.28)

$$Maintenance\ Costs = MC_{Tran} + MC_{Sub} \tag{4.28}$$

Where,

$$MC_{Tran} = \sum_{i \in n_b} .01 * TI \tag{4.29}$$

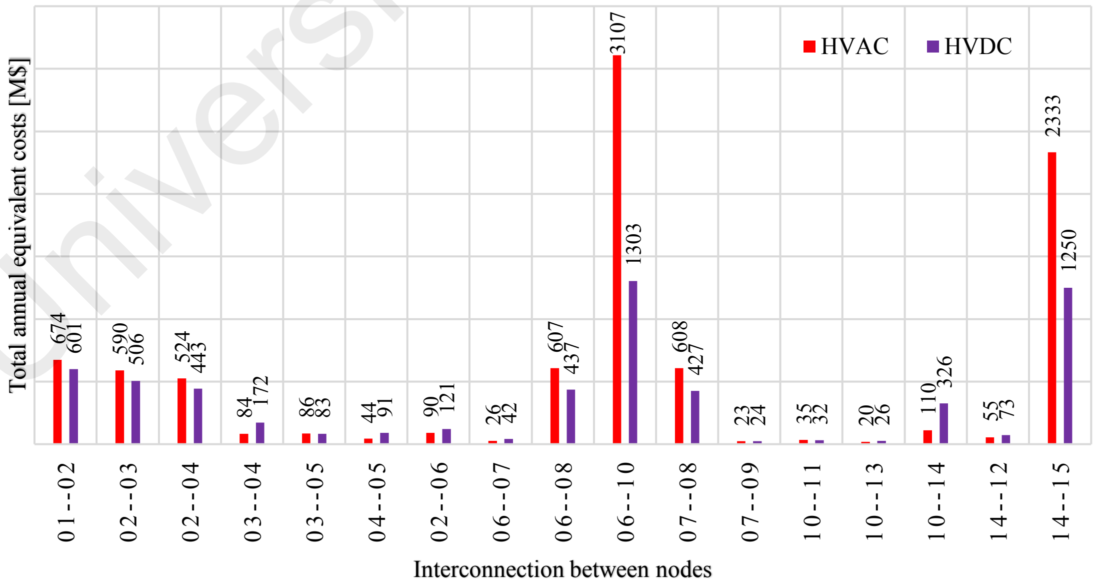
$$MC_{Sub} = \sum_{i \in n_b} .004 * TI \tag{4.30}$$

In (4.28), (4.29), and (4.30), n_b is the number of cross-border transmission link among the individual TSOs, MC_{Tran} is the maintenance costs for the transmission system, MC_{Sub} is the maintenance costs for substations, and *TI* is the total investment costs of individual cross-border interconnection.

4.5 Economic comparison between HVDC and HVAC options

The annualized costs of each transmission technology are compared. Therefore, lifetime costs are broken down over the expected lifetime of transmission lines. The lifetime of transmission lines is 30 years, and the capital recovery factor for this lifetime is calculated by considering the 12% discount rate (Elliott et al., 2016; WPD, 2014; Zhu, Lu, Gao, Yi, & Chen, 2016). The costs of the total annual energy losses during transmission are computed using the average marginal cost of electricity generation of the model, which is 38.56 USD/MWh. Section 4.4 shows the detail formulations of calculating annual equivalent costs associated with individual cross-border transmission link. Annual costs for the cross-border interconnections for the HVAC and HVDC transmission technologies are calculated by using the formulation of Section 4.4.

The comparison of annual costs for the cross-border interconnections for the HVAC and HVDC transmission technologies is shown in Figure 4.2. From Figure 4.2, it is observed that the HVDC transmission systems are feasible for Myanmar–Thailand, Thailand–Laos, Thailand–Cambodia, Laos–Vietnam, P. Malaysia–Sumatra, P. Malaysia – Sarawak (Malaysia), Singapore–Sumatra, Sarawak (Malaysia)–W. Kalimantan, and Sabah (Malaysia)–Luzon (Philippines) because of their advantages of low operation and maintenance costs for long-distance bulk power transmission. In addition, reactive compensation is required for the HVAC option, which requires more capital cost for long-distance power transmission. For the remaining interconnections, the HVAC option is more beneficial than the HVDC because of the small transmission distance involved in those interconnections, in which capital costs are higher for HVDC than for the HVAC.



Myanmar (01); Thailand (02); Laos (03); Cambodia (04); Vietnam (05); Peninsular Malaysia (06); Singapore (07); Sumatra (08); Batam (09); Sarawak (10); West Kalimantan (11); East Kalimantan (12); Brunei (13); Sabah (14); Luzon (Philippines) (15)

Figure 4.2: Comparison of total annual costs of HVAC and HVDC of the interconnections.

The comparison hourly transmission losses of the individual cross-border transmission links are shown in Table 4.3 which have been calculated from (4.8) to (4.10) and (4.22) to (4.27). It can be said from Table 4.3 that the HVAC transmission technology experiences more loss than HVDC transmission system. The comparison of annual costs due to energy losses during transmission is presented in Figure 4.3. Annual costs due to energy losses for individual interconnections have been calculated from (4.7) and (4.21). Figure 4.3 exhibits that the HVDC transmission technology has lesser annual costs due to lower transmission loss and no reactive power, as well as lesser reactive power compensation loss than the HVAC transmission technology. The annual cost of the HVAC transmission systems is 1,180 (Million USD) M$ more than the HVDC in the selected interconnections of APG. And, this is mainly due to the energy losses associated with the HVAC system. Therefore, in terms of energy efficiency, HVDC options are more suitable than the HVAC for these APG interconnections. The following subsections represent the breakdown of the total annual equivalent costs for individual interconnections for both the HVDC and HVAC transmission systems. These costs are calculated from (4.2) to (4.13) and (4.15) to (4.30) for HVDC and HVAC transmission system respectively.

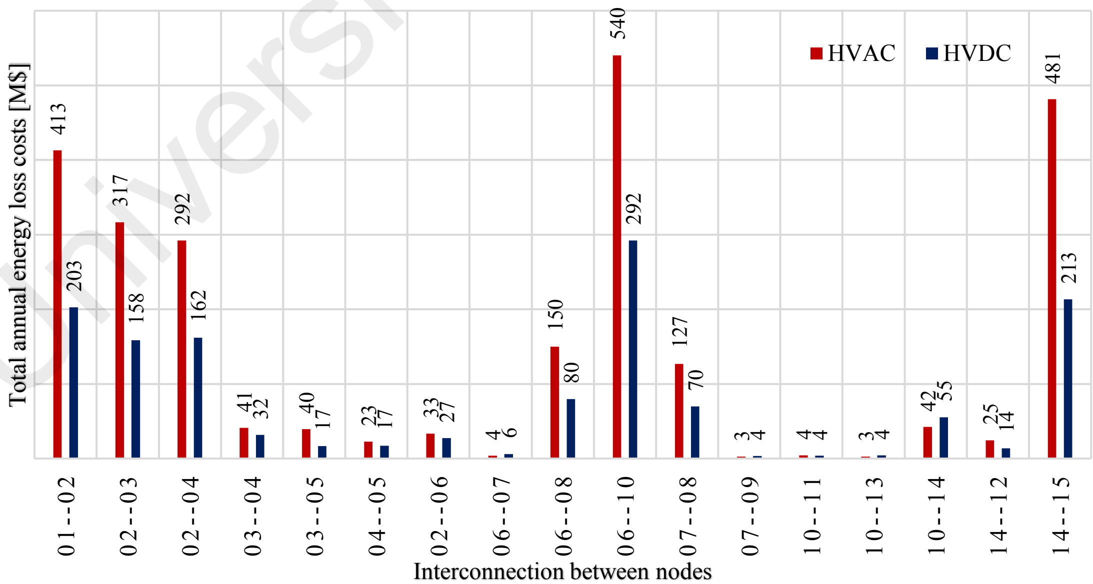
Table 4.3: Steady-state transmission losses of the individual interconnection of APG

From	To	Transmission Losses (MW)						
		HVDC			HVAC			
		P_{Trans}	P_{AC-DC}	Total	P_{Trans}	P_{Sub}	P_{RC}	Total
Myanmar	Thailand	408.5	191.1	599.6	1066.4	104.3	52.1	1222.7
Thailand	Laos	308.8	159.9	468.7	806.2	87.2	43.6	937.0
Thailand	Cambodia	347.9	131.5	479.4	756.8	71.7	35.9	864.4
Laos	Cambodia	18.7	74.6	93.3	81.3	40.7	0.0	122.0
Laos	Vietnam	21.6	28.2	49.8	94.0	15.4	7.7	117.0
Cambodia	Vietnam	10.5	39.6	50.1	45.7	21.6	0.0	67.3
Thailand	Peninsular Malaysia	33.4	47.6	81.0	72.7	26.0	0.0	98.7
Peninsular Malaysia	Singapore	0.6	17.3	17.9	2.3	9.4	0.0	11.8

Table 4.3, Continued

From	To	Transmission Losses (MW)						
		HVDC			HVAC			
		P_{Trans}	P_{AC-DC}	Total	P_{Trans}	P_{Sub}	P_{RC}	Total
Peninsular Malaysia	Sumatra	142.6	93.1	235.7	367.3	50.8	25.4	443.4
Peninsular Malaysia	Sarawak	799.5	65.8	865.3	1383.7	35.9	179.5	1599.1
Singapore	Sumatra	120.1	86.2	206.3	305.3	47.0	23.5	375.8
Singapore	Batam	0.5	9.9	10.4	2.3	5.4	0.0	7.7
Sarawak	West Kalimantan	1.7	9.9	11.6	7.4	5.4	0.0	12.8
Sarawak	Brunei	0.2	11.9	12.1	1.1	6.5	0.0	7.6
Sarawak	Sabah	13.2	150.5	163.7	43.0	82.1	0.0	125.1
Sabah	East Kalimantan	13.3	27.6	40.8	57.7	15.0	0.0	72.7
Sabah	The Philippines (Luzon)	523.5	107.9	631.4	1219.0	58.8	147.1	1424.9

P_{Trans} = Power loss in individual cross-border interconnection link, P_{AC-DC} = Power loss in AC-DC converter station, P_{Sub} = Power loss in substation, and P_{RC} = Power loss in reactive compensation substation

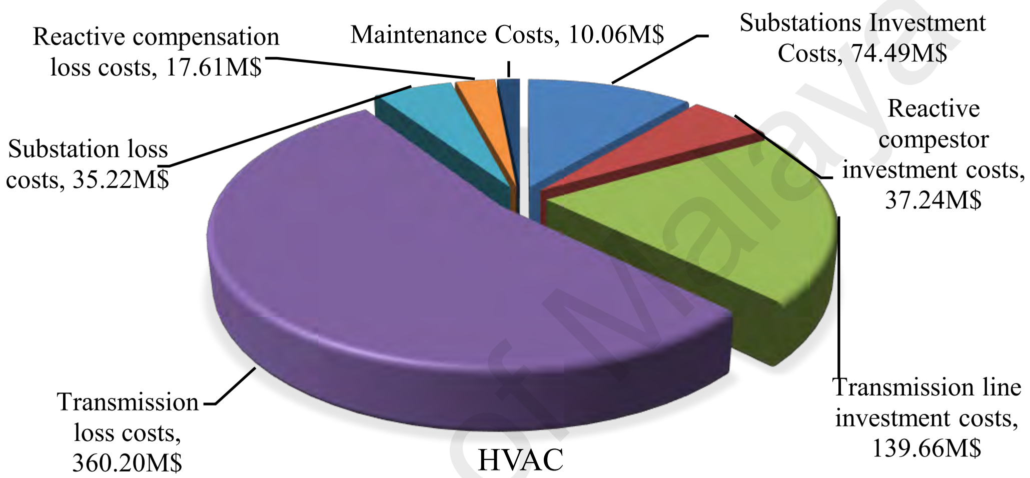


Myanmar (01); Thailand (02); Laos (03); Cambodia (04); Vietnam (05); Peninsular Malaysia (06); Singapore (07); Sumatra (08); Batam (09); Sarawak (10); West Kalimantan (11); East Kalimantan (12); Brunei (13); Sabah (14); Luzon (Philippines) (15)

Figure 4.3: Comparison of total annual costs due to energy loss.

4.5.1 Interconnection between Myanmar and Thailand

The breakdown of the total annual equivalent costs associated with the interconnection between Myanmar and Thailand for both HVAC and HVDC is shown in Figure 4.4. Cost due to losses along transmission lines has the largest contribution to the total cost for the HVAC, and cost due to AC-DC converter investment is the largest for the HVDC; these costs are equivalent annually to 360.20M$ and 323.57 M$, respectively.



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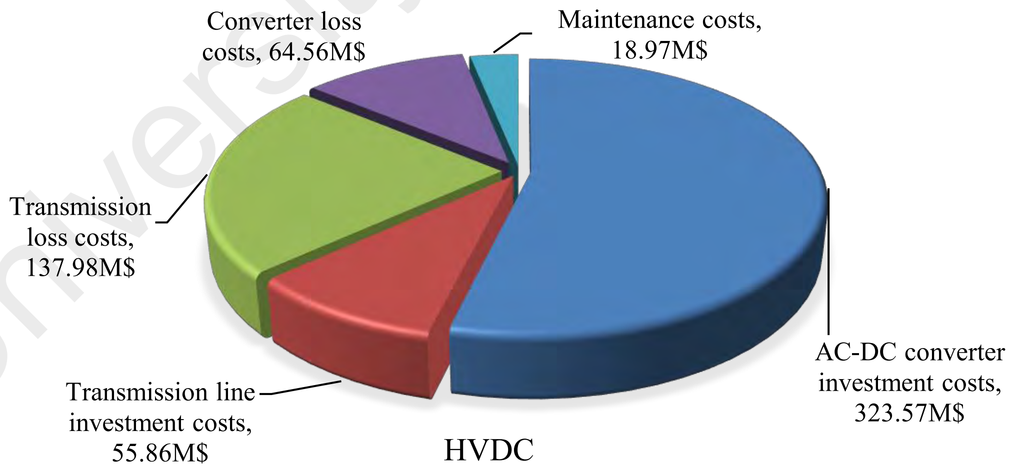


(b)

Figure 4.4: Total annual equivalent costs of the interconnection between Myanmar and Thailand (in M$), (a) HVAC, (b) HVDC.

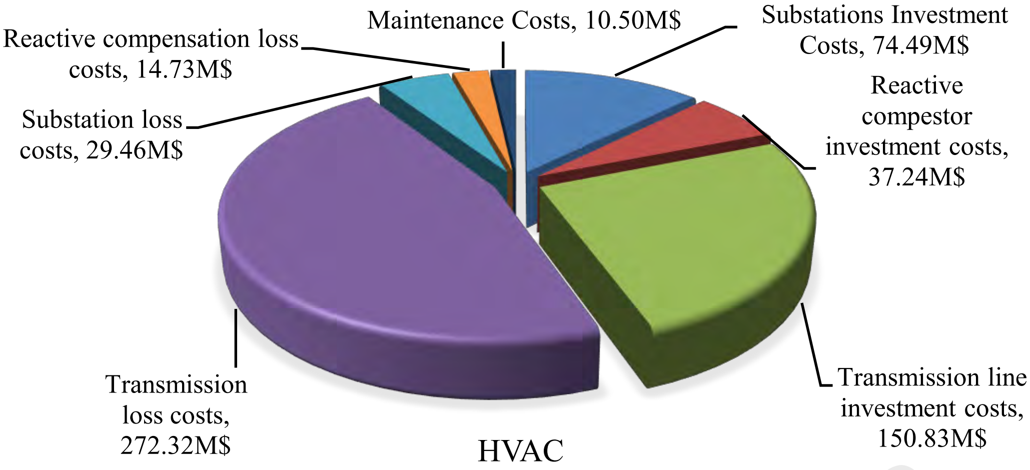
Transmission line losses account for 53.40%, and HVDC converter investment costs account for 53.84% of the total annual equivalent cost for the HVAC and HVDC transmission options, respectively, as presented in Table 4.4. From the table, it can be seen that the HVAC transmission line investment costs and the HVDC transmission line loss costs at 20.71% and 22.96%, respectively, are the second-largest contributor to the total costs. The investment costs of substations and reactive compensators also have a significant contribution to the total cost for HVAC at 11.04% and 5.52%, respectively. The HVDC converter loss and the HVDC transmission line investment costs at 10.74% and 9.30%, respectively, have a significant contribution in the HVDC case.

Table 4.4: Cost weighting of each item as a percentage of total annual equivalent costs in M$

Item	HVAC	HVDC
Transmission Line Investment	20.71%	9.30%
Transmission Loss	53.40%	22.96%
Substation/Converter Investment	11.04%	53.84%
Substation/Converter Loss	5.22%	10.74%
Reactive compensation Investment	5.52%	-
Reactive Compensation Loss	2.61%	-
Maintenance	1.49%	3.16%

4.5.2 Interconnection between Thailand and Lao PDR

The breakdown of the total annual equivalent costs associated with the interconnection between Thailand and Lao PDR for both HVAC and HVDC is shown in Figure 4.5. Cost due to losses along transmission lines has the largest contribution to the total cost for the HVAC, and cost due to AC-DC converter investment is the largest for the HVDC; these costs are equivalent annually to 272.32 M$ and 270.72 M$, respectively.



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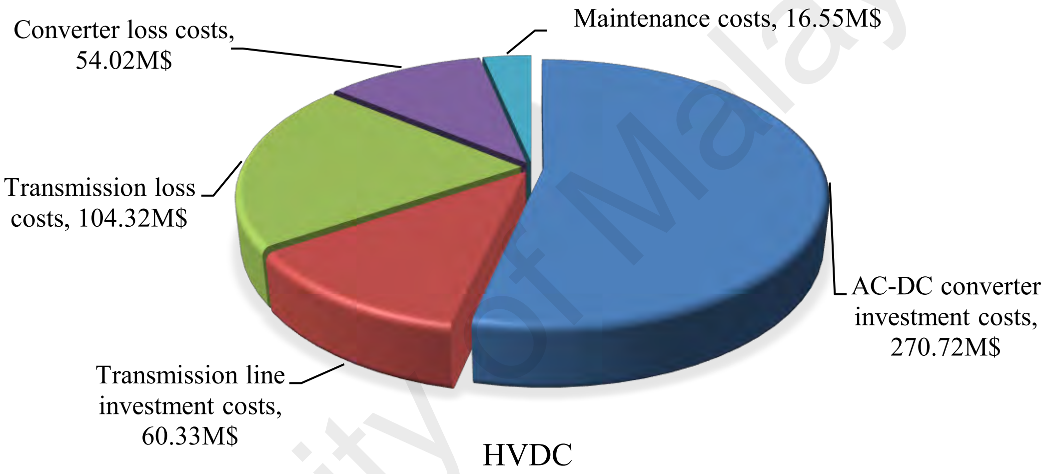


(b)

Figure 4.5: Total annual equivalent costs of the interconnection between Thailand and Lao PDR (in M$), (a) HVAC, (b) HVDC.

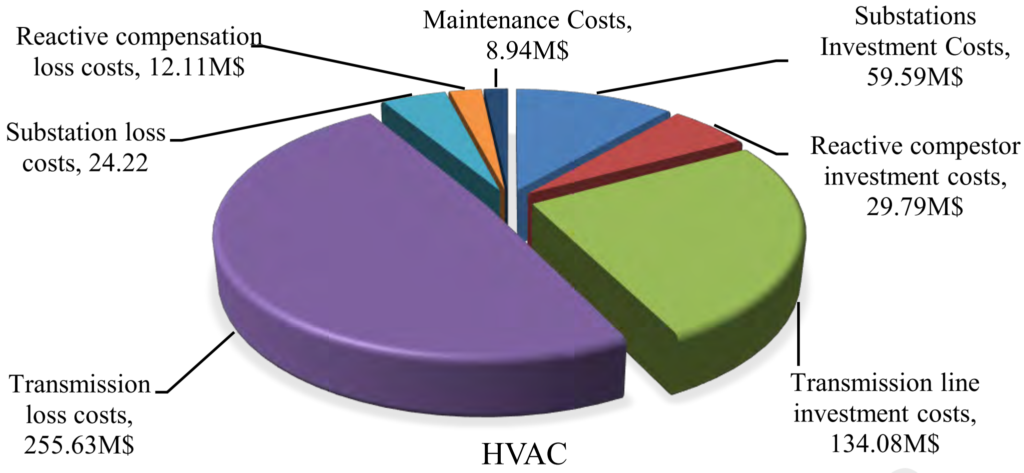
Cost weighting of each item as a percentage of total annual equivalent costs for both HVAC and HVDC transmission system between Thailand and Lao PDR are shown in Table 4.5. Table 4.5 shows that transmission line losses account for 46.19%, and HVDC converter investment costs account for 53.51% of the total annual equivalent cost for the HVAC and HVDC transmission options, respectively. It can be seen that transmission line investment costs are the second-largest contributor to the total costs for HVAC which are 25.58% and transmission loss costs are the second largest contributor for HVDC which are 20.62%. The investment costs of substations and reactive compensators also have a significant contribution to the total cost for HVAC at 12.63% and 6.32%, respectively. The HVDC transmission line investment and the HVDC converter loss costs at 11.93% and 10.68%, respectively, have a significant contribution in the HVDC case. HVAC have substation and reactive compensation loss costs which are 5.00% and 2.50% respectively. Maintenance costs of HVAC and HVDC contribute 1.78% and 3.27% to the total costs for HVAC and HVDC respectively.

Table 4.5: Cost weighting of each item as a percentage of total annual equivalent costs in M$

Item	HVAC	HVDC
Transmission Line Investment	25.58%	11.93%
Transmission Loss	46.19%	20.62%
Substation/Converter Investment	12.63%	53.51%
Substation/Converter Loss	5.00%	10.68%
Reactive compensation Investment	6.32%	-
Reactive Compensation Loss	2.50%	-
Maintenance	1.78%	3.27%

4.5.3 Interconnection between Thailand and Cambodia

The breakdown of the total annual equivalent costs associated with the interconnection between Thailand and Cambodia for both HVAC and HVDC is shown in Figure 4.6. Cost due to losses along transmission lines has the largest contribution to the total cost for the HVAC, and cost due to AC-DC converter investment is the largest for the HVDC; these costs are equivalent annually to 255.63 M$ and 222.56 M$, respectively.



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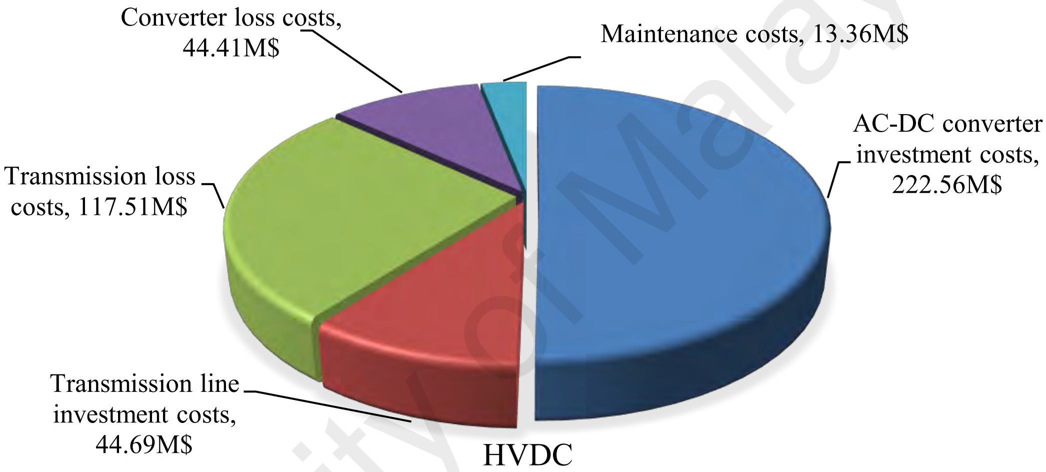


(b)

Figure 4.6: Total annual equivalent costs of the interconnection between Thailand and Cambodia (in M$), (a) HVAC, (b) HVDC.

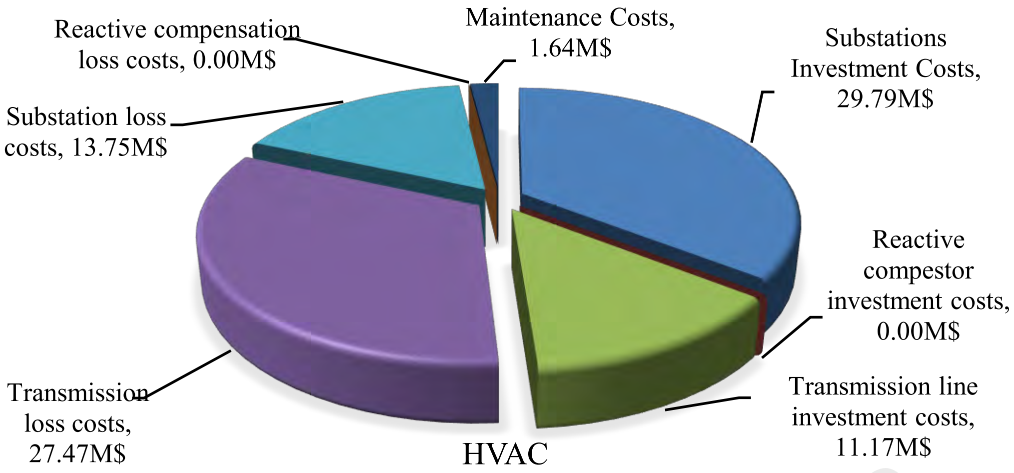
Cost weighting of each item as a percentage of total annual equivalent costs for both HVAC and HVDC transmission system is shown in Table 4.6. Table 4.6 shows that transmission line losses account for 48.75%, and AC-DC converter investment costs account for 50.29% of the total annual equivalent cost for the HVAC and HVDC transmission options, respectively. It can be seen that transmission line investment costs are the second-largest contributor to the total costs for HVAC which are 25.57% and transmission loss costs are the second largest contributor for HVDC which are 26.55%. The investment costs of substations and reactive compensators also have a significant contribution to the total cost for HVAC at 11.36% and 5.68%, respectively. The HVDC transmission line investment and the HVDC converter loss costs at 10.10% and 10.04%, respectively, have a significant contribution in the HVDC case. HVAC have substation and reactive compensation loss costs which are 4.62% and 2.31% respectively. Maintenance costs of HVAC and HVDC contribute 1.70% and 3.02% to the total costs for HVAC and HVDC respectively.

Table 4.6: Cost weighting of each item as a percentage of total annual equivalent costs in M$

Item	HVAC	HVDC
Transmission Line Investment	25.57%	10.10%
Transmission Loss	48.75%	26.55%
Substation/Converter Investment	11.36%	50.29%
Substation/Converter Loss	4.62%	10.04%
Reactive compensation Investment	5.68%	-
Reactive Compensation Loss	2.31%	-
Maintenance	1.70%	3.02%

4.5.4 Interconnection between Lao PDR and Cambodia

The breakdown of the total annual equivalent costs associated with the interconnection between Lao PDR and Cambodia for both HVAC and HVDC is shown in Figure 4.7. Substation investment costs have the largest contribution to the total cost for the HVAC, and cost due to AC-DC converter investment is the largest for the HVDC; these costs are equivalent annually to 29.79 M$ and 126.37 M$, respectively.



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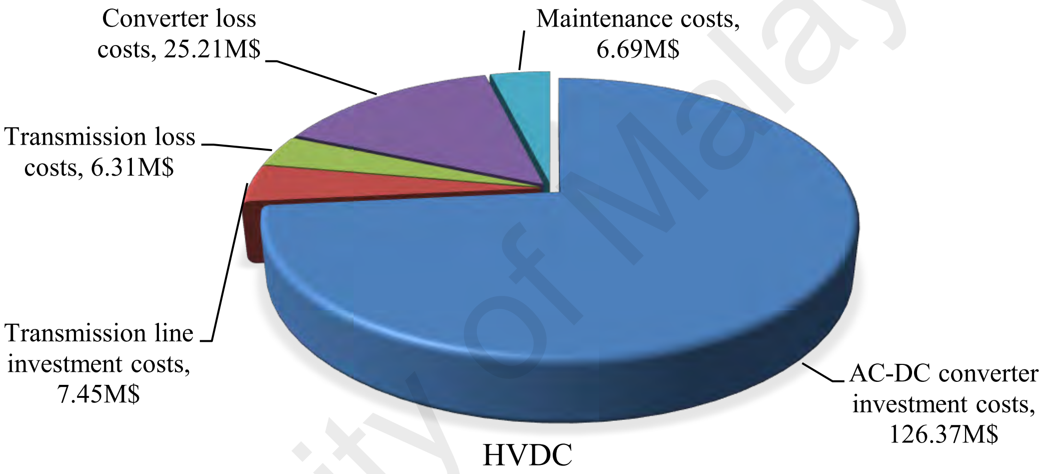


(b)

Figure 4.7: Total annual equivalent costs of the interconnection between Lao PDR and Cambodia (in M$), (a) HVAC, (b) HVDC.

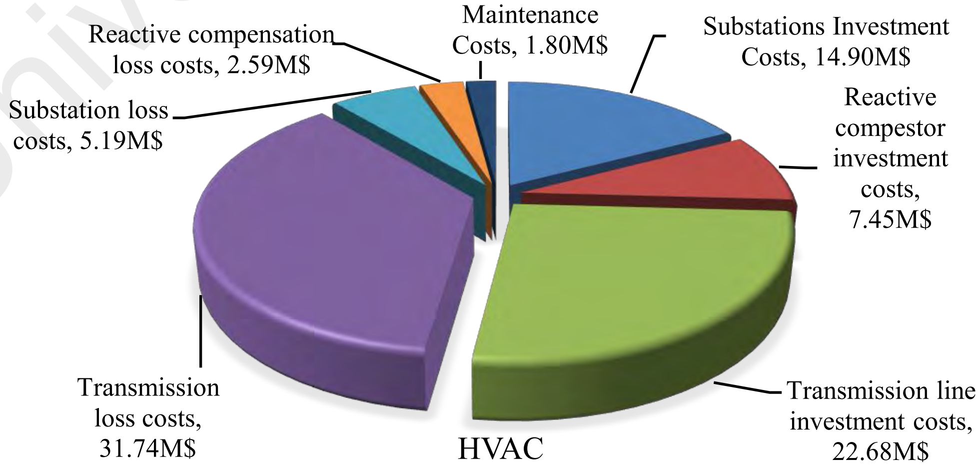
Substation investment costs account for 35.54%, and HVDC converter investment costs account for 73.45% of the total annual equivalent cost for the HVAC and HVDC transmission options, respectively, as presented in Table 4.7. From the table, it can be seen that the HVAC transmission loss costs and the AC-DC converter loss costs at 32.77% and 14.66%, respectively, are the second-largest contributor to the total costs. Substation loss costs and transmission line investment costs also have a significant contribution to the total cost for HVAC at 16.41% and 13.33%, respectively. The HVDC transmission line investment costs at 4.33% and maintenance costs at 3.89%, have a significant contribution in the HVDC case.

Table 4.7: Cost weighting of each item as a percentage of total annual equivalent costs in M$

Item	HVAC	HVDC
Transmission Line Investment	13.33%	4.33%
Transmission Loss	32.77%	3.67%
Substation/Converter Investment	35.54%	73.45%
Substation/Converter Loss	16.41%	14.66%
Reactive compensation Investment	0.00%	-
Reactive Compensation Loss	0.00%	-
Maintenance	1.95%	3.89%

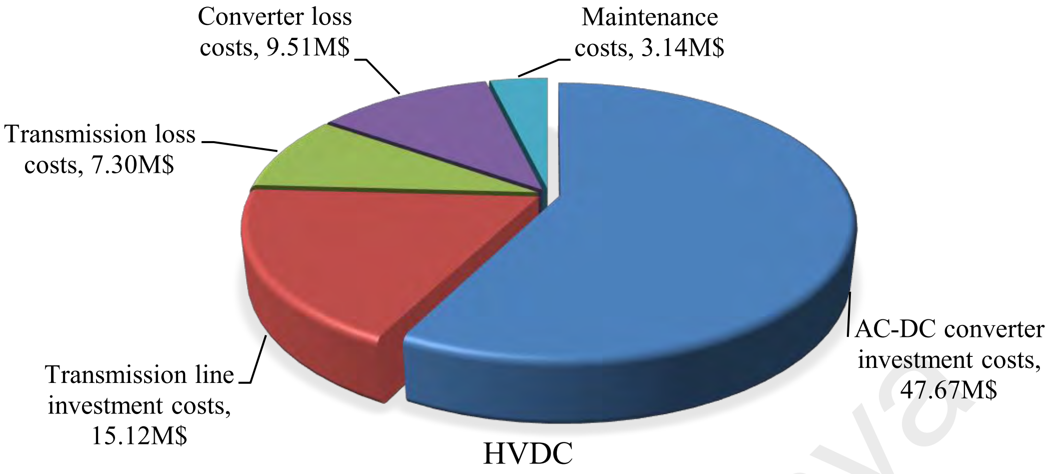
4.5.5 Interconnection between Lao PDR and Vietnam

The breakdown of the total annual equivalent costs associated with the interconnection between Lao PDR and Vietnam for both HVAC and HVDC is shown in Figure 4.8. Transmission loss costs have the largest contribution to the total cost for the HVAC, and cost due to AC-DC converter investment is the largest for the HVDC; these costs are equivalent annually to 31.74 M$ and 47.67 M$, respectively.



(a)

Figure 4.8: Total annual equivalent costs of the interconnection between Lao PDR and Cambodia (in M$), (a) HVAC, (b) HVDC.



(b)

Figure 4.8, Continued.

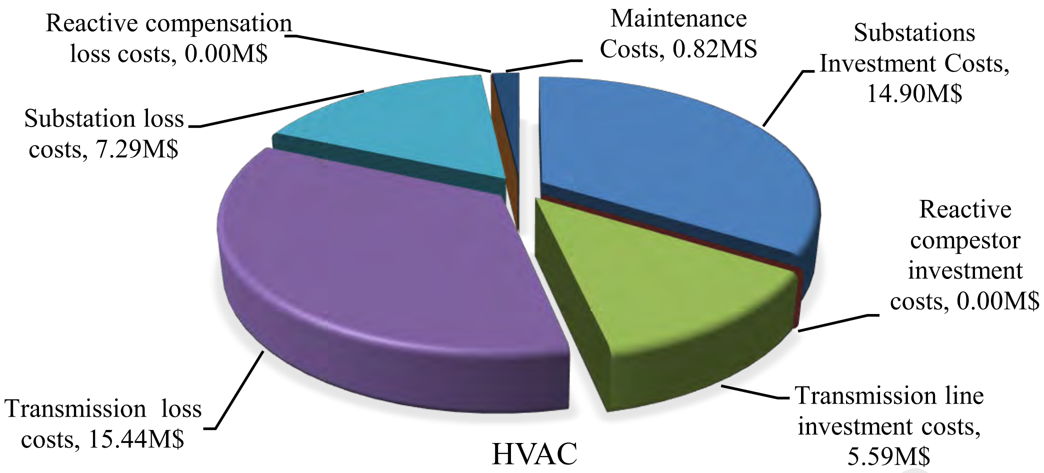
Cost weighting of each item as a percentage of total annual equivalent costs for both HVAC and HVDC transmission system is shown in Table 4.8. Table 4.8 shows that transmission line losses account for 36.76%, and AC-DC converter investment costs account for 57.62% of the total annual equivalent cost for the HVAC and HVDC transmission options, respectively. It can be seen that transmission line investment costs are the second-largest contributor to the total costs for both HVAC and HVDC which are 26.27% and 18.28% respectively. The investment costs of substations and reactive compensators also have a significant contribution to the total cost for HVAC at 17.25% and 8.63%, respectively. The HVDC converter loss and transmission loss costs at 11.50% and 8.82%, respectively, have a significant contribution in the HVDC case. HVAC have convertor loss and reactive compensation loss costs which are 6.01% and 2.31% respectively. Maintenance costs of HVAC and HVDC contribute 2.09% and 3.79% to the total costs for HVAC and HVDC respectively.

Table 4.8: Cost weighting of each item as a percentage of total annual equivalent costs in M$

Item	HVAC	HVDC
Transmission Line Investment	26.27%	18.28%
Transmission Loss	36.76%	8.82%
Substation/Converter Investment	17.25%	57.62%
Substation/Converter Loss	6.01%	11.50%
Reactive compensation Investment	8.63%	-
Reactive Compensation Loss	3.00%	-
Maintenance	2.09%	3.79%

4.5.6 Interconnection between Cambodia and Vietnam

The breakdown of the total annual equivalent costs associated with the interconnection between Cambodia and Vietnam for both HVAC and HVDC is shown in Figure 4.9. Transmission loss costs have the largest contribution to the total cost for the HVAC, and cost due to AC-DC converter investment is the largest for the HVDC; these costs are equivalent annually to 15.44 M$ and 67.00 M$, respectively.



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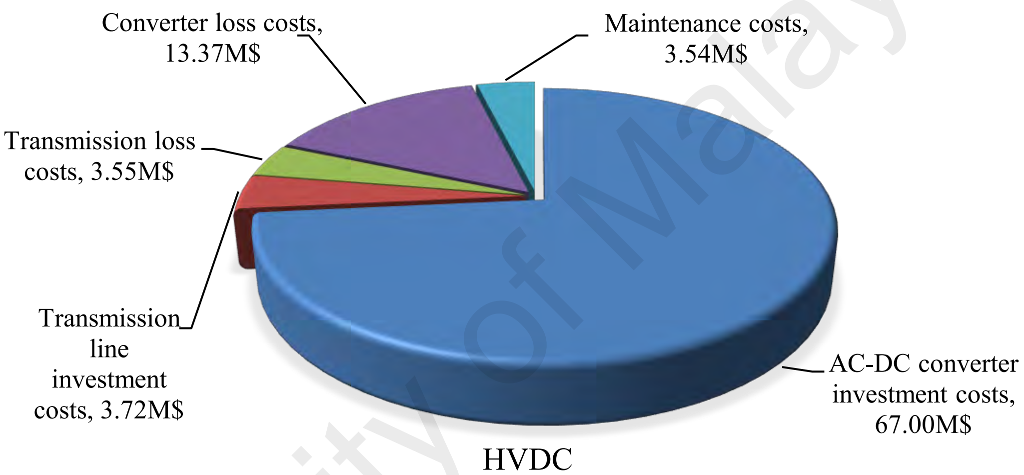


(b)

Figure 4.9: Total annual equivalent costs of the interconnection between Cambodia and Vietnam (in M$), (a) HVAC, (b) HVDC.

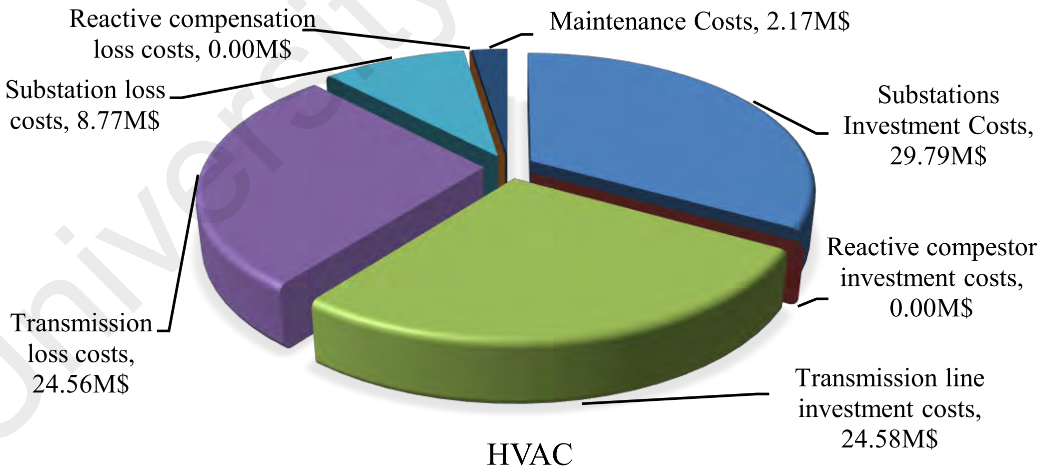
Transmission loss costs account for 35.07%, and HVDC converter investment costs account for 73.48% of the total annual equivalent cost for the HVAC and HVDC transmission options, respectively, as presented in Table 4.9. From the table, it can be seen that the HVAC substation investment costs and the AC-DC converter loss costs at 33.83% and 14.66%, respectively, are the second-largest contributor to the total costs. Substation loss costs and transmission line investment costs also have a significant contribution to the total cost for HVAC at 16.56% and 12.69%, respectively. The HVDC transmission line investment costs at 4.08% and maintenance costs at 3.88%, have a significant contribution in the HVDC case.

Table 4.9: Cost weighting of each item as a percentage of total annual equivalent costs in M$

Item	HVAC	HVDC
Transmission Line Investment	12.69%	4.08%
Transmission Loss	35.07%	3.89%
Substation/Converter Investment	33.83%	73.48%
Substation/Converter Loss	16.56%	14.66%
Reactive compensation Investment	0.00%	-
Reactive Compensation Loss	0.00%	-
Maintenance	1.86%	3.88%

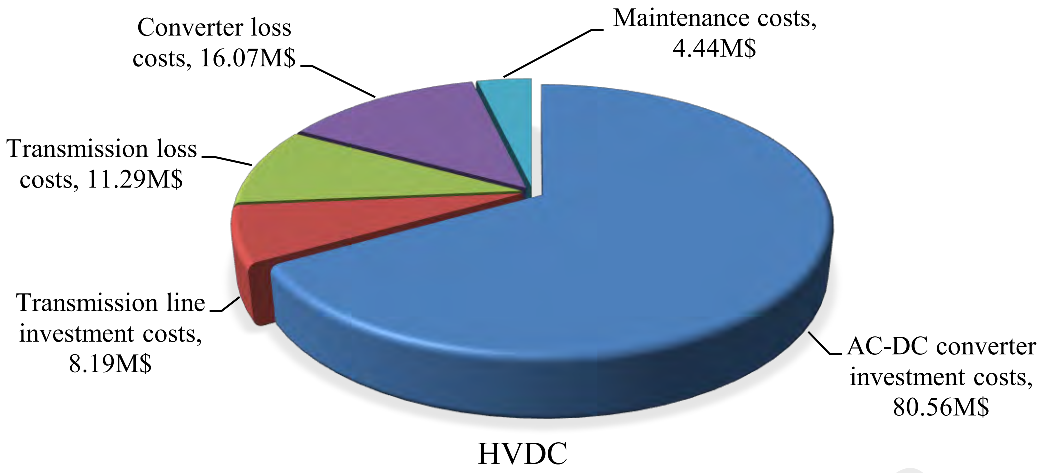
4.5.7 Interconnection between Thailand and Peninsular Malaysia

The breakdown of the total annual equivalent costs associated with the interconnection between Thailand and Peninsular Malaysia for both HVAC and HVDC is shown in Figure 4.10. Substation investment costs have the largest contribution to the total cost for the HVAC, and cost due to AC-DC converter investment is the largest for the HVDC; these costs are equivalent annually to 29.79 M$ and 80.56 M$, respectively.



(a)

Figure 4.10: Total annual equivalent costs of the interconnection between Thailand and Peninsular Malaysia (in M$), (a) HVAC, (b) HVDC.



(b)

Figure 4.10, Continued.

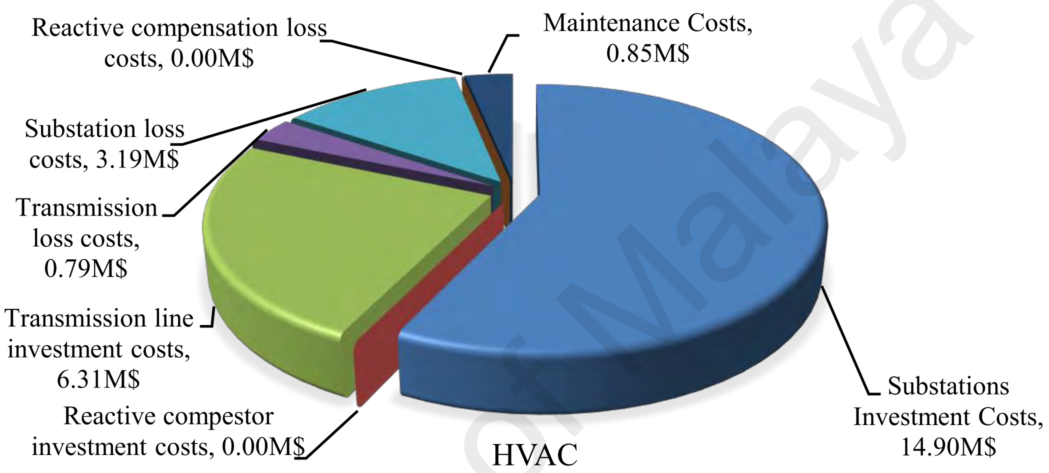
Substation investment costs account for 33.15%, and HVDC converter investment costs account for 66.82% of the total annual equivalent cost for the HVAC and HVDC transmission options respectively, as presented in Table 4.10. From the table, it can be seen that the transmission line investment costs and the AC-DC converter loss costs at 27.35% and 13.33%, respectively, are the second-largest contributor to the total costs. Transmission and substation loss costs also have a significant contribution to the total cost for HVAC at 27.33% and 9.76%, respectively. The HVDC transmission line investment and transmission loss costs at 9.36% and 6.80%, respectively, have a significant contribution in the HVDC case.

Table 4.10: Cost weighting of each item as a percentage of total annual equivalent costs in M$

Item	HVAC	HVDC
Transmission Line Investment	27.35%	6.80%
Transmission Loss	27.33%	9.36%
Substation/Converter Investment	33.15%	66.82%
Substation/Converter Loss	9.76%	13.33%
Reactive compensation Investment	0.00%	-
Reactive Compensation Loss	0.00%	-
Maintenance	2.42%	3.88%

4.5.8 Interconnection between Peninsular Malaysia and Singapore

The breakdown of the total annual equivalent costs associated with the interconnection between Peninsular Malaysia and Singapore for both HVAC and HVDC is shown in Figure 4.11. Substation investment costs have the largest contribution to the total cost for the HVAC, and cost due to AC-DC converter investment is the largest for the HVDC; these costs are equivalent annually to 14.90 M$ and 29.31 M$, respectively.



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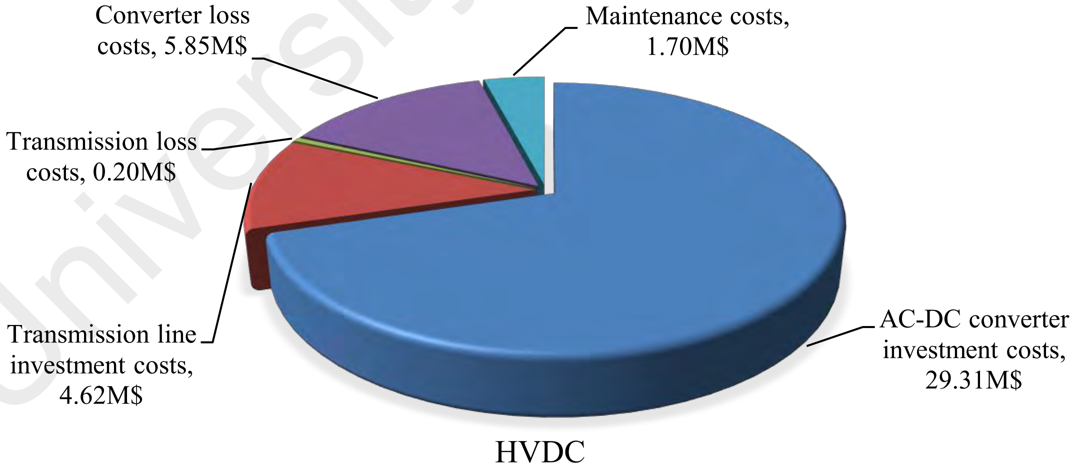


(b)

Figure 4.11: Total annual equivalent costs of the interconnection between Peninsular Malaysia and Singapore (in M$), (a) HVAC, (b) HVDC.

Substation investment costs account for 57.22%, and HVDC converter investment costs account for 70.33% of the total annual equivalent cost for the HVAC and HVDC

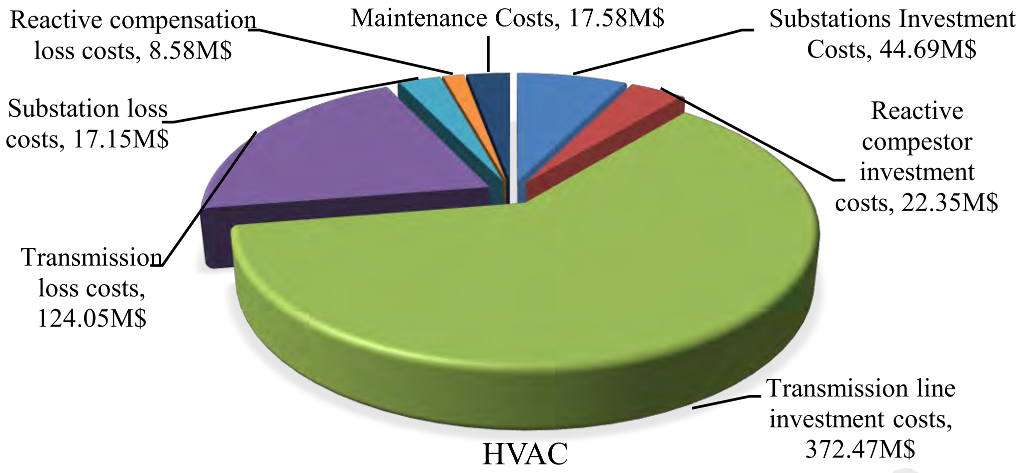
transmission options, respectively, as presented in Table 4.11. From the table, it can be seen that the transmission line investment costs and the AC-DC converter loss costs at 24.22% and 14.03%, respectively, are the second-largest contributor to the total costs. Substation and transmission loss costs also have a significant contribution to the total cost for HVAC at 12.25% and 3.04%, respectively. The HVDC transmission line investment and maintenance costs at 11.08% and 4.07%, respectively, have a significant contribution in the HVDC case.

Table 4.11: Cost weighting of each item as a percentage of total annual equivalent costs in M$

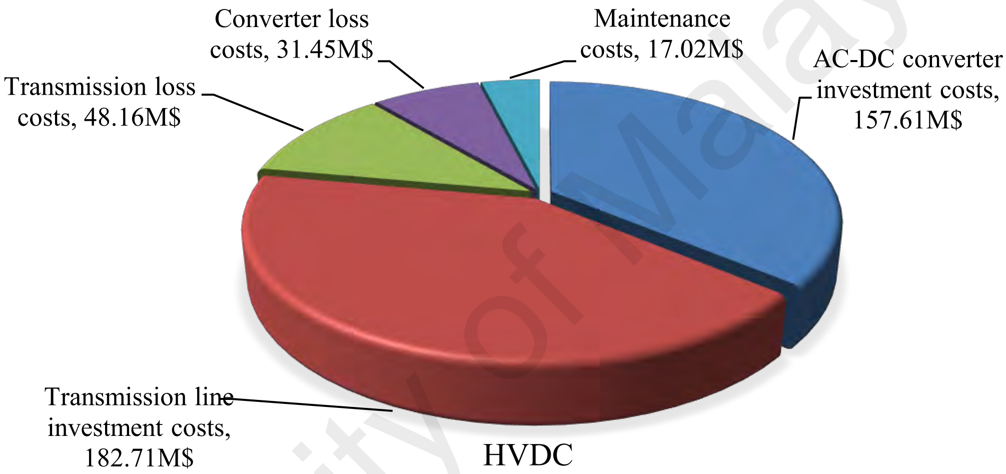
Item	HVAC	HVDC
Transmission Line Investment	24.22%	11.08%
Transmission Loss	3.04%	0.4%
Substation/Converter Investment	57.22%	70.33%
Substation/Converter Loss	12.25%	14.03%
Reactive compensation Investment	0.00%	-
Reactive Compensation Loss	0.00%	-
Maintenance	3.26%	4.07%

4.5.9 Interconnections between Peninsular Malaysia and Sumatra

The breakdown of the total annual equivalent costs associated with the interconnection between Peninsular Malaysia and Sumatra for both HVAC and HVDC is shown in Figure 4.12. Transmission line investment costs have the largest contribution to the total cost for both the HVAC and HVDC; these costs are equivalent annually to 372.47 M$ and 182.71 M$, respectively.



(a)



(b)

Figure 4.12: Total annual equivalent costs of the interconnection between Peninsular Malaysia and Sumatra (in M$), (a) HVAC, (b) HVDC.

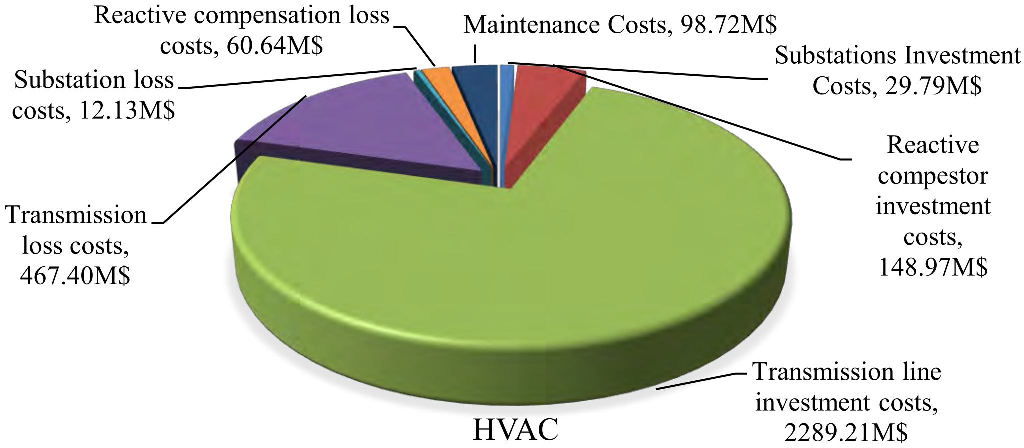
Cost weighting of each item as a percentage of total annual equivalent costs for both HVAC and HVDC transmission system is shown in Table 4.12. Table 4.12 shows that transmission line investment costs account for 61.38% for HVAC and 41.82% for HVDC of the total annual equivalent cost. It can be seen that transmission loss costs are the second-largest contributor to the total costs for HVAC which are 20.44%, and AC-DC converter investment costs are the second largest contributor for HVDC which are 36.07%. The investment costs of substations and reactive compensators also have a significant contribution to the total cost for HVAC at 7.36% and 3.68%, respectively. The HVDC transmission loss and the HVDC converter loss costs at 11.02% and 7.20%, respectively, have a significant contribution in the HVDC case. HVAC have substation and reactive compensation loss costs which are 2.83% and 1.41% respectively. Maintenance costs of HVAC and HVDC contribute 2.90% and 3.89% to the total costs respectively.

Table 4.12: Cost weighting of each item as a percentage of total annual equivalent costs in M$

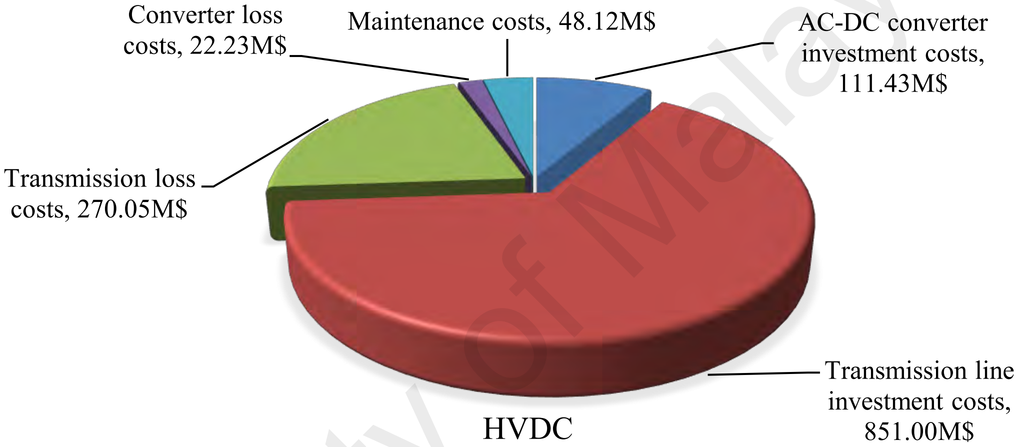
Item	HVAC	HVDC
Transmission Line Investment	61.38%	41.82%
Transmission Loss	20.44%	11.02%
Substation/Converter Investment	7.36%	36.07%
Substation/Converter Loss	2.83%	7.20%
Reactive compensation Investment	3.68%	-
Reactive Compensation Loss	1.41%	-
Maintenance	2.90%	3.89%

4.5.10 Interconnections between Peninsular Malaysia and Sarawak

The breakdown of the total annual equivalent costs associated with the interconnection between Peninsular Malaysia and Sarawak for both HVAC and HVDC is shown in Figure 4.13. Transmission line investment costs have the largest contribution to the total cost for both the HVAC and HVDC; these costs are equivalent annually to 2289.21 M$ and 851.00 M$, respectively.



(a)



(b)

Figure 4.13: Total annual equivalent costs of the interconnection between Peninsular Malaysia and Sarawak (in M$), (a) HVAC, (b) HVDC.

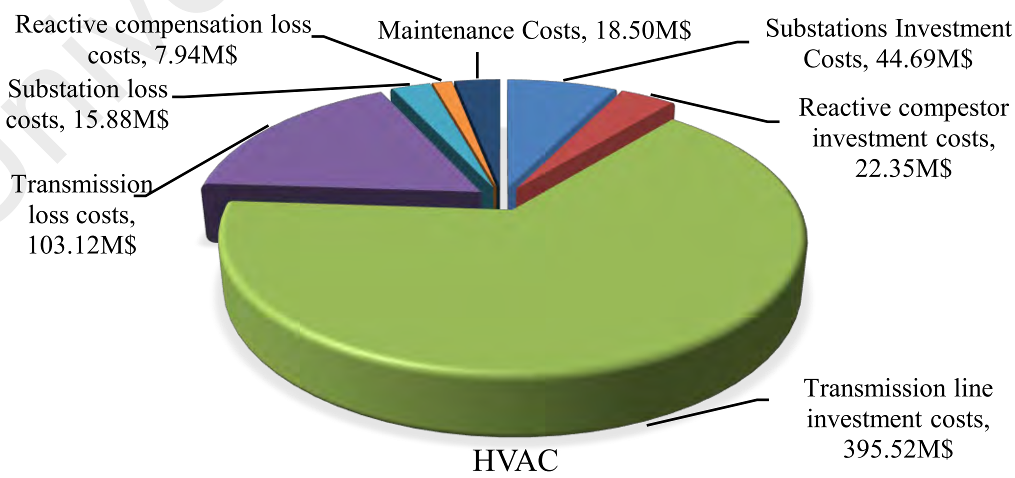
Cost weighting of each item as a percentage of total annual equivalent costs for both HVAC and HVDC transmission system is shown in Table 4.13. Table 4.13 shows that transmission line investment costs account for 73.68% for HVAC and 65.32% for HVDC of the total annual equivalent cost. It can be seen that transmission loss costs are the second-largest contributor to the total costs for both HVAC and HVDC which are 15.04%, and 20.73% respectively. The investment costs of reactive compensators and maintenance cost also have a significant contribution to the total cost for HVAC at 4.76% and 3.18%, respectively. The HVDC convertor investment and maintenance costs at 8.55% and 3.69%, respectively, have a significant contribution in the HVDC case. HVAC substation investment and substation loss costs have very less contribution to the total annual equivalent costs which are 0.96% and 0.39% respectively.

Table 4.13: Cost weighting of each item as a percentage of total annual equivalent costs in M$

Item	HVAC	HVDC
Transmission Line Investment	73.68%	65.32%
Transmission Loss	15.04%	20.73%
Substation/Converter Investment	0.96%	8.55%
Substation/Converter Loss	0.39%	1.71%
Reactive compensation Investment	4.79%	-
Reactive Compensation Loss	1.95%	-
Maintenance	3.18%	3.69%

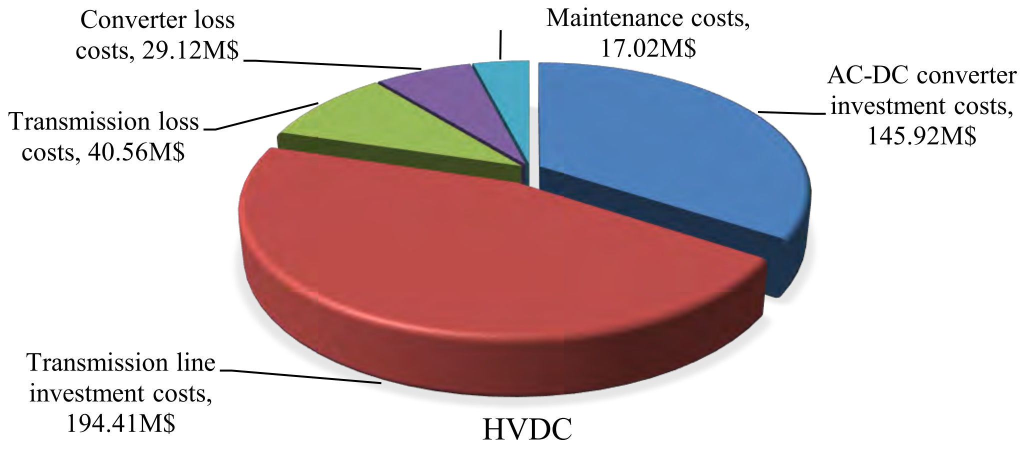
4.5.11 Interconnections between Singapore and Sumatra

The breakdown of the total annual equivalent costs associated with the interconnection between Singapore and Sumatra for both HVAC and HVDC is shown in Figure 4.14. Transmission line investment costs have the largest contribution to the total cost for both the HVAC and HVDC; these costs are equivalent annually to 395.52 M$ and 194.41 M$, respectively.



(a)

Figure 4.14: Total annual equivalent costs of the interconnection between Singapore and Sumatra (in M$), (a) HVAC, (b) HVDC.



(b)

Figure 4.14, Continued.

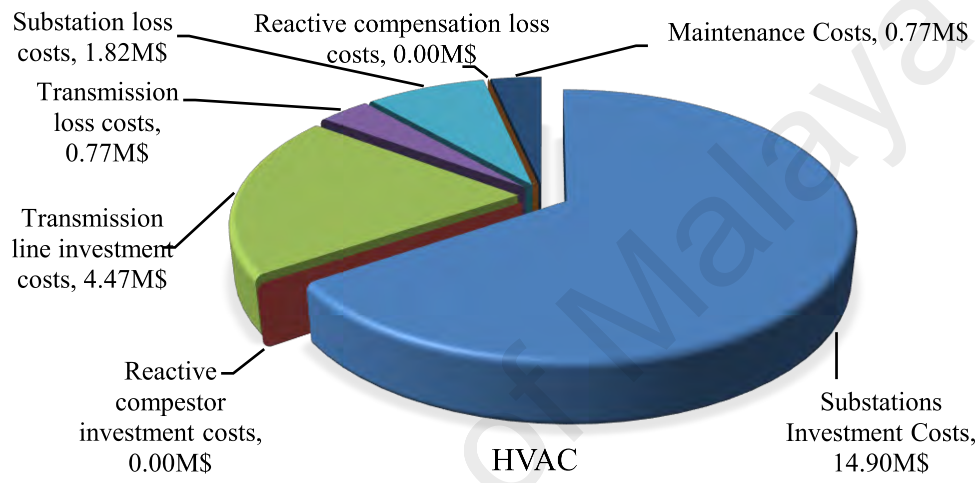
Cost weighting of each item as a percentage of total annual equivalent costs for both HVAC and HVDC transmission system is shown in Table 4.14. Table 4.14 shows that transmission line investment costs account for 65.05% for HVAC and 45.53% for HVDC of the total annual equivalent cost. It can be seen that transmission loss costs are the second-largest contributor to the total costs for HVAC and AC-DC convertor investment costs for HVDC which are 16.96%, and 34.17% respectively. The investment costs of the substation and reactive compensators also have a significant contribution to the total cost for HVAC at 7.35% and 3.68%, respectively. The HVDC transmission and substation loss costs at 9.50% and 6.82%, respectively, have a significant contribution in the HVDC case. HVAC substation loss, reactive compensation loss, and maintenance costs have the contribution of 2.61%, 1.31% and 3.04%, respectively to the total annual equivalent costs.

Table 4.14: Cost weighting of each item as a percentage of total annual equivalent costs in M$

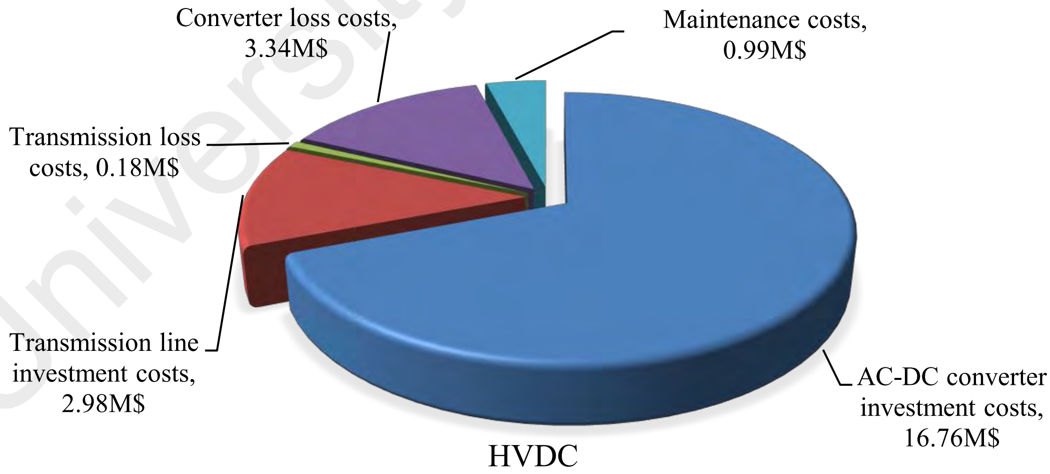
Item	HVAC	HVDC
Transmission Line Investment	65.05%	45.53%
Transmission Loss	16.96%	9.50%
Substation/Converter Investment	7.35%	34.17%
Substation/Converter Loss	2.61%	6.82%
Reactive compensation Investment	3.68%	-
Reactive Compensation Loss	1.31%	-
Maintenance	3.04%	3.98%

4.5.12 Interconnection between Singapore and Batam

The breakdown of the total annual equivalent costs associated with the interconnection between Singapore and Batam for both HVAC and HVDC is shown in Figure 4.15. Substation investment costs have the largest contribution to the total cost for the HVAC, and cost due to AC-DC converter investment is the largest for the HVDC; these costs are equivalent annually to 14.90 M$ and 16.76 M$, respectively.



(a)



(b)

Figure 4.15: Total annual equivalent costs of the interconnection between Singapore and Batam (in M$), (a) HVAC, (b) HVDC.

Substation investment costs account for 65.52%, and HVDC converter investment costs account for 69.12% of the total annual equivalent cost for the HVAC and HVDC

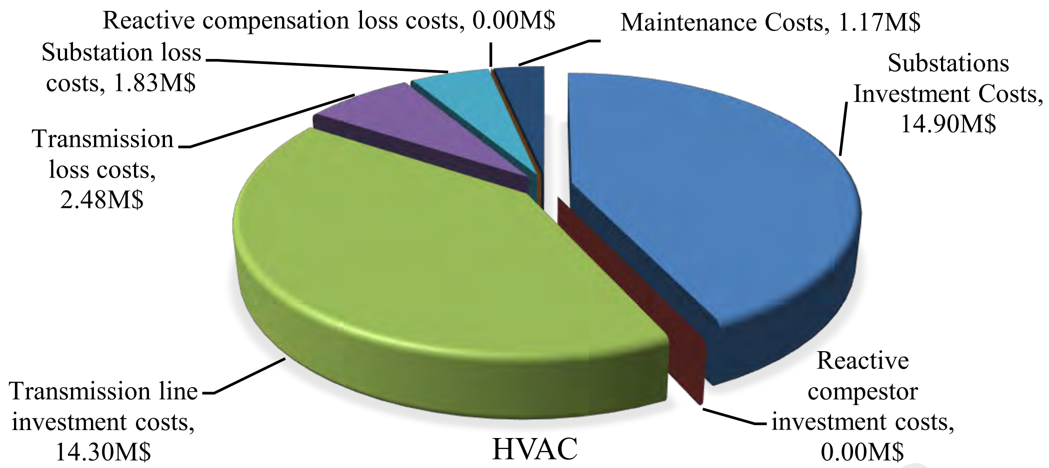
transmission options, respectively, as presented in Table 4.15. From the table, it can be seen that the transmission line investment costs and the AC-DC converter loss costs at 19.65% and 13.79%, respectively, are the second-largest contributor to the total costs. Substation and transmission loss costs also have a significant contribution to the total cost for HVAC at 8.02% and 3.04%, respectively. The HVDC transmission line investment and maintenance costs at 12.29% and 4.07%, respectively, have a significant contribution in the HVDC case.

Table 4.15: Cost weighting of each item as a percentage of total annual equivalent costs in M$

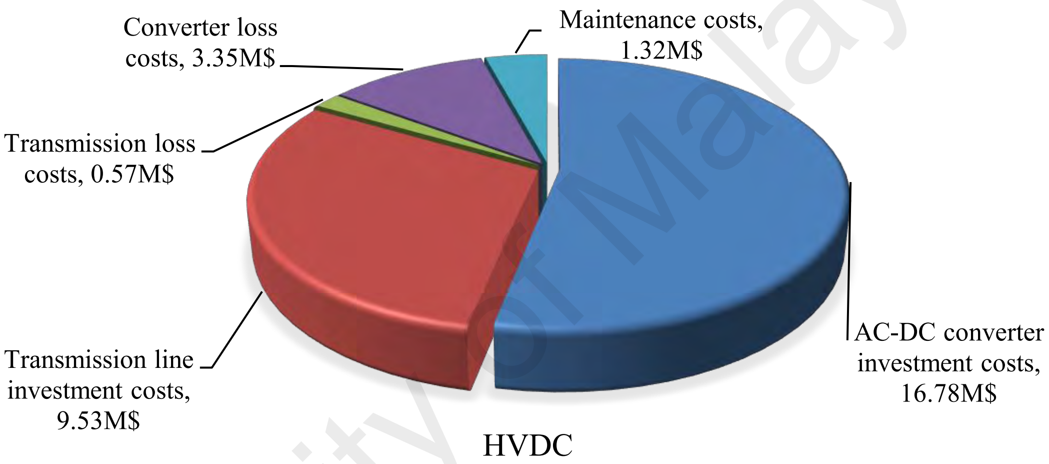
Item	HVAC	HVDC
Transmission Line Investment	19.65%	12.29%
Transmission Loss	3.40%	0.73%
Substation/Converter Investment	65.52%	69.12%
Substation/Converter Loss	8.02%	13.79%
Reactive compensation Investment	0.00%	-
Reactive Compensation Loss	0.00%	-
Maintenance	3.41%	4.07%

4.5.13 Interconnection between Sarawak and West Kalimantan

The breakdown of the total annual equivalent costs associated with the interconnection between Sarawak and West Kalimantan for both HVAC and HVDC is shown in Figure 4.16. Substation investment costs have the largest contribution to the total cost for the HVAC, and cost due to AC-DC converter investment is the largest for the HVDC; these costs are equivalent annually to 14.90 M$ and 16.78 M$, respectively.



(a)



(b)

Figure 4.16: Total annual equivalent costs of the interconnection between Sarawak and West Kalimantan (in M$), (a) HVAC, (b) HVDC.

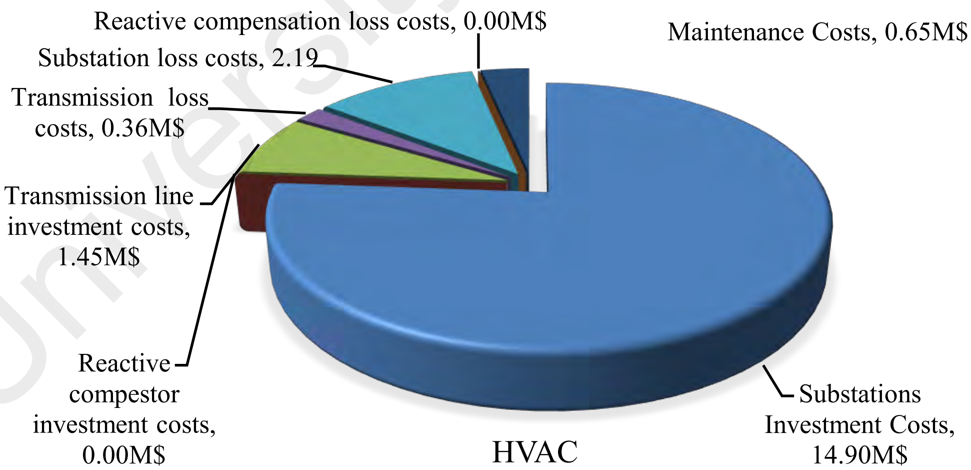
Substation investment costs account for 42.97%, and HVDC converter investment costs account for 53.19% of the total annual equivalent cost for the HVAC and HVDC transmission options, respectively, as presented in Table 4.16. From the table, it can be seen that the transmission line investment costs at 41.25% for HVAC and at 30.22% for HVDC are the second-largest contributor to the total costs. Transmission loss and substation loss costs also have a significant contribution to the total cost for HVAC at 7.15% and 5.27%, respectively. The AC-DC converter loss and maintenance costs at 10.61% and 4.17%, respectively, have a significant contribution in the HVDC case.

Table 4.16: Cost weighting of each item as a percentage of total annual equivalent costs in M$

Item	HVAC	HVDC
Transmission Line Investment	41.25%	30.22%
Transmission Loss	7.15%	1.81%
Substation/Converter Investment	42.97%	53.19%
Substation/Converter Loss	5.27%	10.61%
Reactive compensation Investment	0.00%	-
Reactive Compensation Loss	0.00%	-
Maintenance	3.37%	4.17%

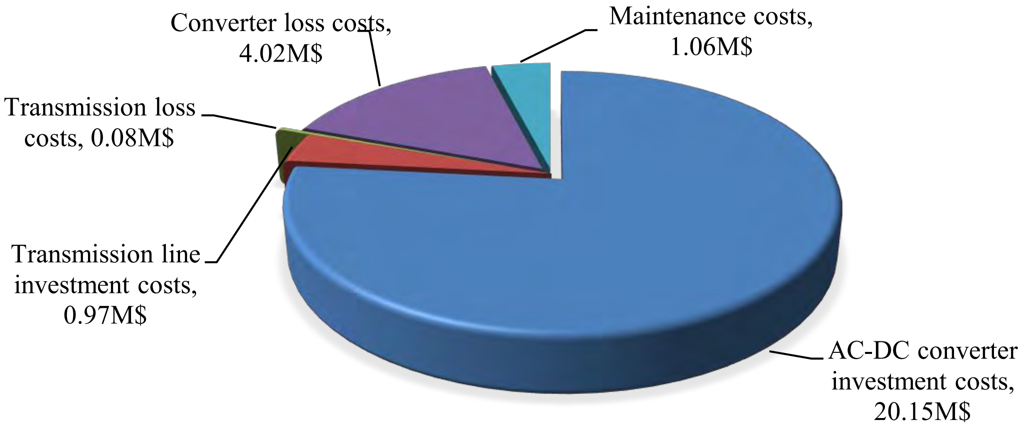
4.5.14 Interconnection between Sarawak and Brunei

The breakdown of the total annual equivalent costs associated with the interconnection between Sarawak and Brunei for both HVAC and HVDC is shown in Figure 4.17. Substation investment costs have the largest contribution to the total cost for the HVAC, and cost due to AC-DC converter investment is the largest for the HVDC; these costs are equivalent annually to 14.90 M$ and 20.15 M$, respectively.



(a)

Figure 4.17: Total annual equivalent costs of the interconnection between Sarawak and Brunei (in M$), (a) HVAC, (b) HVDC.



(b)

Figure 4.17, Continued.

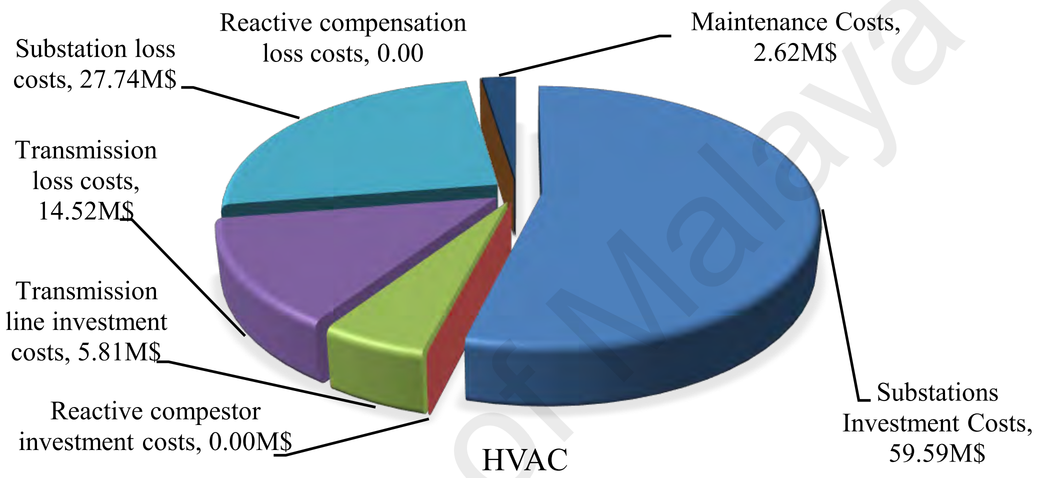
Substation investment costs account for 76.16%, and HVDC converter investment costs account for 76.68% of the total annual equivalent cost for the HVAC and HVDC transmission options, respectively, as presented in Table 4.17. From the table, it can be seen that substation loss costs at 11.21% for HVAC and AC-DC converter loss costs at 15.30% for HVDC are the second-largest contributor to the total costs. Transmission line investment, transmission loss, and maintenance costs also have a significant contribution to the total cost for HVAC at 7.43%, 1.86%, and 3.34%, respectively. Transmission line investment, transmission loss, and maintenance costs at 3.69%, 0.32%, and 4.02%, respectively, have a significant contribution in the HVDC case.

Table 4.17: Cost weighting of each item as a percentage of total annual equivalent costs in M$

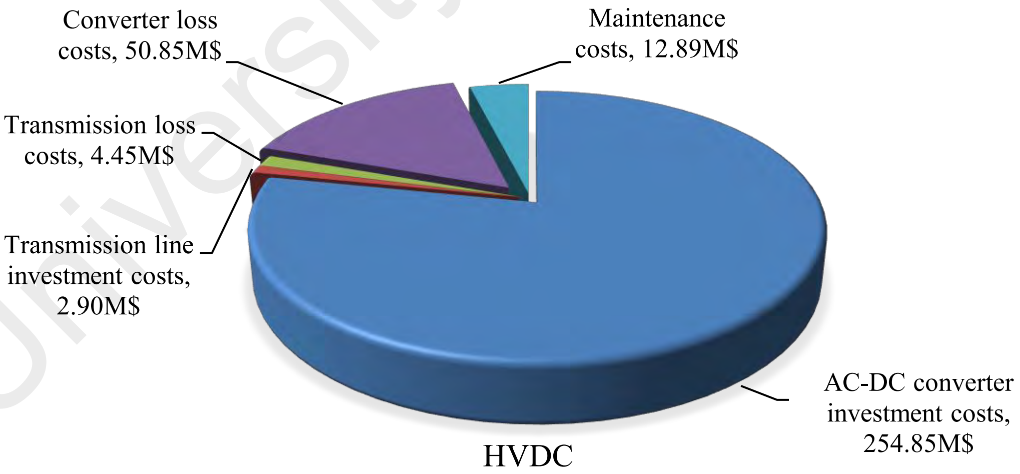
Item	HVAC	HVDC
Transmission Line Investment	7.43%	3.69%
Transmission Loss	1.86%	0.32%
Substation/Converter Investment	76.16%	76.68%
Substation/Converter Loss	11.21%	15.30%
Reactive compensation Investment	0.00%	-
Reactive Compensation Loss	0.00%	-
Maintenance	3.34%	4.02%

4.5.15 Interconnection between Sarawak and Sabah

The breakdown of the total annual equivalent costs associated with the interconnection between Sarawak and Sabah for both HVAC and HVDC is shown in Figure 4.18. Substation investment costs have the largest contribution to the total cost for the HVAC, and cost due to AC-DC converter investment is the largest for the HVDC; these costs are equivalent annually to 59.59 M$ and 254.85 M$, respectively.



(a)



(b)

Figure 4.18: Total annual equivalent costs of the interconnection between Sarawak and Sabah (in M$), (a) HVAC, (b) HVDC.

Substation investment costs account for 54.04%, and HVDC converter investment costs account for 78.19% of the total annual equivalent cost for the HVAC and HVDC

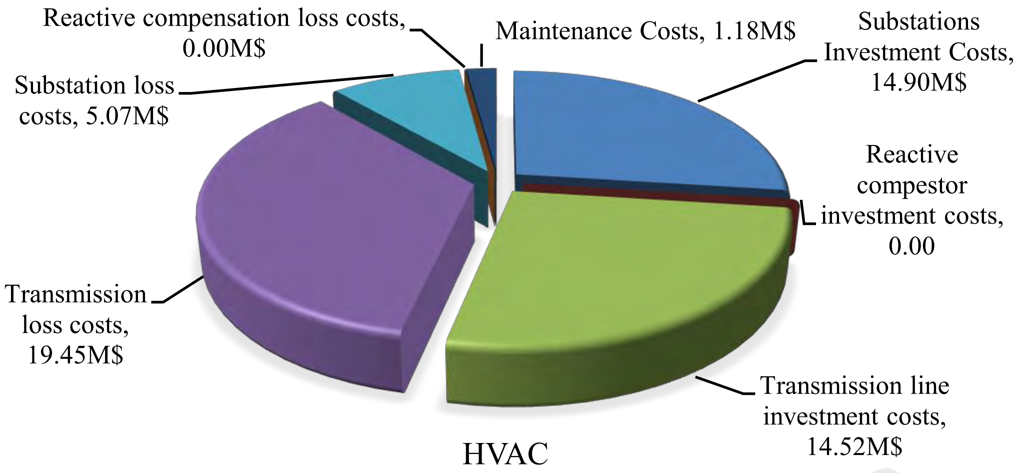
transmission options, respectively, as presented in Table 4.18. From the table, it can be seen that substation loss costs at 25.15% for HVAC and AC-DC converter loss costs at 15.60% for HVDC are the second-largest contributor to the total costs. Transmission loss, transmission line investment, and maintenance costs also have a significant contribution to the total cost for HVAC at 13.17%, 5.27%, and 2.37%, respectively. Transmission loss, transmission line investment, and maintenance costs at 1.37%, 0.89%, and 3.95%, respectively, have a significant contribution in the HVDC case.

Table 4.18: Cost weighting of each item as a percentage of total annual equivalent costs in M$

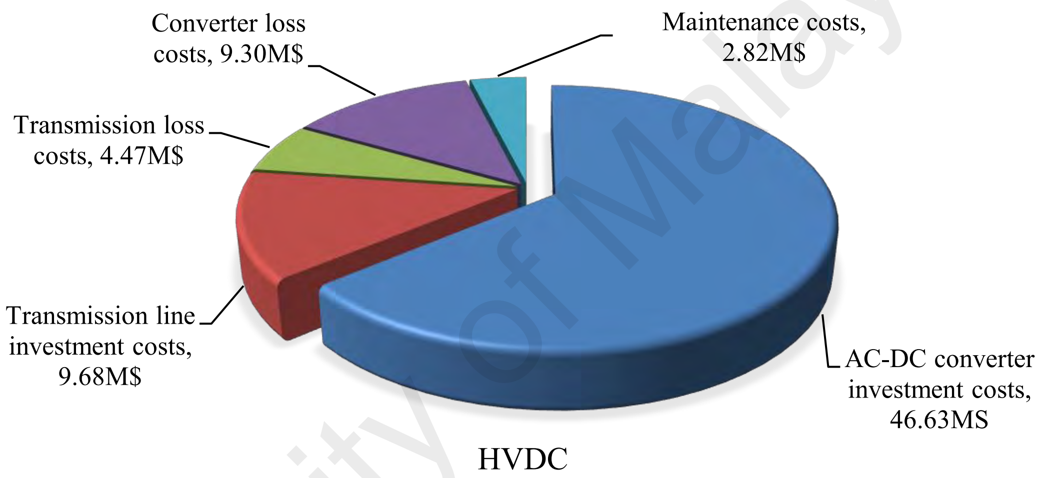
Item	HVAC	HVDC
Transmission Line Investment	5.27%	0.89%
Transmission Loss	13.17%	1.37%
Substation/Converter Investment	54.04%	78.19%
Substation/Converter Loss	25.15%	15.60%
Reactive compensation Investment	0.00%	-
Reactive Compensation Loss	0.00%	-
Maintenance	2.37%	3.95%

4.5.16 Interconnection between Sabah and East Kalimantan

The breakdown of the total annual equivalent costs associated with the interconnection between Sabah and East Kalimantan for both HVAC and HVDC is shown in Figure 4.19. Transmission loss costs have the largest contribution to the total cost for the HVAC, and cost due to AC-DC converter investment is the largest for the HVDC; these costs are equivalent annually to 19.45 M$ and 46.63 M$, respectively.



(a)



(b)

Figure 4.19: Total annual equivalent costs of the interconnection between Sarawak and Sabah (in M$), (a) HVAC, (b) HVDC.

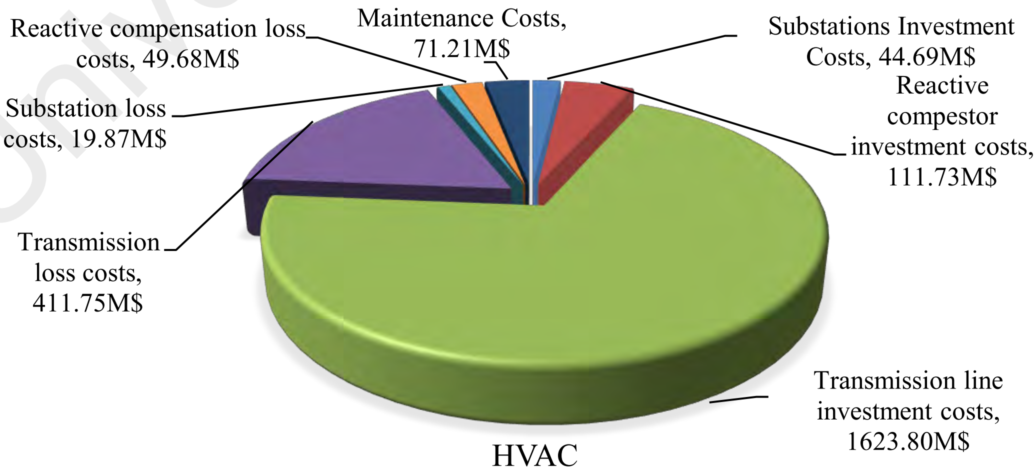
Transmission loss costs account for 35.28%, and HVDC converter investment costs account for 63.96% of the total annual equivalent cost for the HVAC and HVDC transmission options, respectively, as presented in Table 4.19. From the table, it can be seen that substation investment costs at 27.03% for HVAC and transmission line investment costs at 15.60% for HVDC are the second-largest contributor to the total costs. Transmission line investment, substation loss, and maintenance costs also have a significant contribution to the total cost for HVAC at 26.35%, 9.21%, and 2.14%, respectively. HVDC converter loss, transmission loss, and maintenance costs at 12.76%, 6.13%, and 3.86%, respectively, have a significant contribution in the HVDC case.

Table 4.19: Cost weighting of each item as a percentage of total annual equivalent costs in M$

Item	HVAC	HVDC
Transmission Line Investment	26.35%	13.28%
Transmission Loss	35.28%	6.13%
Substation/Converter Investment	27.03%	63.96%
Substation/Converter Loss	9.21%	12.76%
Reactive compensation Investment	0.00%	-
Reactive Compensation Loss	0.00%	-
Maintenance	2.14%	3.86%

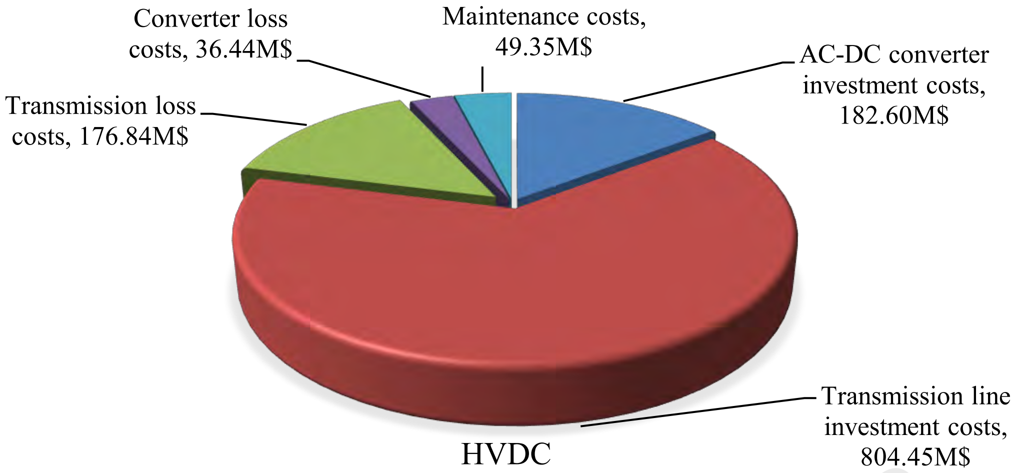
4.5.17 Interconnections between Sabah and the Philippines (Luzon)

The breakdown of the total annual equivalent costs associated with the interconnection between Sabah and the Philippines (Luzon) for both HVAC and HVDC is shown in Figure 4.20. Transmission line investment costs have the largest contribution to the total cost for both the HVAC and HVDC; these costs are equivalent annually to 1623.80 M$ and 804.45 M$, respectively.



(a)

Figure 4.20: Total annual equivalent costs of the interconnection between Sabah and the Philippines (Luzon) (in M$), (a) HVAC, (b) HVDC.



(b)

Figure 4.20, Continued.

Cost weighting of each item as a percentage of total annual equivalent costs for both HVAC and HVDC transmission system is shown in Table 4.20. Table 4.20 shows that transmission line investment costs account for 69.61% for HVAC and 64.37% for HVDC of the total annual equivalent cost. It can be seen that transmission loss costs are the second-largest contributor to the total costs for HVAC which are 17.65%, and AC-DC converter investment costs are the second largest contributor for HVDC which are 14.61%. Reactive compensators investment and reactive compensation loss costs also have a significant contribution to the total cost for HVAC at 4.79% and 2.13%, respectively. The HVDC transmission loss and the HVDC converter loss costs at 14.15% and 2.92%, respectively, have a significant contribution in the HVDC case. HVAC have substation investment and substation loss costs which are 1.92% and 0.85% respectively. Maintenance costs of HVAC and HVDC contribute 3.05% and 3.95% to the total costs respectively.

Table 4.20: Cost weighting of each item as a percentage of total annual equivalent costs in M$

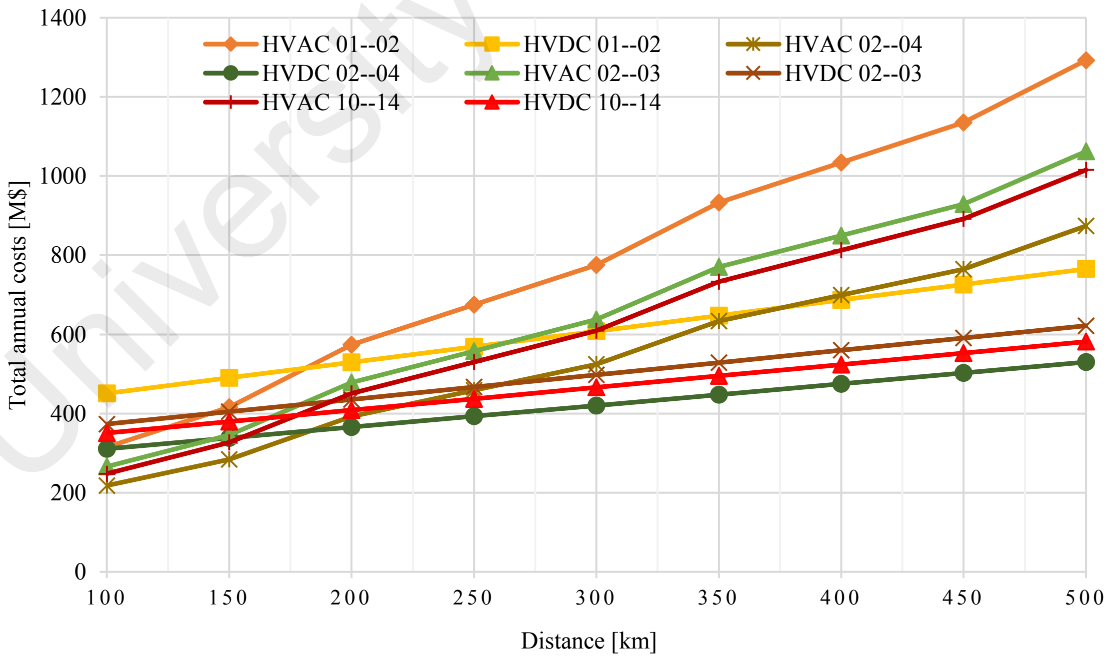
Item	HVAC	HVDC
Transmission Line Investment	69.61%	64.37%
Transmission Loss	17.65%	14.15%
Substation/Converter Investment	1.92%	14.61%
Substation/Converter Loss	0.85%	2.92%
Reactive compensation Investment	4.79%	-
Reactive Compensation Loss	2.13%	-
Maintenance	3.05%	3.95%

Comparison of individual cost components for the individual transmission interconnections shows that investment costs of the transmission line and transmission loss are mostly dominant for HVAC transmission option for most of the APG transmission links. In contrast, AC-DC converter investment costs and converter loss costs are mostly dominant for HVDC transmission option for most of the APG transmission links. The reduction of HVDC converter investment cost and HVDC converter loss can have a notable effect on the HVDC transmission. Future VSC-HVDC technology can achieve this by, for example, using multilevel VSCs instead of two-level converters to reduce converter loss (Elliott et al., 2016).

4.6 Sensitivity analysis

The obtained results in this thesis are highly dependent on system design, input assumptions used, and requirements of the ASEAN countries. A different set of design and input assumptions can give different results. For example, HVAC options are suitable for short distances and low power transfer because of their significantly low capital cost. However, HVAC systems have a higher loss than HVDC. Moreover, if the HVDC converter cost could be reduced to an acceptable level, then the HVDC transmission option could compete with the HVAC for short distance and low cost. Another important variable that can significantly change the final value is the distance of the transmission interconnections. Only the distance of the interconnections between asynchronous grids is considered for calculating the annual cost for either HVAC or HVDC transmission option. Nevertheless, practical situations could be quite different. Sometimes, transferring generated power from one country to the load centers of another country is needed by using neighboring countries' power transmission infrastructure. In this case, power transmission distances are not only limited to the interconnections' distances. For example, the OPF simulation result in Figure 4.1 shows that the generated power from Myanmar, Lao PDR, and Cambodia needs to transfer to the high-demand load centers in Malaysia and Singapore through the transmission infrastructure of Thailand and Malaysia. Presently, the same types of multilateral cross-border power trade from Lao PDR to Singapore through the Lao PDR–Thailand –Malaysia–Singapore Power Integration Project (LTMS-PIP) are being implemented in the ASEAN (APGCC, 2015). As a result, analyzing the feasibility of the transmission options for the interconnections among the asynchronous grids by varying the transmission distances rather than only using the fixed interconnection distances is required. For this reason, sensitivity analysis of the transmission options for the interconnections by varying the distances was conducted for the individual transmission links of APG interconnection. Sensitivity analysis was conducted using (4.1) and (4.14) where distances of individual interconnections are taken as a variable.

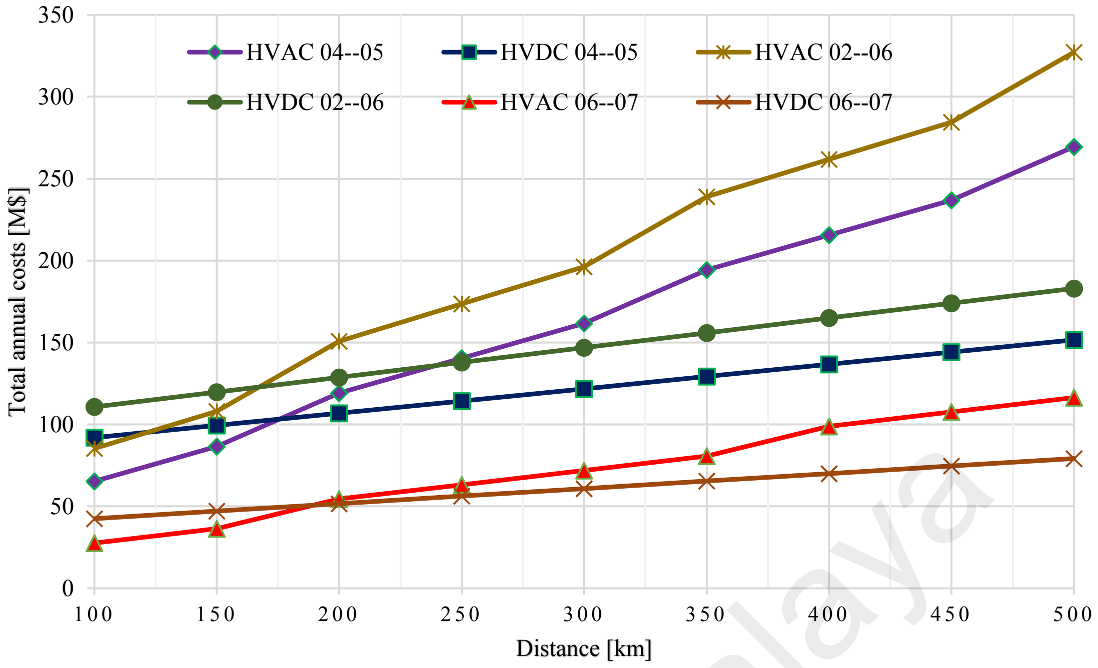
Figure 4.21 shows the sensitivity analysis results for the individual transmission routes of APG. From Figure 4.21(a), (b), (c), (d), (e), and (f) it can be observed that the HVAC transmission systems initially have less annual costs compared to the HVDC transmission systems. This is primarily due to the proportionally higher capital costs associated with HVDC systems and small transmission losses associated with HVAC system. In addition, from Figure 4.21 it is evident that the total annual costs of HVAC transmission systems are increased higher than that of HVDC transmission systems with the increment of transmission distances. This is because of the higher operational and maintenance costs (especially costs of HVAC transmission losses and reactive compensation losses) associated with long distance HVAC transmission systems. Besides, capital costs also increased with the increment of length due to the requirement of reactive compensation of HVAC system after certain distances. As a result, HVDC transmission systems are becoming preferable than HVAC systems with the increment of distances. Furthermore, it can be observed that the cross-over distance at which HVDC connection is cheaper than HVAC occurs depending upon the amount of power transmission through the interconnections. Figure 4.21 shows that the annual costs of HVAC systems are increased significantly after the cross-over distance. Moreover, the annual costs of HVAC become nearly double than HVDC at a distance of 500 km. The aforementioned discussion shows that the HVDC transmission option becomes less expensive with increasing distance, especially in bulk power transmission.



Myanmar (01); Thailand (02); Laos (03); Cambodia (04); Sarawak (10); Sabah (14)

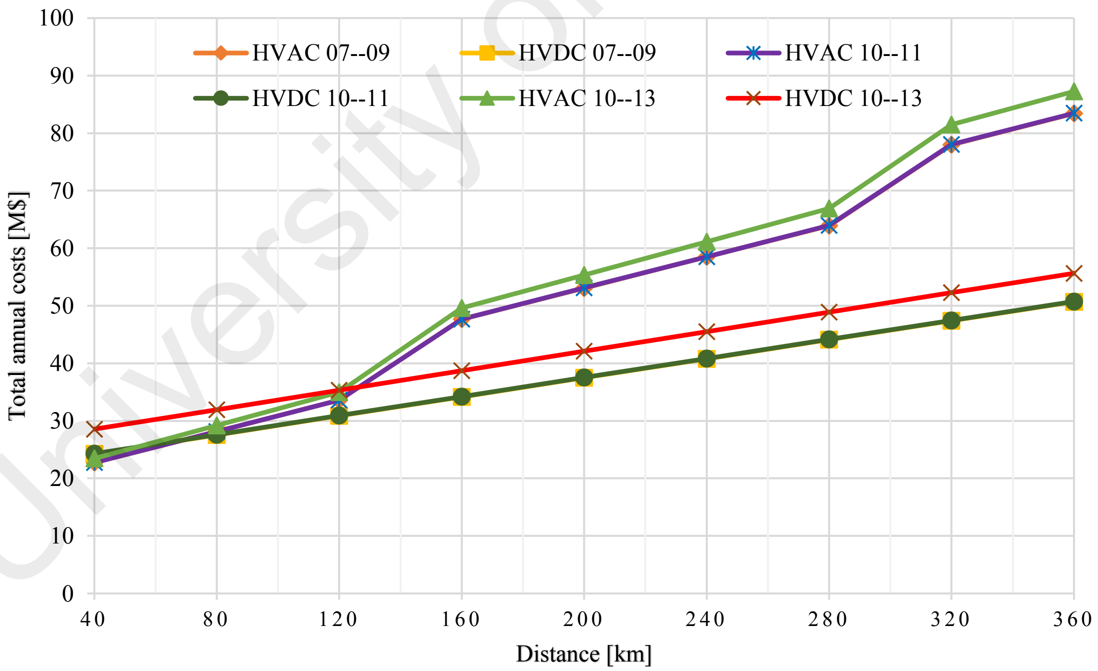
(a) Myanmar – Thailand; Thailand – Cambodia; Thailand – Lao PDR; Sarawak – Sabah

Figure 4.21: Total annual costs of HVAC and HVDC technology for different transmission distances.



Thailand (02); Cambodia (04); Vietnam (05); Peninsular Malaysia (06); Singapore (07)

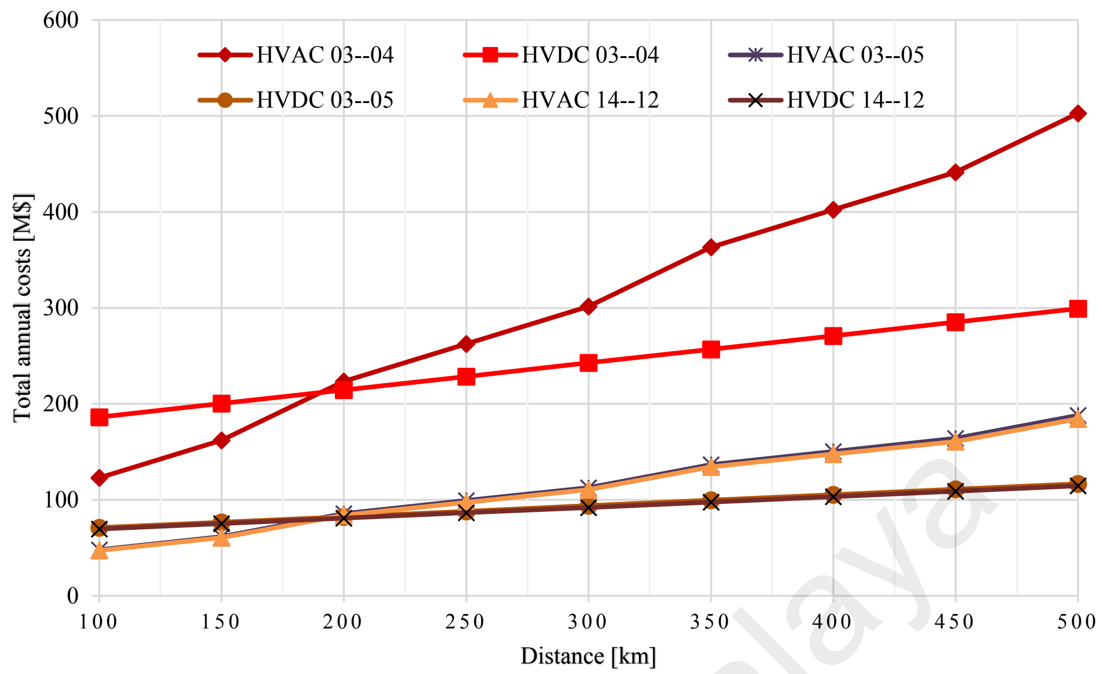
(b) Cambodia – Vietnam; Thailand – P. Malaysia; P. Malaysia – Singapore



Singapore (07); Batam (09); Sarawak (10); West Kalimantan (11); Brunei (13)

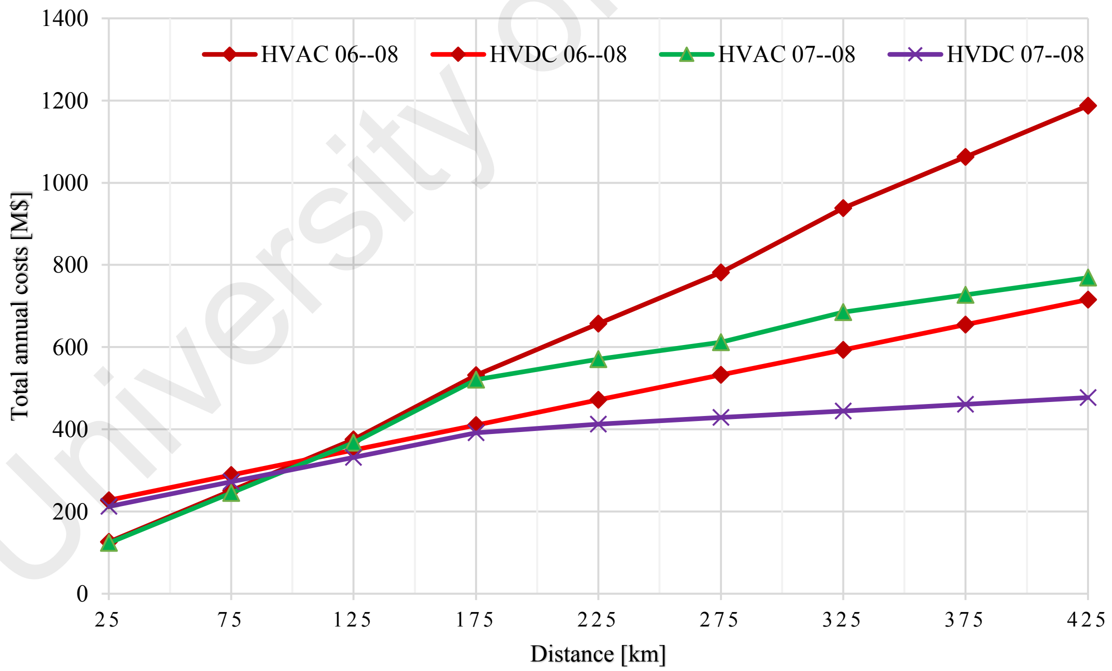
(c) Singapore – Batam; Sarawak – West Kalimantan; Sarawak – Brunei

Figure 4.21, Continued.



Laos (03); Cambodia (04); Vietnam (05); East Kalimantan (12); Sabah (14)

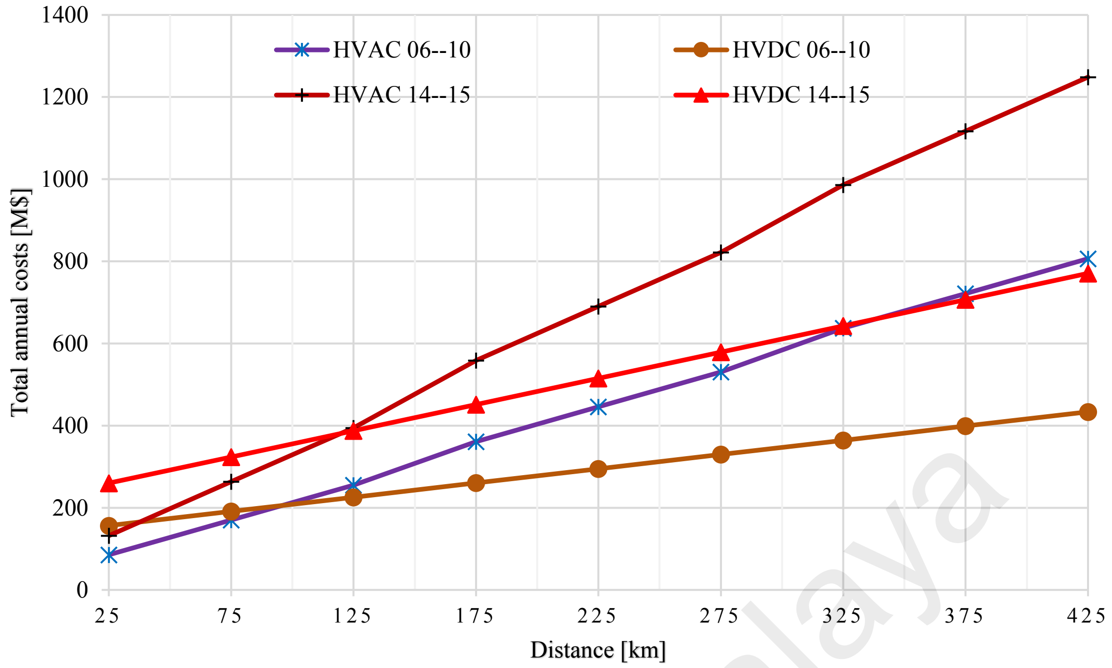
(d) Lao PDR – Cambodia; Lao PDR – Vietnam; Sabah – East Kalimantan



Peninsular Malaysia (06); Singapore (07); Sumatra (08)

(e) P. Malaysia – Sumatra; Singapore – Sumatra;

Figure 4.21, Continued.



Peninsular Malaysia (06); Sarawak (10); Sabah (14); Luzon (Phillipines) (15)

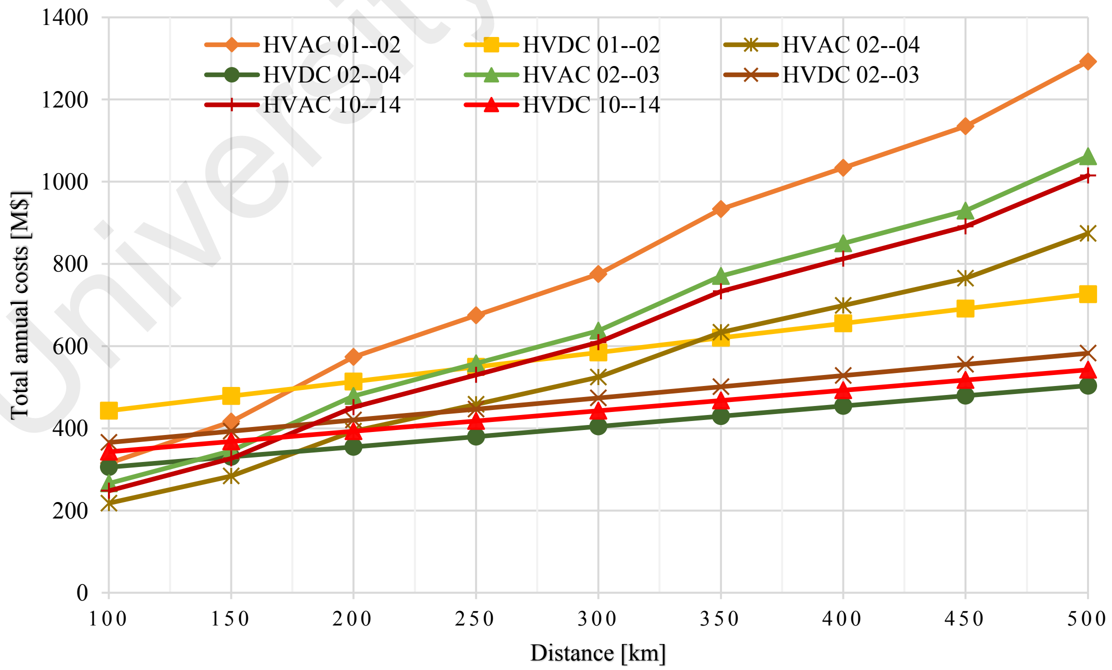
(f) P. Malaysia – Sarawak; Sabah – the Philippines (Luzon);

Figure 4.21, Continued.

Sensitivity analysis of the transmission options was also conducted by removing the metallic earth return from the HVDC bipole system for the individual transmission links of APG interconnection. Removing of metallic earth return save the transmission investment costs (installation cost and cable cost). Figure 4.22 shows the results of total costs of HVAC and HVDC technology for different transmission distances, where the earth return cable has been omitted. Figure 4.22 also shows the similar kind of results like Figure 4.21 and it can be observed from Figure 4.22 that cross-over distances are reducing than that of Figure 4.21. This in turns indicating that in terms of the economic point of view, the omission of metallic earth return could be preferable. However, it is important to conduct the potential impact of the event of a fault on one cable in stable operation of the transmission system and this has not considered in the study.

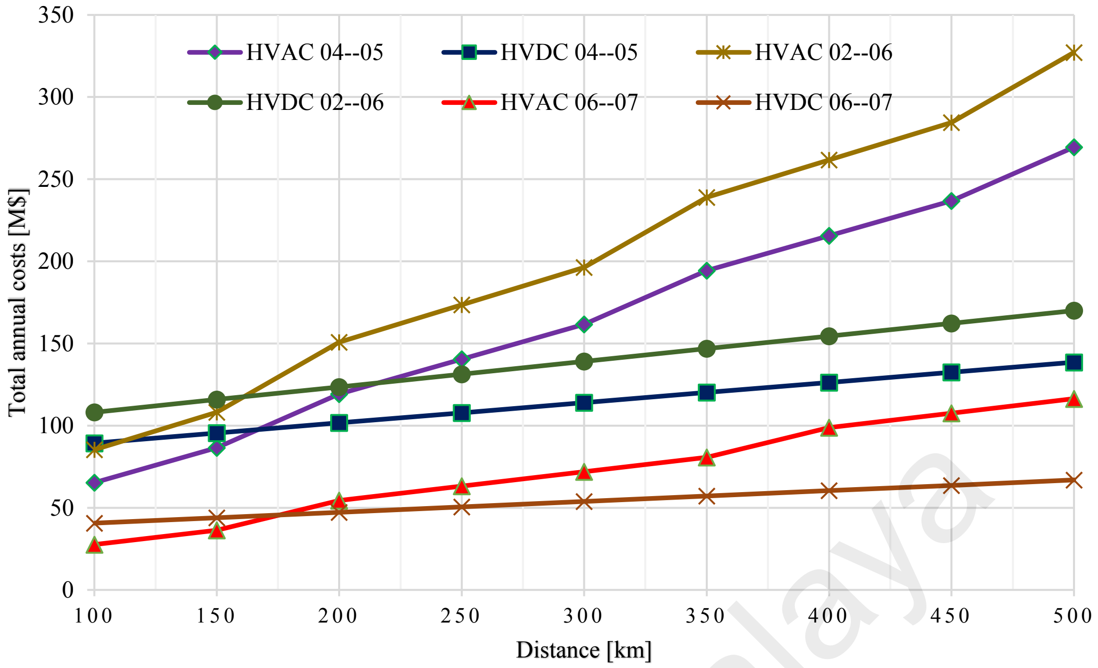
Summary of the cross-over distances for the individual interconnections of APG where HVDC becomes cheaper than HVAC are presented in Table 4.21. It can be seen that metallic earth return removal reduces the cross-over distances and these cross-over distances reduction depends upon the capacity of the individual transmission links and types of transmission (underground or overhead). Cross-over distance reduction is more for underground cable due to more transmission investment costs reduction of HVDC transmission technology.

In conclusion, the HVAC transmission costs are more sensitive to operational costs than the HVDC transmission system, especially to transmission losses. A number of additional factors can be considered in analyzing the sensitivity, such as costs of STATCOM for controlling the voltages for the HVAC case. Considering these values can reduce the crossover or break-even distances at which HVDC becomes less expensive than HVAC.

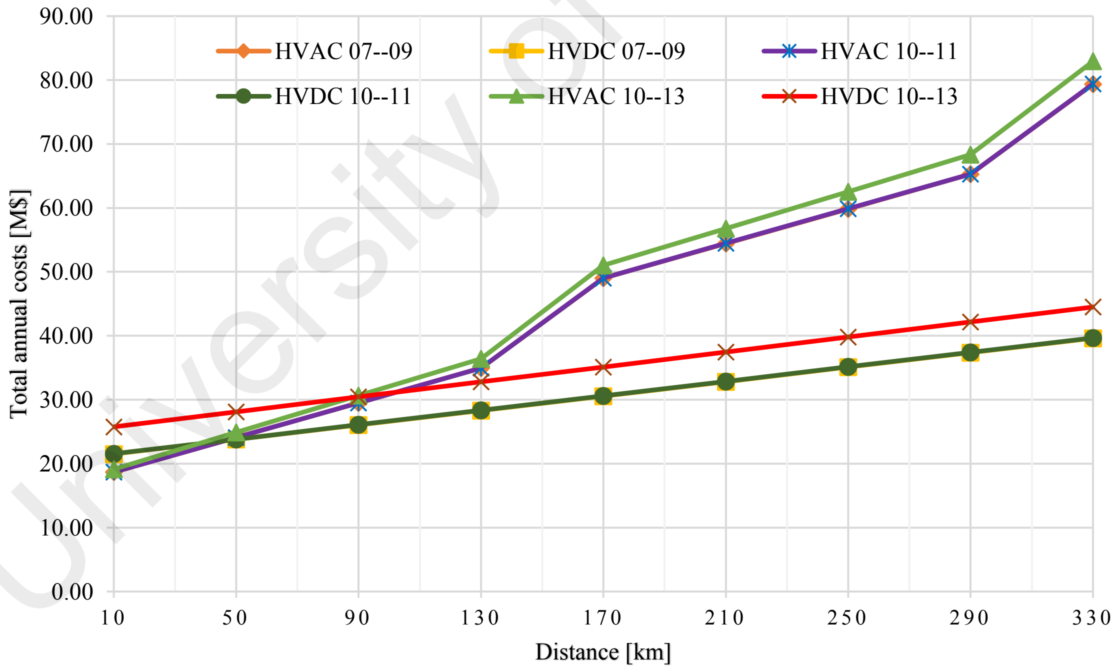


(a) Myanmar – Thailand; Thailand – Cambodia; Thailand – Lao PDR; Sarawak – Sabah

Figure 4.22: Total annual costs of HVAC and HVDC technology for different transmission distances, where the earth return cable has been omitted.

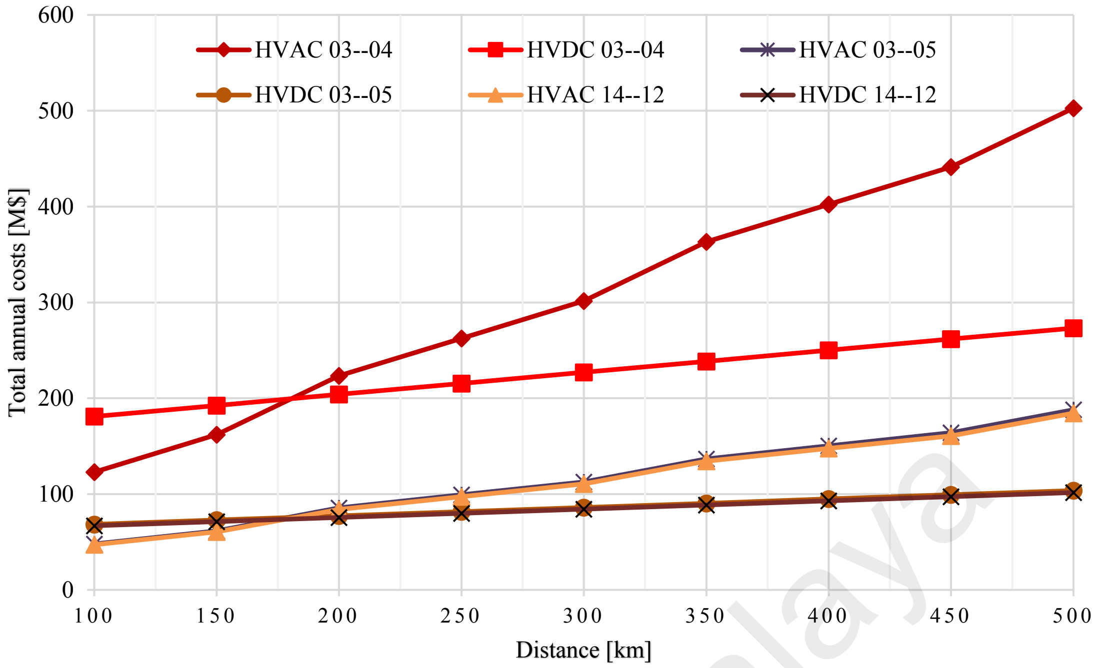


(b) Cambodia – Vietnam; Thailand – P. Malaysia; P. Malaysia – Singapore

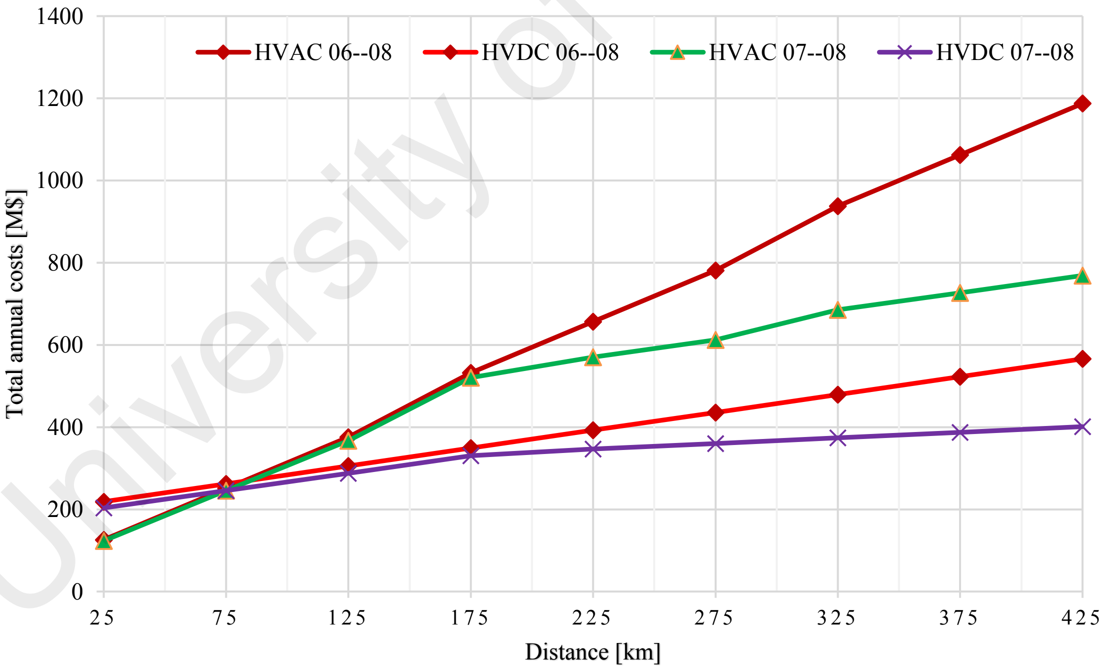


(c) Singapore – Batam; Sarawak – West Kalimantan; Sarawak – Brunei

Figure 4.22, Continued.

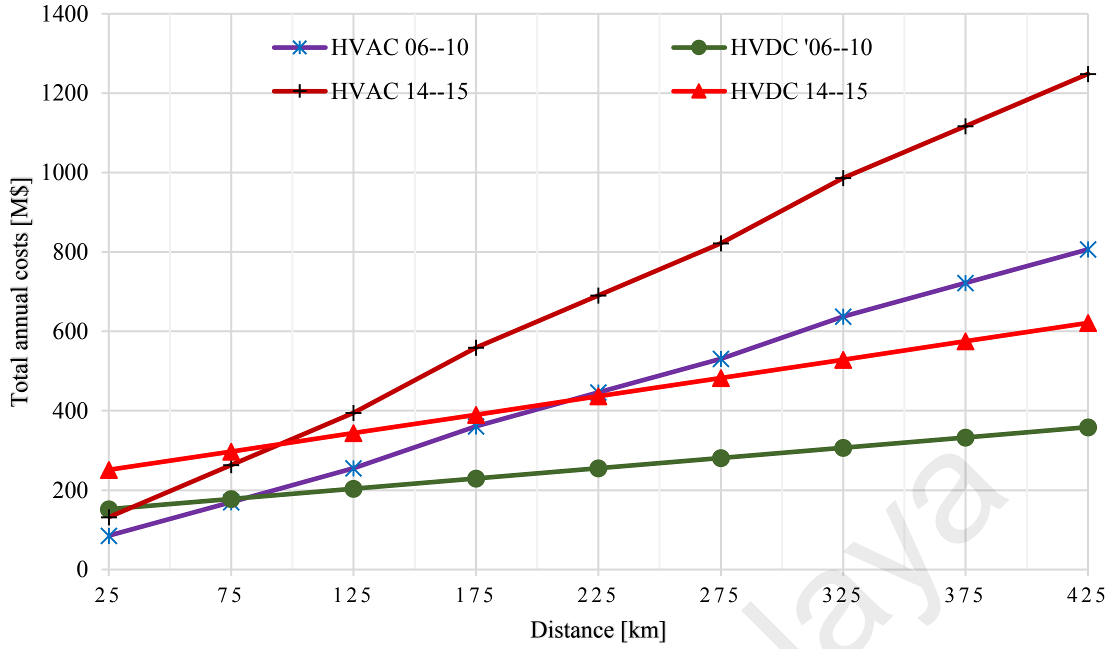


(d) Lao PDR – Cambodia; Lao PDR – Vietnam; Sabah – East Kalimantan



(e) P. Malaysia – Sumatra; Singapore – Sumatra;

Figure 4.22, Continued.



(f) P. Malaysia – Sarawak; Sabah – the Philippines (Luzon);

Figure 4.22, Continued.

Table 4.21: Summary of the cross-over distances of the individual interconnections of APG

No.	Interconnections	Approximate cross-over distances (km)	
		With earth return cable	Without earth return cable
1	Myanmar – Thailand	180	175
2	Thailand – Lao PDR	177	170
3	Thailand – Cambodia	183	176
4	Lao PDR – Cambodia	193	182
5	Lao PDR – Vietnam	191	177
6	Cambodia – Vietnam	175	167
7	Thailand – P. Malaysia	167	160
8	P. Malaysia – Singapore	187	173
9	P. Malaysia – Sumatra	105	80
10	P. Malaysia – Sarawak	100	80
11	Singapore – Sumatra	96	75
12	Singapore – Batam	72	49
13	Sarawak – West Kalimantan	73	50
14	Sarawak – Brunei	120	92
15	Sarawak – Sabah	177	169
16	Sabah – East Kalimantan	192	176
17	Sabah – The Philippines (Luzon)	121	95

4.7 Summary

This chapter presents and discusses the details of cross-border transmission capacity needs to meet the load demand in 2030 generation and demand scenarios in the form of energy market simulation results. In addition, this chapter presents detail economic appraisal to calculate the capital costs, operation and maintenance costs related to HVDC and HVAC transmission options. Economic comparisons between HVDC and HVAC transmission technology for the cross-border interconnections have been presented in the chapter to choose the optimum transmission technology of the transmission links. Finally, sensitivity analysis is carried out by varying the transmission links distances to investigate the impact of transmission links distances on transmission costs for both HVDC and HVAC technology.

CHAPTER 5: EVALUATION OF NET MARKET BENEFIT

5.1 Introduction

APG integrates individual isolated ASEAN energy markets through cross-border transmission links and enables power transportation from abundant generating regions to high load demand regions. The previous chapter presents the optimal cross-border power transmission requirements to meet the load demand of 2030 scenarios from low-cost generation options. The previous chapter also shows the optimal transmission technology options for the individual cross-border transmission links of APG interconnections. However, establishing interconnection among the ASEAN energy markets through APG requires a large amount of investment costs. These investment costs should have been justified through the expected benefit in ASEAN electricity market environment.

The aim of this chapter is to provide an economic study in the form of cost-benefit analysis of APG integration. This chapter explores the benefit for investment in APG by means of cross-border electricity transmission investment in ASEAN by 2030. The benefit of investing cross-border transmission is analyzed by considering the expected generation portfolio. Net market evaluation framework of APG interconnection is proposed in the chapter which includes consumer, producer, transmission owner and environmental benefit for APG interconnection. The study is performed with APG model presented in Chapter 3 and the results of optimal cross-border transmission requirements in Chapter 4. The impact of cross-border transmission capacity on net market benefit is analyzed by considering the cross-border transmission capacity limit mentioned by ACE and optimal transmission limits in Chapter 4.

The rest of the chapter is organized as follows: Section 5.2 contains an overview of net market benefit evaluation process in the context of large-scale transmission expansions. The proposed net market benefit evaluation framework is described in Section 5.3

followed by considered net market benefit evaluation scenarios in Section 5.4. Analytical results for the considered scenarios are presented in Section 5.5. Yearly required revenue calculation for cross-border transmission is presented in Section 5.6 followed by a comparison between yearly required revenue (YRR) and net market benefit of APG expansion in section 5.7. At last, Section 5.8 includes the summary of the chapter.

5.2 Overview of market benefit evaluation

Transmission expansion planning in any jurisdiction requires a huge amount of investment. It is necessary that this transmission investment must be justified through the expected benefits in a market environment. Individual transmission network service providers or market operators utilize their individual market models to evaluate the benefit of new transmission system expansion or upgradation. However, modernized electricity markets are comprised of several independent TSOs that have independent decision-making authority which directly affects the transmission line utilization. For this reason, a new approach is necessary to evaluate the economic benefit of modernized electricity markets (CAISO, 2004). Transmission Economic Assessment Methodology (TEAM) developed by the California Independent System Operator (CAISO) is one of the most-established methodology to evaluate the economic benefit of transmission upgradations (CAISO, 2004; Hasan, Saha, Chattopadhyay, et al., 2014; Hasan, Saha, & Eghbal, 2014; Sauma & Oren, 2006; Wu, Zheng, & Wen, 2006). TEAM has the ability to provide necessary economic information to market participants, policy makers, and approving authorities for evaluating transmission upgradations in an effective and consistent manner. TEAM utilizes a framework that measures the benefit of transmission expansions and provides economic impacts of a transmission upgradation from a regional perspective as well as from consumers, producers, and TSOs perspective.

5.3 Proposed net market benefit evaluation framework for APG

Restructured ASEAN electricity markets through APG consists of 15 independent decision making TSOs. As a result, market benefit evaluation is necessary in terms of cost-benefit aspects to evaluate this vertical integration of 15 isolated TSOs. The market benefit evaluation framework is adopted and modified from the article presented in (CAISO, 2004; Hasan, Saha, Chattopadhyay, et al., 2014; Hasan, Saha, & Eghbal, 2014; Sauma & Oren, 2006; Wu et al., 2006). The total market benefit is evaluated by considering both the consumer benefits and producer benefits. The environmental benefit also incorporated in the net market benefit analysis framework of this thesis because APG has an environmental impact to the ASEAN community as APG aims to enhance renewable energy generation in the electricity generation mix in the ASEAN to reduce the electricity generation-related CO_2 emissions (ACE, 2015c; IEA, 2013). Besides, ASEAN region is the most vulnerable to climate change and for this ASEAN member states have announced voluntary CO_2 emissions reduction targets (ASEAN Cooperation on Environment, 2017; IEA, 2013). As a result, the environmental benefits of APG interconnection is evaluated in terms of emission pricing or CO_2 pricing. The objective function of net market benefit framework consists of consumer surplus, producer surplus, transmission owner benefit (merchandizing surplus), and CO_2 price. Formulation of net market benefit is shown in (5.1) (CAISO, 2004; Hasan, Saha, Chattopadhyay, et al., 2014; Hasan, Saha, & Eghbal, 2014; Sauma & Oren, 2006; Wu et al., 2006),

$$\max \sum_{t=1}^{8760} \left[\sum_{i \in n_d} \left(CS_d^{i''} - CS_d^{i'} \right) + \sum_{i \in n_g} \left(p_g^i . \lambda_g^i - p_g^i . \varphi_g^i \right) + \left(\sum_{i \in n_d} p_d^i . \lambda_d^i - \sum_{i \in n_g} p_g^i . \lambda_g^i \right) - \left(\sum_{i \in n_g} (C_i . E_{CO_2} \right) \right] \tag{5.1}$$

In (5.1), t (=1, 2, ….8760) is the t^th^ hour per year (hour), n_d is the number of loads in the system, n_g is the number of generators in the system, $CS_d^{i''}$ is consumer surplus earned by consumer i after APG transmission expansion ($), $CS_d^{i'}$ is consumer surplus earned by consumer i before APG transmission expansion ($), p_g^i is the generated power of generator i (MW), λ_g^i is the LMP at generator bus i ($/MWh), φ_g^i is the active power generation cost of generator i ($), p_d^i is the power demand of load i (MW), λ_d^i is the LMP of load bus i ($/MWh), C_i is the amount of CO_2 produced by generator i (ton), and E_{CO_2} is the CO_2 emission cost ($/ton).

The net market benefit of APG is calculated based on the optimal power flow simulation of the ASEAN energy market, efficient generation dispatch, corresponding levelized operation and maintenance cost, generation revenue, LMPs of individual nodes, and network flow. Details of the net market benefit framework are described in the following:

5.3.1 Consumer Surplus

The consumer surplus is the difference between the consumers' willingness to payment and consumers' actual payment for a product. Consumers' willingness to pay in the energy market can be measured by Value of Lost Load (VOLL) which in turns indicates the approximate value of avoiding involuntary energy curtailments (CAISO, 2004). Consumer and producer surplus are presented in Figure 5.1 where there is no transmission losses and demand is perfectly inelastic.

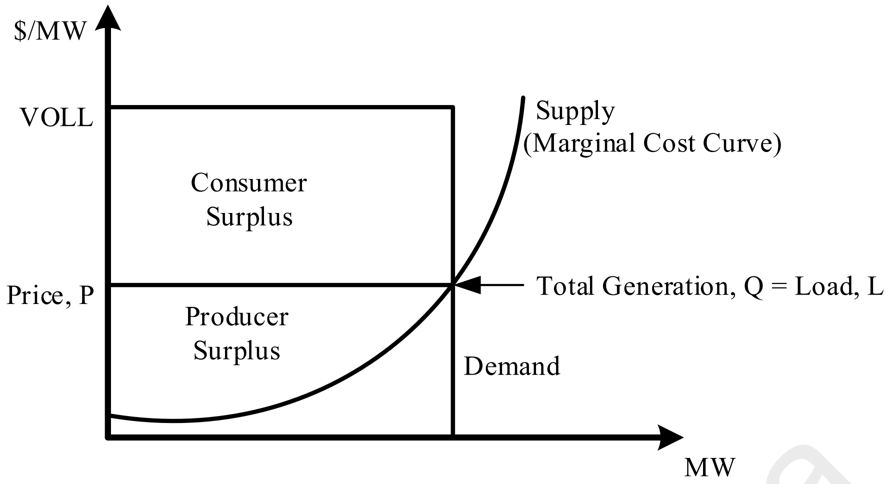


Figure 5.1: Consumer and producer surplus.

Consumer surplus can be calculated from (5.2).

$$\begin{aligned} CS &= (VOLL - price) * Load \\ &= VOLL * L \; - \; CTL \end{aligned} \tag{5.2}$$

In (5.2), *VOLL* is the value of lost load, *L* is total load which is equivalent to the generator in this case, *CTL* is total Cost-to-Load.

CTL can be calculated from (5.3).

$$CTL = \sum_{t=1}^{8760} \lambda_d^i * L_d^i \tag{5.3}$$

In (5.3), *t* (=1, 2, ….8760) is the t[th] hour per year (hour), λ_d^i is LMP ($/MWh) of load bus *i*, L_d^i is the total load of the corresponding load bus *i* (MW). Thus, the total consumer surplus can be calculated as (5.4).

$$CS_d = \sum_{t=1}^{8760} VOLL * L_d^i - \sum_{t=1}^{8760} \lambda_d^i * L_d^i \tag{5.4}$$

For the case of ASEAN energy market integration through the APG network, consumer surplus can be defined as the benefit of ASEAN electricity consumers for the integration ASEAN energy market through APG. These benefits of the electricity consumers can be calculated as the difference between the consumers' surplus before and after the ASEAN energy market integration. Therefore, consumer surplus (CS) can be calculated as (5.5).

$$\mathrm{CS} = CS_d^{i''} - CS_d^{i'} \tag{5.5}$$

In (5.5), $CS_d^{i''}$ is consumer surplus earned by consumer *i* after APG transmission expansion (\$), $CS_d^{i'}$ is consumer surplus earned by consumer *i* before APG transmission expansion (\$).

Equations (5.4) and (5.5) can be written as (5.6),

$$\mathrm{CS} = \left(\sum_{t=1}^{8760} VOLL'' * L_d^{i''} - \sum_{t=1}^{8760} \lambda_d^{i''} * L_d^{i''} \right) - \left(\sum_{t=1}^{8760} VOLL' * L_d^{i'} - \sum_{t=1}^{8760} \lambda_d^{i'} * L_d^{i'} \right) \tag{5.6}$$

In (5.6), $VOLL''$ is the value of lost load after APG interconnection, $L_d^{i''}$ is the total load of the corresponding load bus *i* (MW) after APG interconnection, $\lambda_d^{i''}$ is LMP (\$/MWh) of load bus *i* after APG interconnection, $VOLL'$ is the value of lost load before APG interconnection, $L_d^{i'}$ is the total load of the corresponding load bus *i* (MW) before APG interconnection, $\lambda_d^{i'}$ is LMP (\$/MWh) of load bus *i* before APG interconnection.

For the simplicity of calculating the consumer surplus, it has been considered that there is no change in the reliability for APG expansion, which means before and after APG establishment all the loads of ASEAN energy market are served. Therefore, VOLL in (5.6) will cancel each other and total consumer surplus of APG interconnections can be written as (5.7), which in turns is the difference between consumer payments for consumed power before and after the APG establishment.

$$\mathrm{CS} = \left(\sum_{t=1}^{8760} \lambda_d^{i'} * L_d^{i'} - \sum_{t=1}^{8760} \lambda_d^{i''} * L_d^{i''} \right) \tag{5.7}$$

5.3.2 Producer Surplus

Producer surplus is the difference between producer revenue or total generation revenue earned by generators and production cost or generation cost which is shown in Figure 5.1. Producer surplus (PS) can be represented as (5.8)

$$\mathrm{PS} = \sum_{t=1}^{8760} \left[\sum_{i \in n_g} \left(p_g^i . \lambda_g^i - p_g^i . \varphi_g^i \right) \right] \tag{5.8}$$

In (5.8), t (=1, 2, ….8760) is the tth hour per year (hour), p_g^i is the generated power of generator i (MW), λ_g^i is the LMP at generator bus i (\$/MWh), and φ_g^i is the active power generation cost of generator i (\$).

5.3.3 Transmission owner benefit

Transmission owner benefit is the difference between the total payments of consumers for consuming electricity and the total producer income. When in a transmission system is free of congestion, transmission losses, and wheeling charges, there will be no benefit for transmission owner or there will be no congestion revenue and in that case, total payments of consumers will be equal to the total income of producer. On the contrary, when any line of the transmission system has congestion, total payments of consumers will not be equal to the total income of producer and there will be congestion revenue or transmission owner benefit. This is because of the payments difference of consumers for consuming electricity and producers for generating electricity, as, consumers pay for electricity at their locational price while generators are paid the prices according to their generation buses. As a result, transmission owner benefit of congestion revenue can be expressed as (5.9).

$$CR = \sum_{t=1}^{8760} \left[\left(\sum_{i \in n_d} p_d^i . \lambda_d^i - \sum_{i \in n_g} p_g^i . \lambda_g^i \right) \right] \quad (5.9)$$

In (5.9), t (=1, 2, ….8760) is the t[th] hour per year (hour), p_d^i is the power demand of load i (MW), λ_d^i is the LMP of load bus i (\$/MWh), p_g^i is the generated power of generator i (MW), and λ_g^i is the LMP at generator bus i (\$/MWh).

5.3.4 Emission pricing

Emission pricing is considered during net market benefit analysis of ASEAN energy market integration through APG. It has been considered that generators need to pay the penalty for emitting CO_2 during generating electricity. Emission pricing is calculated based on CO_2 emission by the generators for generating electricity and respective CO_2 emission price per unit. Emission pricing (EP) can be expressed as (5.10). For calculating the total amount of CO_2 emission from different types of power generation technologies, carbon emission coefficients are taken from (Chang & Li, 2015; WNA, 2017) which is shown in Table 5.1. Carbon pricing for ASEAN is shown in Table 5.2 which is taken from (Chang & Li, 2015).

$$EP = \sum_{t=1}^{8760} \left[\left(\sum_{i \in n_g} (C_i . E_{CO_2} \right) \right] \quad (5.10)$$

In (5.10), t (=1, 2, ….8760) is the t[th] hour per year (hour), n_g is the number of generators in the system, C_i is the amount of CO_2 produced by generator i (ton), and E_{CO_2} is the CO_2 emission cost (\$/ton).

Table 5.1: Different power generation technologies carbon emissions coefficient (Chang & Li, 2015; WNA, 2017)

Generation Technologies	Carbon Emissions (ton/MWh)
Coal CCS	0.1
Diesel	0.8
NG	0.5
NG CCS	0.038
Large Hydro	0.001
Small Hydro	0.001
Geothermal	0.05
Wind	0.01
PV	0.05
Biomass	0.05
Nuclear	0.029

Table 5.2: Prices of carbon emissions for ASEAN countries (Chang & Li, 2015)

Year	Assumed price of CO_2 emissions ($/ton)	Year	Assumed price of CO_2 emissions ($/ton)
2012	26.06	**2022**	28.73
2013	32.07	**2023**	35.36
2014	18.74	**2024**	20.66
2015	19.28	**2025**	21.26
2016	19.68	**2026**	21.69
2017	27.37	**2027**	30.17
2018	33.67	**2028**	37.13
2019	19.68	**2029**	21.70
2020	20.25	**2030**	22.32
2021	20.66	**2031**	22.78

5.3.5 Economic considerations

The capital costs of cross-border transmission links are annualized in calculating the net market benefit. The lifetime of transmission lines is considered 30 years (Elliott et al., 2016). Details of the capital cost assumptions of HVAC and HVDC transmission lines are described in Section 4.3.1, Table 4.1, and Table 4.2.

The capital recovery factor of the transmission and generation investment for this lifetime is calculated according to (5.11) by considering the 12% discount rate (Torre, Conejo, & Contreras, 2008). Therefore, total annual equivalent investment costs of cross-border transmission will be the total investment costs multiplied with CRF according to (5.12).

$$CRF = \frac{r.(1+r)^n}{(1+r)^n - 1} \tag{5.11}$$

In (5.12), r is the discount rate, and n is the lifetime (number of years).

$$\text{Annual equivalent investment cost} = TI * CRF \tag{5.12}$$

where, *TI* is total investment costs of individual cross-border interconnection, and *CRF* is capital recovery factor.

The operation and maintenance (O&M) costs of cross-border transmission are calculated by using the DC OPF simulation results data and calculating procedure describes in Section 4.3.2. Finally, the addition of annual equivalent investment costs and yearly operation and maintenance (O&M) costs of cross-border transmission gives the total yearly revenue requirement (YRR) for interconnecting 15 individual isolated transmission systems of ASEAN through APG.

5.4 Net market benefit evaluation scenarios

Net market benefit of APG interconnection has been evaluated with the use of designed APG model in Chapter 3. However, some design considerations have been modified according to the requirements of net market benefit evaluation framework. Net market benefit evaluation has been carried out for the following two scenarios:

Scenario I: Scenario I considers that in 2030 APG is fully operated in this region according to ASEAN Center for Energy (ACE). It also considers all types of generation and demand portfolios of individual nodes of APG for 2030 scenarios as mentioned in Table 3.4 and cross-border transmission capacities of the individual transmission links are limited according to the individual transmission links' transmission limit mentioned in Table 3.6.

Scenario II: Scenario II considers that in 2030 APG is fully operated in this region according to ASEAN Center for Energy (ACE), however, individual transmission links capacity are not considered according to ACE/HAPUA. It considers APG is operating in the ASEAN where cross-border transmission links capacities are limited according to optimal cross-border power flows mentioned in Figure 4.1. It also considers all types of generation and demand portfolios of individual nodes of APG for 2030 scenarios as mentioned in Table 3.4.

Flowchart of net market benefit evaluation framework is shown in Figure 5.2. The APG model is simulated for both the scenarios. OPF results give the required generation, power flows and economic information of the APG model which has been used for evaluating net market benefit.

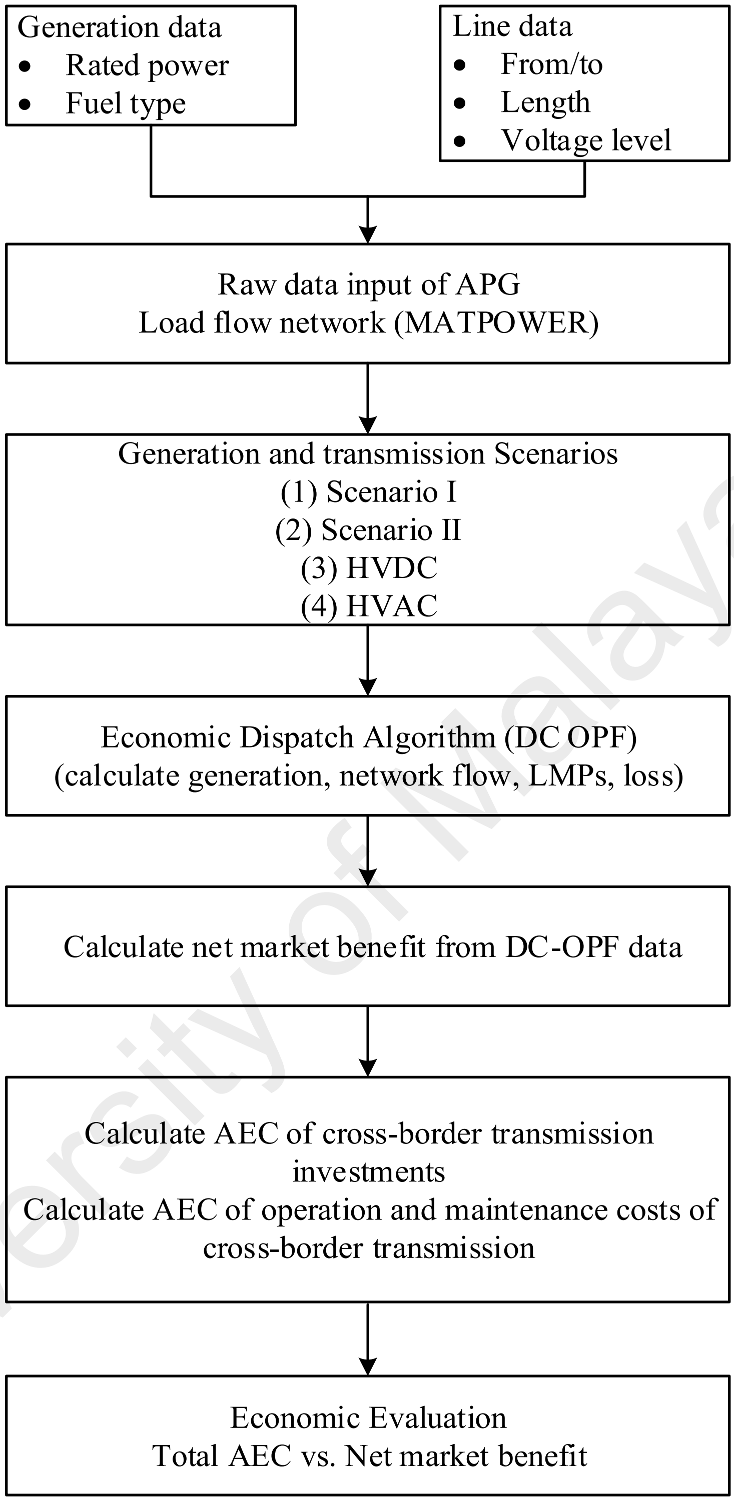


Figure 5.2: Flowchart of the net market benefit evaluation framework.

5.5 Illustrative Numerical Analysis

The market benefit depends upon the electricity market prices of different generation technologies. Establishment of new transmission link enhances the opportunity of transferring power from a less LMP region to a high LMP region. As mentioned earlier, APG brings the individual ASEAN energy market into single energy market and enhances the opportunity to access low-cost generation resources. This in turns affects the net market benefit of ASEAN electricity market. For evaluating the net market benefit of APG integration, APG market scenarios for 2030 are simulated and analyzed by utilizing the available generation and transmission facilities. Simulation results are utilized for calculating the net market benefit. Hourly DC OPF results calculate the market dispatch and power flows. Hourly DC OPF results are shown in Appendix B and Appendix C for Scenario I and Scenario II. Then, these results are used in equations (5.7) to (5.10) for calculating consumer surplus, producer surplus, transmission owner benefit and emission price by generators. The net market benefit is calculated by aggregating consumer surplus, producer surplus, transmission owner benefit and emission price according to (5.1). Following sub-sections describes the benefits of individual ASEAN electricity market participants and net market benefit of APG integration.

5.5.1 Consumer surplus

Individual market participants consumer surplus for the two considered scenarios of APG is shown in Figure 5.3 which is calculated from (5.7). Table 5.3 shows the branch flow constraints for Scenario I. Figure 5.3 shows that Scenario I have less consumer benefit (1797.87 Million $/year) compared with the Scenario II (47490.44 Million $/year). This is due to no NTC limits are considered for the transmission links in Scenario II which in turns increase the access of low-cost generations option and lessen the LMP for the ASEAN electricity consumers. It can be seen that network constraints have a great effect on consumer surplus. Electricity consumers receive more benefit when there is no NTC limit of the cross-border transmission links.

Table 5.3: Branch flow constraints for Scenario I

Branch	From Bus	To Bus	From Bus P (MW)	To Bus P (MW)	Limit (P_{max}) (MW)
3	2	4	-2300.00	2300.00	2300
4	3	4	300.00	-300.00	300
6	4	5	665.00	-665.00	665
7	2	6	-1080.00	1080.00	1080
8	6	7	1050.00	-1050.00	1050
10	6	10	-3200.00	3200.00	3200
11	7	8	-600.00	600.00	600
13	10	11	230.00	-230.00	230
14	10	13	200.00	-200.00	200
15	10	14	100.00	-100.00	100
16	14	12	-200.00	200.00	200

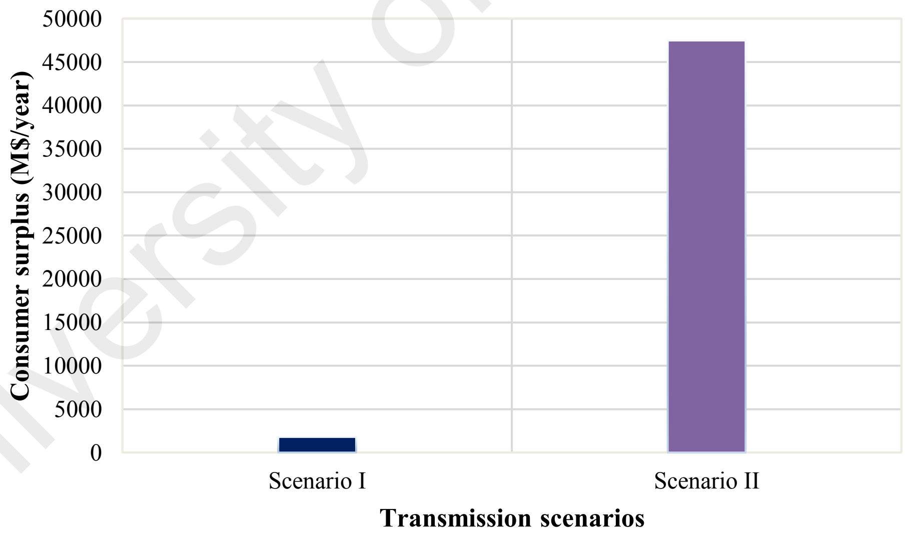


Figure 5.3: Consumer surplus for two scenarios.

5.5.2 Producer surplus

Producer surplus calculated from (5.8) for the APG market participants is shown in Figure 5.4. Producer receives more benefit in Scenario I (43486.00Million$/year) compared with the Scenario II (5910.44 Million$/year). It can be seen that, as like as consumer surplus, producer surplus is also affected by the network constraints and generation adequacy. In the case of Scenario II, APG network has higher power penetration from low-cost generation options especially from hydro and geothermal energy sources from Laos, Cambodia, Sumatra and Vietnam as there is no NTC limits of individual transmission links for Scenario II. For this reason, producer receives less benefit for Scenario II than Scenario I.

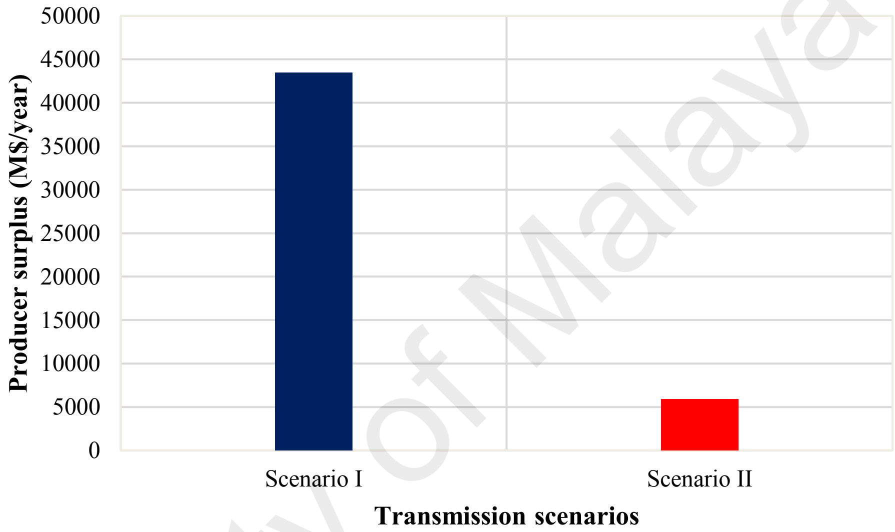


Figure 5.4: Producer surplus for two scenarios.

5.5.3 Transmission owner benefit

Transmission owner benefits calculated from (5.9) is shown in Figure 5.5 for the two considered APG scenarios. It can be seen that, scenario II has no transmission owner benefit as it has no network congestion due to no NTC limits of the cross-border transmission links. As a result, LMP is identical to all participating nodes and the total amount of money collected from the consumers are paid to the generators. On the contrary, Scenario I have high transmission owner benefit due to high network congestion as it considers NTC limits of the cross-border interconnection links which in turns increases the LMPs of the participating nodes. Therefore, the total amount collected by generators are not equal to the total payment paid by the consumers. Therefore, it can be seen that, transmission owner benefit is also affected by the network constraints and generation adequacy as like as consumer surplus, and producer surplus.

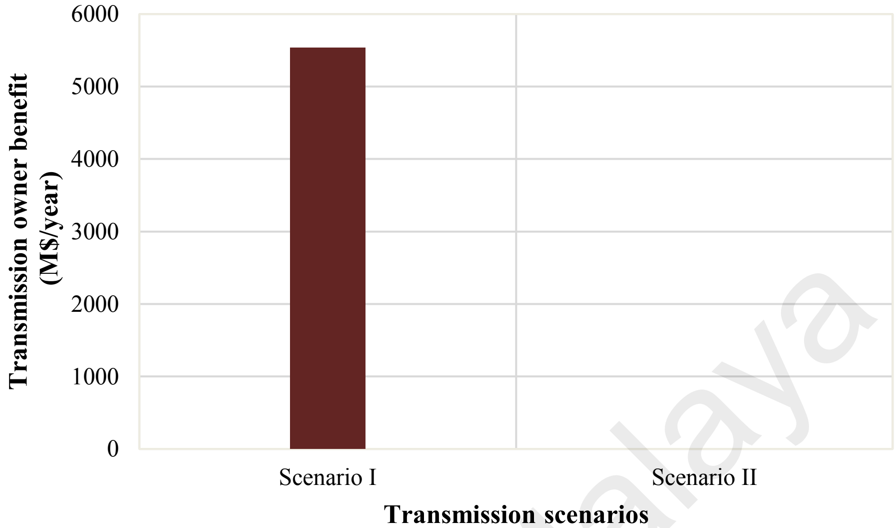


Figure 5.5: Transmission owner benefit for two scenarios.

5.5.4 Emission pricing

Emission price calculated from (5.10) is shown in Figure 5.6 for the two considered APG scenarios. It can be seen that Scenario I pay 4168.77 Million$/year and Scenario II pay 3818.31 million$/year due to electricity generation-related CO_2 emission. Scenario I pay more penalty for emission as it has less access to the renewable energy generation options due to the specific NTC limits of the individual transmission links. Conversely, Scenario II allows the free movement of green electricity as it does not consider any capacity limits of the individual transmission links, hence, need to pay less for emission.

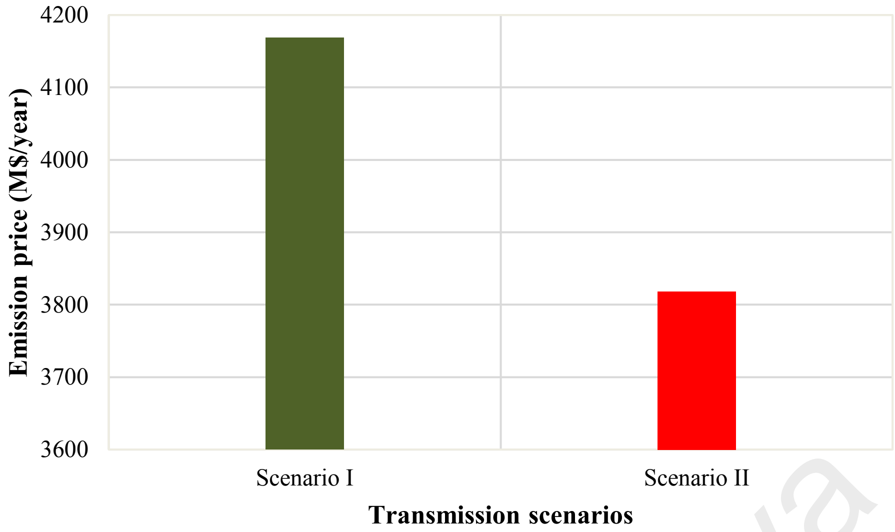


Figure 5.6: Emission payment by the generators for two scenarios.

5.5.5 Net market benefit

Net market benefit calculated from (5.1) is shown in Table 5.4 for the considered scenarios of APG. It can be seen from Table 5.4 that, Scenario I and Scenario II have the net market benefit of 46648.00M$/year and 49582.63M$/year respectively. The main contribution of the net market benefit comes from producer surplus and transmission owner benefit (congestion revenue) for Scenario I. On the contrary, consumer benefit and emission price is the main contributors for the net market benefit for scenario II. It can be seen that, overall Scenario II have more net market benefit compared with Scenario I. Therefore, it can be said that the APG model with optimal NTC limits of the cross-border transmission links have more benefit than the APG model with NTC limits mentioned by ACE.

Table 5.4: Market participants surplus and net market benefit

Scenario	Consumer Surplus (M$/year)	Producer Surplus (M$/year)	Transmission owner benefit (M$/year)	Emission Price (M$/year)	Net market benefit (M$/year)
Scenario I	1797.87	43486.00	5532.90	4168.77	46648.00
Scenario II	47490.44	5910.44	0.00	3818.31	49582.63

5.6 Yearly required revenue of cross-border transmission

Yearly required revenue (YRR) comprises annual investment costs and operation and maintenance costs. Annual equivalent costs of cross-border transmission investments are calculated from the expression (5.12).

Table 5.5 shows the total YRR for interconnecting individual isolated power system networks of ASEAN countries through cross-border transmission links (APG interconnections) for both the considered scenario. It also shows the annual equivalent investment costs as well as yearly operation and maintenance costs for both the transmission technology options. YRR of Scenario I for HVAC and HVDC transmission technology are 6097 M$/year and 4866 M$/year respectively. While YRR of Scenario II for HVAC and HVDC transmission technology are 8880 M$/year and 5857 M$/year respectively. It can be seen that YRR of Scenario I is less compared with the Scenario II because of having less NTC values of individual cross-border transmission links in Scenario I than Scenario II. In addition, for both the scenarios HVAC transmission technology have higher annual equivalent investment costs than HVDC transmission technology. This is due to the requirement of high investment costs for reactive compensators for long distance HVAC transmission technology. Moreover, it can be seen that for both Scenarios I and II, HVAC transmission options require more operation and maintenance costs annually due to higher transmission loss than HVDC during transferring power through APG.

Table 5.5: Total YRR of transmission technology for both the scenarios

Scenarios	Transmission technology	Annual equivalent transmission investment costs (M$/year)	O&M costs (M$/year)	YRR (M$/year)
Scenario I	HVAC	4524	1573	6097
	HVDC	3998	868	4866
Scenario II	HVAC	6229	2786	9015
	HVDC	4379	1576	5955

5.7 Yearly required revenue and net market benefit of APG interconnections

Cost-benefit analysis of APG interconnections in the form of YRR for establishing the cross-border transmission links (cost) and net market benefit for establishing cross-border transmission interconnections among the 15-individual isolated TSOs of ASEAN countries (benefit) is shown in Table 5.6. It can be seen from Table 5.6 that APG interconnections have huge benefit than the costs for both the scenarios. However, optimal cross-border power transmission scenario (Scenario II) have 2934.63M$/year more benefit compared with Scenario I. Nevertheless, Scenario II is preferable during establishing APG interconnections despite its higher YRR. Investors and policy makers could get supportive directions for decision making from the results shown here in this study.

Table 5.6: Comparison between YRR and net market benefit

Scenarios	Transmission technology	YRR (M$/year)	Net market benefit (M$/year)
Scenario I	HVAC	6097	46648.00
	HVDC	4866	
Scenario II	HVAC	9015	49582.63
	HVDC	5955	

5.8 Summary

This chapter presents and discusses the details of economic analysis in the form of cost-benefit analysis of APG interconnections. Net market benefit evaluation framework has been modeled and discussed in the chapter. Developed net market benefit framework considers consumer surplus, producer surplus, transmission owner benefit and emission pricing. In addition, this chapter presents the yearly required revenue (YRR) calculation for interconnecting isolated TSOs through cross-border transmission links during establishing APG. Finally, the comparison between cost and benefit of APG have been presented and discussed which can support investors and policy makers for decision making.

CHAPTER 6: CONCLUSIONS AND FUTURE WORK

6.1 Overview and overall conclusions

In this study, building blocks of a transmission system expansion methodology have been developed. The developed methodology is suitable for long-term ASEAN power grid expansion studies and can deliver an optimal transmission structure to exchange clean and sustainable energy in the ASEAN region. Transmission planners can integrate this developed methodology in existing ASEAN power grid planning methodologies. To obtain the optimal grid structure, basic assumptions and data are chosen very carefully. It is very much difficult to identify future low-cost generation location, renewable generation capacity, transmission links capacity need, power flows, and cost information. It is necessary to analyze case studies by considering these parameters to minimize the investment risks and optimize the benefit of transmission expansion.

In Chapter 2, comprehensive review on ASEAN countries energy potentials, future energy demand growth, challenges of integrating renewable generators in transmission grid planning, present and future status of APG along with challenges of integrating TSOs are presented. The economic characteristics of HVAC and HVDC transmission technologies are investigated in this study. The results of this study can be utilized for cross-border transmission interconnection during the establishment of the APG. The minimum-cost power generation model is developed in Chapter 3 by considering the proposed APG network for the ASEAN region to calculate the optimal cross-border electricity flows among 15 nodes of 10 countries in the ASEAN for the 2030 power generation and demand. Chapter 4 presents the simulation results of APG. Aside from the OPF model development, analysis of economic characteristics using either transmission technology to interconnect the individual power systems of ASEAN countries is also conducted in Chapter 4. In the economic analysis, the cost of necessary equipment of either technology is considered according to relevant standards, such as reactive compensation for HVAC transmissions. Capital and operational costs are considered for both technologies to show a comparison. Evaluating market benefit of transmission expansion is necessary for justifying the investments during APG establishment and to minimize investment risks. Finally, Chapter 5 presents net market benefit evaluation framework which considers consumer surplus, producer surplus, transmission owner benefit and emission pricing. The following important conclusions are drawn on the basis of the objectives of the research work.

The countries in ASEAN possess an abundance of geographically distributed energy sources, including fossil fuels and renewables. Statistical data show that despite the abundance of renewables, 74% of the primary energy demand is supplied from fossil fuels in 2015. Moreover, the further projection has shown that the fossil fuel dependency will increase to 79% by 2040. Electricity demand contributes 52% of the primary energy demand, and it is projected that 74% of electricity will be generated from fossil fuels by 2040. This study pointed out that ASEAN has taken the initiative to increase renewable generations, and future generation target from renewables are set to minimize the dependency on fossil fuels. The present study reveals that this high fossil fuel dependency is due to the uneven distribution of renewables throughout its geographical region, high capital cost involvement of renewables generation, and the lack of transmission expansion planning by ASEAN countries for remotely located renewable generators. Renewable power generations could be expedited by utilizing semi-shallow transmission expansion planning. In addition, the ASEAN power market integration via the establishment of APG could be another possible solution in meeting the increasing electricity demand from clean energy sources.

The establishment of APG will create a sustainable and secure power system network, where investors can invest beyond borders to renewable generators, and could easily transfer the generated power from cross-border trades. However, the establishment of APG via the integration of large geographical distributed power markets faces certain barriers and technical challenges, since APG aims to bring multiple power system TSOs within similar platforms. Renewable generation capacity estimation, generation reserve margin to enhance the reliability, cross-border transmission capacity needs, transmission technology, network congestion and identification of future investment zone to maximize the benefit of investment are the major barriers and technical challenges towards the establishment of APG. APG policy makers could potentially mitigate the technical barriers and challenges.

Energy market simulation result from the developed APG model shows that, designed APG model is capable of predicting future cross-border transmission needs of the ASEAN countries. Also, energy market simulation results show that the electricity demand of ASEAN countries can be supplied from minimum-cost power generators through the APG to promote renewable power generation in the ASEAN region. Case studies indicate that the nodes with abundant renewable potentials (especially hydropower and geothermal) in Myanmar, Lao PDR, Cambodia, Sumatra (Indonesia), Batam (Indonesia), and Sarawak (Malaysia) can significantly contribute to the cross-border power export through the APG. In addition, countries such as Vietnam, Thailand, P. Malaysia, Singapore, Sabah (Malaysia), and Luzon (Philippines), which have a high demand with a small low-cost and renewable generation potential, can become importing and exporting hubs in the ASEAN region.

Economic comparison results between HVAC and HVDC transmission technology demonstrate that HVDC transmission options are feasible for transferring bulk power for

2030 generation and demand scenarios. HVDC transmission technology have more economic benefit in the form of total annual cost reductions, especially, for the interconnections of Myanmar–Thailand, Thailand–Laos, Thailand–Cambodia, Laos–Vietnam, P. Malaysia–Sumatra, P. Malaysia–Sarawak (Malaysia), Singapore–Sumatra, Sarawak (Malaysia)–W. Kalimantan, and Sabah (Malaysia)–Luzon (Philippines). In addition, the results show that HVDC transmission technology exhibits less transmission losses than HVAC technology. So, HVDC options are more suitable than the HVAC for these APG interconnections in terms of energy efficiency for 2030 scenarios. APG may have to go a long way to reach the level of bulk power transferring of 2030 scenarios in the study, however, this study shows that HVDC is more beneficial than HVAC during establishing APG. Therefore, Heads of ASEAN Power Utilities / Authorities (HAPUA) should investigate more to select the transmission options during integrating regional electricity market through APG.

Net market benefit shows that transmission infrastructure based on optimal cross-border transmission limits have more economic benefit than the transmission infrastructure with the cross-border transmission limits of ACE. In addition, the calculation results show that HVDC technology has more cost savings than HVAC technology for the long distance APG transmission infrastructure. Moreover, optimal APG transmission infrastructure has less CO_2 emission and have more environmental benefit than the transmission infrastructure with the cross-border transmission limits of ACE.

6.2 Future work

The future work of this thesis consists of the following parts.

(i) Developed APG model considers only a set of given power system parameters without considering uncertainty. Future research could consider a stochastic approach to study the impact of, for example, uncertain demand growth, fuel price, hydro and renewable generation growth.

(ii) Extending the developed model by considering generation and demand time series. These generation and demand time series includes steady state time-dependent generation and demand data for individual nodes.

(iii) Extending and investigating the ASEAN Power Grid in case of multi-terminal HVDC system. In this case, optimal transmission technology could be investigated by considering HVAC, HVDC, and multiterminal HVDC transmission technology.

(iv) Analyzing the effect of interconnecting Mindanao (the Philippines) Power Grid and Java-Bali (Indonesia) Power Grid with ASEAN power grid model.

(v) Cost-benefit analysis by considering new generation entry in ASEAN power market for supplying cross-border electricity demand. In this case, it could be considered that new generation entry in the power market will be in the border of one country which will be built for supplying the cross-border demand.

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