Chapter 7

Infrastructure Investments for Power Trade and Transmission in ASEAN+2: Costs, Benefits, Long-Term Contracts, and Prioritised Development

Yanfei Li
Economic Research Institute for ASEAN and East Asia (ERIA)

Youngho Chang
Division of Economics, Nanyang Technological University

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CHAPTER 7

Infrastructure Investments for Power Trade and Transmission in ASEAN+2: Costs, Benefits, Long-Term Contracts, and Prioritised Development

YANFEI LI

Economic Research Institute for ASEAN and East Asia (ERIA)

YOUNGHO CHANG

Division of Economics, Nanyang Technological University

This study establishes a system approach in assessing the financial viability of power infrastructure investment for the Greater Mekong Subregion (GMS) and ASEAN Power Grid (APG) in the ASEAN+2 (ASEAN plus China and India) region. It aims to identify the financial and finance-related institutional barriers of implementing such regional power interconnectivity. A whole-grid/system simulation model is built to assess both their financial and commercial viability, which implies profitability for investors and bankability for financiers of new transmission projects with the optimised pattern of power trade. The study also determines the optimised planning of new transmission capacities. Results show that the existing planning of power transmission infrastructure in the region, so-called APG+, stands as a commercially and financially viable plan. However, there is room for improvement in the planning in terms of timing, routes, and capacity of the cross-border transmission lines. The study also recommends that GMS-related projects should be prioritised.

Keywords: cross-border power trade, power infrastructure, financial viability, commercial viability

JEL: Q40, Q41, Q48

Introduction

The Greater Mekong Subregion (GMS) program lead by the Asian Development Bank (ADB) and the ASEAN Power Grid (APG) program lead by the Association of Southeast Asian Nations (ASEAN) have made steady progress, mainly driven by bilateral power trade that comes with long-term power purchase agreements (PPAs). According to ADB definitions, this progress constitutes the stage 1 developments of regional power interconnections. Three more stages of developments are to be witnessed before an integrated GMS or ASEAN power market comes into being (ADB, 2013; Zhai, 2010).

The four stages of developments are

- Stage 1, bilateral trade with PPAs;
- Stage 2, grid-to-grid power trading between any pairs of member countries, even using the transmission lines through a third member country;
- Stage 3, development of transmission lines dedicated to free power trading instead of specific PPAs; and
- Stage 4, fully competitive regional market with multiple sellers and buyers from each member country.

Table 7.A1 and 7.A2 in Appendix A show the existing power transmission lines for cross-border interconnections, and the ongoing and planned transmission line projects within ASEAN and extended to the neighbouring parts of Southwest China[1] and Northeast India[2] (ASEAN+2). Table 7.A2 covers the APG program and additional programs initiated by governments in the region, which will be referred to as "APG+" henceforth.

It is evident that a significant amount of investment in the interconnection capacities should be done. According to the ASEAN Plan of Action for Energy Cooperation (APAEC), 2010-2015 (ASEAN Centre for Energy,

[1] Yunnan and Guangxi provinces.
[2] Northeastern states.

2007), the total investment of APG, which includes 15 projects, amounts to US$5.9 billion.[3] While governments and intergovernmental organisations, such as ADB and the World Bank, could lead the early stage of developing the interconnected and integrated power markets, the next stages of intensive investment in the infrastructure would inevitably need to engage the private sector.[4] Therefore, new investment in cross-border transmission lines should stand commercially and financially viable—profitable for investors and bankable for financiers—to attract investments from the private sector. The following concerns are identified as the key issues.

First, investment in transmission lines is a capital-intensive business, usually costing from millions to billions in US dollars. Table 7.1 shows the capital expenditure (CAPEX) of some typical projects undertaken in the ASEAN countries, using data from ADB. The average cost of a transmission line in megawatt per kilometre (MW/km) terms decreases as the length and capacity of the line increases.

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[3] According to APAEC 2010-2015, a potential savings of about US$662 million dollars in new investment and operating costs of the grid/system is estimated to result from the proposed APG interconnection projects.

[4] For example, the ASEAN Infrastructure Fund (AIF) has a total lending commitment through 2020 that is expected to be around US$4 billion. If the 70% cofinancing to be leveraged from ADB is added, the total amount of public finance available will be US$13 billion, which covers not only the energy sector, but also investments in infrastructure for clean water, sanitation, and better forms of transportation. http://www.adb.org/features/fast-facts-asean-infrastructure-fund

Table 7.1: CAPEX of Power Transmission Lines in the ASEAN Context

Case	Voltage	Line Length (km)	Capacity	CAPEX (US$)	$/MWh*
1	500 kV	200	500	167,200,000	9.1
2	500 kV	400	500	297,900,000	16.1
3	500 kV	200	1000	242,000,000	6.6
4	500 kV	200	1000	152,400,000	4.1
5	500 kV	400	1000	449,500,000	12.2
6	500 kV	200	2000	312,100,000	4.2
7	500 kV	200	2000	292,200,000	4.0
8	500 kV	400	2000	732,500,000	9.9
9	500 kV	400	2000	630,800,000	8.5

Note: CAPEX = capital expenditure, km = kilometre, kV = kilovolt, MWh = megawatt-hour.

* *Embedded assumptions include: 40 years of asset life, 10% discount rate, load factor at 5,000 hours per year, operation costs as 2% of the CAPEX, and transmission loss at 2%.*

Source: Hedgehock and Gallet (2010).

Second, cross-border power trade further complicates the business with political, social, and environmental considerations. It is for these reasons that the projects are considered high risks and require long-term contracts to reduce the risks and secure the stream of revenue. These include long-term public-private partnership (PPP) contracts such as build-own-operate-transfer (BOOT) and build-operate-transfer (BOT), and long-term power service contracts such as power purchasing agreements (PPAs) or concession-based contract with guaranteed payment for the new line. The costs, especially financial costs of transmitting power across borders, then critically depend on these factors (Barreiro, 2011; World Bank, 2012; Neuhoff, *et al*., 2012).

Third, the profitability of each transmission line will depend on the evolution of the pattern of cross-border power trade in the region. This is because the demand and supply landscape may change quickly in some countries in the region, and new transmission lines dilute the power demand from existing transmission lines (Hogan, 1999; Joskow and Tirole, 2003; Kristiansen and Rosellon, 2010). Thus, understanding future power trade patterns and regionally integrated planning are critical to investment decisions in transmission lines.

These concerns—high CAPEX, investment risks, and uncertainty about future regional power trade pattern—raise the key question of commercial and financial viability of the proposed new cross-border transmission capacities in the region. On the one hand, literature on the benefits of regional power market interconnection in ASEAN generally reflects positive results, particularly from the Asia Pacific Energy Research Centre (2004), ASEAN Centre for Energy (2007), and Chang and Li (2013a). Chang and Li (2013b) also show that APG enables further policy options in the region to achieve sustainable development, namely to promote renewable energy and carbon emissions reduction, in the power sector. However, in view of the progress of interconnection in the real world, few literatures extend the discussion into financial viability of new transmission infrastructure investment in this region. This study will fill this gap with a comprehensive perspective in optimally planning the power infrastructure development.

In this study, a financial sub-model for investments in power transmission infrastructure is to be developed and integrated into a dynamic linear programming model developed by Chang and Li (2013a and 2013b). The sub-model will specifically address the financial viability of power transmission infrastructure for regional power trade and power market interconnectivity among the ASEAN+2 countries.

The model produces the optimised pattern of both bilateral power trade in the early stage, and multilateral trade in a fully competitive and integrated regional power market by considering the costs of generating electricity and transmitting power across borders. The optimised trade pattern, thus, shows the most likely development of power trade in the region. Based on this outlook on power trade, the model indicates where new power transmission capacities are needed most, resulting in high utilisation rate of the new capacities and, therefore, making the investment financially viable.

The results could also be used to suggest an investment priority in new power transmission lines by envisioning the needs of the future power trade pattern. This future power trade pattern depends on the different energy resource endowment of countries in the region, the growth of domestic power demand, and the evolving power generation technologies and fuel costs. Thus, power trade is envisioned as dynamically changing, and this determines the financial viability of new cross-border transmission capacities. These facts are duly reflected in the model.

Lastly, it is worth noting that this model takes the perspective of a regional transmission grid planner and optimises investments in infrastructure to ensure commercial and financial viability of these investments. Such a methodology echoes the call for a single international/regional planning body to effectively implement cross-border grid expansion through accurate market modeling and projection. The European cross-border power market is an example of this kind (Frontier Economics, 2008).

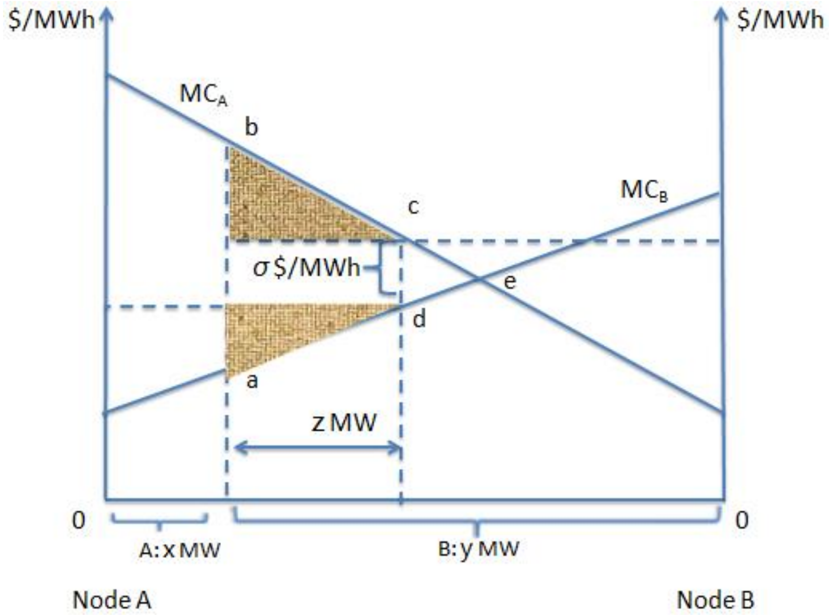
In this paper, specific research questions and what methodology would be applied to address the questions are discussed in section 2. Section 3 expounds what data would be required for this study and how to acquire such data. Section 4 presents and analyses results from the model. Finally, section 5 concludes with policy implications based on these results.

Methodology and Scenarios

Assessment of Financial Viability of New Transmission Lines

It is a well-known theory that the value of transmission line should be determined by the cost of congestion in the grid and the idea of congestion charge is developed accordingly, which is the commercial value as well as the source of revenue of a transmission line in a competitive electricity market (Joskow and Tirole, 2003; Kirschen, 2011). Figure 7.1 shows how the optimal transmission capacity should be determined in a simplified case, which in this case is a two-node electricity market.

Figure 7.1: Commercial Value of Transmission Line and Optimal Capacity



Source: authors

The horizontal axis shows the power demand at nodes *A* and *B*, respectively, in megawatts (MW), while the vertical axis shows the marginal cost of power generation in dollar per megawatt-hour ($/MWh). Clearly, nodes *A* and *B* have different levels of power demand, and different marginal cost curve of power generation. At node *A*, the power demand is *x* MW, while at node *B*, the power demand is *y* MW. This results in different marginal costs of power at the two nodes, at levels corresponding to where points *a* and *b* are for nodes *A* and *B*, respectively.

If there is a transmission line to connect nodes *A* and *B*, node *A* could produce more than *x*MW and supply node *B* at a lower marginal cost of power. If the transmission is free of cost, node *A* should supply as much as when its marginal cost of power is equal to that of node *B* at point e. This is known as the no congestion case. However, if transmission is costly, optimal capacity of transmission is where the savings in the marginal cost (the difference between marginal cost of generation from node *B* and that from node *A*) is equal to the marginal cost of transmission capacity. Assuming that the marginal cost of transmission capacity is σ $/MWh, as shown in the figure, the optimal capacity of transmission capacity is determined at *z* MW.

In this optimal case, σ \$/MWh is equal to the congestion cost to the system and, therefore, the commercial value of the transmission line. In a competitive market, σ \$/MWh should be charged accordingly for using the transmission line. The actual utilisation rate of the transmission line, which means how many MWh of electricity is transmitted, determines whether the investment in the transmission line could expect a reasonable return. Usually, this is where long-term PPP contracts come in to ensure the financial viability of the investment.

It is noted that such an investment in the transmission capacity generates a positive net savings to the system, which consist of nodes A and B. The savings is represented by the two shaded triangle area in Figure 7.1. Such net savings is the key to proving the commercial viability of the new transmission line; otherwise, the line has no commercial value added and should not be built.

In a grid with multiple nodes, the estimation of congestion cost is complicated, and it becomes necessary to take a whole-grid/system approach (Lesieutre and Eto, 2003). Network externality effect of new transmission lines further complicates the issue. Therefore, in this study, a whole-grid/system approach is taken in assessing both the financial and commercial viability of new transmission projects with optimised pattern of power trade; the approach is also suitable for optimising the planning of new transmission capacities.

First, the model integrates a 30-year contract for new transmission capacities, which ensures that revenues collected over this period will meet the commercial investors' internal rate of return (IRR) requirement. *Second*, with costs of new transmission lines modeled as such, the system generates cost minimisation planning for all power infrastructures—namely, power plants and cross-border transmission lines—so as to meet the growing demand for electricity in the region during the modeling period. *Lastly*, the minimised total system cost is to be compared with the benchmark case in which no new cross-border transmission line is built. Should the former be smaller than the latter, it means that there is net system savings resulting from the optimised planning for new cross-border transmission lines.

In this case, recalling the simplified grid case in Figure 7.1, the power trade with an optimised planning of new transmission lines not only ensures the investors' IRR to be achieved but also delivers net system savings, which means that such a transmission investment plan stands as both financially and commercially viable. [5] Should the net system savings be negative, it implies that the financial viability of the new projects with long-term contracts could not hold or be self-sustaining. This methodology is a major innovation and, thus, is a contribution to the literature. It enables the comprehensive assessment of financial viability of cross-border transmission investment plans from a system perspective.

The mathematical model could be found in Appendix B. Specifically, the cost of new transmission lines under the long-term contract is specified in Equation 3 in Appendix B. The objective value in Equation 4 represents the total cost of the system.

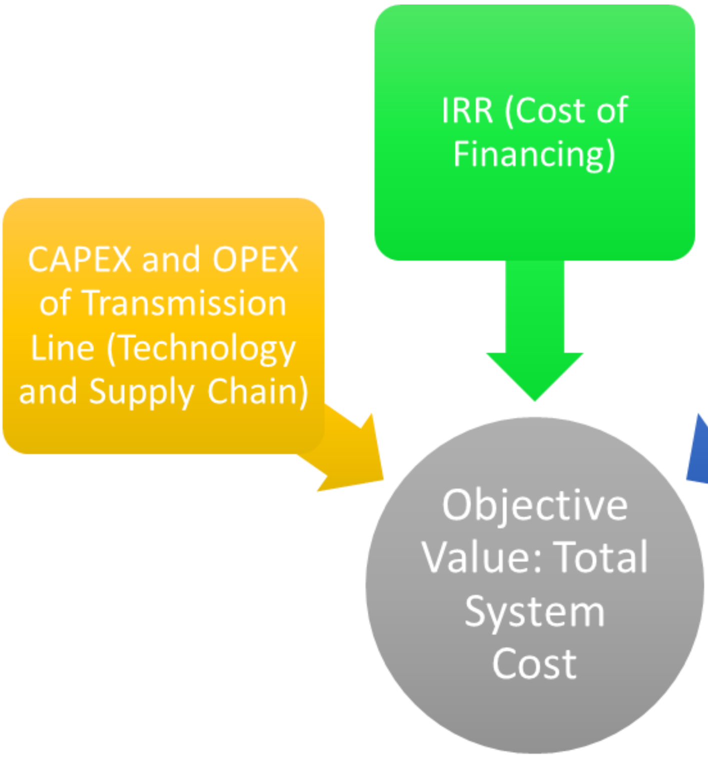
Modeling Policy Options and Financial Viability of Transmission Lines

Various policies are identified as key factors to financial viability (Figure 7.2). *First,* CAPEX and operation expenditure (OPEX) directly drive up the cost of transmission lines. Policies toward the introduction and absorption of new technologies could help reduce the cost. Policies that help reduce lead-time of the new transmission project, such as facilitating project preparation, supply chain coordination, construction, and grid connection can also significantly reduce the cost of new transmission lines. *Second*, financial costs of transmission line investments are very sensitive to the IRR of investors, which in turn is sensitive to all project-related risks including market risks, technical risks, institutional risks, and political risks. Policies that relieve these risks could help reduce the cost of transmission lines significantly. *Third*, power trade policies of countries in the region—namely ASEAN + China (Yunnan and Guangxi) and India (Northeastern provinces)—determine the demand for the import and export of power and, therefore, the commercial value of new transmission lines. In this study, such policies are modeled as

[5] In other words, the new transmission lines have net commercial value, and financial viability is not achieved at the expense of the total system but, in fact, by saving the total system costs.

the percentage of domestic power demand to be met through power trading with other countries.

Figure 7.2: Key Factors for the Financial Viability of Cross-Border Transmission Lines



Source: authors.

In this study, scenarios are built mainly to assess the impact of policies that facilitate power trade in the region, as the demand for power trade and future trade pattern are the most fundamental forces in determining where new transmission lines are needed and when they are needed.

This study aims to conduct two experiments. The first one aims to identify what would be the optimal plan of new transmission capacity development, which is not only financially viable but also maximises net savings for the system. The second aims to assess the financial viability of the APG+ plan as it is currently announced. The optimised development plan will then be compared to the existing APG+ plan to derive some policy implications. Table 7.2 summarises the scenarios.

Table 7.2: Scenarios for Simulation of Interconnected Regional Power Market

Scenario	**Description**
Benchmark	No new transmission line will be developed
Opt-20	Optimised transmission development with countries allowing up to 20% of domestic power demand to be met by trade with other countries
Opt-50	Optimised transmission development with countries allowing up to 50% of domestic power demand to be met by trade with other countries
Opt-80	Optimised transmission development with countries allowing up to 80% of domestic power demand to be met by trade with other countries
APG-20	APG for transmission development with countries allowing up to 20% of domestic power demand to be met by trade with other countries
APG-50	APG for transmission development with countries allowing up to 20% of domestic power demand to be met by trade with other countries
APG-80	APG for transmission development with countries allowing up to 20% of domestic power demand to be met by trade with other countries

Source: authors

Data Inputs

Data about the CAPEX (capital expenditure) and OPEX (operation expenditure) and their relations to key drivers, such as length and capacity of the transmission line, will be the key inputs into the proposed new model. In this study, CAPEX of the transmission line is assumed to be US$1,086/MW per km and OPEX is assumed to be 2% of the CAPEX, following the data reported by Hedgehock and Gallet (2010). IRR is assumed to be 10% with a

30-year contract period for investors to own and operate the transmission capacity. The modeling period is 2012–2050, considering the long life span of power infrastructure assets.

Other data inputs required for the model, such as demand for power, energy resources, cost of power generation capacities and so on, have been discussed in detail in Chang and Li (2013a and 2013b). The dataset is updated and extended according to the scope of this study, mainly for the inclusion of China and India into this study.

Results and Analysis

New Transmission Lines and Net Savings of Total System Cost

As shown in Table 7.2, the simulation focuses on the cross-border power trade policy of the ASEAN+2 region, which fundamentally determines the commercial value of new transmission lines for cross-border power interconnectivity. Table 7.3 provides a summary on how the total power system cost in each scenario with new transmission capacity is compared with that of the benchmark scenario, which assumes no new capacity added. With positive net savings in the total system cost achieved, financial viability of the new infrastructure development is implied.

Table 7.3: Comparison of Total System Costs in Different Scenarios and the Net Savings*

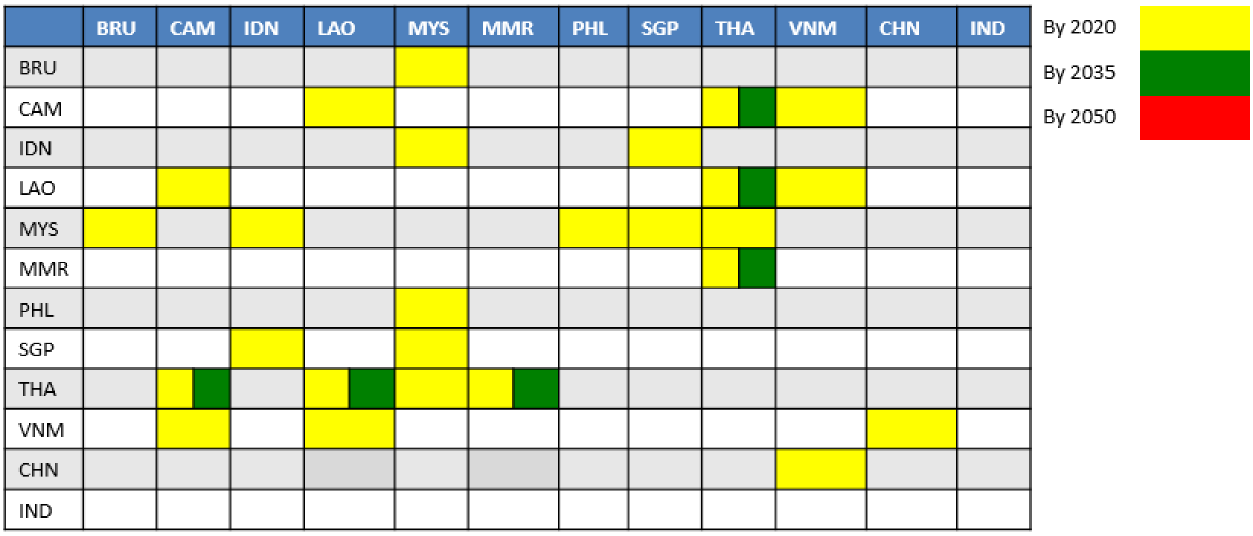
Scenario	Total System Cost (US$ trillion)	Benchmark Scenario Total System Cost (US$ trillion)	Net Savings (US$ billion)	Percentage of Savings
Opt-20	1.240	1.242	2.0	0.16
Opt-50	1.187	1.195	8.0	0.67
Opt-80	1.165	1.176	11.0	1.00
APG-20	1.241	1.242	1.0	0.10
APG-50	1.192	1.195	3.0	0.25
APG-80	1.172	1.176	4.0	0.34

Note: * Numbers are rounded.
Source: authors.

From the table, it is observed that the current APG+ stands as a financially and commercially viable program, since the net total system savings are positive from APG-20 to APG-80. However, the net savings from APG+ are much smaller compared to the scenarios from Opt-20 to Opt-80 in which transmission development is optimised. Such implies that there is room for improvements in the existing APG+ plan in terms of routes, timing, and scale of projects.

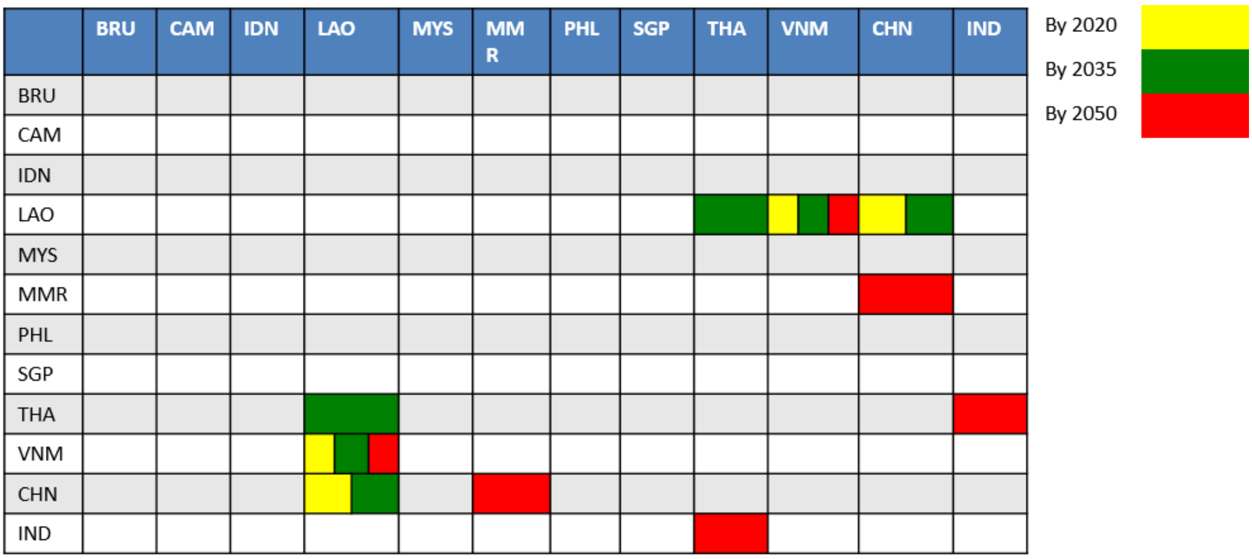
Figures 7.3 to 7.6 provide a visual description of the difference between optimised transmission development plans and the APG+ plan.

Figure 7.3: The Existing APG+ Plan



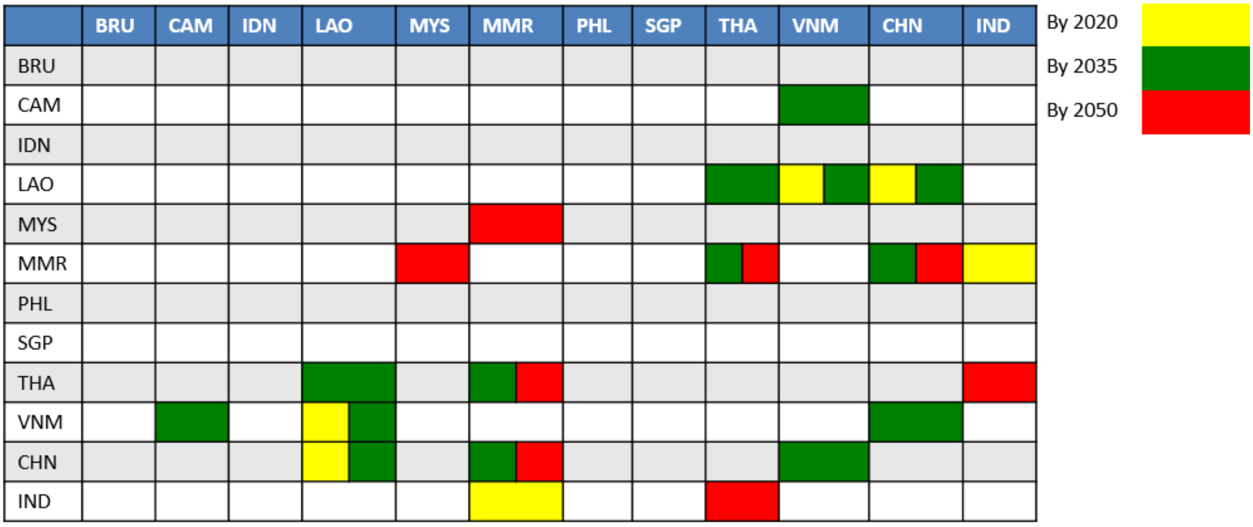
Source: authors

Figure 7.4: Optimal Transmission Development under Opt-20



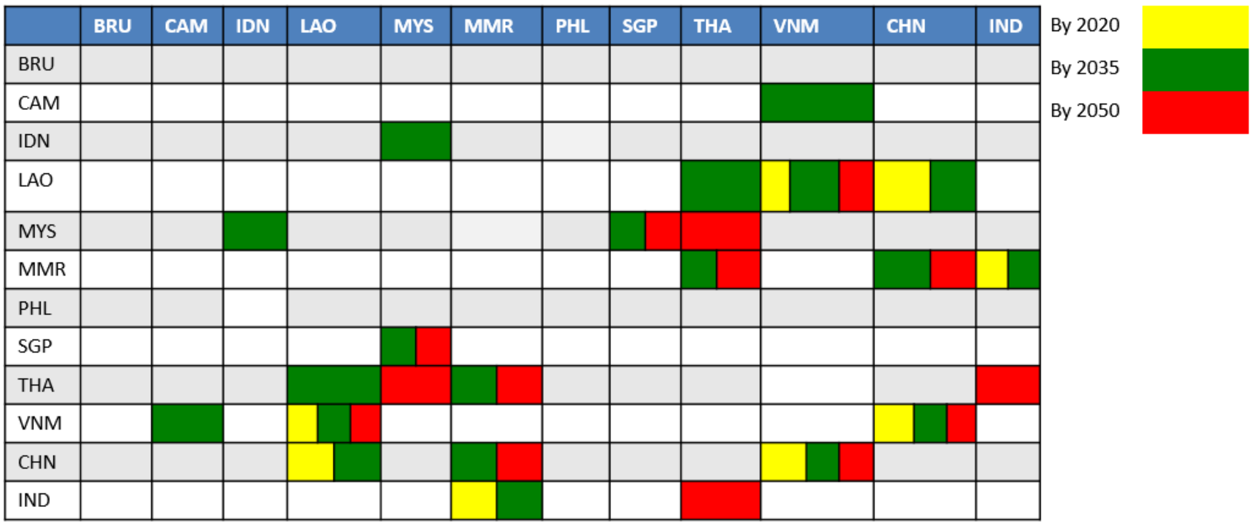
Source: authors.

Figure 7.5: Optimal Transmission Development under Opt-50



Source: authors.

Figure 7.6: Optimal Transmission Development under Opt-80



Source: authors

Comparing Figure 7.3 with Figures 7.4, 7.5 and 7.6, it is observed that

(1) optimal transmission development only agrees with APG+ on the priority of interconnectivity between the Lao People's Democratic Republic (Lao PDR), Viet Nam, and China;

(2) optimal transmission development suggests that interconnectivity between Lao PDR, China, Myanmar, and India be prioritised and should materialise before 2020;

(3) many other projects proposed in APG+ should be put in the second priority and be developed before 2035 rather than 2020. Examples of such projects include the interconnectivity among Cambodia, Viet Nam, Lao PDR, Myanmar, and Thailand; and

(4) all simulations show that new transmission developments in the GMS subregion is at the centre of future regional cross-border power trade.

The findings are also in line with those from ERIA (2014), which takes the case study approach and agrees that some of the APG projects need to reconsider their priority in development to ensure financial viability.

Optimal Power Trade Pattern in the Region

Results in the previous subsection are derived based on how power generation capacities will be optimally developed based on resources available, cost of the capacity, cost of transmission, and on how cross-border power trade will be optimally carried out based on the amount of power needed, the time it is needed, and where it is needed. Therefore, it is necessary to check if the simulation results of these two variables are reasonable and realistic.

Figure 7.7: Pattern of Power Trade in the Opt-20 vs. Apt-20

Source: authors.

Since allowing 20% of domestic power demand to be met by cross-border trade is the most realistic policy case, Figure 7.7 focuses on scenarios with such a policy assumption. A single arrow indicates one-way power trade, while double arrows mean two-way power trade. Red colour represents the trade routes optimised in the Opt-20 scenario, while yellow colour represents trade routes added in addition to the red ones in the APG-20 scenario. The dashed red arrow represents a trade route that existed in the Opt-20 scenario but not in the APG-20 scenario. In addition, there are two more trade routes in the APG-20 not shown in this map and they are the Malaysia to Brunei one-way trade, and the Malaysia to the Philippines two-way trade.

In the Opt-50 scenario, which allows for up to 50% of domestic power demand to be met by trade with other countries, all routes in the APG-20 are adopted, except for those to Brunei and the Philippines. In addition, a two-way trade between India and Myanmar will be added.

The practice on the comparison of future trade pattern has two implications: (1) Most of the cross-border power trade will happen in the GMS region, with possible extension to Northeast India; and (2) APG+ brings more opportunities of power trade in the ASEAN+2 region. However, if trade policy is not bold enough as to, for example, allow up to 50% of demand met by trade, then it is unclear whether these trade brings more total system cost savings as the cost of investment on APG+ is also very high.

In Opt-50 (see Figure 7.5), the scale of investment on ASEAN+2 interconnectivity is similar to APG+ with most of the routes of transmission lines the same. However, Opt-50 brings more total system cost savings (0.67%) than APG-20 (0.10%) or APG-50 (0.25%).

Conclusions and Policy Implications

This study aims to develop a financial sub-model of cross-border power transmission lines in the ASEAN+2 region and integrate it into the ASEAN cross-border power trade model developed by Chang and Li (2013a and 2013b). The results of this new model, thus, draw the implications on the financial viability of cross-border transmission infrastructure to be developed in the future based on a comprehensive vision of future power trade patterns that considers the interacted effects from all existing and proposed transmission line projects. For example, the completion of a new transmission line may change the current trade pattern that is built on existing infrastructure. It is the new trade pattern after the completion of this new line that will determine the utilisation of the new asset and therefore the financial viability of it. Such a comprehensive market-modelling approach for the estimation of financial viability is better than looking at the cost and benefit of a new transmission line project alone with assumptions that are fixed and isolated from the dynamic development of trade pattern in the region.

The following key observations are made based on the results of the model.

1. Existing APG+ stands as a commercially and financially viable plan if long-term PPP contracts, which allow as long as 30 years of payback

time with 5% of discount rate and 10% of IRR for investors, are applied.

2. Projects in the GMS area should be given priority, as they are most desired in future cross-border power trade in the region. These projects also stand financially viable under certain conditions, while policies should be designed to encourage and facilitate the entry of private sector investment.
3. This model further indicates that by optimising the routes and timing of the power interconnectivity in the region, the total system costs could be further reduced and, therefore, the commercial and financial viability of the connectivity projects could be further strengthened.
4. Policies on cross-border power trade are critical to the financial viability of investment in new transmission capacities. Other policies that affect the CAPEX and OPEX of the investment, and the risks associated with the investment, are also important and their impacts on financial viability could also be assessed using this model.
5. It is noted that this simulation model is only an assessment of theoretical financial viability, which assumes the projects are all delivered on time without meeting barriers in cross-border regulation, legislation, or standards harmonisation. In this sense, to ensure that theoretical financial viability becomes reality, policies should be designed and implemented to relieve non-financial barriers so as to keep investment risks low and enable the financial viability.

The following types of policy implications could thus be derived based on the above observations.

1. Power interconnectivity in the ASEAN+2 region stands as commercially and financially viable, given that supportive policies, such as long-term PPP contracts for infrastructure investment, more freedom for cross-border power trade, harmonisation of regulation and standards to reduce risks associated with these infrastructure, and lead time of project development, are in place.
2. Systemic and detailed modelling of the power interconnectivity in the ASEAN+2 region is needed to optimise the planning of infrastructure investment and to accurately assess the financial viability of these investment projects.

3. Despite the theoretical feasibility of ASEAN+2 power interconnectivity indicated by this study, many economic and political issues should be further studied. As Neuhoff, *et al*. (2012) correctly pointed out in studying the financing of European Union's power interconnectivity, in reality, the question of how to share the costs and benefits of the transmission infrastructure with an international mechanism between two or three countries involved should also be paid attention to since these are cross-border transmission lines and there will be mismatched incentives for different parties.

Despite the meaningful findings, it is noted that this study has its limitations. Future studies are needed as the region needs more detailed models for both long-term power infrastructure investment planning and system operation modeling, as in the case of the European Union (EU) and the regional markets in the United States (US). For EU, examples are REMIND (Leimbach, *et al*., 2010), WITCH (Bosetti, *et al*., 2006), MESSAGE-MACRO (Messner and Schrattenholzer, 2000), and POLES (Russ and Criqui, 2007) on a global scale, and PRIMES (Capros, *et al*., 2010) on the European level. For the US, examples on a European scale are ELMOD (Leuthold, *et al*., 2008), representing the European transmission infrastructure with great detail, and ReMIX (SRU, 2010), which calculates hourly dispatch and transmission flows for one complete year.

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Appendix A: Existing Power Transmission Lines for Cross-Border Interconnections

Table 7.A1: Existing Cross-Border Power Transmission Lines

Country A	Country B	Project Name	Capacity (MW)
Malaysia	Singapore	Plentong - Woodlands	450
Thailand	Malaysia	Sadao - Chuping	80
Thailand	Malaysia	Khlong Ngae - Gurun	300
Lao PDR	Thailand	Theun Hinboun - Thakhek - Nakhon Phanom	220
Lao PDR	Thailand	Houay Ho - Ubon Ratchathani 2	150
Lao PDR	Thailand	Nam Theun 2 - Roi Et 2	1,000
Lao PDR	Thailand	Nam Ngum 2 - Na Bong -Udon Thani 3	615
Lao PDR	Thailand	Theun Hinboun (Expansion) - Thakhek - Nakhon Phanom 2	220
Lao PDR	Viet Nam	Xehaman 3 - Thanhmy	248
Viet Nam	Cambodia	Chau Doc - Takeo - Phnom Penh	200
Viet Nam	Cambodia	Tai Ninh - Kampong Cham	200
Thailand	Cambodia	Aranyaprathet - Banteay Meanchey - Siem Reap - Battambang	120
China	Viet Nam	Xinqiao - Lai Cai	250-300
China	Viet Nam	Maguan - Ha Giang	200
Myanmar	China	Shweli 1 - Dehong	600

Source: Chimklai (2013); Zhai (2010); ADB (2013); APERC (2004); Bunthoeun (2012).

Table 7.A2: Ongoing and Planned Cross-Border Power Transmission Line Projects (APG+)

Country A	Country B	Project Name	Capacity (MW)
Thailand	P. Malaysia	Su - ngai Kolok - Rantau Panjang	100
Thailand	P. Malaysia	Khlong Ngae - Gurun (Addition)	300
Malaysia	Sumatra (Indonesia)	Melaka - Pekan Baru (AIM II Priority Project)	600
Sarawak (Malaysia)	W. Kalimantan (Indonesia)	Mambong - Kalimanyan	230
Sabah (Malaysia)	E. Kalimantan (Indonesia)	Newly Proposed	200
Sarawak-Sabah (Malaysia)	Brunei	Sarawak - Brunei	200
Lao PDR	Thailand	Hong Sa - Nan 2 - Mae Moh 3	1,473
Lao PDR	Thailand	Nam Ngiep 1 - Na Bong - Udon Thani 3	269
Lao PDR	Thailand	Xe Pien Xe Namnoi - Pakse - Ubon Ratchathani 3	390
Lao PDR	Thailand	Xayaburi - Loei 2 - Khon Kaen 4	1,220
Lao PDR	Thailand	Nam Theun 1- Na Bong - Udon Thani 3	510
Lao PDR	Thailand	Nam Kong 1 & Don Sahong - Pakse - Ubon Ratchathani 3	315
Lao PDR	Thailand	Xekong 4-5 - Pakse - Ubon Ratchathani 3	630
Lao PDR	Thailand	Nam Ou - Tha Wang Pha - Nan 2	1,040
Lao PDR	Viet Nam	Ban Hat San - Pleiku	1,000
Lao PDR	Viet Nam	Nam Mo - Ban Ve - (Vinh)	100
Lao PDR	Viet Nam	Sekamas 3 - Vuong - Da Nang	250
Lao PDR	Viet Nam	Xehaman 1 - Thanhmy	488
Lao PDR	Viet Nam	Luang Prabang - Nho Quan	1,410
Lao PDR	Viet Nam	Ban Sok - Steung Treng (Cambodia) - Tay Ninh	Unknown
Lao PDR	Viet Nam	Ban Sok - Pleiku	1,151
Lao PDR	Cambodia	Ban Hat - Stung Treng	300
P.Malaysia	Singapore		600
Batam (Indonesia)	Singapore	Batam - Singapore	600
Sumatra (Indonesia)	Singapore	Sumatra - Singapore	600
Philippines	Sabah (Malaysia)		500
Sarawak - Sabah (Malaysia)	Brunei	Sarawak - Sabah - Brunei	100
Thailand	Lao PDR	Nong Khai - Khok saat; Nakhon Phanom - Thakhek; Thoeng - Bokeo;	600
Thailand	Cambodia	Prachin Buri 2- Battambang	300

Thailand	Cambodia	Trat 2 - Stung Meteuk (Mnum)	100
Thailand	Cambodia	Pluak Daeng - Chantaburi 2 - Koh Kong	1,800
Myanmar	Thailand	Mai Khot - Mae Chan - Chiang Rai	369
Myanmar	Thailand	Hutgyi - Phitsanulok 3	1,190
Myanmar	Thailand	Ta Sang - Mae Moh 3	7,000
Myanmar	Thailand	Mong Ton - Sai Noi 2	3,150
China	Viet Nam	Malutang - Soc Son	460
China	Thailand	Jinghong - Lao PDR - Bangkok	1,500
Myanmar	India	Tamanthi - India	960
Cambodia	Viet Nam	Sambor CPEC - Tan Dinh	465

Source: Chimklai (2013); Zhai (2010); ADB (2013); APERC (2004); Bunthoeun (2012).

Appendix B: A Dynamic Linear Programming Model for Cross-Border Power Trade

CAPEX

The following models the capital expenditure (CAPEX) of a certain type of power generation capacity at a certain point of time. Let x_{miv} be the capacity of plant type *m*, vintage *v*,[6] in country *i*.[7] And c_{miv} is the corresponding capital cost per unit of capacity of the power plant. So the total capital cost during the period of this study would be $\sum_{i=1}^{I}\sum_{v=1}^{T}\sum_{m=1}^{M} c_{miv} * x_{miv}$. (In GAMS code, for consistency in presentation with the other cost terms, a time dimension is added to the equation besides the vintage dimension. By doing that, capital cost is amortised using a capital recovery factor).

OPEX

The following models the operational expenditure (OPEX) of a certain type of power generation capacity at a certain point of time. Let u_{mijtvp} be power output of plant *m*, vintage *v*, in year *t*, country *i*, block *p* on the load, and exported to country *j*. Let F_{mitv} be the corresponding operating cost, which varies with *v*, and θ_{jp} be the time interval of load block *p* within each year in the destination country. *Opex*(*t*) in year t is expressed as

$$Opex(t) = \sum_{i=1}^{I}\sum_{j}^{J}\sum_{v=-V}^{t}\sum_{p=1}^{P}\sum_{m=1}^{M} F_{mitv} * u_{mijtvp} * \theta_{jp} \quad (1)$$

Carbon Emissions

The model considers carbon emissions of different types/technologies of power generation capacity and takes the cost of carbon emissions into consideration. Let ce_m be the carbon emissions per unit of power plant capacity of type *j* plant, and cp_t be the carbon price per unit of carbon

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[6] Vintage indicates the time a certain type of capacity is built and put into use.

[7] This variable represents investment in new power generation capacity. Investment is considered done once the power generation facility has been constructed and not at the moment when investment decision is made and construction commences.

emissions in year *t*. The amount of carbon emissions produced are expressed as $\sum_{m=1}^{M}\sum_{i=1}^{I}\sum_{j=1}^{J}\sum_{v=-V}^{T} u_{mijtvp} * \theta_{jp} * ce_m$, and carbon cost in year *t* is

$$CC(t) = cp_t * (\sum_{m=1}^{M}\sum_{i=1}^{I}\sum_{j=1}^{J}\sum_{v=-V}^{T} u_{mijtvp} * \theta_{jp} * ce_m) \qquad (2)$$

Cross-Border Transmission Cost

The costs of cross-border transmission come in two forms. One is the tariff paid to recover the capital investment and operational cost of the grid line. The other is the transmission loss, which could be significant if the distance of transmission is long. To model the tariff of transmission, let tp_{ijv} be the amount of new transmission capacity added between country *i* and *j* at year *v*. ct_{ijv} and co_{ijv} are the annualised CAPEX (with a 30-year contract and stipulated IRR embedded) and OPEX of the new transmission capacity, respectively. Let *TC*(*t*)be the total cost of cross-border power transmission in year *t*, and we have

$$TC(t) = \sum_{i=1}^{I}\sum_{j=1}^{J}\sum_{v=-V}^{T}(ct_{ijv} + co_{ijv}) * tp_{ijv} \quad (3)$$

Objective function

As discussed earlier in the methodology section, the objective is to minimise the total cost of electricity during the period of this study. The objective function is written as follows:

$$obj = \sum_{i=1}^{I}\sum_{v=1}^{T}\sum_{m=1}^{M} c_{miv} * x_{miv} + \sum_{t=1}^{T}\{Opex(t) + CC(t) + TC(t)\} \quad (4)$$

Constraint conditions

Optimising the above objective function is subject to the following constraints. Equation (5) shows a first set of constraints, which require total power capacity to meet total power demand in the region. Let Q_{itp} be the power demand of country *i* in year t for load block *p*.

$$\sum_{i=1}^{I}\sum_{j=1}^{J}\sum_{m=1}^{M}\sum_{v=-V}^{t} u_{mijtvp} \geq \sum_{i=1}^{I} Q_{itp} \qquad (5)$$

The second one, shown in equation (6), states the constraint of load factor lf_{mi} of each installed capacity of power generation. Let kit_{mi} be the initial vintage capacity of type *m* power plant in country *i*.

$$u_{mijtvp} \le lf_{mi} * (kit_{mi} + x_{miv}) \tag{6}$$

The third constraint, shown in equation (7), says that power supply of all countries to a certain country must be greater than the country's power demand. Let $tl_{i,j}$ be the ratio of transmission loss in cross-border electricity trade between country *i* and country *j*.

$$\sum_{j=1}^{J} \sum_{m=1}^{M} \sum_{v=-V}^{t} u_{mijtvp} \cdot tl_{ij} \ge Q_{itp} \tag{7}$$

Equation (8) states that total supply of power of one country to all countries (including itself) must be smaller than the summation of the country's available power capacity at the time.

$$\sum_{j=1}^{J} u_{mijtvp} \le \sum_{m=1}^{M} \sum_{v=-V}^{t} lf_{mi} * (kit_{mi} + x_{miv}) \tag{8}$$

The fifth constraint, shown in equation (9), is capacity reserve constraint. Let pr be the rate of reserve capacity as required by regulation. And let $p = 1$ represent the peak load block.

$$\sum_{i}^{I} \sum_{m=1}^{M} \sum_{v=-V}^{t} lf_{mi} * (kit_{mi} + x_{miv}) \ge (1 + pr) * \sum_{i}^{I} Q_{it,p=1} \tag{9}$$

Specially, hydro-facilities have the so-called energy factor constraint as shown in equation (10). Let ef_{mi} be the energy factor of plant type *m* in country *i*. Other facilities will have $ef = 1$.

$$\sum_{p=1}^{P} \sum_{j=1}^{J} u_{mijtvp} \le ef_{mi} * (kit_{mi} + x_{miv}) \tag{10}$$

Development of power generation capacity faces resource availability constraint, which is shown in equation (11). Let $XMAX_{mi}$ be the type of resource constraint of plant type *m* in country *i*.

$$\sum_{v=1}^{T} x_{miv} \leq XMAX_{mi} \tag{11}$$

Lastly, power traded across border should be subject to the constraint of transmission capacities available at a certain point of time, which is specified in the model as follows.

$$\sum_{i=1}^{I} \sum_{j}^{J} \sum_{v=-V}^{t} \sum_{p=1}^{P} \sum_{m=1}^{M} u_{mijtvp} \leq \sum_{i=1}^{I} \sum_{j=1}^{J} \sum_{v=-V}^{t} tp_{ijv} \tag{12}$$