Chapter 3

Optimising Power Infrastructure Development

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CHAPTER 3

OPTIMISING POWER INFRASTRUCTURE DEVELOPMENT

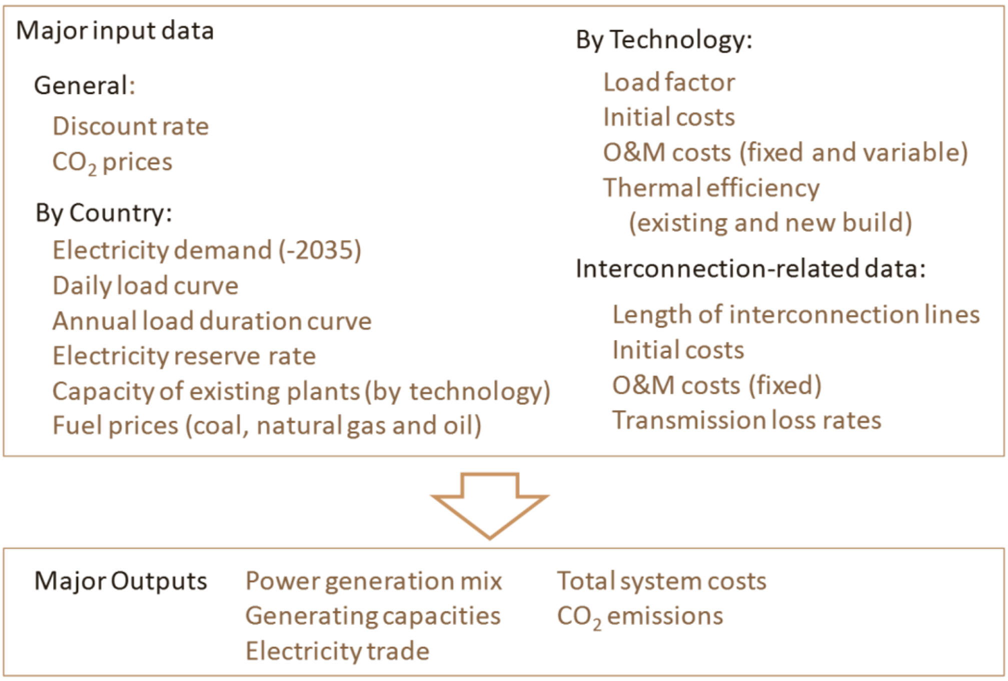
Optimising calculations were carried out according to the conditions set in the previous chapter, using an optimal power generation planning model and a supply reliability evaluation model employing the Monte Carlo method. An overview is displayed below.

3.1. Model overview

3.1.1. Optimal power generation planning model

In this study, an optimal power generation planning model using linear programming method was employed to estimate future power demand and supply. The model's main preconditions and output results are shown in Figure 3.1.

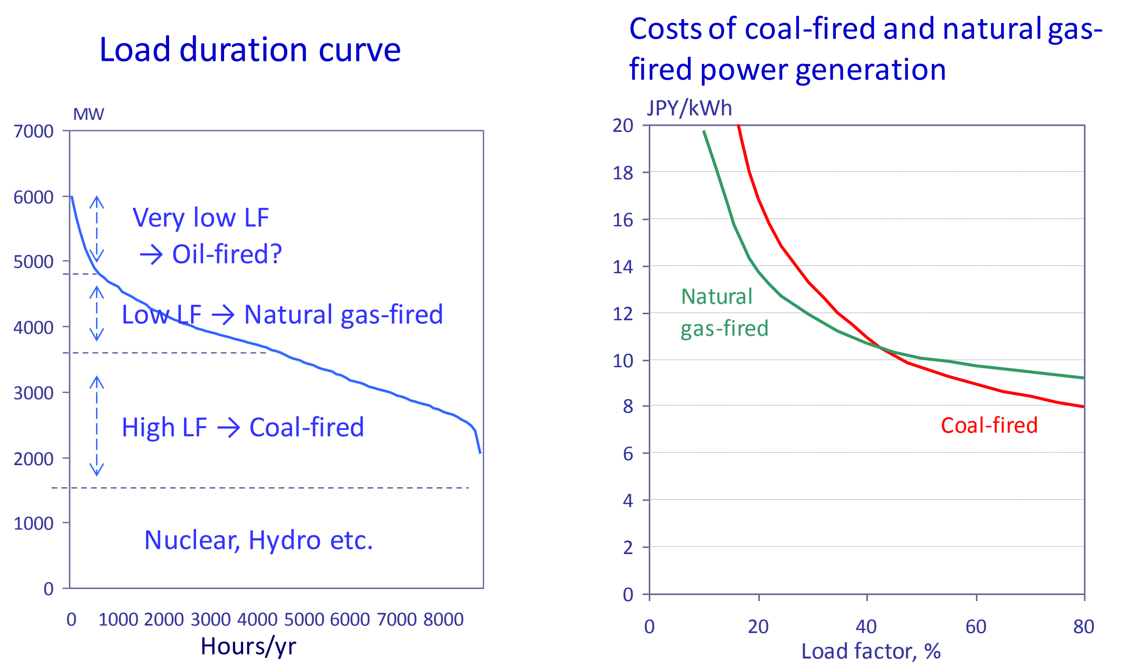
Figure 3.1: Preconditions and outputs of the optimal power generation planning model



In this model, the cost-optimal (i.e. the minimum total system cost) power generation mix for each country is estimated, with preconditions such as the power demand and load curve of each country and the cost and efficiency of each power generating technology.

When comparing coal-fired power generation and natural gas-fired power generation, the former has higher initial investments and lower fuel costs. Thus, as shown on the right in Figure 3.2, coal-fired generation is cost-advantageous when the load factor is high, and natural gas-fired is cost-advantageous when the load factor is low. Consequently, according to cost minimisation calculations in the annual load duration curve shown on the left in Figure 3.2, in the domain where the annual operating volume is large (the middle and lower part of the figure) coal-fired is chosen; and in the domain where the annual operating volume is small, (middle and upper part of the figure) natural gas-fired or oil-fired is chosen.

Figure 3.2: Power source choices in the optimal calculations



Additionally, in this study, it was assumed possible to simulate electricity trade using international interconnection lines. At a certain time on a certain day, if power export of Z (MW) is carried out from Country A to Country B, the operating capacity of the power generating facilities in Country A must be larger than the power demand by Z, while the operating capacity of the facilities in Country B will be less than the demand by Z × (1 - transmission loss rate). Here, Z cannot exceed the transmission line capacity, and alongside the cost incurred in constructing transmission lines, if an upper limit is set on the transmission line capacity, Z cannot exceed that upper limit.

The objective function and main constraint equations are shown below. It should be noted, however, that although the power generation facility operation, the power trade, and the power consumption are variables dependent upon day *d* and time *t*, for simplicity, these subscripts are omitted.

(Objective function)

$$TC = \sum_{r,i,T,d,t} \left\{ Xe_{r,i,T} \left(Cv_{r,i} + P_{i,T} / Ee_{r,i} \right) + \sum_{T'<T} Xn_{r,i,T,T'} \left(Cv_{r,i} + P_{i,T} / En_{r,i,T'} \right) \right\} (1-dr)^{T}$$

$$+ \sum_{r,T',d,t} \left\{ \sum_{i} Yn_{r,i,T'} \left(I_{r,i} + \sum_{T>T'} Cf_{r,i} (1-dr)^{T-T'} \right) I_{r,i} \right.$$

$$\left. + \sum_{r'} W_{r,r',T'} \left(II_{r,r'} + \sum_{T>T'} Cif_{r,r'} (1-dr)^{T-T'} \right) \right\} (1-dr)^{T'}$$

Where:

T: year of operation, *T'*: year of construction, *r, r'*: country number,
i: number indicating power generation technology, *dr*: discount rate,
Xe: operation of existing facilities, *Xn*: operation of new facilities,
Yn: capacity of new facilities, *W*: interconnection line capacity,
Cv: variable operation and maintenance (O&M) costs (power generation facilities),
Cf: fixed O&M costs (power generation facilities),
Cif: variable O&M costs (interconnection lines),
P: fuel price,
I: unit construction cost (power generation facilities),
II: unit construction cost (interconnection lines),
Ee: existing power generation facility efficiency,
En: new power generation facility efficiency,
d: day and *t*: time

(Power supply and demand) For all *d* and *t*,

$$D_{r,T} < \sum_{i}\left(Xe_{r,i,T} + \sum_{T'} Xn_{r,i,T,T'} \right)(1 - ir_i) + \sum_{r'}\{(1 - lr_{r,r'})Z_{r',r,T} - Z_{r,r',T}\}$$

where *D*: power consumption (including transmission loss etc.), *ir*: auxiliary power ratio,
Z: power trade: *lr*: transmission loss rate

(Existing facility power generation capacity constraints) For all *d* and *t*,

$$Xe_{r,i,T} < F_{r,i} Ye_{r,i,T}$$

where *Ye*: existing facility capacity, *F*: load factor

(New facility power generation capacity constraints) For all *d* and *t*,

$$Xn_{r,i,T} < F_{r,i} \sum_{T'<T} Yn_{r,i,T'}$$

(Power trade capacity constraints) For all *d* and *t*,

$$Z_{r,r',T} < \sum_{T'<T} W_{r,r',T'}$$

(Supply reserve margin)

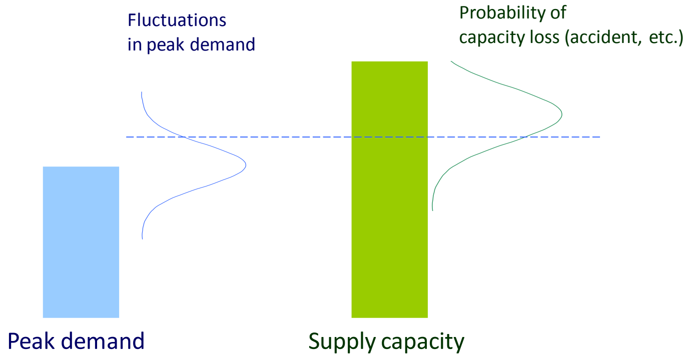
$$PD_{r,T}(1 + s_r) < \sum_{i} F_{r,i}\left(Ye_{r,i,T} + \sum_{T'<T} Yn_{r,i,T'} \right)$$

where *PD*: maximum demand, *s*: supply reserve rate

3.1.2. Supply reliability evaluation model

In these calculations, a supply reliability evaluation model employing the Monte Carlo method was used in combination with the abovementioned optimal power generation planning model. A conceptual diagram of this model is shown in Figure 3.3.

Figure 3.3: Supply reliability evaluation model



If there are no concerns with the power generation facilities, it is possible to manage the power supply system with some leeway because a certain reserve capacity is envisaged. In reality, however, power generation facilities suffer breakdowns with a degree of certainty, and so their effective supply capacity drops. Forecast power demand changes with a certain standard deviation, and when the latter exceeds the former, it results in a power outage. In this study, the probability of a trouble occurring at one plant is assumed at 5 percent and the standard deviation of power demand changes is assumed to be ±1 percent. Based on the output results of the optimal power generation planning model, the loss of load expectation (LOLE) is calculated. This is then fed back, and as a result, a supply reserve rate is set for each country and region as a precondition for the power generation planning model so that the LOLE becomes 24 hours/year.

In a case where there is no international grid connection present, because changes in power demand must be handled using only domestic power generation facilities, the LOLE becomes relatively high. By comparison, when an international grid connection is envisioned, the LOLE declines remarkably because even if breakdown occurs at a domestic power generation facility, it will be possible to avert a power outage by importing power. Or, if the LOLE is set at 24 hours, the supply reserve rate for responding to a breakdown declines, and it becomes possible to economise on the corresponding initial investment and fixed operating and maintenance costs.

3.2. Major assumptions and case settings

3.2.1. Major assumptions

In this study, the optimal power generation planning model and the supply reliability evaluation model mentioned earlier were utilised to estimate the optimum power generation mix and power trade up to 2035 by making use of the data described in Chapter 2. Because the introduction of renewable energy (other than hydro) and nuclear power are chiefly swayed by policy, they were set in line with the forecast figures in the ERIA Outlook, and only thermal power generation (coal, natural gas and oil) and hydropower generation were calculated by the model. Of those energies, the introduction of hydropower generation was as in the ERIA Outlook in Cases 0a, 0b and 1 discussed in the following section, while in the other cases, the figures discussed in Chapter 2 were utilised to show additional hydro-potential.

In employing the optimal power generation planning model, the time interval was assumed at five years. That is to say, 2010 is the latest actual value, and the figures from 2015 onward are forecast figures. In the supply reliability evaluation model, the number of trials with the Monte Carlo method was approximately 140,000 times.

3.2.2. Case settings

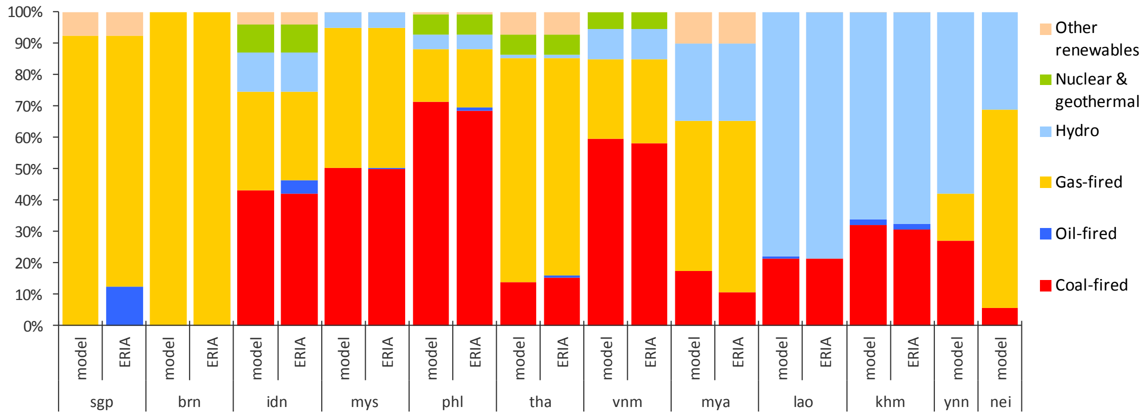
The calculation cases were set as follows:

(1) Calculations covering the total system
Calculations were made based on the following case configurations, covering all the 12 countries and regions:

Case 0 : Reference case (no additional grid connection)
Case 1 : Additional grid connection, no additional hydro-potential
Case 2a : Additional grid connection, additional hydro-potential
Case 2b : Additional grid connection, additional hydro-potential for export purpose only
Case 3 : Same as Case 2b, with no upper limit set on the grid connection capacity

Case 0 does not take grid connection into account, and is a scenario in which a power generation mix is attained that resembles the ERIA Outlook through the utilisation of the domestic power generation facilities of each country only. Figure 3.4 presents a comparison between results of each country's 2035 mix (model output for Case 0) and the ERIA Outlook.

Figure 3.4: Comparison between the calculation results for each country's power generation mix and the ERIA Outlook



Generally, with low discount rates (for example, 3-5%), coal-fired power generation is more cost-advantageous than natural gas-fired. In this study, however, a relatively high real discount rate (10%) is envisioned, and so selections are made with a certain ratio of both coal-fired and natural gas-fired, according to each country's load curve and load duration curve. For the most part, those results do not show significant variance with ERIA's forecasts, but they do differ on several points.

First, in ERIA's forecasts, oil-fired power generation is utilised in countries such as Singapore and Indonesia, but in the results for the optimal model, oil-fired is not selected due to its high cost. Conceivably, oil-fired would actually be utilised based on contributing factors other than just cost such as supply capability. That said, even in ERIA's forecasts, the share accounted by oil-fired is not high, and consequently in this study, no adjustment was made to the model.

Second, in the ERIA Outlook, coal-fired is not utilised in Singapore or Brunei. This is conceivable based on realistic supply capability. In this study, an upper limit of zero was set for coal-fired in both of these countries.

Third, in ERIA's forecasts, Thailand's coal-fired ratio in 2035 is 15 percent, which is relatively low. This is because in Thailand, until now, abundant natural gas resources are being utilised. The construction of new coal-fired power generation plants, however, is currently restricted mainly for political reasons. Consequently, in this study, the 2035 coal-fired power generation capacity was set at the same level as that of the ERIA Outlook by imposing an upper limit constraint on new coal-fired power plant construction in Thailand.

In the case of other countries, the model results are also made to basically match ERIA's forecasts by placing upper limit constraints on new facility construction for either coal-fired or natural gas-fired. The reason why upper limits were set here but not lower limits was in order to make it possible to estimate how much the power generation capacity of coal- and natural gas-fired, respectively, would decline according to the model, in the event that supply from hydropower generation increases and supply from thermal power decreases in Cases 2a, 2b and 3.

Case 1 was configured so that interconnection up to the upper limit set on the grid connection capacity indicated in Table 2.2 is possible, but the additional hydro-potential is not taken into account. In this case, as a result of interconnection, the supply reserve margin is trimmed down, and the thermal power-generation mix (the ratio of coal-fired and natural gas-fired) changes slightly.

In Case 2a, as in Case 1, grid connection is made possible and additional hydropower generation is possible with the hydropower generation potential presented in Chapter 2 as the upper limit. In this case, as will be explained later, additional hydropower generation is made to satisfy the domestic power demands of the country concerned. In reality, in Indonesia, for example, due to its characteristic features as an archipelago country, the domestic power system itself is not connected as one. Thus, even if significant hydropower generation potential existed in some islands, unless additional grid connection was carried out, it would not be possible to fully utilise that potential. Similar circumstances are present in other countries to some degree and consequently, the ERIA Outlook does not assume that it will be possible to fully exploit hydropower generation potential in order to meet domestic demand at least over the period up to 2035. In this perspective, Case 2b was configured as a case in which additional power generation can only be used for export and cannot be exploited as supply to cover domestic demand.

Case 3 is similar to Case 2B, in which additional hydropower generation can only be allocated to exports, but no cap is set on grid connection capacities. Consequently, hydropower generation potential can be utilised fully, and in particular, large amounts of power are exported from Myanmar, which is envisioned to have the largest potential. Again, this is not necessarily realistic, and Case 3 could be described as assessing what kind of situation lies ahead should interconnection on a scale exceeding HAPUA's upper limits on interconnection becomes possible.

(2) Calculations covering specific interconnection lines

In addition to the calculations applicable to the total system as mentioned above, in order to make it possible to assess the economics of the individual interconnection lines discussed in Chapter 4, calculations were made for cases that permitted grid connections between specific regions only, and were compared against the case without grid connections. The assumed connections are as follows:

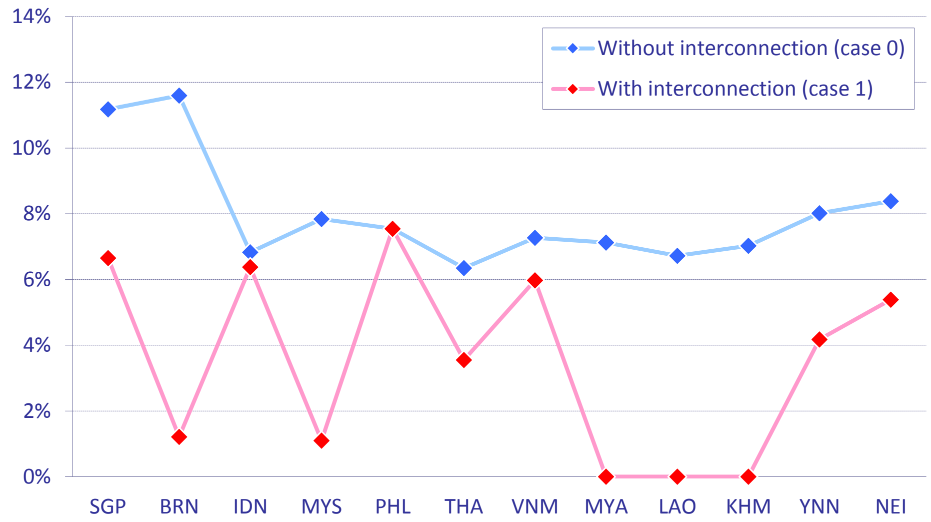
a. Cambodia – Thailand (2.3GW)
b. Lao PDR – Thailand (7.9GW)
c. Myanmar – Thailand (11.7GW)
d. Myanmar – Thailand – Malaysia – Singapore (11.7GW/0.8GW/1.1GW)
e. Viet Nam – Lao PDR – Thailand (2.7GW/7.9GW)
f. Indonesia – Malaysia (2.2GW)
g. Lao PDR – Thailand – Malaysia – Singapore (7.9GW/0.8GW/1.1GW)

3.3. Results and discussions

3.3.1. Supply reserve margin savings arising from grid connections

Figure 3.5 shows the supply reserve margin in each country and region. In Case 0, which does not envisage a grid connection, the reserve margin is 7-8 percent for most countries, and around 11-12 percent for Singapore and Brunei where the systems are small relative to the scale of the power generation facilities. In the cases where grid connections are assumed, the supply reserve margin to achieve the same 24-hour LOLE declines substantially. The degree by which the reserve margin declines differs, however, depending on the country. In the Philippines, where interconnection does not take place due to the high interconnection costs, the supply reserve rate is not reduced; and in Indonesia, which has a relatively large power system and is directly interconnected only with Malaysia, a net power importer in 2035, the supply reserve margin saving is small.

Figure 3.5: Required reserve margin to gain the same LOLE



3.3.2. Power generation mix in 2035

Figure 3.6 to Figure 3.10 show the power supply in 2035 for each case. In these figures, the areas designated with purple sloping lines show net imports (representing net imports if they are positive and net exports if they are negative).

Figure 3.6 represents the power supply mix in Case 0, where a grid connection is not envisioned. As mentioned above, apart from oil-fired generation, these results basically conform to the ERIA Outlook study.

Figure 3.6: Power supply mix in 2035 (Case 0)

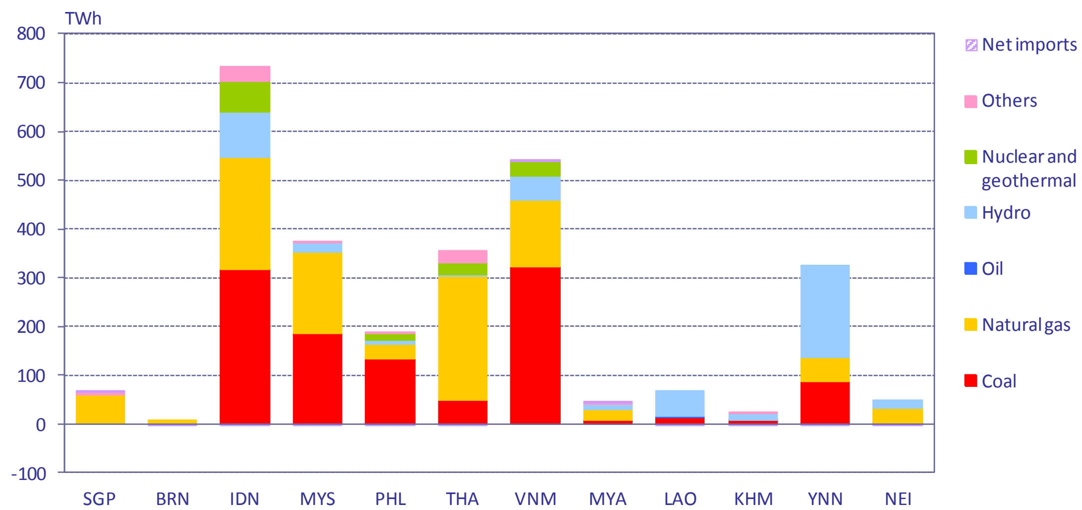


Figure 3.7 shows the power supply mix in Case 1. For this case, hydropower generation is the same as for Case 0, but changes can be detected in the thermal power generation. In Thailand the natural gas ratio is high in Case 0 compared to the cost-optimised. Its natural gas-fired power generation is reduced in Case 1 and is covered by coal-fired power generation from neighbouring countries (in this instance Lao PDR). In this way, there is a possibility that a more cost-optimal power generation mix could be achieved through the utilisation of international interconnection lines, taking into account each country's particular restraints (in this case, restraints on new coal-fired power plant construction in Thailand).

Figure 3.7: Power supply mix in 2035 (Case 1)

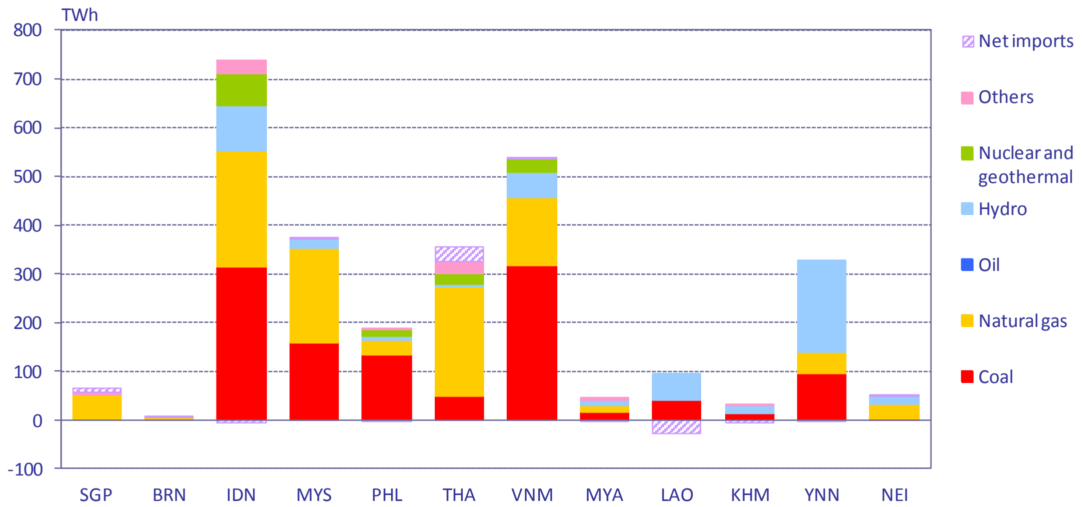


Figure 3.8 shows the power supply mix in Case 2a. In this case, utilisation of additional hydropower potential in each country takes place and exports occur from countries and areas possessing significant potential such as Myanmar, Lao PDR, Cambodia, southern China and Northeast India to Thailand, Viet Nam, Singapore and Brunei.

Additional hydropower generation potential also exists in countries such as Indonesia, the Philippines and Viet Nam. In Case 2a, growth in hydropower generation in these countries will be utilised to meet their domestic power demands. Consequently, hydropower generation accounts for 36 percent of total electricity supply in Indonesia and 45 percent in Viet Nam in 2035. In reality, despite the hydropower generation potential that physically exists in these countries, most of these resources cannot be utilised due to geographical and economic factors. In view of this and as shown in the ERIA Outlook, a situation in which hydropower generation covers nearly 40 percent of the power supply cannot be anticipated in these countries.

In Case 2a, hydropower generation accounts for 95 percent of Myanmar's power supply and 93 percent of Cambodia's power supply. From the viewpoint of power system operation, though, it is not realistic to assume hydropower generation percentages as high as these. From that perspective, although Case 2a shows some potential in terms of approaches to utilise international interconnection lines, it should not be regarded as a realistic picture in 2035.

Figure 3.8: Power supply mix in 2035 (Case 2a)

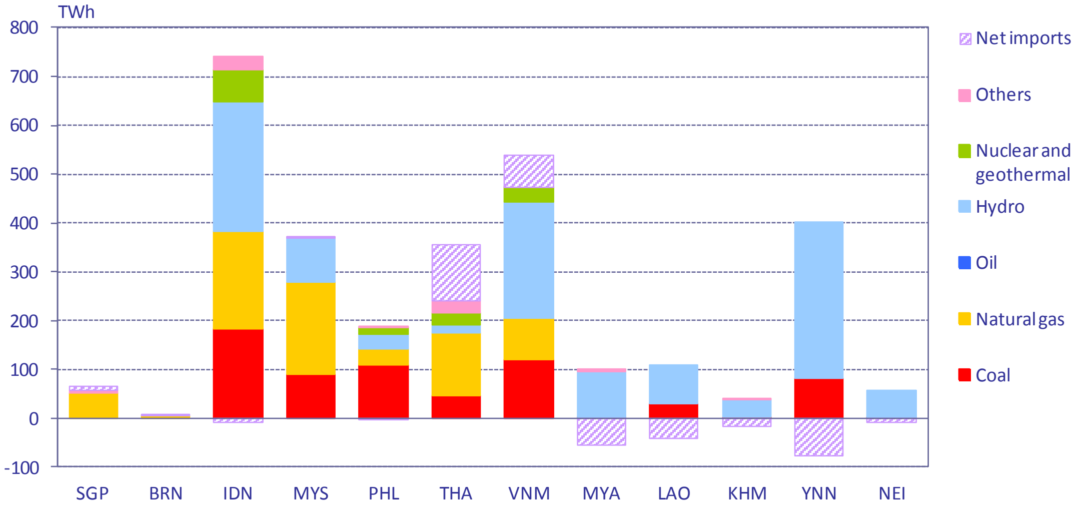


Figure 3.9 represents the power supply mix in Case 2b. Case 2b envisions that additional hydropower generation capacity will only be used for exports. For that reason, the hydropower generation in Indonesia and Viet Nam is smaller than in Case 2a. In terms of domestic power supplies in Myanmar and Cambodia, a certain amount of thermal power generation is used alongside hydro; thus, the surplus hydropower generation portion is exported. Compared to Case 2a, Case 2b therefore presents a more realistic picture.

Figure 3.9: Power supply mix in 2035 (Case 2b)

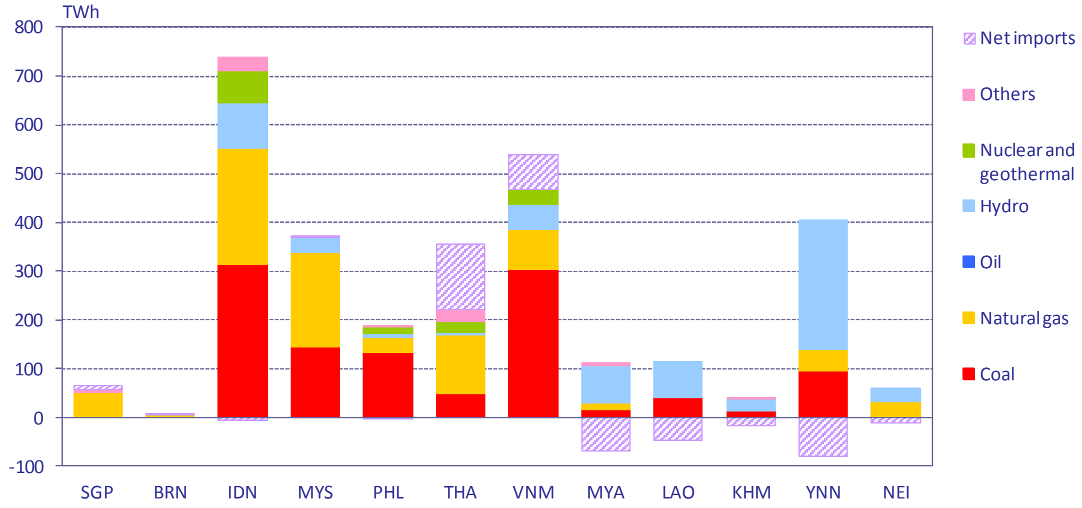


Figure 3.10 represents the power supply mix in Case 3. In this case, hydropower generation in Myanmar in particular is extremely large, with the country exporting 250TWh of electricity per year. At the same time, power is also exported from Lao PDR, Cambodia, southern China and Northeast India which contributes to the supply in Thailand, Viet Nam, Malaysia, Indonesia, Singapore and Brunei. In reality, even if there were no upper limit constraints on interconnection lines, the issue is whether or not the hydropower generation potential in Myanmar could be economically developed on this scale. This will therefore need to be studied further.

Figure 3.10: Power supply mix in 2035 (Case 3)

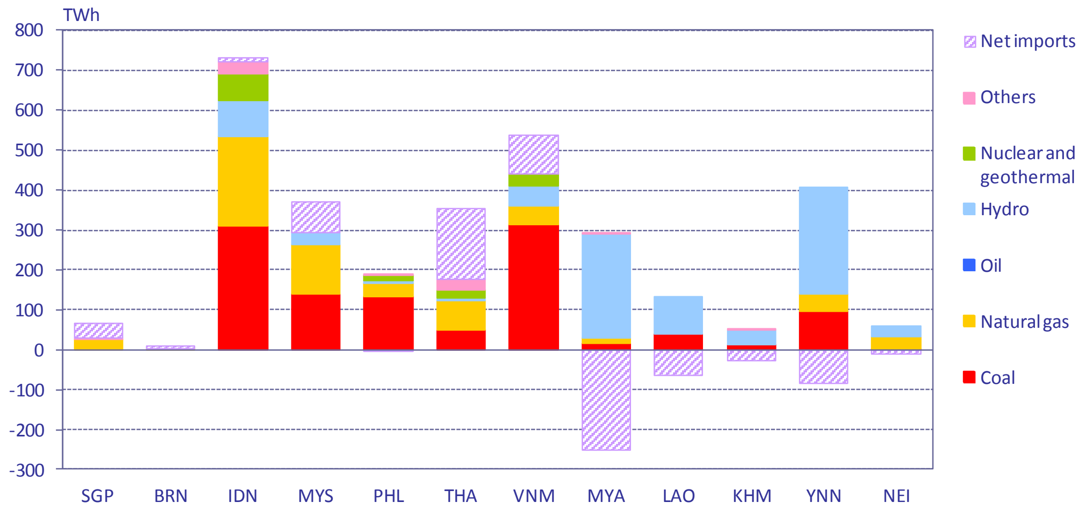
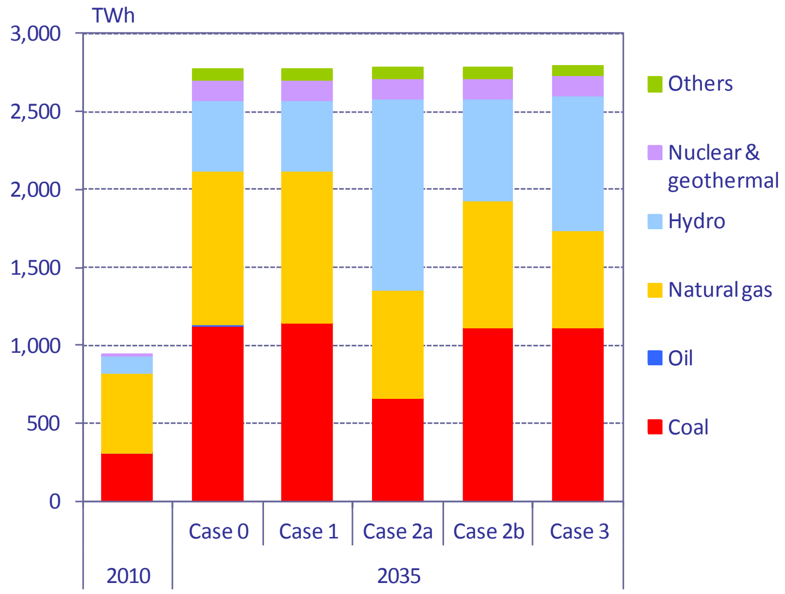


Figure 3.11 shows the power supply mix for all 12 countries and regions combined.

The area's total power generation capacity will expand from 940TWh in 2010 to roughly 2,800TWh in 2035. In Case 0, which does not envisage grid connection, the power generation mix in 2035 consists of coal-fired (40%), natural gas-fired (36%), hydro (16%), and others such as nuclear and renewables (7%). By comparison, in Case 1, the coal-fired thermal ratio increases slightly to 41 percent.

In Case 2a, as a result of utilising additional hydropower generation potential, the hydropower generation ratio rises to 44 percent and accordingly, the shares covered by both coal-fired and natural gas-fired decline. By comparison, in the more realistic scenario of Case 2b, the hydropower generation ratio rises to 23 percent and in Case 3, which does not take grid connection constraints into account, the ratio rises to 31 percent. In Cases 2b and 3, the hydropower generation increases compared to Case 1; thus, the dominance of natural gas-fired power generation declines accordingly.

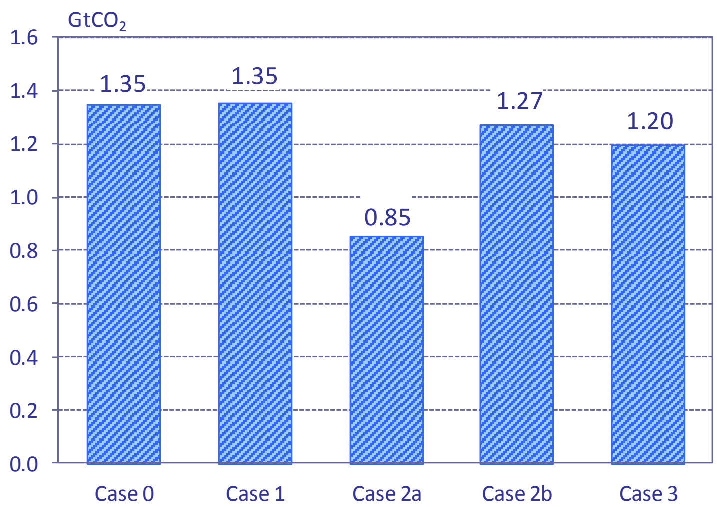
Figure 3.11: Power supply mix by case in 2035 (total of the regions)



3.3.3. CO_2 emissions in 2035

Figure 3.12 shows CO_2 emissions in 2035 (the total for the 12 countries and regions). Compared to Case 0, Case 1 does not have additional hydropower generation and at the same time, the ratio of coal-fired power generation increases slightly as a result of cost optimisation across the entire system based on grid connection. ,. In view of this, CO_2 emissions increase by a small amount, from 1.346Gt in Case 0 to 1.354Gt in Case 1. By comparison, in Cases 2a, 2b and 3, which make use of grid connection along with additional hydropower generation, there are striking declines in CO_2 emissions. This is especially true in Case 2a where the utilisation of domestic hydro-potential in Indonesia and Viet Nam progresses, reducing CO_2 emissions significantly to 0.85Gt. However, as mentioned above, this cannot be described as a realistic case, The CO_2 emission reductions compared to Case 0 are around 0.07Gt in Case 2b, where a grid connection limit corresponding to HAPUA's limit is set; and around 0.15Gt in Case 3, which does not set a limit to interconnection capacity.

Figure 3.12: CO_2 emissions in 2035

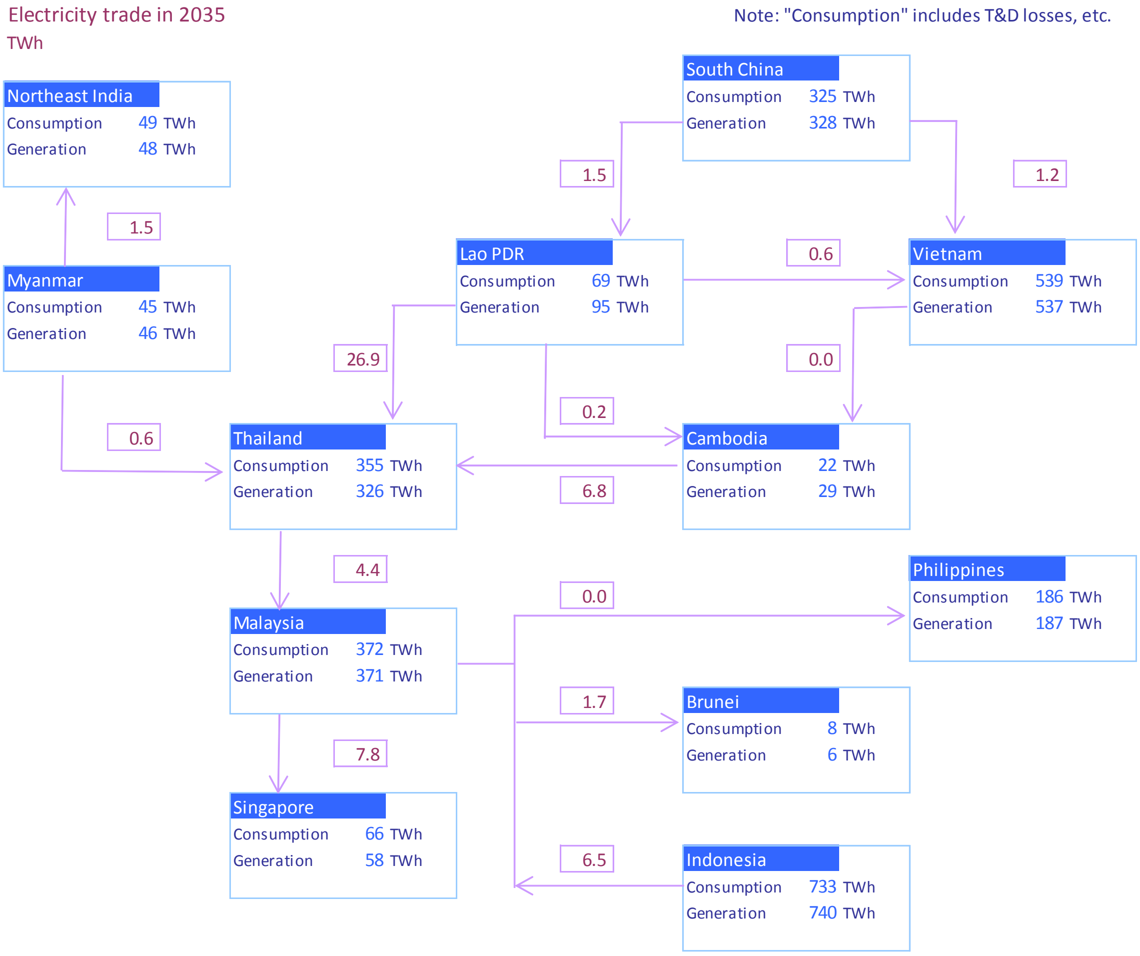


3.3.4. Power trade flows in 2035

Figure 3.13 to Figure 3.16 show power trade flows in 2035.

In Case 1, which is shown in Figure 3.13, the quantity of power trade is small compared to Cases 2a, 2b and 3 because the utilisation of additional hydro-potential is not envisioned. However, even in this case, due to the changes (in thermal power generation) power trade takes place with Thailand being the biggest importer of power, followed by Singapore. The biggest power exporter is Lao PDR, which supplies electricity to Thailand.

Figure 3.13: Power trade flows in 2035 (Case 1)

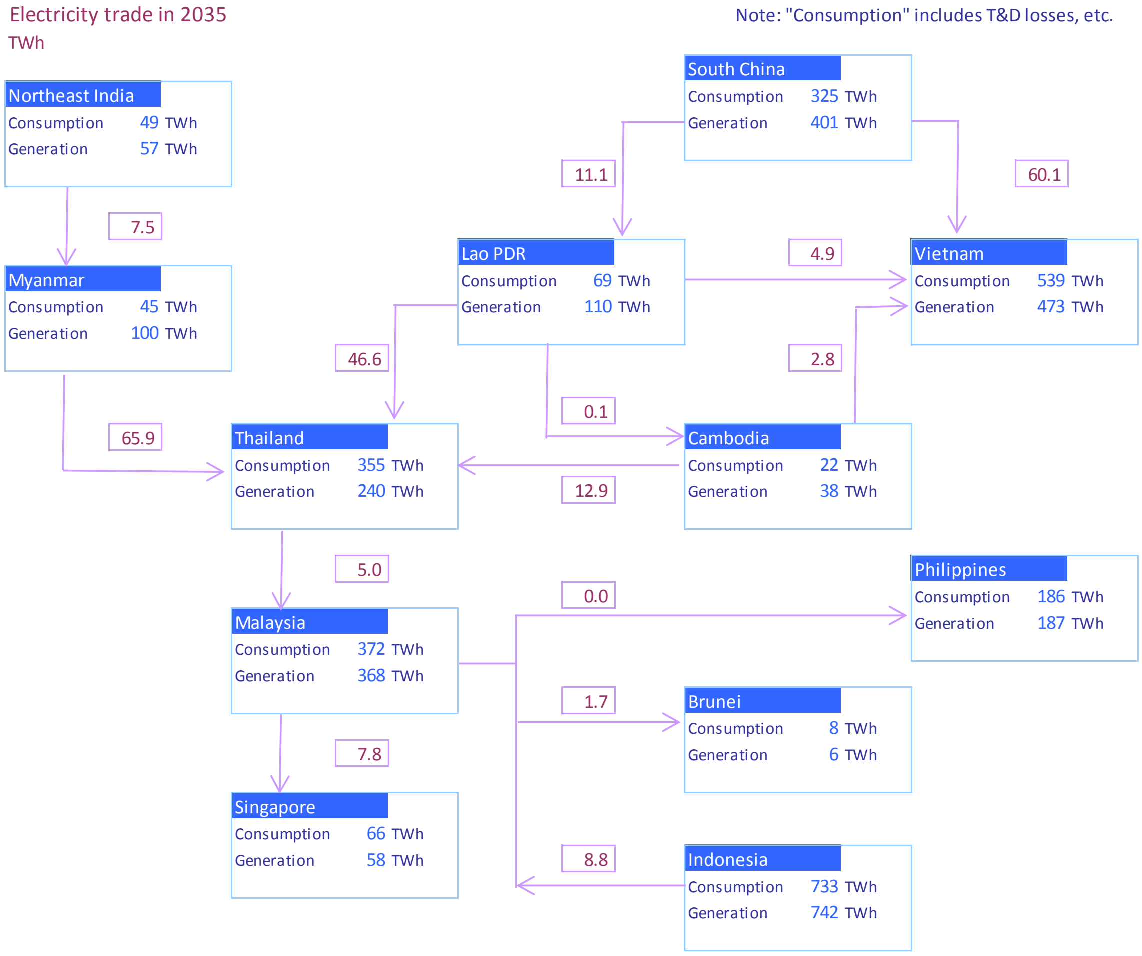


In Case 2a, which envisions the utilisation of additional hydro-potential, power is exported to Thailand from three neighbouring countries, namely, Myanmar, Lao PDR and Cambodia. Substantial volumes are advanced from Lao PDR and Myanmar in particular, countries which have large additional hydro-potential. Moreover, in this scenario, power is also supplied to Thailand from northeastern India via Myanmar. Southern China also supplies power to Thailand via Lao PDR, but it supplies more power to Viet Nam.

Meanwhile, power flows to Malaysia from Thailand. Part of the power is utilised for power supply to Malaysia and part is used, along with power advanced from Indonesia, to satisfy power demand in Singapore.

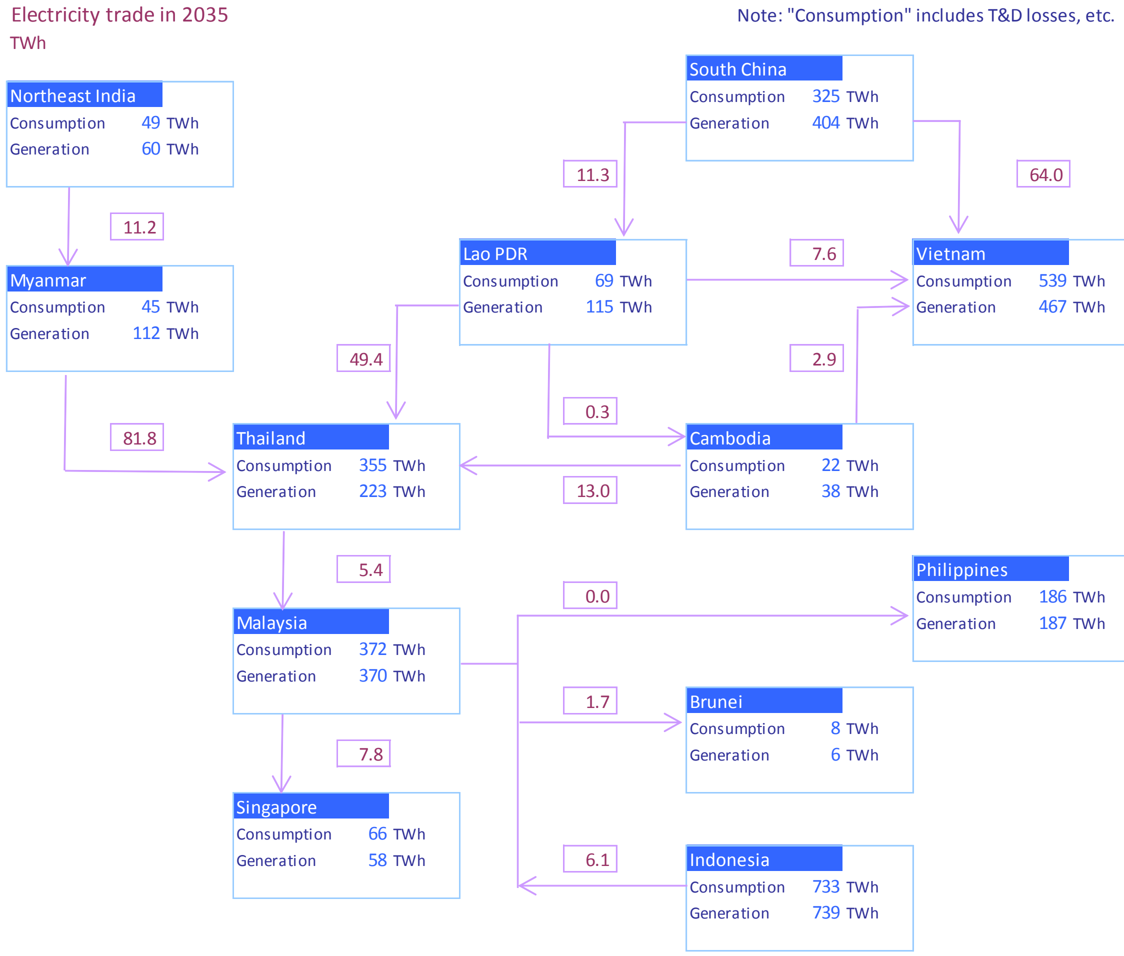
The Philippines is a latent power importer. However, based on the model analysis results, it does not import power. This is because the distance covered by a seafloor cable from Malaysia (Borneo) to the Philippines would be extremely long and the construction cost would exceed the advantages to be reaped from getting the supply.

Figure 3.14: Power trade flows in 2035 (Case 2a)



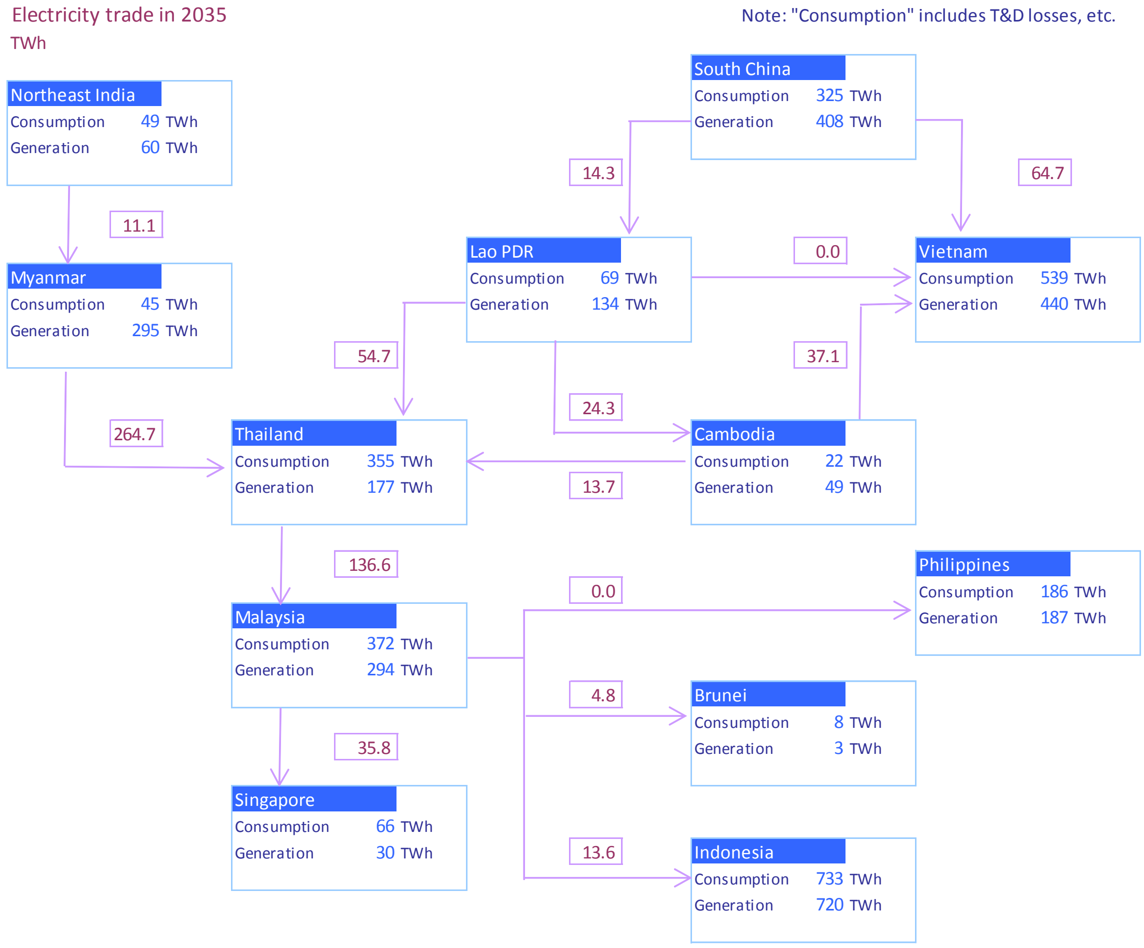
Case 2b envisions a scenario in which additional hydropower generation potential is not used to satisfy domestic demand in the country concerned but only used for exporting. As mentioned above, this case is more realistic. From the standpoint of the quantity of power trade, the outcomes in this case basically resemble those in Case 2a.

Figure 3.15: Power trade flows in 2035 (Case 2b)



Case 3 is a case in which no limit is set on grid connection and additional hydropower generation potential is exercised to the fullest. Myanmar, in particular, is recognised as having massive potential capacity and would supply Thailand with 265TWh of power per year as well as supply power to Singapore, Indonesia and Brunei from Thailand via Malaysia. As mentioned above, though, a more detailed exploration of whether it would be possible to utilise additional hydropower generation to this extent is required. The results of Case 3 can be viewed as suggesting one orientation for looking at a case where power supply on a scale exceeding HAPUA's plans is envisioned, and where a rational form for its being able to do so in terms of power supply and demand can be determined.

Figure 3.16: Power trade flows in 2035 (Case 3)



3.3.5. Changes in power trade in Case 2b

Figure 3.17 to Figure 3.20 show changes to power interchange in Case 2b. This case envisions grid connection lines to be constructed around 2020 and to commence operations beginning around 2025. In these figures, positive numbers indicate that power is being supplied towards that direction while negative numbers indicate that power is being supplied in the opposite direction.

Figure 3.17 presents the annual flow via four interconnection lines from southern China to Viet Nam and Lao PDR, from Cambodia to Viet Nam, and from Lao PDR to Viet Nam. Power supply from southern China to Viet Nam continuously grows. In contrast, a flow develops from Viet Nam to Cambodia and Lao PDR in 2025, which occurs in order to supply power to Thailand via these countries. The direction of power trade in these interconnection lines is determined as a result of Thailand’s and Viet Nam’s demand balance.

The ERIA Outlook sketches a scenario in which Viet Nam's power supply and demand grows the most rapidly as time moves towards 2035. Consequently, in 2035, the trend reverses, and power is supplied from Cambodia and Lao PDR to Viet Nam. Accompanying the expansion in supply from southern China to Viet Nam is the decrease in the export of power from southern China to Lao PDR towards 2035.

Figure 3.17: Changes in power trade in Case 2b (1)

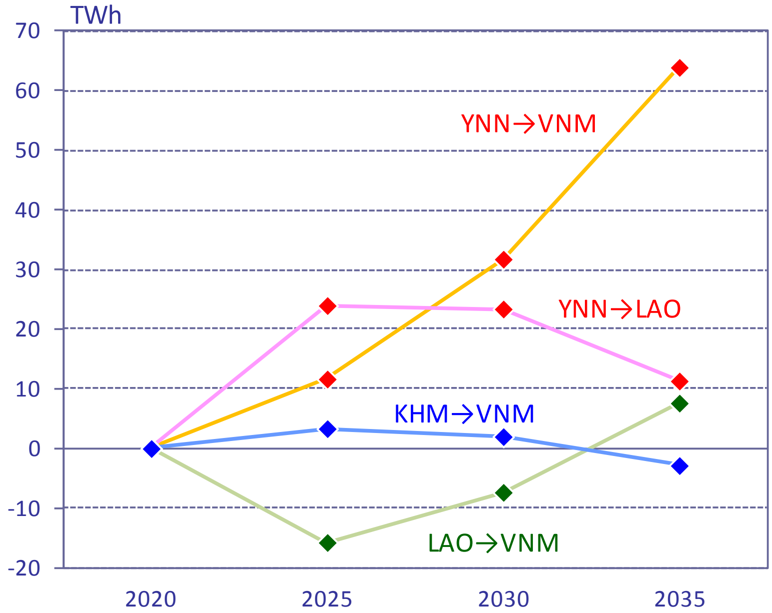


Figure 3.18 shows the power supply from Myanmar, Lao PDR, Cambodia and Malaysia to Thailand. As of 2025, Lao PDR is the largest supplier of power to Thailand, followed by Myanmar and Cambodia. However, accompanying the rapid expansion in Viet Nam's demand, the supply coming from Lao PDR and Cambodia begins to decrease and Myanmar assumes the position of being the largest supplier towards 2035. Meanwhile, despite being in a small net import position with Malaysia in 2025, Thailand will be in a reverse position by 2035 as it begins to export power. As a result, as shown in Figure 3.15, it becomes possible to supply hydro-potential power from the northern regions to the southern regions, including Singapore. This will be particularly noticeable around 2035 when supply in the south begins to run short given the expanding demand in Indonesia.

Figure 3.18: Changes in power trade in Case 2b (2)

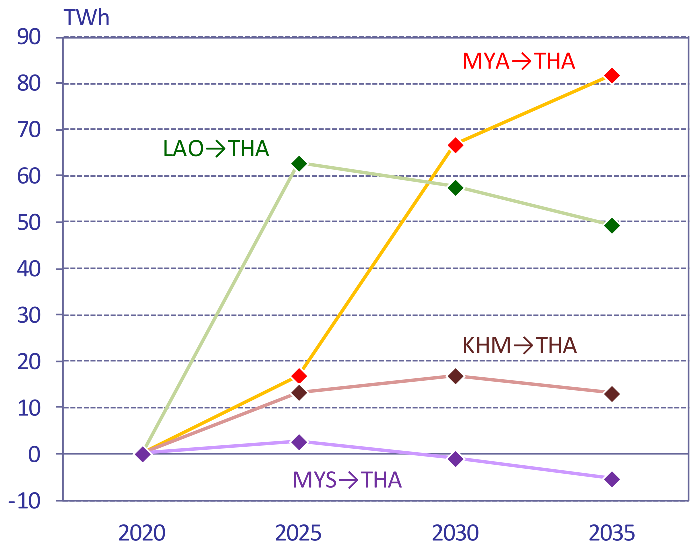


Figure 3.19 presents the export from Malaysia to Singapore, Brunei, Thailand and Indonesia. As this figure shows, Singapore and Brunei enjoy a stable power supply via Malaysia. The countries providing the supply for that are Indonesia and Thailand, but their supply amounts change over time. Supply coming from Indonesia shrinks due to the rapid growth in domestic demand. Accordingly, the reliance on northern hydro that passes through Thailand increases. This region's supply capacity itself is around 5-10TW and is small in scale when compared to the supply and demand balance in the northern region shown in Figure 3.17 and Figure 3.18 which center on Thailand and Viet Nam.

Figure 3.19: Changes in power trade in Case 2b (3)

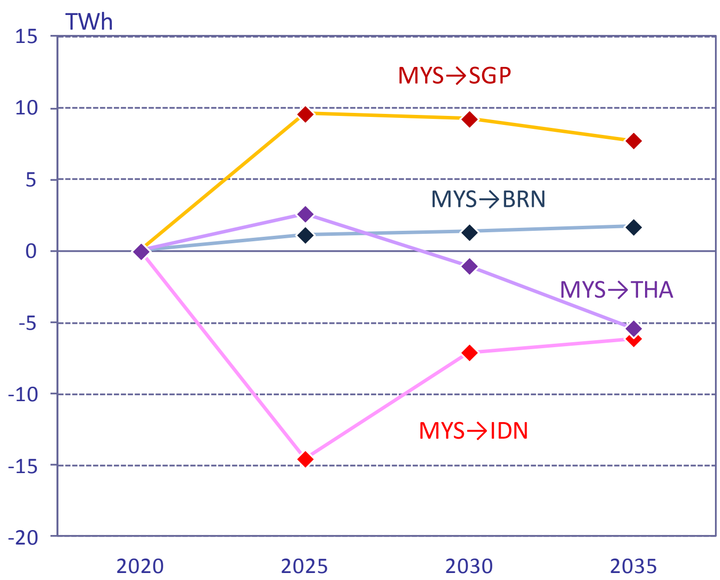
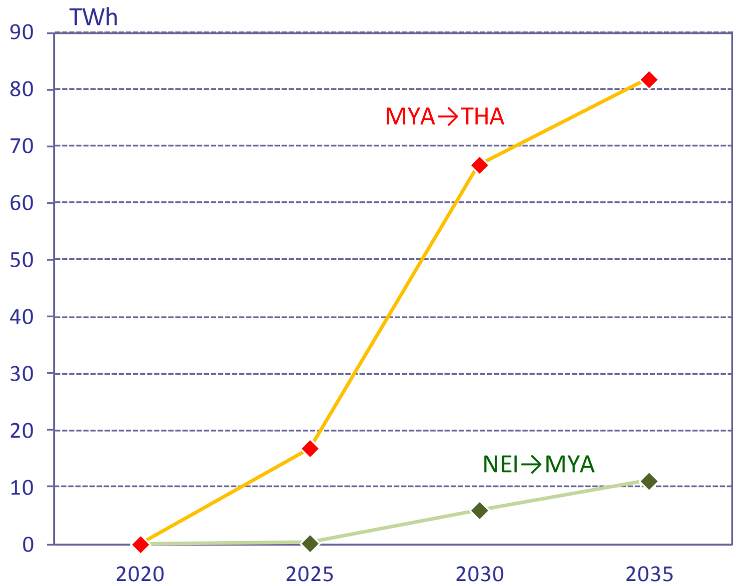


Figure 3.20 shows the export from Northeast India to Myanmar and from Myanmar to Thailand. This interchange continues to grow up to 2035. In other words, amid the ongoing expansion in power demand in Viet Nam, Thailand, and Indonesia in the long term, the importance of these regions' power supply capacity will increase more.

Figure 3.20: Changes in power trade in Case 2b (4)



3.3.6. Cumulative costs up to 2035 and 2050

Figure 3.21 shows the differences in the cumulative costs (up to 2035 and 2050) in Cases 1, 2b and 3, compared to Case 0.

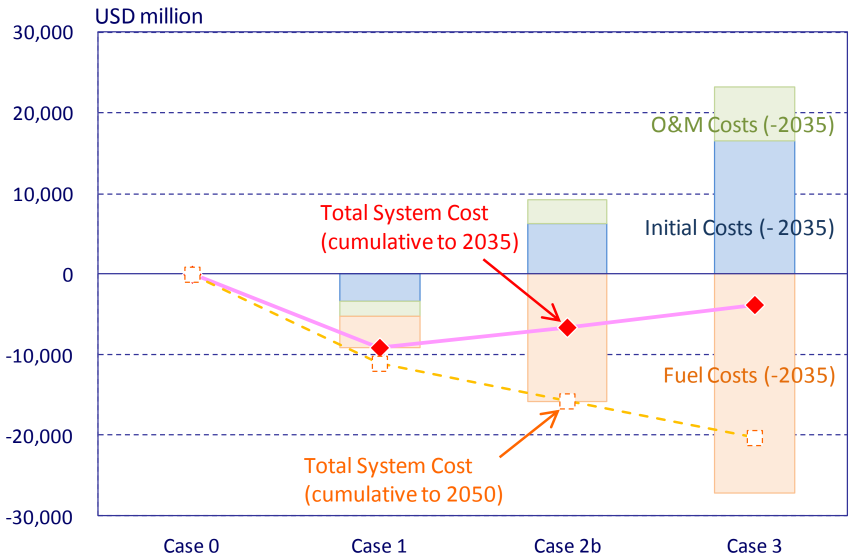
In Case 1, accompanying the decline in the supply reserve rate arising from power interchange compared to Case 0, the required initial investment amount decreases. Accordingly, the O&M costs also fall, and the fossil fuel expenses also decline accompanying the replacement of natural gas-fired by coal-fired thermal. In total, the cumulative costs up to 2035 (the total for the 12 countries and regions) decline by around 9.1 billion USD.

In contrast, in Case 2b, which takes into account the utilisation of additional hydropower potential, fossil fuel expenses decrease substantially, on the one hand, while initial investments and O&M costs increase, on the other, as a result of a shift from natural gas-fired to hydro. When these outcomes are all totaled, the cumulative costs up to 2035 fall by 6.6 billion

USD compared to Case 0, and increase by 2.5 billion USD compared to Case 1. In Case 3, where the usage of additional hydropower generation potential is greater, there is a 3.8-billion USD decline in cumulative costs compared to Case 0 and a 5.3-billion USD increase compared to Case 1.

The increase in cumulative costs up to 2035 accompanying the utilisation of additional hydro points to the fact that it will not be possible to fully recover the initial investment needed for hydropower generation facilities. If the cumulative costs are evaluated over a longer time scale such as until 2050, however, then the cumulative costs in Cases 2b and 3 will decline compared to Case 1 because more of the initial investment for hydro will be recovered. Therefore, the economies of constructing international interconnection lines improves under systematic planning with a long-term perspective.

Figure 3.21: Cumulative costs in each case



3.4. Conclusion

This study uses an optimal power generation planning model that takes into account international interconnection together with a supply reliability model that employs the Monte Carlo method to analyse international grid connection options up to 2035. Grid connections in the ASEAN region would reduce the costs of the overall power system and bring massive benefits to the region through effective utilisation of additional hydropower generation potential and reduction of supply reserve margin. However, when it comes to utilising additional hydro-thermal power potential, it might not be possible to recover the initial investment required due to unavoidable barriers if the time scale is until 2035. Consequently, it is necessary to draw up plans with a longer time scale that looks ahead to, say, 2050.

In this study a constant cost for additional hydro-potential was employed. However, the fact is that the economics of hydropower generation changes depending on location. As a result, there is a possibility that the feasibility of hydro-potential shown in Chapter 2 will also differ. In the future, it will be advantageous if a more realistic evaluation were to be done by assessing, among others, the costs of each kind of power generation, most notably, hydro-generation, and the grid connection costs for each region.