Chapter 4

Results and Discussion

September 2021

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Chapter 4

Results and Discussion

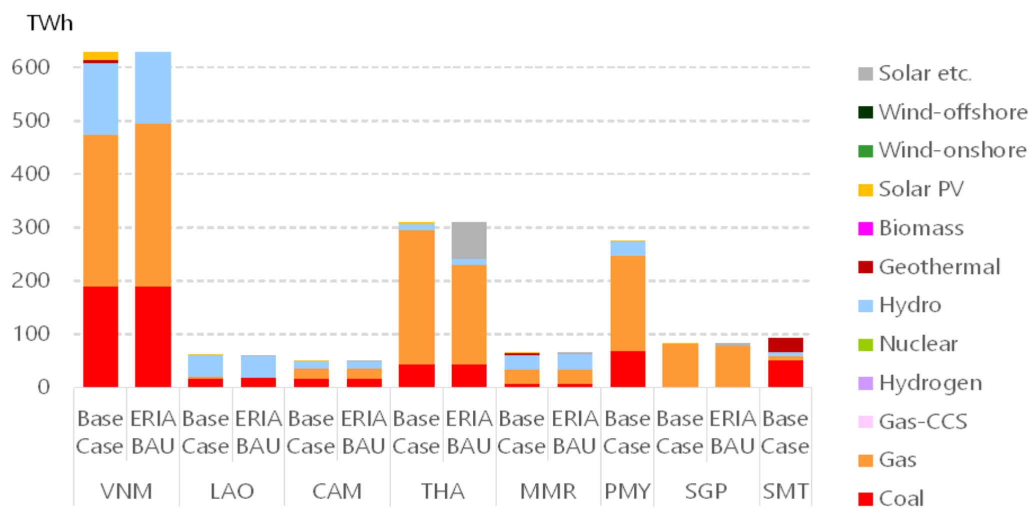
1. Base case

1.1 Base case (existing interconnection case)

The base case refers to a case in which, basically, individual countries maintain a balance between supply and demand based on their domestic power generation, although only the existing interconnection is considered. Neither the external cost nor the carbon price is set for thermal power generation. The conditions have been set to roughly match the business-as-usual (BAU) scenario of the ERIA Outlook.

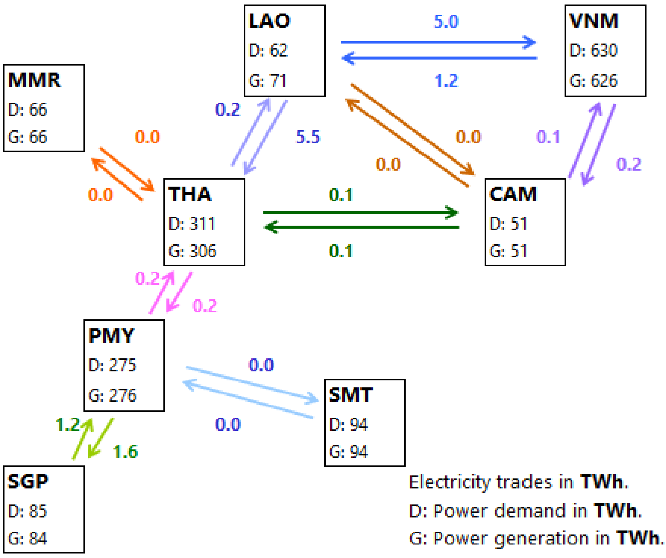
Figure 4.1 shows that thermal power is the main power source in 2040, accounting for around 80% of the power generation mix for all the target regions. On the other hand, hydropower is adopted in countries such as Viet Nam, the Lao PDR, and Myanmar, which have high potential for hydropower generation. The introduction of variable renewable energies (VRE), such as solar photovoltaic (PV) and wind power, has progressed little. Figure 4.2 shows the electricity trade flows in the base case.

Figure 4.1. Comparison of the base case with the ERIA Outlook (power generation mix in 2040)



BAU = business as usual, CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Source: Authors' analysis.

Figure 4.2. The base case (trade flows)



TWh = terawatt hour.

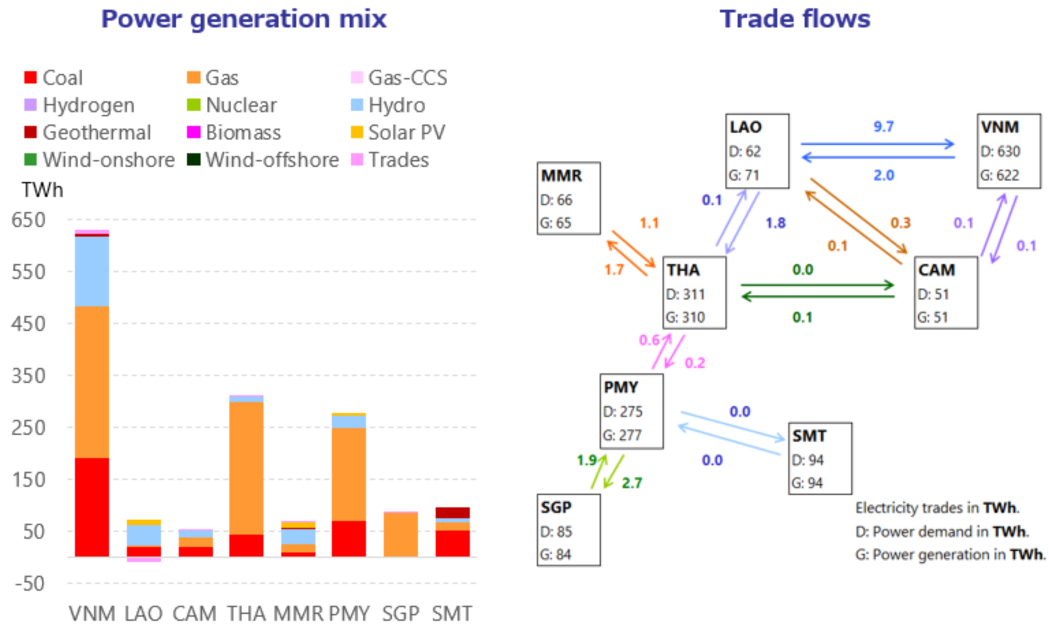
Source: Authors' analysis.

1.1.1. Planned interconnection case

The planned interconnection case has made electric power trade possible up to a planned interconnection capacity, as shown in Table 2.3. Neither the external cost nor the carbon price is set for thermal power generation.

Figure 4.3 shows the power generation mix and the electricity trade flows in the planned interconnection case. The trade flows are not much different from the existing interconnection case, even considering the planned interconnection expansion as long as the external cost and carbon price for thermal power are zero. The primary reason is that the utilisation of domestic coal-fired power is prioritised over using the potential for hydropower by other countries from the perspective of economic efficiency because the levelised cost of electricity (LCOE) of hydropower is higher than that of coal-fired power. In countries with high capacity factors of solar PV, such as Myanmar and the Lao PDR, a small amount of solar PV is introduced due to the low LCOE of solar PV.

Figure 4.3. The planned interconnection case



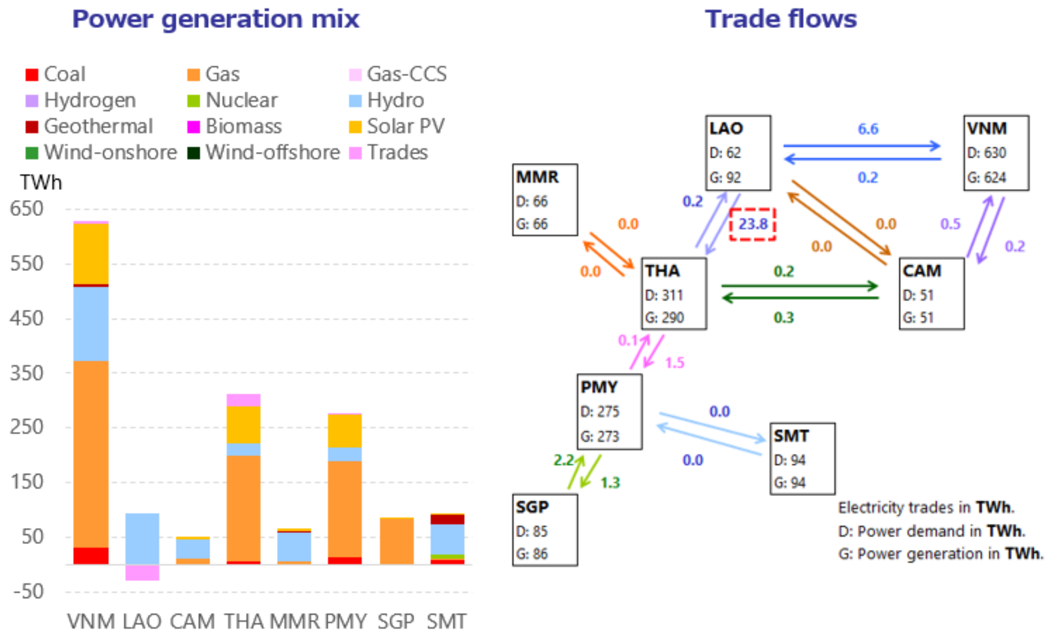
CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Source: Authors' analysis.

1.1.2. The US$50/t$CO_2$ carbon price case

In the case of setting the carbon price at US$50/t$CO_2$, which indicates strong policies towards decarbonisation, the LCOE of coal-fired power is within the range of 8.3–9.5 US cents/kWh, resulting in a deterioration in price competitiveness. As a result, it is expected that coal-fired power would almost go out of use in any country regardless of the presence of interconnections.

Figure 4.4 shows the power generation mix and the electricity trade flows in the US$50/t$CO_2$ carbon price case with existing interconnection. Most electricity is supplied by hydropower in countries such as the Lao PDR, Cambodia, and Myanmar, which have a high potential for hydropower. In other countries, gas-fired power is adopted as a major power source, and the introduction of solar PV is expected to progress. Regarding trade flows, trade from the Lao PDR to Thailand increases, and hydropower in Lao PDR is expected to replace part of thermal power in Thailand.

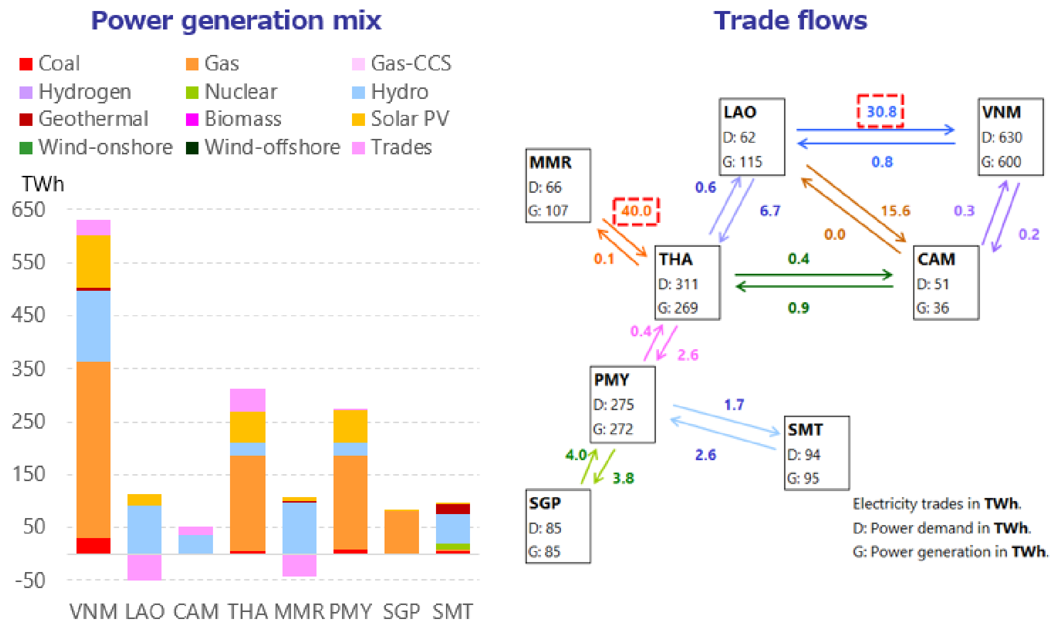
Figure 4.4. The US$50/$tCO_2$ carbon price case with existing interconnection



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Source: Authors' analysis.

On the other hand, hydropower in Myanmar is used effectively in the planned interconnection case. Currently, there is no interconnection between Myanmar and Thailand, however, there are plans to expand the interconnection with a large capacity of 14.9 gigawatts (GW) in the future. Figure 4.5 shows that exports from Myanmar to Thailand increase significantly, and in turn, Lao PDR increases exports to Viet Nam, reducing exports to Thailand. As a result, thermal power generation in Thailand and Viet Nam are curtailed.

Figure 4.5. The US$50/$tCO_2$ carbon price case with planned interconnection



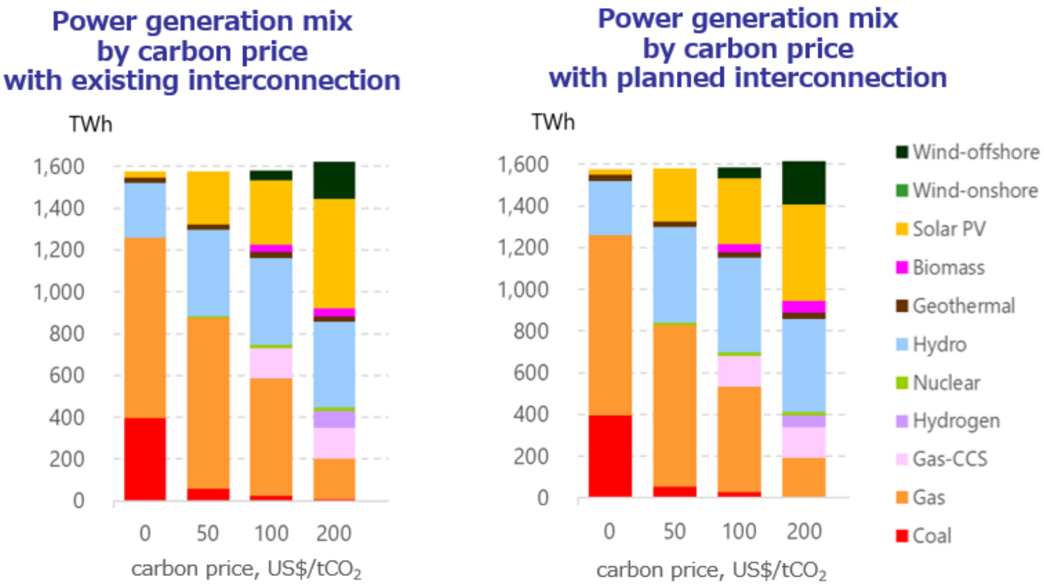
CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Source: Authors' analysis.

1.1.3. Power generation mix: Total for the eight regions

As mentioned above, when the carbon price is zero, about 80% of the power generation mix depends on thermal power regardless of the presence of an interconnection. Coal-fired power would almost go out of use when the carbon price reaches US$50/$tCO_2$, and the utilisation of hydropower and solar PV would rise along with a further carbon price rise or strong policy measures towards decarbonisation.

Comparing the power generation mix of the existing interconnection case and the expanded interconnection case, there is no significant difference in the entire region.

Figure 4.6. Power generation mix by carbon price



CCS = carbon capture and storage, PV = photovoltaic.
Source: Authors' analysis.

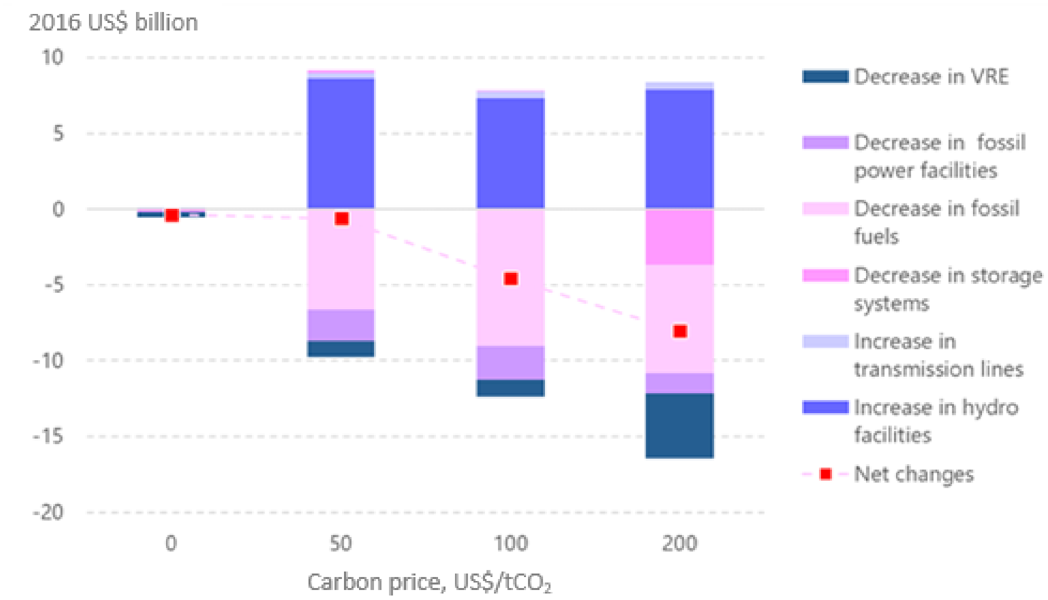
However, considering individual countries, the power generation mix is different depending on the interconnection capacity along with a further carbon price rise or strong policy measures towards decarbonisation.

Under a high carbon price or strong policy measures towards decarbonisation, in the existing interconnection case, the hydropower potential in Myanmar and the Lao PDR is mainly used in their own countries. The capacity to export electricity generated in Myanmar and the Lao PDR is limited so that the countries with poor hydropower potential need to introduce a large amount of VRE to replace thermal power generation. On the other hand, in the planned interconnection case, the hydropower potential is effectively utilised in the entire region. In countries with abundant hydropower potential, such as Myanmar and the Lao PDR, hydropower can be exported to earn foreign currency, whilst the domestic power supply can be supplemented by solar PV. Countries with poor hydropower potential can get closer to a well-balanced power generation mix by utilising imported hydropower and their own VRE.

A massive introduction of VRE, including solar PV and wind, leads to additional costs related to intermittency. Also, hydropower alone cannot meet the electricity demand in the dry season because the amount of electricity generation decreases during the dry season. The expansion of the interconnection can be expected to adjust the output fluctuation of renewable energy in the entire region and enable more efficient utilisation of regional renewable energy resources.

Figure 4.6 shows the changes in the total annual system cost for carbon prices ranging from US$0/$tCO_2$ to US$4200/$tCO_2$ in cases with planned interconnection lines compared to those without interconnection lines. The presence of interconnection lines means that there will be transmission line costs and expansion of hydro power generation as well. On the other hand, the decrease in thermal power generation and VRE cost makes them a net benefit. In particular, in the case where the carbon price is very high at US$200/t$CO_2$, although the expansion of VRE would require a large amount of storage batteries, the presence of interconnection lines would greatly reduce the actual quantity of batteries needed. Thus, cross-border interconnection lines throughout the region have the potential to generate great benefits when strong policy measures are implemented.

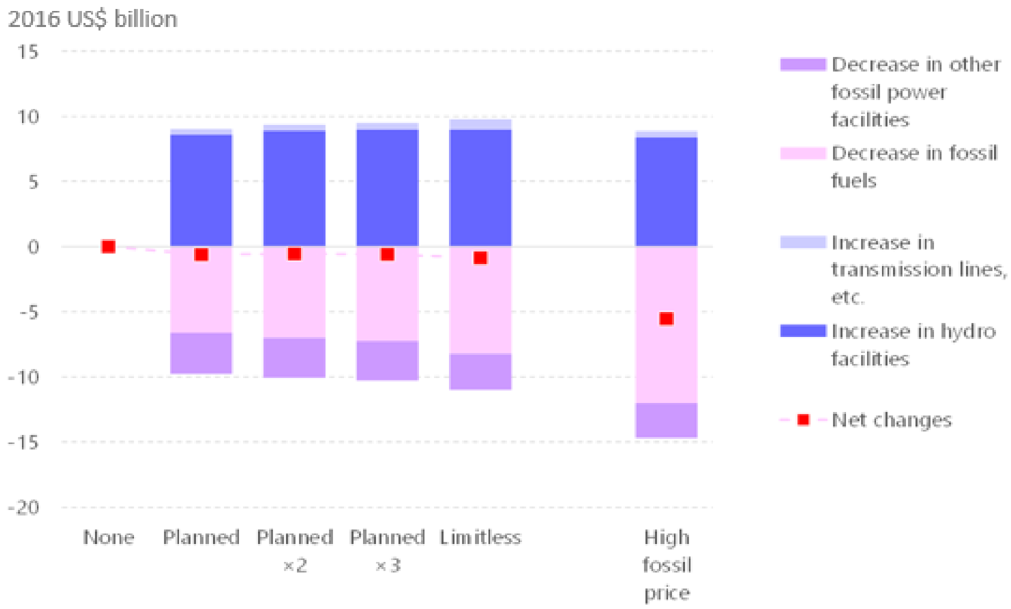
Figure 4.6. Changes in the total annual system cost (eight areas in total): Impact of carbon pricing



VRE = variable renewable energies.
Source: Authors' analysis.

Figure 4.8 shows cases where the capacities of interconnection lines are doubled or tripled compared to the planned levels and when there are no constraints, as well as changes in the total system cost when carbon prices are high. Even though the net benefit grows slightly as the capacity of the interconnection lines increases, the change is smaller than that caused by differences in carbon prices. In the case of high fuel prices, the benefit would be almost as great as when the carbon price is at around US$100/tCO2. It is understood from these results that the economic effect of transmission lines depends strongly on how much fossil fuel prices increase, whilst it can be seen that interconnections between areas are generally possible with transmission lines at the existing planned level.

Figure 4.8. Changes in the total annual system cost (eight areas in total): Capacity of interconnection lines and impact of the fuel price



Source: Authors' analysis.

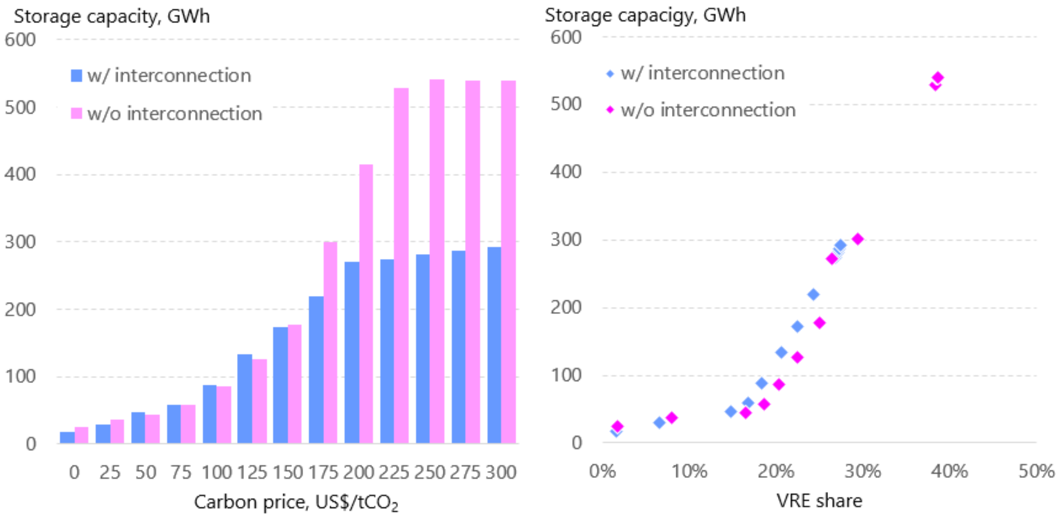
As mentioned above, regardless of whether interconnection lines are in place, the ratio of VRE, led by solar power, rises together with increases in carbon prices. As the VRE ratio increases, the power system needs to become more flexible, and this is where batteries play an important role.

Batteries are considered to play the role of mitigating the risk of power supply disruptions caused by the natural variability of VRE. In other words, it is considered that the required battery capacity, obtained using an optimised model, is calculated as the sufficient energy storage to compensate for the power supply deficit caused by consecutive days with weak sunlight in the case of the solar power generation ratio (Matsuo et al., 2020). Therefore, the required amount of batteries not only indicates the cost of the stabilisation measures necessary for achieving the energy mix but also provides a benchmark for indicating the instability of the energy supply.

The graph on the left-hand side of Figure 4-9 shows the required battery capacity by carbon price. As described previously, the VRE ratio increases along with rises in the carbon price, causing the required amount of batteries to rise as well. In the case of planned transmission interconnection, however, the increase in the required batteries is curbed at the level around which the carbon price exceeds US$200/t$CO_2$. This suggests that a cross-border interconnection line has the effect of decreasing the risk of energy supply breakdown and reduce the energy system cost, especially when achieving high VRE ratios.

The chart on the right-hand side of Figure 4-9 plots battery capacity against the VRE share based on the same estimate results, indicating that the capacity rapidly increases when the VRE share exceeds 15%. In other words, it is possible to integrate a VRE system relatively easily as long as the VRE share falls within a range up to around 15%, whereas the need to secure adjusting capability for batteries rapidly increases when the share exceeds this range because VRE output fluctuations have a great impact on the balance of supply and demand. Therefore, it is important to consider not only the power generation cost but also the costs required for system integration when introducing VRE on a large scale.

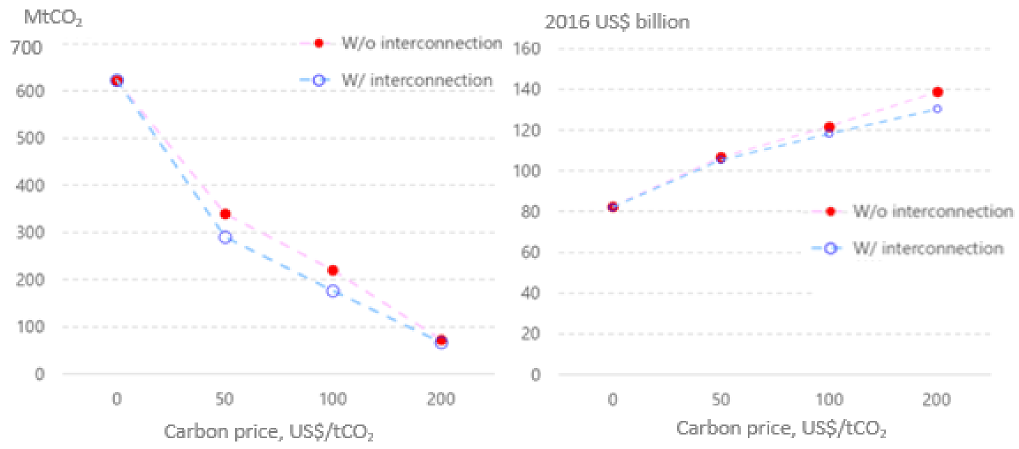
Figure 4.9. Quantity of batteries introduced (eight areas in total)



GWh = gigawatt hour, VRE = variable renewable energies.
Source: Authors' analysis.

Finally, CO_2 emissions depending on the presence of planned interconnection lines were compared with the total annual cost. Figure 4.10 shows a reduction in CO_2 emissions, as well as an increase in the total annual cost along with carbon price rises regardless of whether interconnection lines are present. However, it is understood that utilising interconnection lines contributes to reducing not only CO_2 emissions but also the total annual cost by comparing between cases with and without interconnection lines.

Figure 4.10. Comparison of differences in results depending on the presence of interconnection lines



CO_2 emissions | Total annual cost

Source: Authors' analysis.

1.2. Analysis of other cases

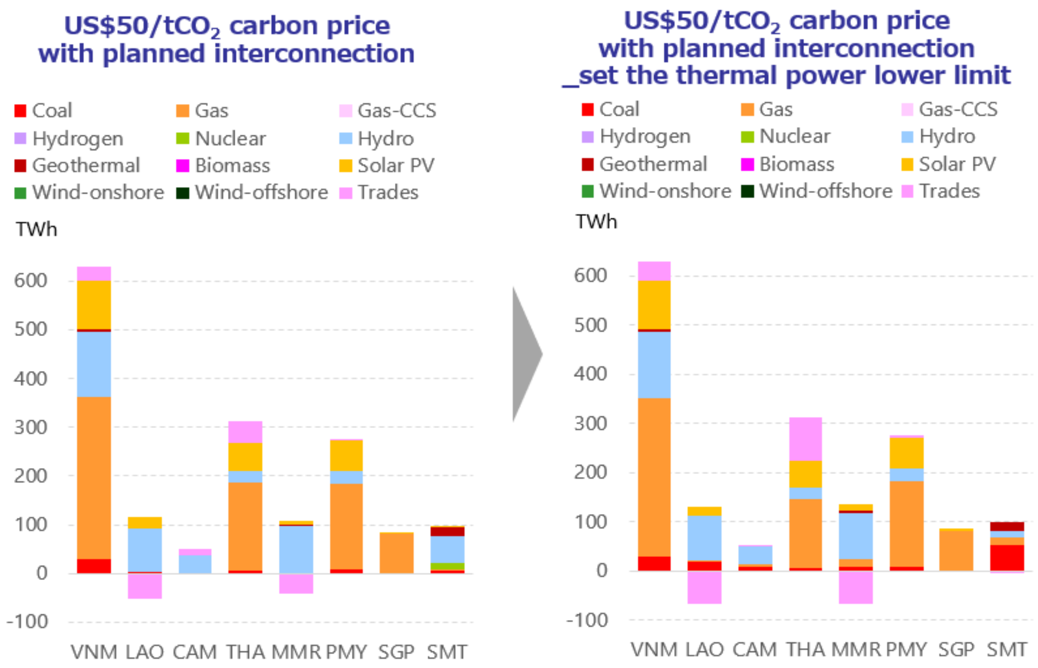
1.2.1. Thermal power lower limit case

In Section 1.3 of this chapter, we showed the power generation mix of each country in the case of a US$50/t$CO_2$ carbon price with planned interconnection (see Figure 4.5). In this case, most electricity is supplied by hydropower in regions such as the Lao PDR, Cambodia, Myanmar, and Sumatra, which have high hydro potentials.

However, this result is not realistic given the current policies of each country and energy security. Each country expects to utilise a certain amount of thermal power as an economical power source in the future to respond to the rapid increase in electricity demand and to utilise hydropower for exporting to earn foreign currency. In addition, hydropower alone cannot meet the electricity demand in the dry season because of the reduction in power generation. Therefore, in this case, the lower limits of thermal power are set in some countries to get closer to a more realistic power generation mix. The lower limits of thermal power are set in the Lao PDR, Cambodia, Myanmar, and Sumatra. The lower limits are based on the amount of thermal power generation in each country without carbon prices.

Comparing the power generation mix and trade flows with and without the thermal power lower limits, the exports from Myanmar, the Lao PDR and Cambodia to Thailand mainly increase and replace gas-fired power in Thailand. On the other hand, the exports from Sumatra to the Malay Peninsula increase only slightly. This is because the cost of the submarine interconnection is high, and it is not economical.

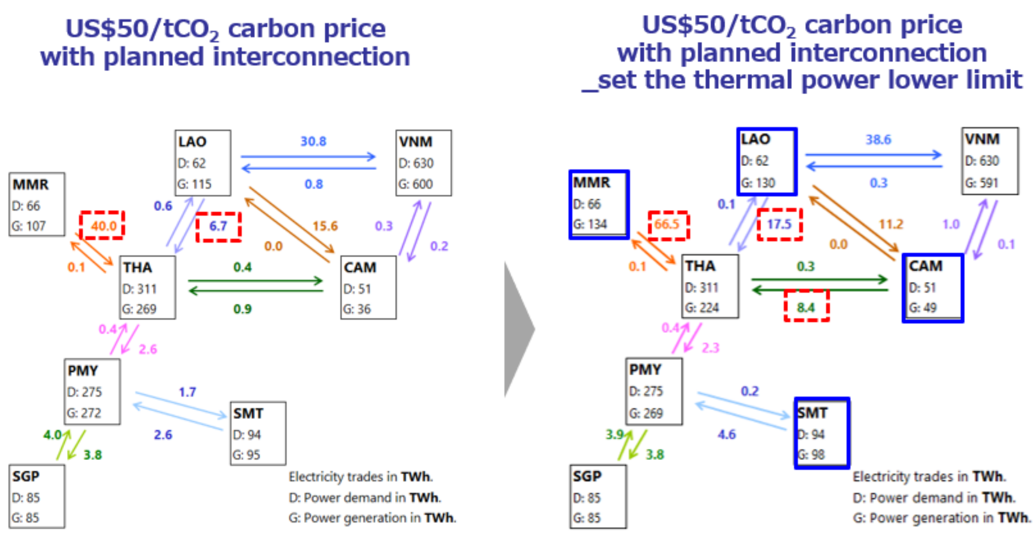
Figure 4.11. Power generation mix with and without thermal power lower limits



CCS = carbon capture and storage, PV = photovoltaic.

Source: Authors' analysis.

Figure 4.12. Trade flows with and without thermal power lower limits



TWh = terawatt hour.

Source: Authors' analysis.

Since thermal power generation would increase in the thermal power lower limit case, CO_2 emissions would also increase from 314 Mt-CO_2 to 369 Mt-CO_2. However, the costs would change little across the entire region. This is considered to bring about an income redistribution effect, since electricity exports would increase from relatively poor nations to relatively rich ones, although CO_2 emissions would increase.

1.2.2. Low solar PV cost case

The levelised cost of electricity (LCOE) of solar power PV is declining sharply worldwide, and further cost reductions are expected in ASEAN. The low solar PV cost case is implemented in order to identify the impact of a cost reduction in solar PV on the power generation mix.

Table 4.1 shows the LCOE of solar PV in each country. For the power generation costs of solar PV in 2050, the Indonesian data from Dewan Energi Nasional (DEN) and the Danish Energy Agency (DEN, 2017) shown in Section 5.1 of Chapter 5 are also applied to all regions, as in 2040. In 2050, the LCOE of solar PV is expected to decrease by 0.6–0.8 cents compared to 2040.

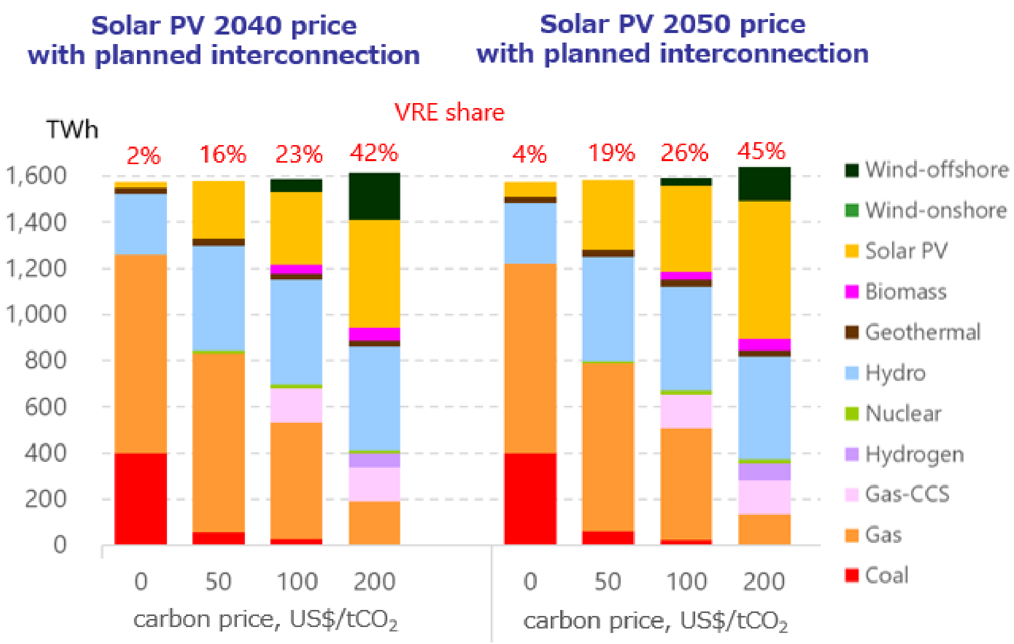
Table 4.1. Assumed LCOE of solar PV (cents/kWh)

Country	CAM	SMT	LAO	PMY	MMR	SGP	THA	VNM
2040	4.4	5.3	4.2	4.6	3.7	4.9	4.4	4.7
2050	3.8	4.5	3.5	3.9	3.1	4.2	3.7	4.0

Source: Authors.

Figure 4.13 shows a comparison of the power generation mix with default (2040) and low (2050) solar PV costs. The VRE share increases slightly with the low assumptions. The reason why the power generation mix does not change largely is that solar PV cannot replace thermal power and hydropower easily because of its low capacity credit.

Figure 4.13. Power generation mix of the 2040 and 2050 solar PV price cases



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Source: Authors' analysis.

1.2.3. High fuel prices case

Increases in coal and gas prices may put additional upward pressure on the costs of coal- and gas-fired power generation plants. As seen in Section 1.2 of this chapter , coal- and gas-fired thermal power accounts for a large share of the power generation mix in target regions, where fuel is at the base price assumptions used in this study and a carbon price has not been introduced. Therefore, a power generation mix and trade flows that are different from those in the base price case could be economically optimal when assuming a future environment in which coal and gas prices fluctuate at a level exceeding the base prices. The high fuel prices case is implemented in order to quantitatively examine the changes.

Table 4.2 shows a comparison of the coal and gas prices in 2040 in the base price assumptions in this study and the high fuel prices case.

Table 4.2. Base price assumptions (left) and high fuel prices (right)

	Malaysia, Singapore	Other regions
Coal (2016 US$/t)	87.8	49.3
Gas (2016 US$/MMbtu)	6.1	

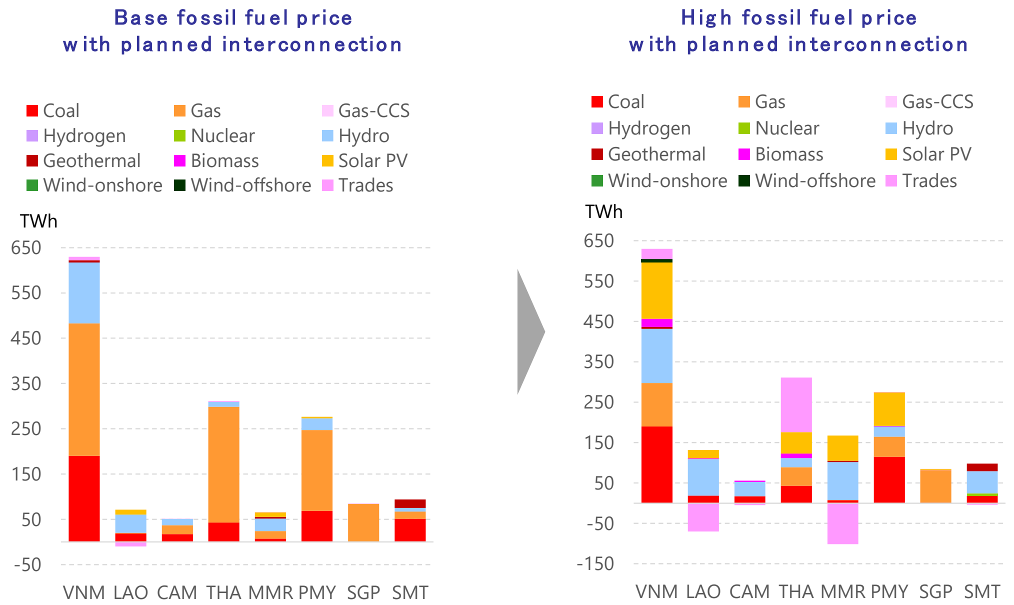
	All regions
Coal (2016 US$/t)	127.1
Gas (2016 US$/MMbtu)	12.7

Source: Authors.

In addition, it is assumed in these cases that a carbon price will not be imposed and that the interconnection capacity will be expanded as planned.

Figure 4.14 shows a comparison of the power generation mix for the base prices (i.e., the case shown in Section 1-2 of this chapter and the high prices.

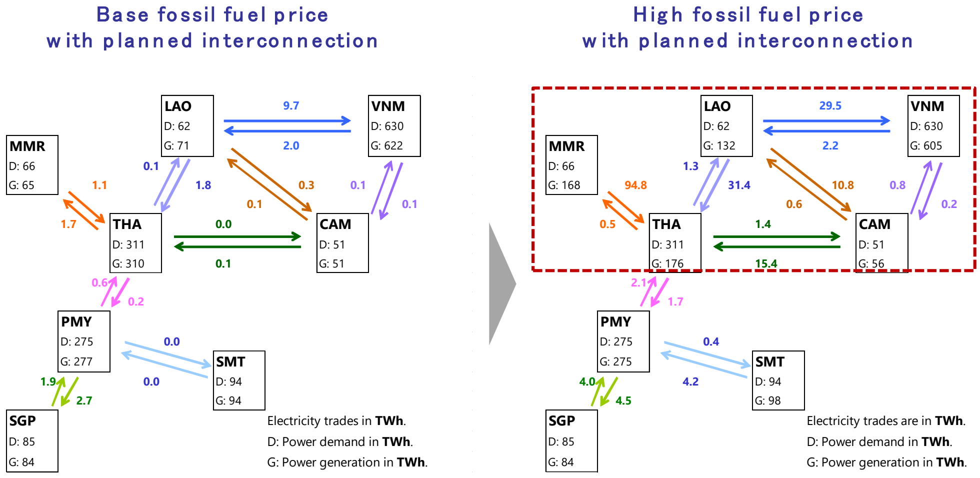
Figure 4.14. Power generation mix in the cases of the base prices and the high fuel prices



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Source: Authors' analysis.

The figure indicates that in this case, whilst the utilisation of renewables will be expanded, the proportion of gas-fired thermal power will decrease due to its increased power generation cost. Figure 4.15 shows a comparison of the trade flows between both cases.

Figure 4.15. Trade flows in the cases of the base prices and high fuel prices



TWh = terawatt hour.
Source: Authors' analysis.

The figure shows that trade flows between some regions have increased in the high prices case. In particular, exports from Myanmar and the Lao PDR have risen remarkably.

Considering the results described above, the high fuel prices case suggests that the securing capacities of interconnections may surely become important from the perspective of economic optimisation in preparation for an increase in trade volume under future price hikes of coal and gas.

1.2.4. Externality case

In general, hazardous substances such as nitrogen oxides (NO_x), sulphur dioxide (SO_x), and particulate material (PM10), which may have adverse impacts on the human body, are generated when burning fossil fuels, such as coal and natural gas. External costs refer to the quantified impacts of such substances on human health. The externality case has been conducted to analyse how the power generation mix would change in the target regions if the external costs were included in the power generation cost.

Even though no uniform method has been established to quantify external costs, values that had been used in a preceding study on external costs for the Indonesian power sector have been referred to (Wijaya and Limmeechokchai, 2010). Table 4.3 shows the assumed external costs in coal- and gas-fired power plants. The costs have been converted to 2016 real prices. In addition, this case assumes that interconnection capacities are equal to planned expansion and that a carbon price is not introduced.

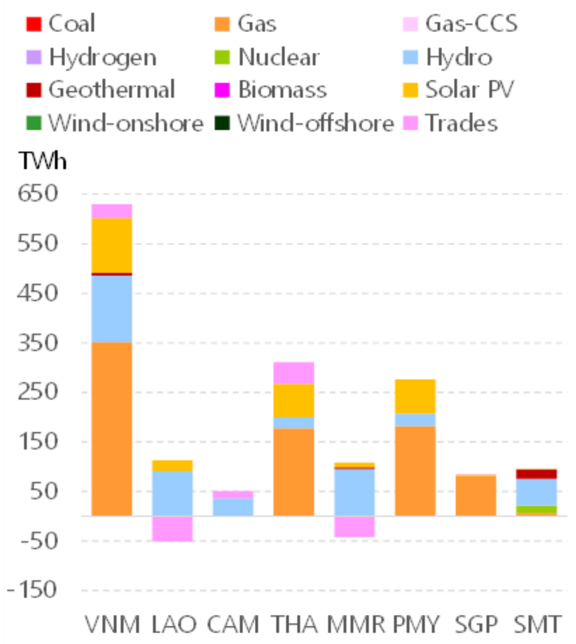
Table 4.3. Assumed external costs

Power plant	SO_x Damage (Cents/kWh)	NO_x Damage (Cents/kWh)	PM_{10} Damage (Cents/kWh)	Total Damage (Cents/kWh)
Coal-fired	6.45	4.67	4.55	15.67
Natural Gas CCGT	negligible	1.90	negligible	1.90

CCGT = combined cycle gas turbine, kWh = kilowatt hour.
Source: Wijaya and Limmeechokchai (2010).

Figure 4.16 shows the power generation mix for the externality case.

Figure 4.16. Power generation mix (externality case)



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Source: Authors' analysis.

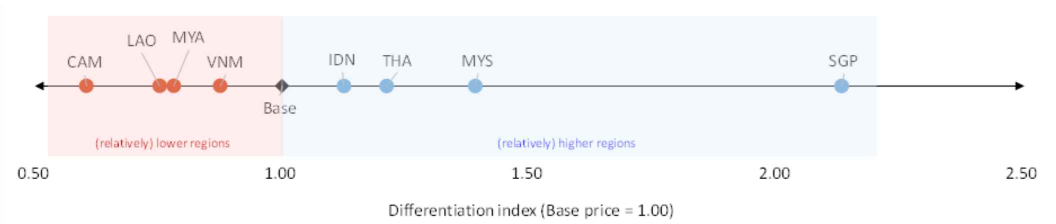
As the figure shows, even under an environment where a carbon price is not introduced, coal-fired power was almost out of the power generation mix due to the increased cost of coal-fired power generation.

1.2.5. Differentiated carbon prices case

In the normal cases where a carbon price is introduced, one price is assumed to be introduced to all target regions. However, there are differences in the levels of actual economic development from region to region, and the impact of carbon pricing on individual regional economies may differ even if the carbon price is the same. In this regard, a case with differentiated carbon prices has been introduced in order to capture the effects when decarbonisation policy measures are introduced at differentiated levels according to the degree of each region's economic development.

In this case, GDP per capita has been adopted as the benchmark for the degree of economic development. Assuming US$50/t$CO_2$ as the base carbon price, higher carbon prices are adopted in regions with relatively higher economic development as of 2040, whilst lower carbon prices are adopted for those with relatively lower GDP per capita. Specifically, taking the natural log of the assumed GDP per capita of each region as of 2040 based on the ERIA Outlook, the assumed carbon prices were differentiated for each region by multiplying the base price by the 'differentiation index', i.e., the ratio of the natural log of GDP per capita of each region with respect to the median value of all regions (Figure 4.17).

Figure 4.17. Differentiation index

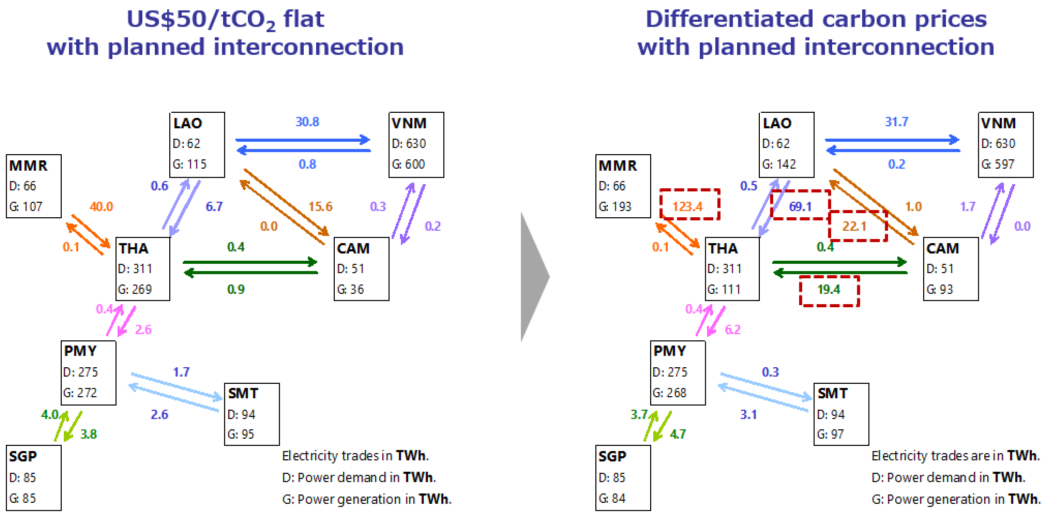


Source: Authors.

In addition, the interconnection capacity is assumed to be equal to the planned expansion in this case.

Figure 4.18 shows a comparison of the trade flows between the case with a uniform carbon price at US$50/t$CO_2$ in all regions (the case in Figure 4.5) and the case with differentiated carbon pricing.

Figure 4.18. Trade flows in the cases of uniform and differentiated carbon prices

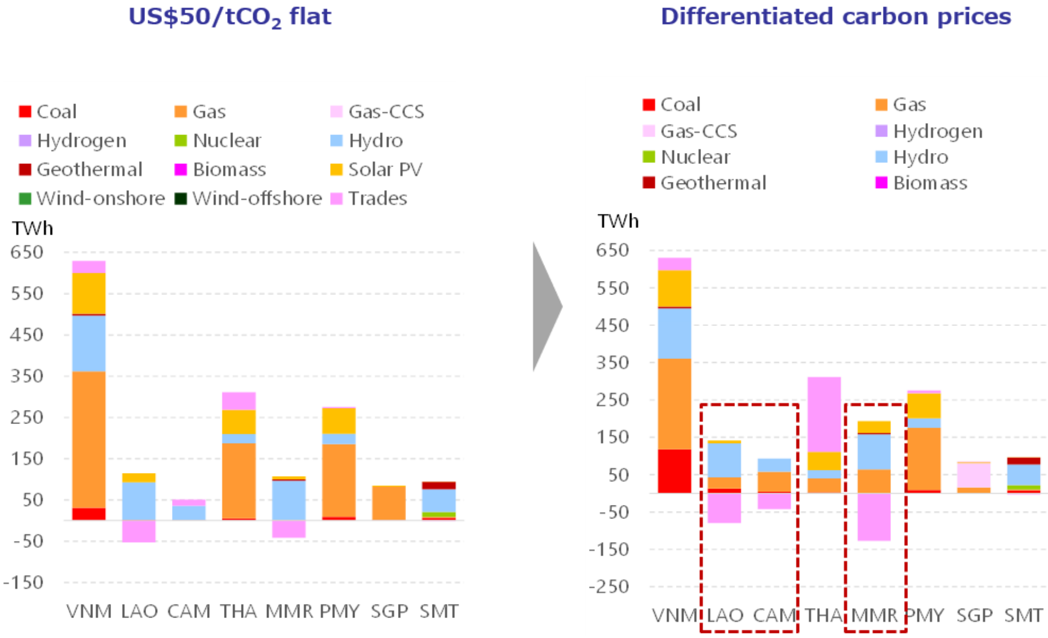


TWh = terawatt hour.
Source: Authors' analysis.

These results show that the exports from the Lao PDR and Cambodia, where relatively lower carbon pricing is adopted, to regions with relatively higher carbon prices would be greater in the case with differentiated carbon pricing.

Figure 4.19 shows a comparison of the power generation mix for both cases. It indicates a result in which Myanmar, the Lao PDR, and Cambodia mainly increase their respective quantities of gas-fired thermal power generation case in order to increase their exports.

Figure 4.19. Power generation mix for the cases with uniform and differentiated carbon prices



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Source: Authors' analysis.

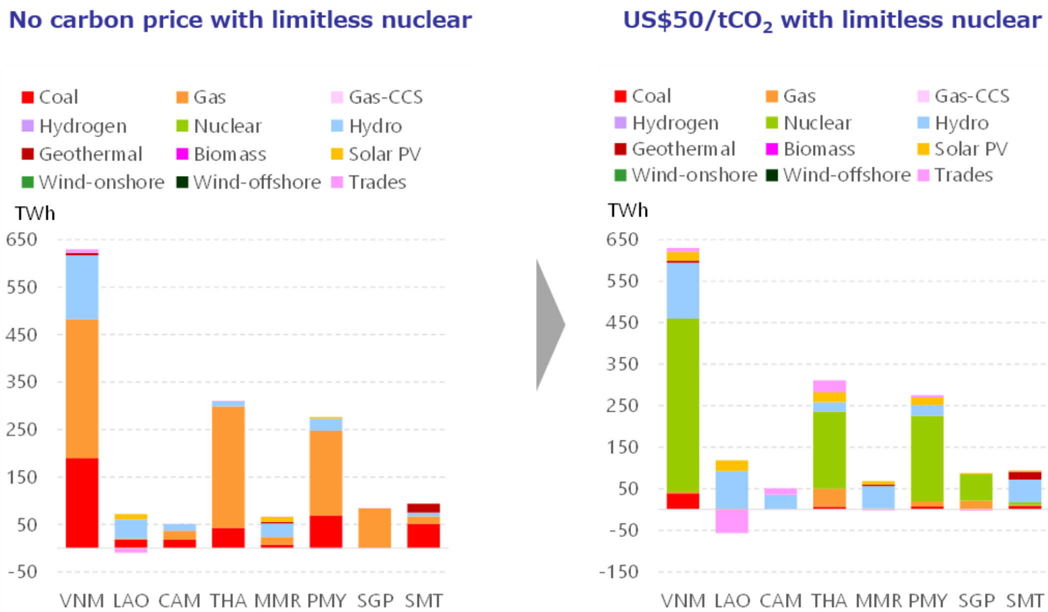
There are two points to consider suggested by the results described above. First, if the intensity of environmental policies differ by region, at least from the perspective of cost optimisation, securing the capacities of interconnection would become important for coping with some of the increase in the trade volume. Second, income redistribution would be enhanced within these regions in that more economically developed regions will import electricity from less economically developed regions and pay the price to them. At the same time, it should be noted that less economically developed regions increase non-CCS gas-fired power generation in order to increase their export amounts, resulting in an increase in CO_2 emissions.

1.2.6. Nuclear capacity limitless case

Nuclear power plants present social and technical problems in their construction and safe operation, even though their environmental load is low. In reality, such shortcomings have led to significant constraints for nuclear power plant construction, and based on the assumptions of this study, the utilisation of nuclear power generation will remain limited.

As such, an analysis has been conducted with an extreme assumption that unlimited nuclear capacities could be built, in order to make it easier to capture the impacts of the additional construction of nuclear power plants on the power generation mix, CO_2 emissions, and electricity costs in the target regions. The carbon price is assumed at US\$0/tCO_2 and US\$50/tCO_2. Figure 4-20 shows the power generation mix for these cases.

Figure 4-1. Power generation mix with carbon prices of US\$0/tCO_2 and US\$50/tCO_2

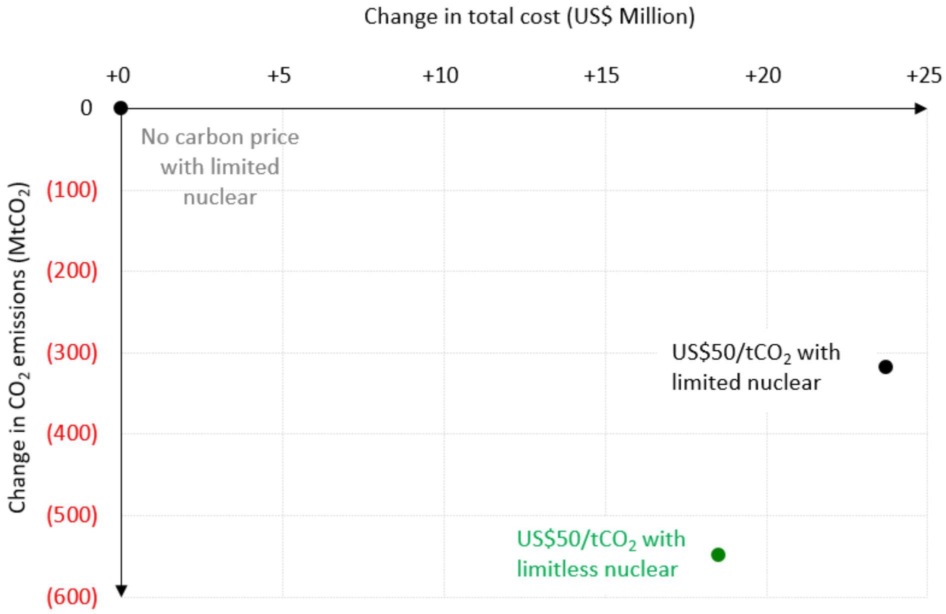


CCS = carbon capture and storage, PV = photovoltaic.
Source: Authors' analysis.

It is understood from the figure that nuclear power does not appear in the power generation mix with a carbon price of US\$0/tCO_2 because of its higher LCOE than those of coal, gas, and hydro power generation. With a carbon price of US\$50/tCO_2, however, the LCOE of nuclear power generation becomes lower than that of coal- and gas-fired power generation. Therefore, nuclear power is introduced to reach a share of 56% in the power mix. It should be also noted that the construction of nuclear power plants is not necessarily a feasible option in all regions. In particular, the result shows that the economic feasibility of nuclear power is reduced in regions that are rich in hydro and geothermal resources, such as the Lao PDR, Cambodia, Myanmar, and Sumatra.

The next point to consider is how the electricity cost and CO_2 emissions change in this case, compared with the case of limits on the additional construction of nuclear power plants as per the assumptions of this study (the case in Figure 4-5 above). Figure 4.21 plots how the electricity cost and CO_2 emissions vary in both cases with a carbon price of US\$50/tCO_2, compared with the case with limited construction without a carbon price (see Section 1.2 of this chapter).

Figure 4.21. Change in total cost and CO_2 emissions



Source: Authors' analysis.

The figure indicates that both the electricity cost and CO_2 emissions are lower in the case without restrictions on the construction of additional nuclear power plants compared with the case with such a restriction.

There are two points to consider that are suggested by the results described above. First, the penetration of nuclear power could be enhanced in the target regions from the perspective of optimising economics as the carbon price increases, based on the assumptions in this study. Second, the electricity cost and CO_2 emissions could be reduced by incorporating much more nuclear power generation into the power generation mix in cases with strong decarbonising policy measures. As mentioned above, it is difficult in reality to build a very large number of nuclear power plants due to various intrinsic problems. In future energy and environmental policies, however, nuclear power may be a feasible option to reduce costs and CO_2 emissions.

1.3. Analysis of individual areas and realistic cases

This subsection proposes calculation results for individual regions with different diffusions of solar PV. Here, we develop several cases for existing and planned grid interconnection. The 'base' cases are those without a carbon price, as shown in Section 1.1 and 1.2 of this chapter. Starting from these cases, we raised the share of solar PV to 10%–40%, and calculated the energy mix and the total annual cost. Additionally, we showed the results of 'advanced' policy cases, which are equivalent to cases with a carbon price of US$50/$tCO_2$ and with lower limits of thermal power generation, shown in Section 2.1 of this chapter.

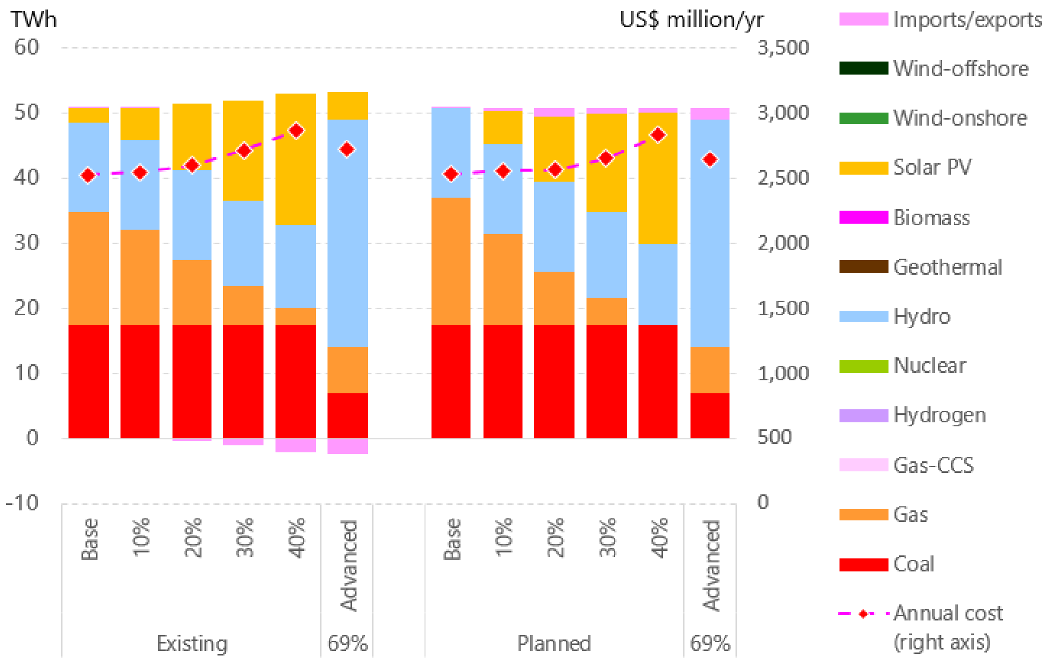
1.3.1. Cambodia

As Figure 4.22 shows, in Cambodia, natural gas- and coal-fired power accounts for about 70% of the total power generation in the base cases. With planned grid interconnection, annual net electricity imports increase almost two times from 54 GWh to 102 TWh. Because of the induced declines in electricity prices, the share of thermal power (coal and natural gas) increases slightly from 69% to 73%, and the optimal share of solar PV declines from 4% to lower than 1%.

With increasing shares of solar PV, the total annual cost increases. With existing interconnection capacities, it increases from US$2,522 million/year in the base case to US$2,863 million/year with a 40% solar PV share.

With advanced policies, the share of renewables expands, whilst the share of thermal power declines to 27%. With existing interconnection capacities, the share of solar PV rises to 9%, whilst that of hydro rises to 69%. With planned grid interconnection, however, the share of solar PV remains less than 1% because of increasing electricity imports from other regions.

Figure 4.22. Power generation mix and the total annual cost in Cambodia



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Note: Percentages indicate the solar PV share. 'Optimal' and 'advanced' represent cases without and with strong policy measures.
Source: Authors' analysis.

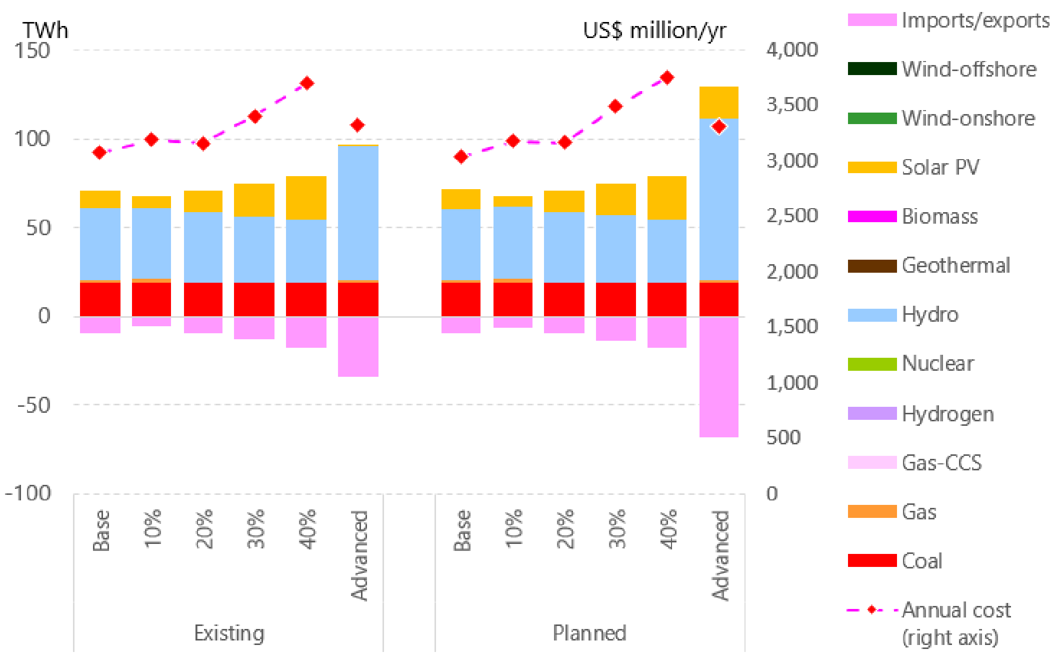
1.3.2. Lao PDR

As Figure 4-23 shows, in the Lao PDR, in the base case with existing grid interconnection, hydropower accounts for 65% of total power generation, whilst thermal power accounts for 34%. With planned grid interconnection, the share of solar PV increases slightly from 16% to 18%, with net electricity exports increasing from 9,165 GWh to 9,671 GWh.

As the optimal shares of solar PV in the base cases are relatively high at 16%–18%, the total annual cost is higher with a solar PV share of 10% (US$3,192 million/year), than with that of 20% (US$3,158 million/year). However, with an even higher solar PV share, the total cost soars: it reaches US$3,700 million/year with a 40% solar PV share with existing grids.

With advanced policies, the share of renewables expands from 81% to 123% with existing grids. As hydropower generation increases to be exported to other regions, the share of solar PV declines to almost zero. However, with planned grid interconnection, the shares of hydro and solar PV rise to 147% and 30%, respectively, and net annual exports amount to 68 TWh.

Figure 4.23. Power generation mix and the total annual cost in the Lao PDR



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Note: Percentages indicate the solar PV share. 'Optimal' and 'advanced' represent cases without and with strong policy measures.
Source: Authors' analysis.

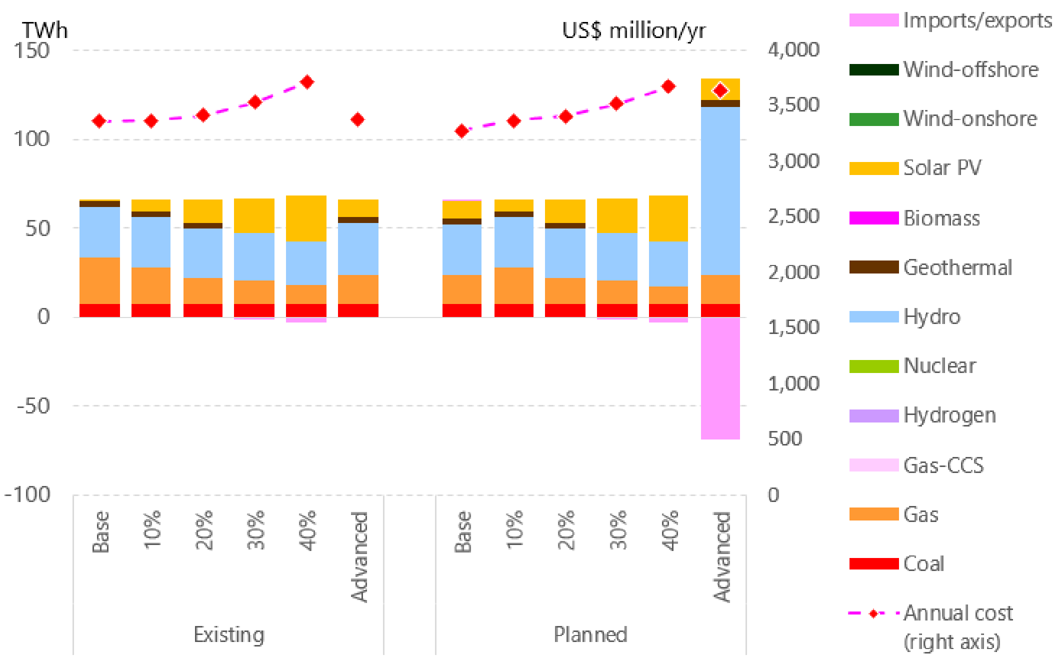
1.3.3. Myanmar

As Figure 4.24 shows, in Myanmar, with the existing grid interconnection, hydropower accounts for 42% of total power generation, whilst thermal, solar PV, and geothermal account for 51%, 1%, and 5%, respectively. However, as electricity prices are lower than in other regions, because of the assumed coal prices, the share of thermal power declines to 36% with the planned grid interconnection because of higher electricity prices.

With increasing shares of solar PV, the total annual cost increases from US$3,362 million/year in the base case to US$3,710 million/year with a 40% share of solar PV with existing grids.

With advanced policies and the existing grids, the share of thermal power declines to 36%, whilst that of solar PV and hydro rise to 15% and 44%, respectively. With the planned grid interconnection, the maximum hydropotential is utilised; the share of hydropower rises to 143%, and annual net exports expand to 69 TWh. However, we should note that this is the case only with affordable costs of grid interconnection lines, under the assumption that large hydro potential is exploited at reasonable costs.

Figure 4.24. Power generation mix and the total annual cost in Myanmar



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.

Note: Percentages indicate the solar PV share. 'Optimal' and 'advanced' represent cases without and with strong policy measures.

Source: Authors' analysis.

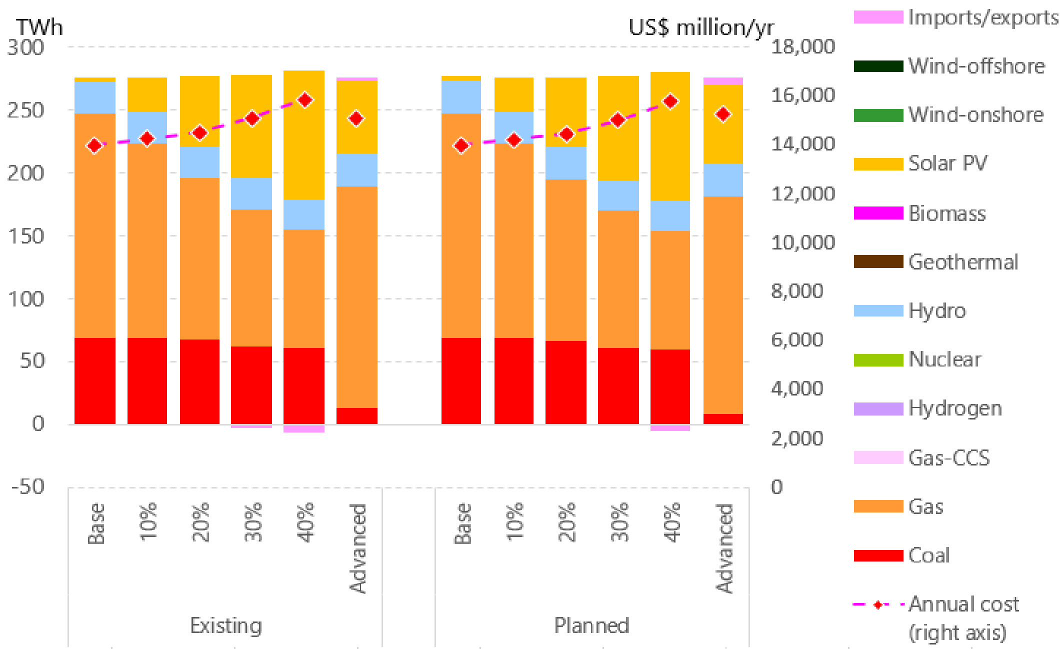
1.3.4. Peninsular Malaysia

As Figure 4.25 shows, in Peninsular Malaysia, in the base case, thermal power accounts for 90%, and the rest is mainly supplied with hydropower, with the share of solar PV at 1%. The results are hardly different for the existing and planned grid interconnection capacities.

The total annual cost increases with the increasing share of solar PV. It rises from US$30,585 million/year in the base case to US$36,323 million/year in the 40% case. With higher solar shares, net annual exports slightly increase and reach 5 TWh in the 40% case.

With advanced policies, the share of solar PV rises to 21% and 23% with the existing and planned grid interconnection capacities, respectively, and the share of coal power generation declines to 9% in both cases.

Figure 4.25. Power generation mix and the total annual cost in Peninsular Malaysia



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.

Note: Percentages indicate the solar PV share. 'Optimal' and 'advanced' represent cases without and with strong policy measures.

Source: Authors' analysis.

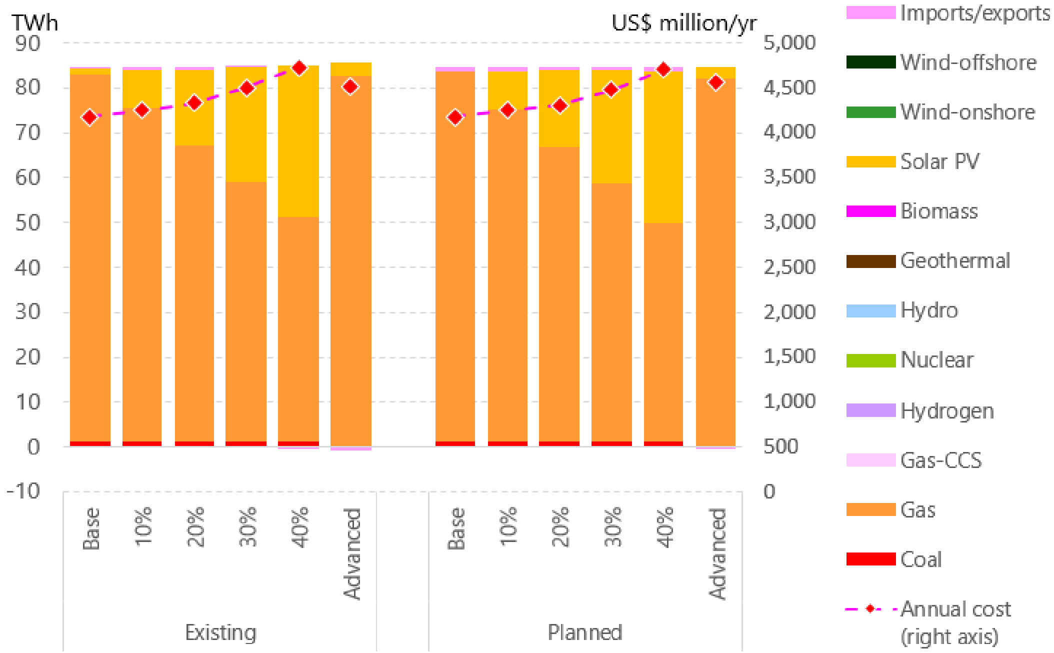
1.3.5. Singapore

As Figure 4.26 shows, in Singapore, natural gas-fired power generation accounts for 97%–98% in the base cases. With existing grids, the share of solar PV is 1%, which declines to nearly 0% with the planned grid interconnection, induced by net imports from Peninsular Malaysia. With increasing shares of solar PV, the total annual cost increases from

US$4,175 million in the base case to US$4,732 million in the 40% solar case. Net annual exports also rise to 400 GWh.

With advanced policies, the share of coal declines from 1% in the base case to 0%, and the share of solar PV rises to 3%, both with the existing and planned grids. Although net exports in the advanced policies case with existing grids expand to 928 GWh, they are much smaller, at 108 GWh, with the planned grid interconnection because the neighbouring region, Peninsular Malaysia, is supplied more with imports from Thailand.

Figure 4.26. Power generation mix and the total annual cost in Singapore



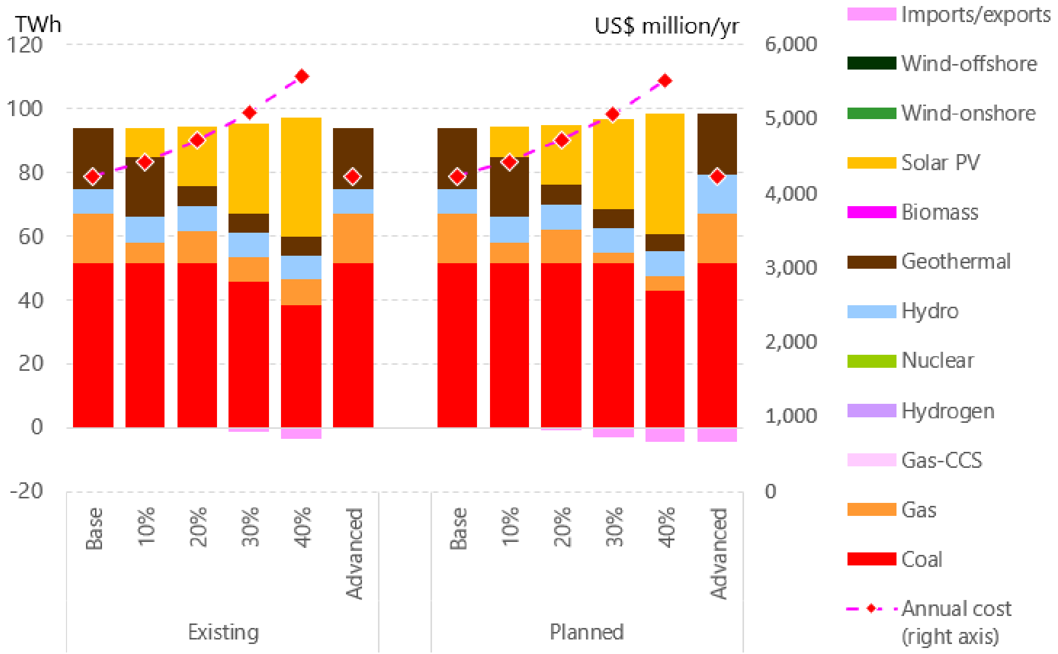
CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Note: Percentages indicate the solar PV share. 'Optimal' and 'advanced' represent cases without and with strong policy measures.
Source: Authors' analysis.

1.3.6. Indonesia (Sumatra)

As Figure 4.27 shows, in Sumatra, in the base cases, thermal power generation accounts for 71% of total power generation, whilst geothermal and hydro account for 20% and 9%, respectively. With an increasing share of solar PV, the shares of thermal and geothermal decline significantly. In the 40% solar PV case with the existing grids, the thermal share declines to 50%, and the geothermal share declines to only 6%. With the planned grid interconnection, the share of thermal power rises to 51%, with a larger share of coal at 46%, and larger net exports of 4,392 GWh in the 40% solar PV case.

With advanced policies, the power generation mix does not change much with the existing grids because a large amount of electricity is already supplied by renewable energies (hydro and geothermal) in the base case. With the planned grid interconnection, the share of hydropower rises to 13%, with large net annual exports of 4,483 GWh.

Figure 4.27. Power generation mix and the total annual cost in Sumatra



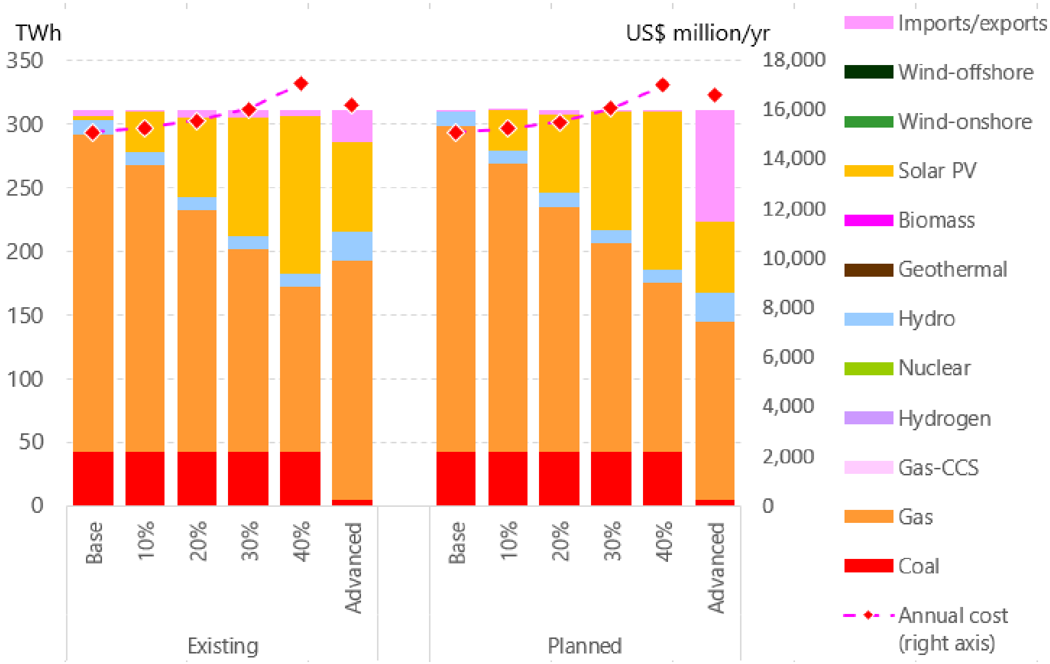
CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.
Note: Percentages indicate the solar PV share. 'Optimal' and 'advanced' represent cases without and with strong policy measures.
Source: Authors' analysis.

1.3.7. Thailand

As Figure 4.28 shows, in Thailand, natural gas and coal power generation account for 80% and 14%, respectively, in the base case with the existing grids; hydro and solar PV account for only 3% and 1%, respectively. The picture does not change significantly with the planned grid interconnection. The total annual cost increases with a rising share of solar PV, from US$15,111 million/year in the base case to US$17,063 million/year in the 40% solar PV case.

With advanced policies, the share of solar PV remarkably expands to 23% with the grid interconnection, associated with net annual imports of 25 TWh. In this case, the share of thermal power declines to 62%. With the planned grid interconnection, net imports reach 88 TWh, with smaller shares of solar PV and thermal power at 18% and 47%, respectively.

Figure 4.28. Power generation mix and the total annual cost in Thailand



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.

Note: Percentages indicate the solar PV share. 'Optimal' and 'advanced' represent cases without and with strong policy measures.

Source: Authors' analysis.

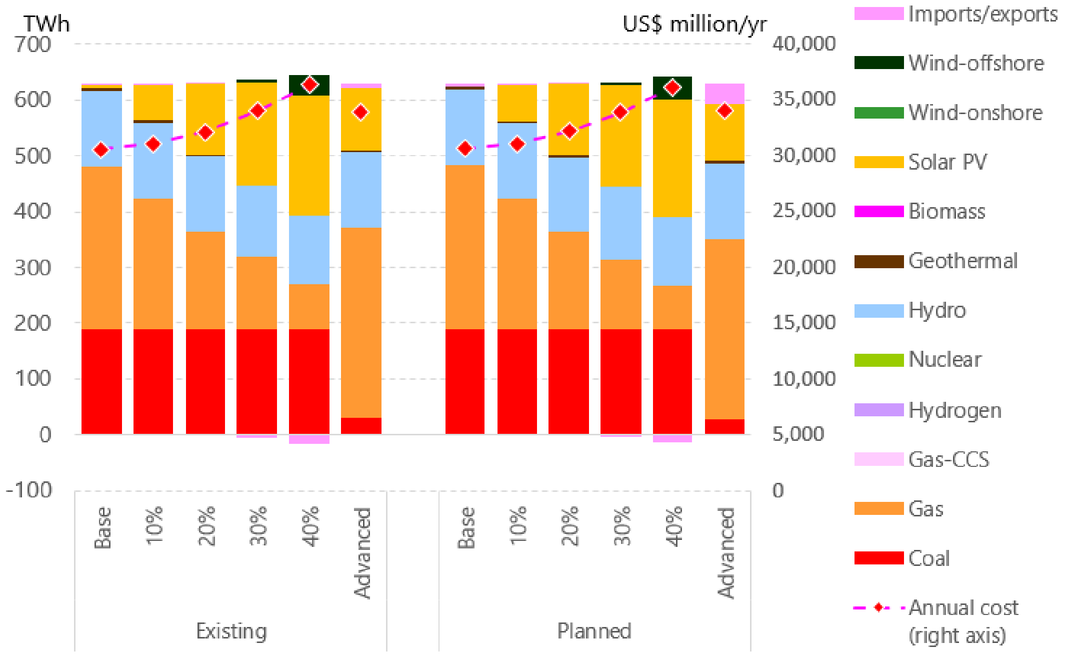
1.3.8. Viet Nam

As Figure 4.29 shows, in Viet Nam, thermal power and hydro account for 76% and 21%, respectively, in the base case with the existing grids. This energy mix does not change much with the planned grid interconnection, with the thermal share only slightly increasing to 77%. The share of solar PV is 1% and 0% with the existing and planned grid interconnection, respectively.

With the existing grid interconnection, the total annual cost increases from US$30,585 million/year in the base case to US$36,323 million/year in the 40% solar PV case. The results imply that offshore wind power will be introduced with high shares of solar PV because the two technologies are complementary, generating electricity at different times.

With advanced policies, the thermal share declines to 59%, whilst the solar PV share increases to 18% if we assume only the existing grids. Net annual imports are relatively small at 8 TWh in this case. With the planned grid interconnection, net imports expand to 39 TWh, with lower shares of thermal power and solar PV at 56% and 16%, respectively.

Figure 4.29. Power generation mix and the total annual cost in Viet Nam



CCS = carbon capture and storage, PV = photovoltaic, TWh = terawatt hour.

Note: Percentages indicate the solar PV share. 'Optimal' and 'advanced' represent cases without and with strong policy measures.

Source: Authors' analysis.