

ASIA
INVESTOR
GROUP
ON
CLIMATE
CHANGE



Power of ASEAN

Accelerating clean energy
in Vietnam and Indonesia

About AIGCC

The Asia Investor Group on Climate Change (AIGCC) is an initiative to create awareness and encourage action among Asia's asset owners and financial institutions about the risks and opportunities associated with climate change and low carbon investing.

AIGCC provides capacity for investors to share best practice and to collaborate on investment activity, credit analysis, risk management, engagement and policy. With a strong international profile and significant network, AIGCC represents the Asian investor perspective in the evolving global discussions on climate change and the transition to a greener economy. AIGCC has over 50 members from 13 markets representing over \$US26 trillion in assets under management.



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GLOSSARY

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|-----------------------|---|----------------|--|
| ADB | Asian Development Bank | mmbtu | million British thermal unit |
| AQCS | Air Quality Control Systems | mmb/d | million barrels/day |
| BAU | Business-As-Usual | MT | million tonnes |
| CAGR | Compounded average annual rate | mtpa | million tonnes per annum |
| CCGT | Combined Cycle Gas Turbine | MO | Market Operator |
| CCS | Carbon Capture and Storage | MW | Mega Watt |
| China Eximbank | China Export-Import Bank | MWh | Mega Watt-hour (10 ⁶ Wh) |
| DPPA | Direct power purchase agreements | NDC | Nationally Determined Contribution |
| ESG | Environment, Social and Governance | NEDA | New Enhanced Dispatch Arrangement |
| ETM | Energy Transition Mechanism | NIMBY | not in my backyard |
| EVN | Electricity of Vietnam | O&M | Operation and Maintenance |
| FIT | Feed-in Tariff | OCGT | Open Cycle Gas Turbine |
| FOM | Fixed operating & maintenance cost | PDP | Power Development Plan |
| GWh | Giga Watt-hour (10 ⁹ Wh) | PLN | Perusahaan Listrik Negara |
| IPP | Independent Power Producer | PPA | Power Purchase Agreement |
| JBIC | Japan Bank for International Cooperation | PJM | Pennsylvania-New Jersey-Maryland Interconnection |
| JICA | International Cooperation Agency of Japan | RE | Renewables |
| KEXIM | Korea Export-Import Bank | RUPTL | Electricity Supply Plan |
| KDB | Korea Development Bank | SLA | Service Level Agreement |
| kWh | Kilo Watt-hour (10 ³ Wh) | SRMC | Short-Run Marginal Cost |
| kt | Thousand tonnes | TNB | Tenaga Nasional Berhad |
| ktpa | Thousand tonnes per annum | TWh | Terra Watt Hour (10 ¹² Wh) |
| LRMC | Long-run Marginal Cost | T&D | Transmission and Distribution |
| m | Million (10 ⁶) | VOM | Variable Operating & Maintenance cost |
| MEMR | Ministry of Energy and Mineral Resources | WACC | Weighted Average Cost of Capital |

Executive Summary

In 2020-2030, the Association of Southeast Asian Nations (ASEAN)'s economy and power consumption are expected to grow rapidly. Based on the latest Power Development Plans (PDPs) in ASEAN, coal capacity is still expected to expand quickly to meet demand growth even though ASEAN governments are increasingly seeking to shift their energy mix towards renewable sources. **We estimate that nearly 50% of incremental demand in 2020-2030 will be met by coal generation.** As a result, carbon dioxide (CO₂) emissions will continue to increase in the power sector, from 613 million tonnes (MT) in 2020 to 925 MT in 2030, at an annual growth rate of 4.2%. This does not align with the global de-carbonization trend nor domestic long-term decarbonisation targets.

ASEAN is endowed with strong solar resources and, in selected locations, good wind resources. **Based on our quantitative assessment, the cost of building new solar and wind capacity is cheaper than building new coal/gas capacity in ASEAN.** The recent increase in coal and gas/LNG price further improves the comparative economics of solar, wind and other renewables (REs). We analyse data on the ground to refine the Business-as-usual (BAU) case, highlighting the divergence between top-down ambitions of reaching net carbon zero in 2050/2060 and action on the ground.

As the increase in carbon emissions in the power sector in Indonesia and Vietnam is expected to account for more than 70% of the total cumulative carbon emission in the power sector in ASEAN in 2020-2030, we focus our analysis on these two countries. We simulate alternative power capacity and generation mix scenarios based on the economics of building new solar/wind capacity and thermal capacity, the impact of COVID-19 on demand growth and greater initiatives on energy efficiency. The results confirm that:

- **Higher solar and wind penetration can lower the average system cost in both countries, whilst meeting demand growth.** The stability of power supply is not compromised under this scenario.
- In Indonesia, about 30 GW of solar and 4-12 GW of wind capacity can economically enter the power system by 2030, five times or more of the capacity planned under the latest draft of RUPTL (Electricity Supply Plan)¹ 2021-2030.
- In Vietnam, about 40 GW of solar and 41-45 GW of wind capacity can enter the power system by 2030. This doubles the capacity planned under the draft Power Development Plan 8 (PDP8d).
- **Should current thermal capacity under construction over the next 3 years be completed, demand growth in the forecast period of 2020-2030 can be fully met from renewables addition in 2025-2030.** This is particularly true for Indonesia as the local power sector is well supplied in the coming years. Pushing for more thermal capacity will exacerbate the oversupply and lead to higher system costs.

1. As of publication, the final RUPTL is released on October 5, 2021. In the final RUPTL, for the period of 2021-2030, total coal capacity addition is slightly increased from 13.6 GW in the draft version to 13.8 GW in the final version, gas capacity addition is reduced from 7.5 GW to 5.8 GW, solar capacity addition is reduced from 6.0 GW to 4.7 GW, geothermal capacity addition is increased from 2.4 GW to 3.4 GW and hydro capacity addition is increased from 9.0 GW to 10.4 GW.

- Our alternate optimisation scenarios, which take costs into account, produce CO2 emissions 20-40% below BAU in Indonesia and 26-51% below BAU in Vietnam by 2030. Furthermore, **CO2 emissions in the power sector peak in 2025 in Indonesia and 2027 in Vietnam**. Reducing the cost of wind projects and pushing ahead with energy efficiency programs will be key to help achieve this.
- **As more solar and wind capacity enters the system, existing gas, large hydro, pumped storage and battery energy storage capacity will need to be run more flexibly.** They need to be ramped up and generate more during 5-10PM, which are the new peak hours after large amount of solar capacity enters the system.

There are still multiple barriers for the economic entry of solar and wind capacity in ASEAN: (1) Regulated Power Market without non-discriminatory Transmission and Distribution (T&D) access and transparent dispatch protocol, a barrier to off-site green corporate PPAs (2) lax emissions standards for CO2 and non-carbon air pollutants; (3) Misalignment of benefits and costs or adverse side-effects; (4) Limited risk tolerance for potential RE investors and lenders.

To mitigate these barriers, we provide the below recommendations:

- **Power market reform should be rolled out widely, similar to what was implemented in Singapore and the Philippines.** T&D assets need to be unbundled from the competitive generation and retail segment, their tariff independently set and non-discriminatory access provided to all generators. Such changes can set up a robust system and process to allow for green corporate PPAs. Ideally, independent entities are also set up for system and market operation; and dispatch of power capacity based on economic and non-discriminatory dispatch protocols. Subsidies for fossil fuels and thermal capacity should also be removed to provide the right investment signal and incentivise end-users to improve their energy efficiency. Furthermore, the removal of those subsidies can help to improve the financial positions and hence credit ratings of government-owned local utilities. This can then help to reduce the counterparty risks of RE developers who sign long-term power purchase agreements with those local utilities in ASEAN.
- **With the help of international organisations, comprehensive studies can be carried out to revise outdated environmental government regulations to align with international best practices.**
- **Test out new mechanisms to incentivise coal retirement and enable a just transition².**
- **Install a stable and transparent regulatory framework for renewables investment.** International Organizations, multilateral banks and other financial institutions can also help to de-risk RE projects by providing credit enhancement mechanisms to the local utilities.

2. An example is The Energy Transition Mechanism, which proposes a Carbon Reduction Facility (CRF) and a Clean Energy Facility (CEF), to help address this financing gap to move away from coal and accelerate the energy transition in developing countries ([How to accelerate the energy transition in developing countries](#) | World Economic Forum)
ADB is currently conducting a feasibility study on the ETM in 3 Southeast Asian countries

1. INTRODUCTION

ASEAN power markets, outside of Singapore and the Philippines, are still highly regulated, resulting in governments and the vertically integrated power utilities having a strong influence on future capacity investment via their drafting of the Power Development Plans (PDPs). The Power Development Plans sets out the country's projections on electricity demand growth, future required capacity addition by technology and associated power infrastructures to meet the demand growth and other policy aims. Investors can often only invest in the capacity and the technologies that are within the latest Power Development Plans (PDPs) in most ASEAN countries.

Based on the existing PDPs, ASEAN carbon emissions from the power sector is expected to grow at an annual rate of 4.2% in 2020-2030. But the current PDPs have not fully incorporated the impact of COVID-19 on power demand growth, and most do not align with the global decarbonisation trend and the local long-term net-zero emissions ambitions. This report aims to objectively establish a new BAU scenario with ASEAN's probable CO₂ emission trajectory by refining key assumptions of the PDPs. It also provides a deep dive into the power markets in Indonesia and Vietnam as they will account for more than 70% of the incremental carbon emission in ASEAN in 2020-2030, with the simulation of alternative power generation mix scenarios based on the economics of building new solar/wind capacity and thermal capacity. The report sets out our research, analysis and findings as follows:

- Chapter 2 discusses the existing PDPs and provides a bottom-up assessment on the Indonesian RUPTL (Electricity Supply Plan) 2021-2030 and Vietnam PDP 8 draft.
- Chapter 3 quantitatively assess the economics of building solar, wind, coal and gas capacity in the ASEAN market based on the Total Value Framework, which considers the three value aspects of generation technologies – Cost, Sustainability and Security.
- Chapter 4 discusses the detailed modelling results for the alternative scenarios and conclude that large-scale deployment of solar and wind capacity is economical in Indonesia and Vietnam and can meet demand growth.
- Chapter 5 discusses key barriers for the economic entry of renewable capacity and proposes solutions to mitigate them.

2. REVIEW OF POWER DEVELOPMENT PLANS IN ASEAN

2.1. EXISTING GOVERNMENT POWER DEVELOPMENT PLANS IN ASEAN

In 2010-20, driven by healthy economic growth, ASEAN's power market grew 4.5% annually to reach roughly 1000 TWh, which is about the same market size as Japan and four times larger than the Australian power market. Coal capacity increased from 33 GW in 2010 to 92 GW in 2020, meaning that a mid-size coal plant (500 MW) was commissioned every month on average (Figure 1). Coal capacity is utilized as base-load capacity and run most of the hours throughout the year. **Thus, over the 10 year period, coal alone accounted for 74% of the incremental generation, and its share increased from 27% in 2010 to 43% in 2020** (Figure 2). CO2 emissions from the power sector increased correspondingly from 0.37 billion tonnes (gigatons, GT) in 2010 to 0.60GT in 2020, with Indonesia and Vietnam accounting for 72% of the increase. Coal accounts for a substantially higher portion of generation than that of installed capacity as it is dispatchable and has lower short-run marginal cost than gas-based capacity.

Figure 1: Capacity Fuel Mix in ASEAN Countries, 2010-2020

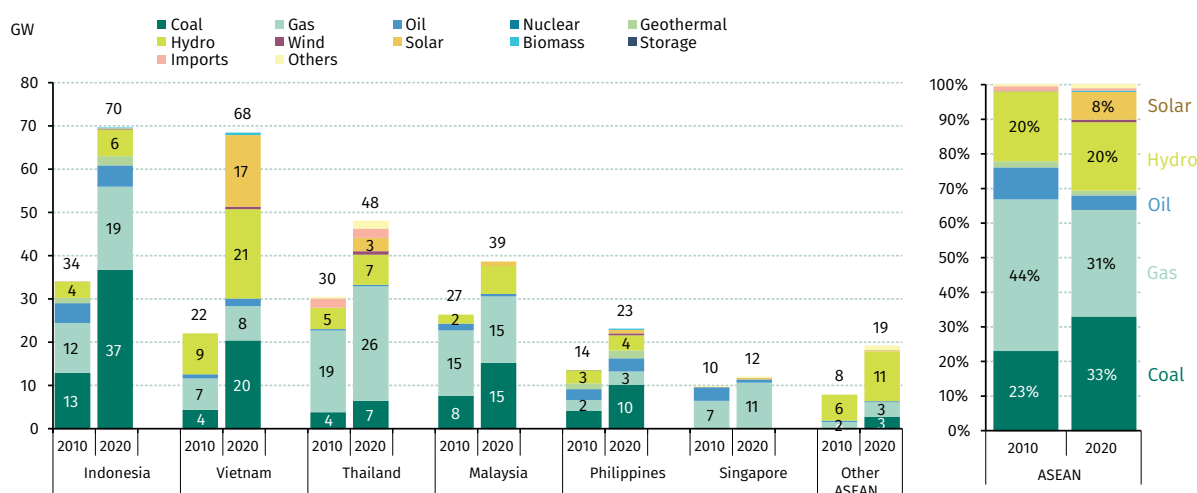
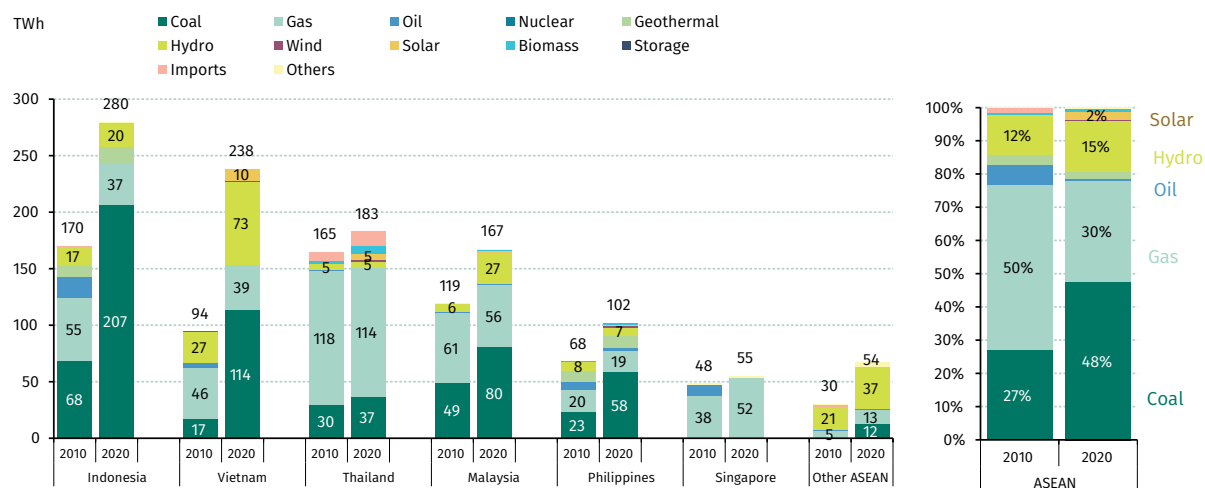


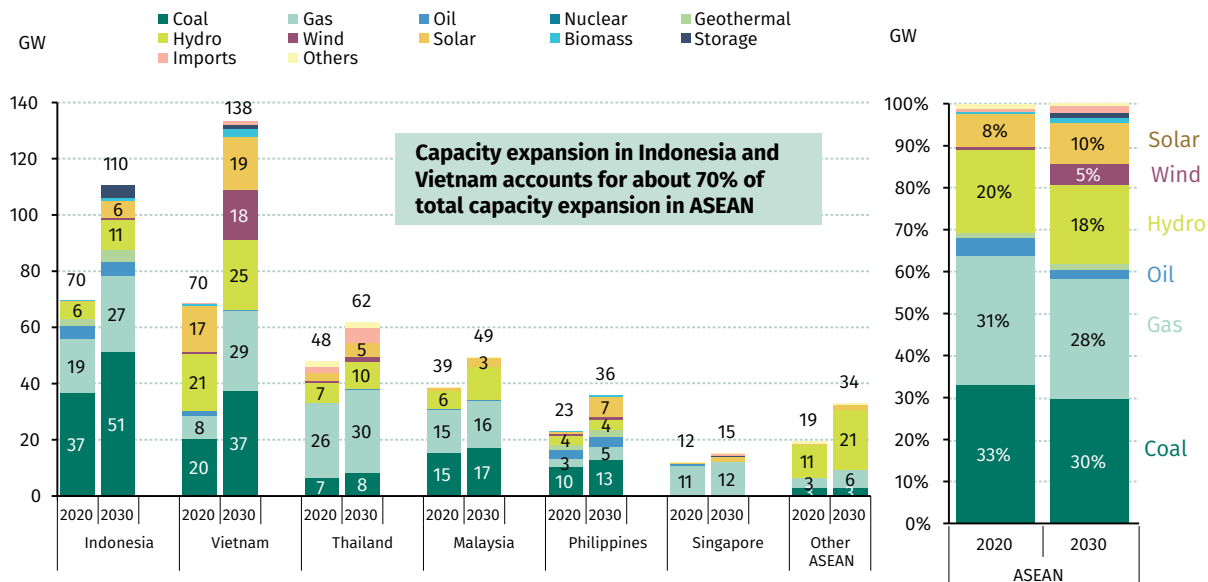
Figure 2: Generation Fuel Mix in ASEAN Countries, 2010-2020



Source: Various publicly available government statistical books and Power Development Plans

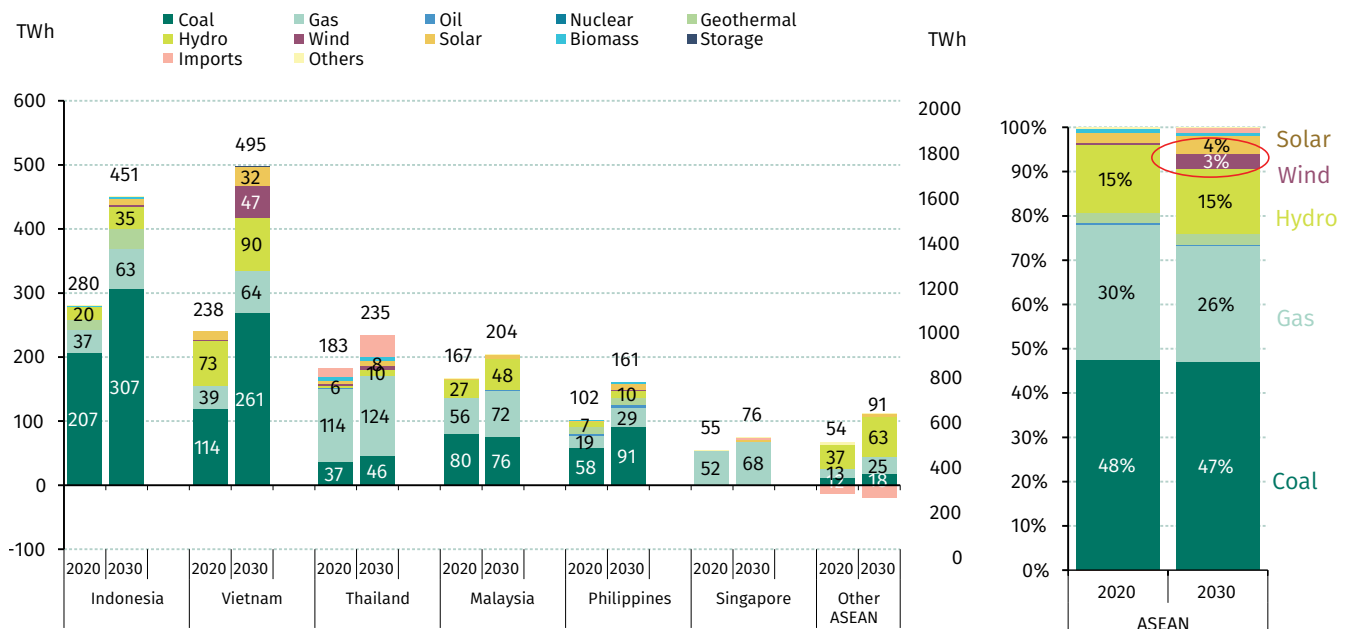
In 2020-2030, ASEAN's economic growth is expected to be around 5.0% per annum³, implying that significant investments in the power sector will be needed to meet growing power demand. ASEAN governments have released power development plans, targeting an increase of total generation capacity from 279 GW in 2020 to 438 GW in 2030, with Indonesia and Vietnam accounting for about 70% of the planned capacity expansion.

Figure 3: Capacity Fuel Mix in ASEAN Under Latest PDPs



Source: Indonesian 2030 capacity is based on the draft Indonesian RUPTL 2021-2030 issued in June 2021; Vietnam 2030 capacity is based on draft PDP 8 issued February 2021; Thailand 2030 capacity is based on Thailand PDP 2018-2030; Malaysia 2030 capacity is based on 2019 PDP for Peninsular Malaysia issued in March 2020; the Philippines, Singapore and other ASEAN 2030 capacity is based on committed capacity and WaterRock Energy.

Figure 4: Generation Fuel Mix in ASEAN, 2020 and 2030



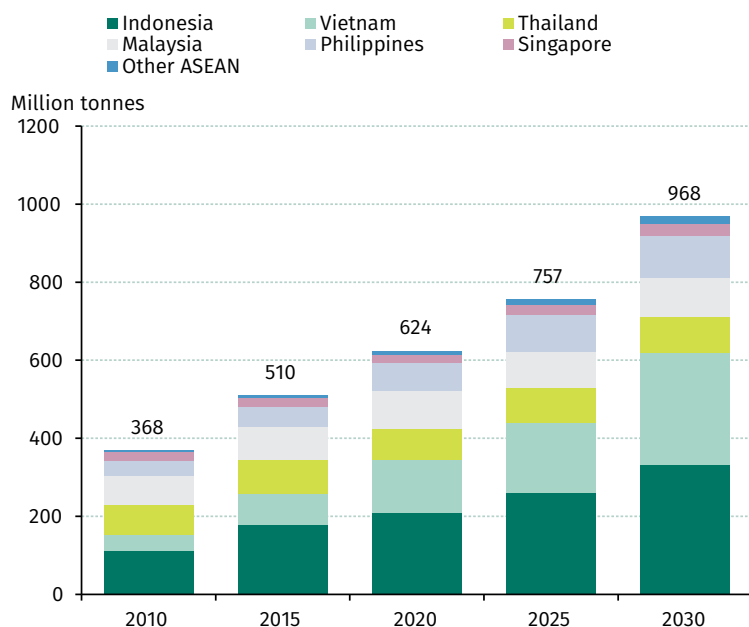
Source: WaterRock Energy modelling and estimates

- Based on the [6th ASEAN Energy Outlook 2017-2040](#) published in November 2020 by ASEAN Centre for Energy, the annual average growth of GDP is 5.0% in 2020-2030; based on [the Southeast Asia Energy Outlook 2019](#) published in October 2019 by IEA, the average GDP growth rate is 4.8% per annum in 2020-2030

Even though most ASEAN high-level officials have talked about shifting away from coal to renewables and gas in their latest government plans, **coal remains a key incremental source to meet the power consumption growth. The coal capacity is targeted to increase by 38 GW in 2020-30 (or one new 500MW coal plant every 1.5 months); its generation is estimated to increase from 500TWh in 2020 to 800TWh in 2030, meeting about 50% of incremental consumption growth.** On the other hand, solar and wind capacity expansion is very modest in ASEAN, and its capacity and generation share are targeted to reach 15% and 7% by 2030. This is far below the global average, where wind and solar generation share had already reached 7% in 2020.

Based on the PDPs, CO2 emissions from the power sector will increase to 0.93 GT by 2030 at a CAGR of 4.2%, mainly driven by the increase in coal generation. Increase in CO2 emissions from Indonesia and Vietnam is estimated to account for about 80% of the total increase in CO2 emissions in ASEAN.

Figure 5: Carbon Emission from the Power Sector in ASEAN, Business-as-usual



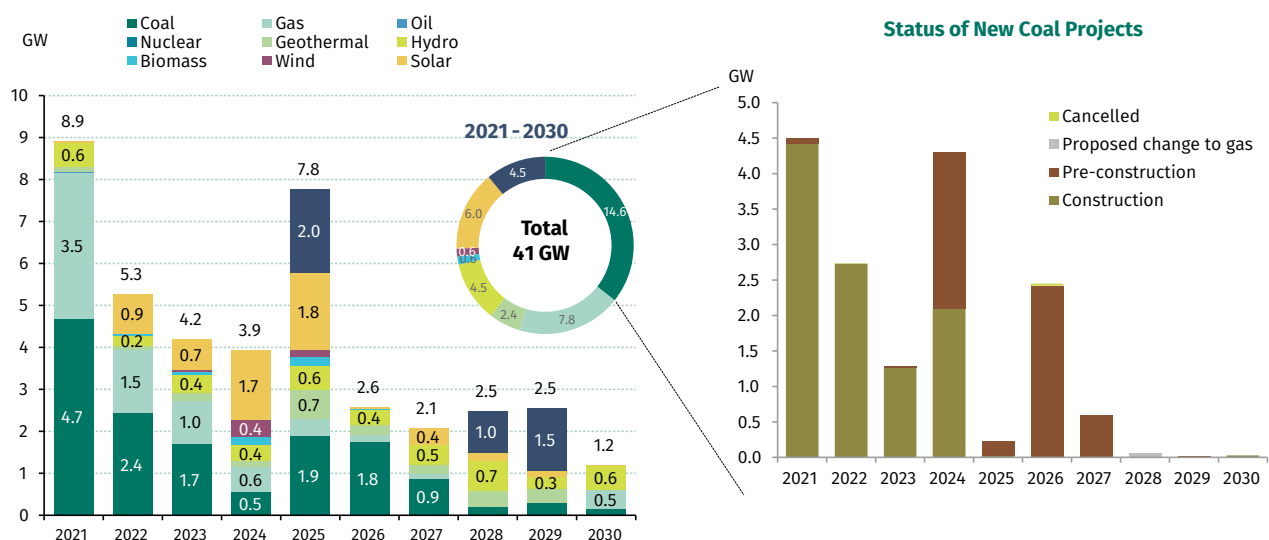
Source: WaterRock Energy Modelling and Estimates

2.2. DEEP DIVE ON INDONESIAN AND VIETNAMESE PDPS

2.2.1. Indonesian RUPTL 2021-2030

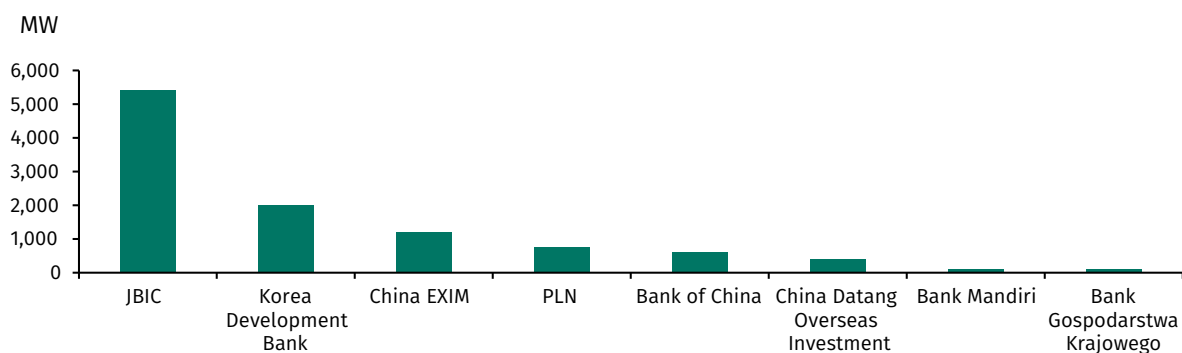
The latest draft of RUPTL (Electricity Supply Plan) 2021-2030, released publicly in mid-June 2021, aims to be a “green RUPTL”. The capacity share of renewables for 10-year capacity addition increases from 30% in RUPTL 2019-2028 to 48% in RUPTL 2021-2030, based on higher planned solar capacity and lower aggregate capacity addition. However, **15 GW of new coal capacity is still expected to be added in 2021-2030; of which, 10.5GW of coal projects are under construction and scheduled to start commercial operation in 2021-2024** (Figure 6). The funding sources of coal projects under construction mainly come from Asian financial institutions. Japan Bank for International Cooperation (JBIC), Korea Development Bank (KDB) and the China Export-Import Bank (China Eximbank) are the lead debt funding banks for about 80% of the 10.5 GW coal projects under construction (Figure 7). These coal projects are under the Fast Track Programs that were initiated by the Indonesian government to avoid power shortages. The rapid expansion of coal capacity in the past decade is also due to the overly optimistic demand forecast by the Indonesian government before 2020.

Figure 6: Indonesian Draft RUPTL 2021-2030



Source: Indonesian RUPTL 2021-2030, WaterRock Energy Research and Analysis

Figure 7: Lead Funding Financial Institutions of the Coal Projects Under Construction



Source: WaterRock Energy Research and Analysis

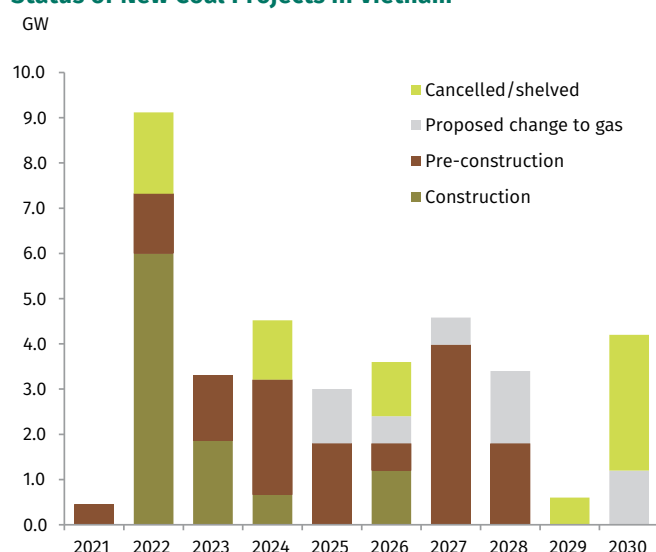
2.2.2. Vietnam Draft PDP8

In February 2021, Vietnam's Ministry of Industry and Trade (MOIT) released the draft Power Development Plan 8 (PDP 8d) for the period of 2021-2030 with a vision to 2045.⁴ Higher renewables and lower coal capacity are planned under draft PDP 8 than under PDP 7 released in 2016.

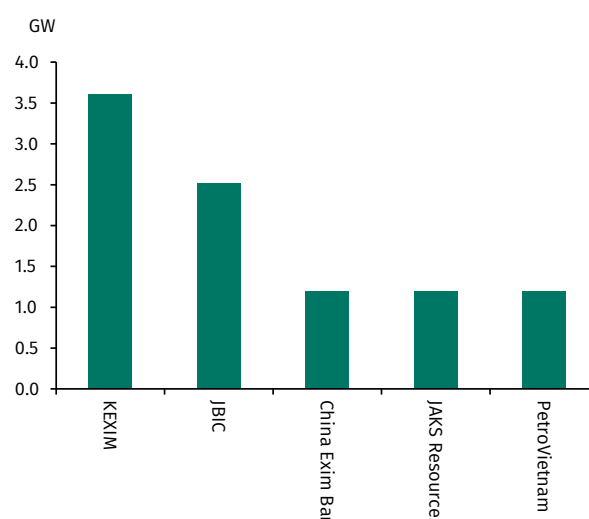
- **Renewables.** There was a big jump in solar capacity addition in December 2020 as new projects were rushing to be commissioned to meet the cut-off deadline of end-December 2020 for the solar Feed-in-tariff (FiT) (USD 70/MWh).⁵ Similarly, there have been activities to develop wind projects and a rush to complete those projects by end of 2023, which is the cut-off date of the wind FiT (USD 85/MWh).
- **Thermal.** Even though much less coal capacity is planned under PDP 8d, **the total capacity is still expected to increase from 20 GW in 2020 to 37 GW in 2030. Of the 17 GW incremental coal capacity in 2020-2030,⁶ we identify 9.7 GW as under construction, of which about 7GW is about to be completed and scheduled to come online in 2022** (albeit with a potential delay of 1-2 years due to COVID-19 restrictions). The Korea Export-Import Bank (KEXIM), JBIC and China Eximbank are the lead funding banks for 75% of the 9.7GW coal projects under construction (Figure 8).

Figure 8: New Coal Projects in Vietnam

Status of New Coal Projects in Vietnam



Key Funding Sources of Coal Projects Under Construction



Source: Source: WaterRock Energy Research and Analysis

- As PDP 8 is not yet finalized, the detailed capacity mix in 2030 is still changing. Based on the latest information as of September 14, 2021, the total installed capacity by 2030 has been modified to be 131 GW as compared to 138 GW in the February 2021 version. The Ministry of Industry and Trade (MOIT) has reduced the onshore wind capacity from 16 GW to 12 GW and offshore wind capacity from 2 GW to 0; biomass and other renewable energy sources from 3 GW to 1 GW. Meanwhile, the MOIT has added another 3 GW coal capacity for the period of 2020-2030. Therefore, the capacity share of renewable energy in the total installed capacity for 2030 would be reduced from 27% to 23% while coal would be increased from 27% to 31%.
- By end-2020, utility scale solar capacity reached 8.5GW and rooftop solar reached 8GW in Vietnam. More than half of those projects were commissioned in December 2020. The lumpy entry of solar capacity is concentrated in Ninh Thuan and Binh Thuan provinces, and there has been solar curtailment (10-25% on average).
- We identify that there is a total of 46GW coal projects in Vietnam's project pipeline. Of which, about 8GW has been cancelled/shelved and 5GW has been approved for conversion from coal to gas-powered.

2.2.3. Misalignment Between the Current PDPs and Global Trend / Domestic Long-term Decarbonisation Plans

Misalignment Between the Current PDPs and Global Decarbonisation Trend

In Indonesia and Vietnam, the PDPs still have a sizeable amount of coal capacity that is seeking financing and about to start construction. This does not align with the global trend that investors and financial institutions are moving away from coal to renewables because: (a) substantial technological improvements that have driven down the cost of renewable resources to the point where, even before accounting for any policy incentives, they can be the lowest cost option for new generating plants; (b) customers' increasing desire to voluntarily procure renewable energy to meet their corporate net carbon zero target; (c) increasing focus on sustainability among the shareholders of financial institutions, restricting finance for coal projects; (d) the growing understanding among institutional investors of the systemic risks to long-term returns from climate change issues including stranded asset risk⁷; and (e) recognition by governments and policymakers that much more renewable energy resources are needed to meet long term emissions reductions goals.

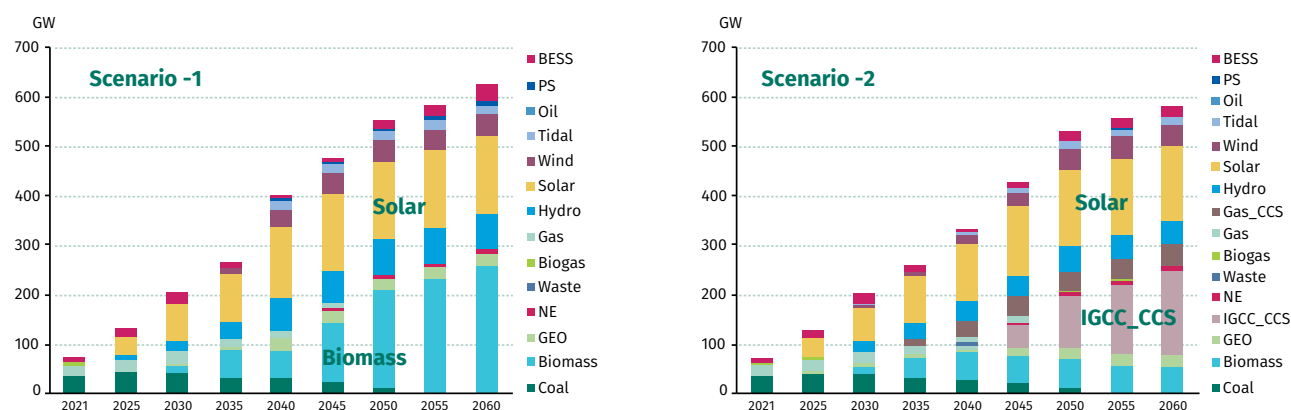
Financing coal projects is getting increasingly difficult, resulting in a high risk of project slippage/cancellation for new planned coal projects. This means that putting a significant emphasis on coal expansion to meet demand growth could lead to supply reliability issues if future capacity cannot be financed. The key lead lenders of coal projects under construction in ASEAN are all under pressure to change their financing policy for new coal projects.

7. Carbon Tracker released a report "[Do Not Revive Coal](#)" in June 2021, and it argues that the total net present value of new coal projects is negative USD 4.7 billion in Indonesia and USD 25 billion in Vietnam.

Misalignment between the Current PDPs and Long-term De-carbonisation Plan

In Indonesia, the government has come out with plans to reach net-zero carbon emissions in the power sector by 2060 (Figure 9). Under the two net zero carbon scenarios, it plans to build large amounts of solar capacity – about 35GW by 2025 and 70GW by 2030. This is more than 10 times the solar capacity target of 6 GW by 2030 under RUPTL 2021-2030. **This indicates the large difference in renewable capacity addition between the RUPTL 2021-2030 and the government’s long term decarbonisation target.**

Figure 9: MEMR Power Generation Capacity Scenarios for Net Zero Carbon in 2060



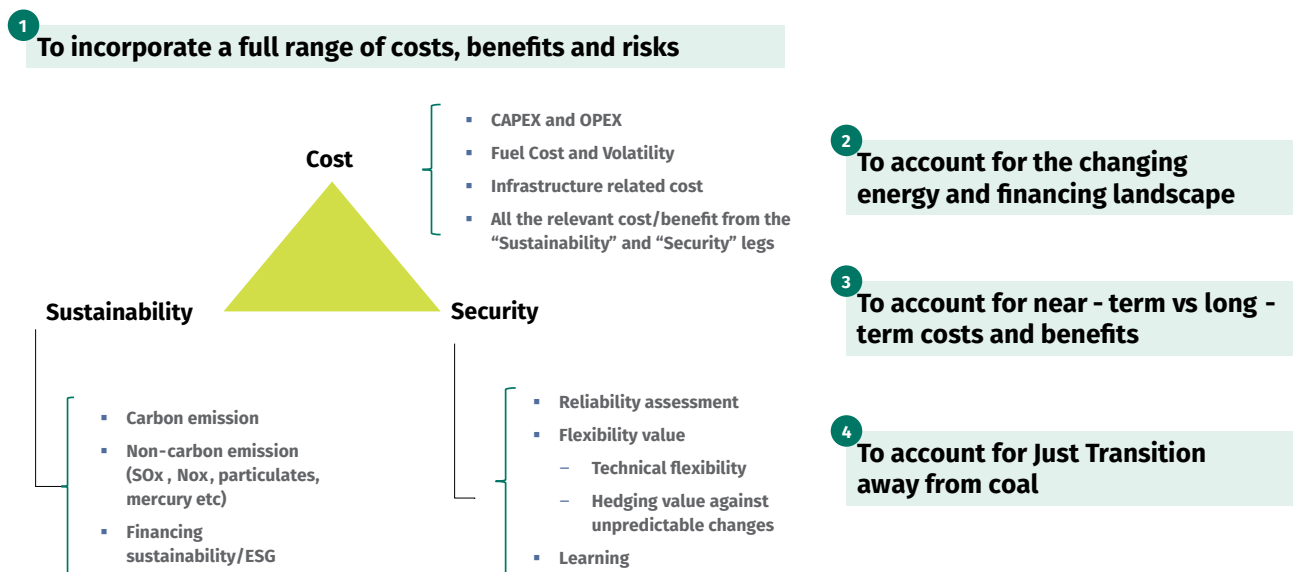
Source: Directorate General of Electricity, Ministry of Energy and Mineral Resources (MEMR), June 4, 2021

The Indonesian net-zero emissions plan focuses on carbon abatement after 2030 by using a large amount of biomass or Carbon Capture and Storage (CCS) technologies. However, this strategy will lead to higher cumulative CO₂ emissions, a point emphasized in the latest [IPCC Report](#). Furthermore, there are further questions around this strategy, such as the availability of the large amount of biomass fuel required and the fact that large-scale CCS is still technologically unproven. Thus, there are risks that those two technologies cannot scale up as expected, resulting in much higher carbon emissions than expected in the long term.

3. ASSESSMENT OF GENERATION TECHNOLOGY IN ASEAN

Due to misalignment between the current PDPs and the global and domestic long-term decarbonisation trends, there is a need for ASEAN governments to re-evaluate their current PDPs, especially for expected capacity addition in 2025-2030. We propose a **Total Value Framework** to evaluate different generation technologies, taking into account cost, sustainability and security (Figure 10).

Figure 10: Total Value Framework



Source: WaterRock Energy

The framework considers a **full range of costs, benefits and risks of specific generation technologies**, similar to the trilemma concept used by regulators around the world. One useful way to turn the trilemma concept into a more actionable framework is to identify and quantify all the costs and benefits for each leg of the trilemma to the extent possible.






When evaluating the key Trilemma sub-items, one also needs to **account for the changing energy landscape**, such as the rapid cost reduction of renewable technologies and higher emphasis on sustainability for project financing and investment. Furthermore, one needs to **account for near-term versus long-term costs, benefits and risks**. Thus, it is important to evaluate the cost-effectiveness of an energy option over a long-term time horizon. The long-term risks of certain energy options could be higher. For example, coal-fired power projects may be dispatched much less in a world with high renewable penetration or forced to be retired before the end of its economic life due to climate change-related regulation. In another word, the long-term stranded risk for coal is higher than other generation capacities.

3.1. LOCAL RENEWABLE SOURCES IN ASEAN

ASEAN has good and largely untapped renewable resources based on official government statistics.

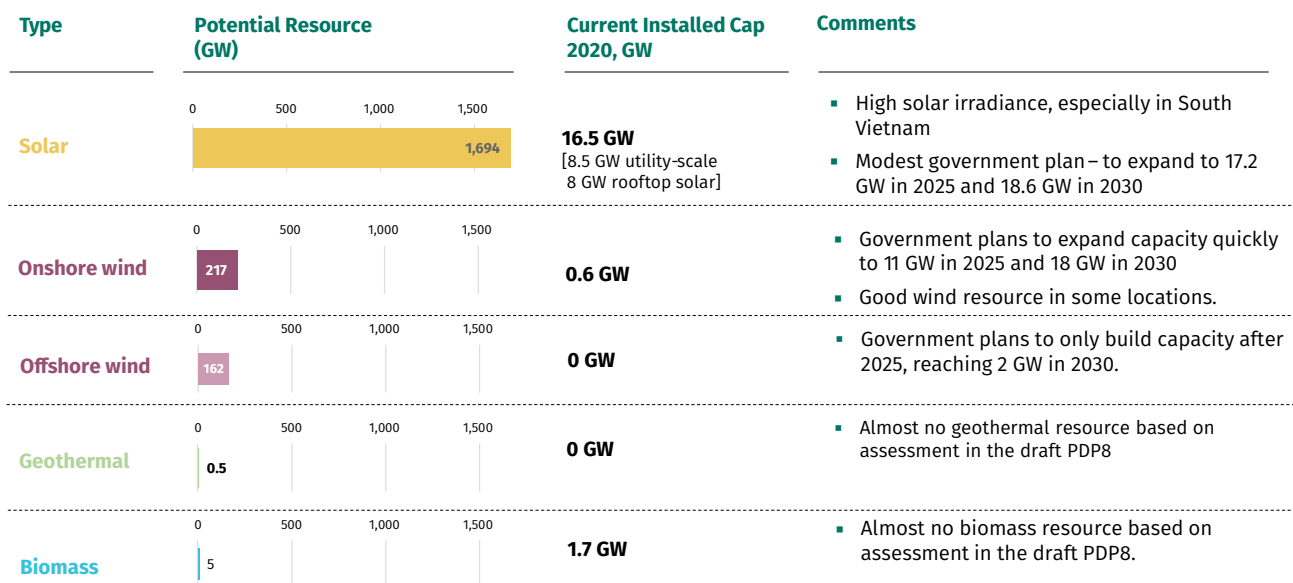
- Many ASEAN countries are located near the equator, resulting in good solar resources. For example, the potential solar resource is 208GW in Indonesia and about 1700GW in Vietnam (Figure 11 and Figure 12).
- Onshore and offshore wind resources are relatively modest in ASEAN. One exception is Vietnam. Based on PDP 8d, Vietnam has a wind resource potential of over 200GW.
- Laos, Myanmar and Indonesia have good untapped hydropower potential. Vietnam also has good hydropower resources, but the commercially viable hydro resources are largely exploited.
- Indonesia and the Philippines have significant geothermal potential, although it requires a large upfront CAPEX to develop the resource.

Figure 11: Renewable Resources in Indonesia

| Type | Potential Resource (GW) | Current Installed Cap 2020, GW | Comments |
|------------|---|--------------------------------|--|
| Solar |  208 | 0.06 GW | <ul style="list-style-type: none"> ▪ High solar irradiance especially in East Java, Nusa Tenggara, Sulawesi ▪ Financing costs and supply chain restriction have driven up cost |
| Wind |  61 | 0.149 GW | <ul style="list-style-type: none"> ▪ Modest government plan (RUPTL 2019 - 2028) ▪ Good wind resource in some locations. |
| Hydro |  75 | 4.4 GW | <ul style="list-style-type: none"> ▪ Small, large and pumped storage hydro are possible, but subject to funding, migration and environment issue |
| Geothermal |  29 | 1.9 GW | <ul style="list-style-type: none"> ▪ High upfront capex and development risk, but with uncertain pricing mechanism, power contracts and inefficient regional tendering processes. |
| Biomass |  33 | 1.7 GW | <ul style="list-style-type: none"> ▪ Undeveloped value chain despite agriculture industry and potential issue related to deforestation. |

Note: Potential resources are based on assessment in RUPTL 2019-2028

Figure 12: Renewable Resources in Vietnam



Note: Potential resources are based on assessment in draft Power Development Plan 8

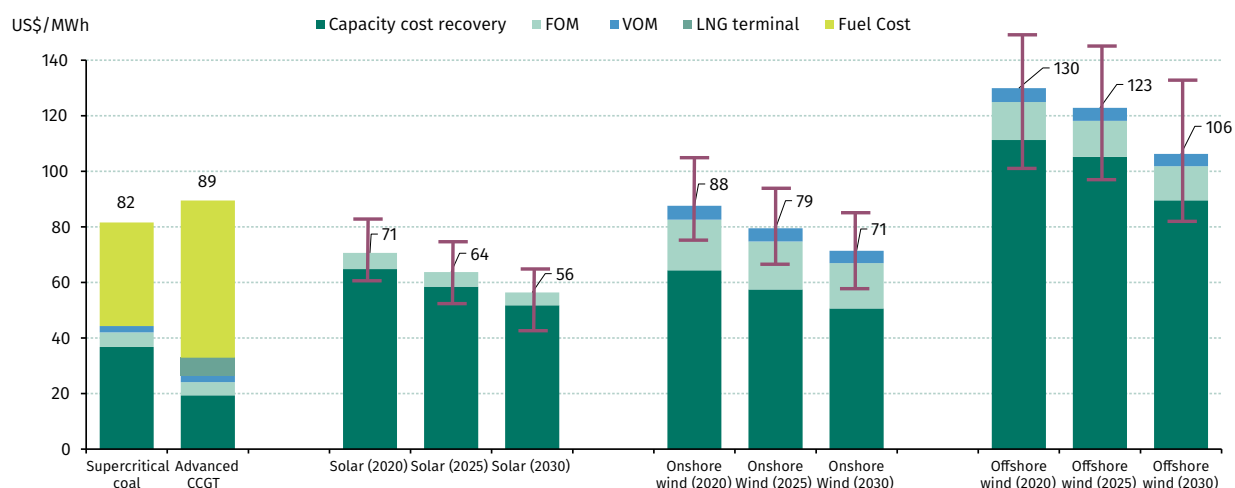
3.2. RENEWABLES VS FOSSIL FUELS UNDER THE TOTAL VALUE FRAMEWORK

Globally, many countries are adding new solar and wind capacity as a cost-effective option to reduce carbon emissions. Based on the local resource endowment in Indonesia and Vietnam, we see solar and wind as cost-effective options to meet the growing demand, mitigate the increase in CO₂ emissions and increase energy security in ASEAN.

3.2.1. Cost Effectiveness

The cost of building solar and wind capacity has declined substantially in the past 10 years (details are discussed in Appendix A).

Figure 13: Comparison of Cost of Thermal Plants vs Wind/Solar



Note: Assumptions are listed in Table 1. **The capacity factor for thermal capacity is assumed to be 70% for base-load application.** Capacity factor is 15-20% (18% on average) for solar, 25-35% (30% on average) for onshore wind, 30-50% (40% on average) for offshore wind. The methodology of LCOE calculation is provided in Appendix B.

Source: WaterRock Energy Research and Analysis

Table 1: Key Assumptions for the Thermal, Solar and Wind Plants in ASEAN

| | Unit | New Supercritical Coal | New CCGT | Utility-scale Solar | Onshore Wind | Offshore Wind |
|-------------------------|-------------|------------------------|----------|------------------------|--------------------------|--------------------------|
| Total CAPEX | USD/kW | 1814 | 930 | 800 (2020), 639 (2030) | 1350 (2020), 1062 (2030) | 3110 (2020), 2503 (2030) |
| After-Tax WACC (ATWACC) | - | 10% | 10% | 10% | 10% | 10% |
| Corporate Tax Rate | - | 20% | 20% | 20% | 20% | 20% |
| Economic life | Year | 30 | 25 | 25 | 28 | 28 |
| Capital recovery cost* | USD/kW-year | 225 | 119 | 129 (2020), 103 (2030) | 244 (2020), 192 (2030) | 390 (2020), 314 (2030) |
| FOM | USD/kW-year | 32 | 29 | 9 (2020), 7 (2030) | 48 (2020), 43 (2030) | 81 (2020), 43 (2030) |
| VOM | USD/MWh | 2.3 | 2.2 | 0 | 5.0 (2020), 4.4 (2030) | 3.7 (2020), 3.1 (2030) |
| Heat rate | GJ/MWh | 9.5 | 6.9 | - | - | - |
| Fuel cost | USD/MMBtu | 4.2 | 9.6 | - | - | - |
| Availability factor | - | 85% | 85% | 15-20% [18% mid-point] | 25-35% [30% mid-point] | 30-50% [40% mid-point] |

*Note: 10% after-tax WACC is sourced from the draft Vietnam PDP8, assuming a 60/40 debt to equity ratio. Details of different items and the process to calculate the levelized cost of energy is discussed in Appendix B.

Source: Vietnam PDP 8 draft, WaterRock Energy Estimates and Analysis

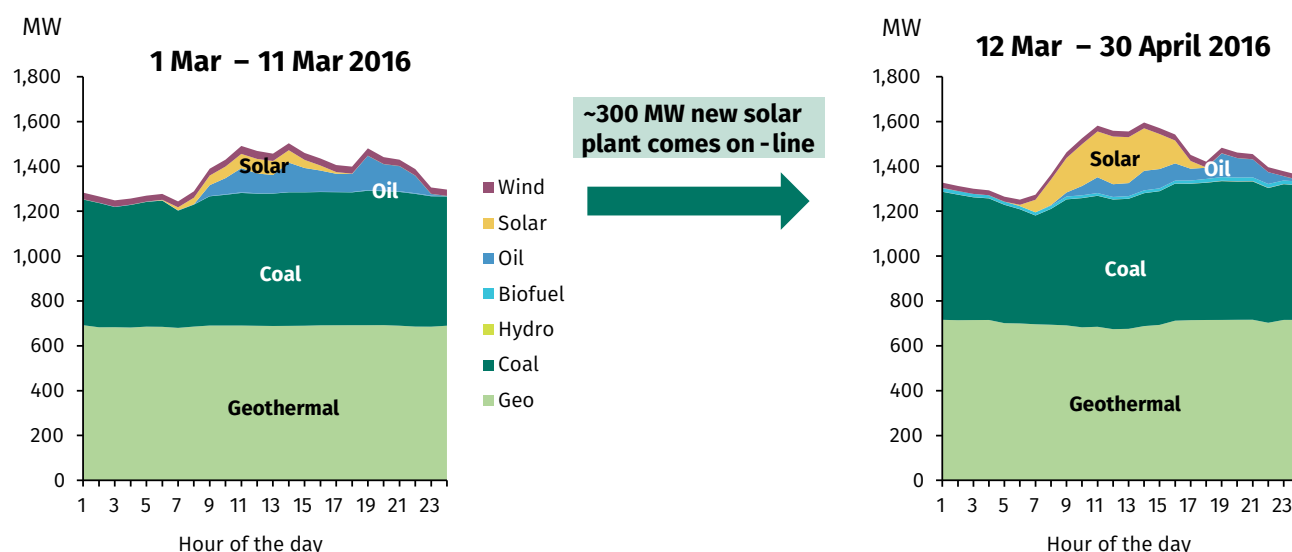
Based on the above assumptions (Table 1), we calculated the levelized cost of energy for coal, gas, solar and wind capacity in ASEAN as shown in Figure 13. The determination of the levelized cost of energy (LCOE) for supercritical coal projects is conservative as we assume that the financing cost for coal projects is the same as other types of capacity and we have not assumed any carbon tax.

- **Solar vs thermal: Since 2020, the LCOE for solar has been cheaper than the new thermal capacity in ASEAN.** The levelized cost of energy (LCOE) for utility-scale solar projects was about USD 71/MWh in 2020, which is slightly cheaper than USD 82/MWh for coal and USD 89/MWh for gas projects running at 70% capacity factor.⁸
- **Wind vs thermal: Based on the LCOE, both onshore and offshore wind projects still have slightly higher average total costs than unabated coal capacity in 2020. We expect this cost to decline below that of thermal capacity by 2025.** The LCOE for wind varies across different regions due to different wind speeds. In some onshore areas within the ASEAN bloc, wind already became economical against thermal capacity from 2020. For offshore wind, recent rapid adoption in Northeast Asia, Europe and the US will likely reduce the cost materially over the next 10 years, making it more economical than expected.

While LCOE is useful to indicate the cost competitiveness of different generation technologies, it does not fully capture the contribution of renewable generation to system reliability. At a low solar penetration rate with generation share of less than 10%, solar generation aligns well with day-time high load and high price hours when expensive plants, like gas and oil plants, have to be run to meet the load. **Thus, solar competes with mid-merit and peaking capacity (i.e. gas or oil), implying that the value of 1MWh solar generation is higher than a typical base-load generation.** For example, when solar capacity entered the Visayas grid in the Philippines in 2016, it replaced expensive oil generation to meet high load during the daytime (Figure 14). Hourly wholesale competitive electricity prices are also generally higher during the solar generating hours than the non-solar hours, indicating the higher value of solar generation.

8. For the existing subcritical coal capacity, the average short-term running and maintenance cost (including fuel, operation and maintenance cost) is USD 51/MWh, which is still lower than the levelized cost of energy (LCOE) of solar and wind. If a carbon tax of USD 20/tonne-CO₂ is imposed, the LCOE of a new solar plant in 2020 can be cheaper than running the existing subcritical coal capacity. If a carbon tax of USD 35/tonne-CO₂ is imposed, the LCOE of a new wind plant in 2020 can be cheaper than running the existing subcritical coal capacity.

Figure 14: Average Hourly Generation in Visayas Grid in the Philippines



Source: Philippines Electricity Market Corporation (PEMC), WaterRock Energy Analysis

As solar and wind tend to produce power at roughly the same time (without bundling with energy storage system) and are not controllable (except by curtailment), their marginal value to the power system declines as more is added. At certain thresholds⁹, they start to crowd each other out and push the peak load for power to off-renewable hours, such as early evening after the sun has set. Storage is a good technical fix for short-term renewable unavailability. **In most ASEAN markets, crowding out is not an issue before 2030 as the generation share of solar and wind remains less than 10%.** By then, battery energy storage solutions would likely become sufficiently cheap for deployment to integrate a large amount of solar and wind capacity into the power system.

In ASEAN, some countries have a large number of diverse archipelagic islands, like Indonesia and the Philippines. Diesel plants are commonly used in remote small islands. Mini-grid solutions with solar and wind will be much more competitive than running diesel plants¹⁰.

9. The IEA has developed a phase categorisation to capture the evolving impacts that variable renewables (VRE) may have on power systems and related integration issues in its report "[Status of Power System Transformation 2019 \(Power System Flexibility\)](#)". When the generation share of variable renewables is less than 10%, it is typically classified under Phase 1 or 2, and the variable renewables have no or minor impact on the power system operation. All ASEAN countries except Vietnam will be still under phase 1 or 2 in 2020-2030. When the VRE generation share is 10-40%, it is classified as phase 3. Battery energy storage, pumped storage plants and other flexible capacity will need to be expanded to integrate all the VRE generation in the grid. As solar and wind capacity expands fast in Vietnam, Vietnam could be under phase 3 after 2025. Technically, the generation share of VRE can increase to more than 80% if large amount of flexible capacity is adopted and the ASEAN grid is integrated.

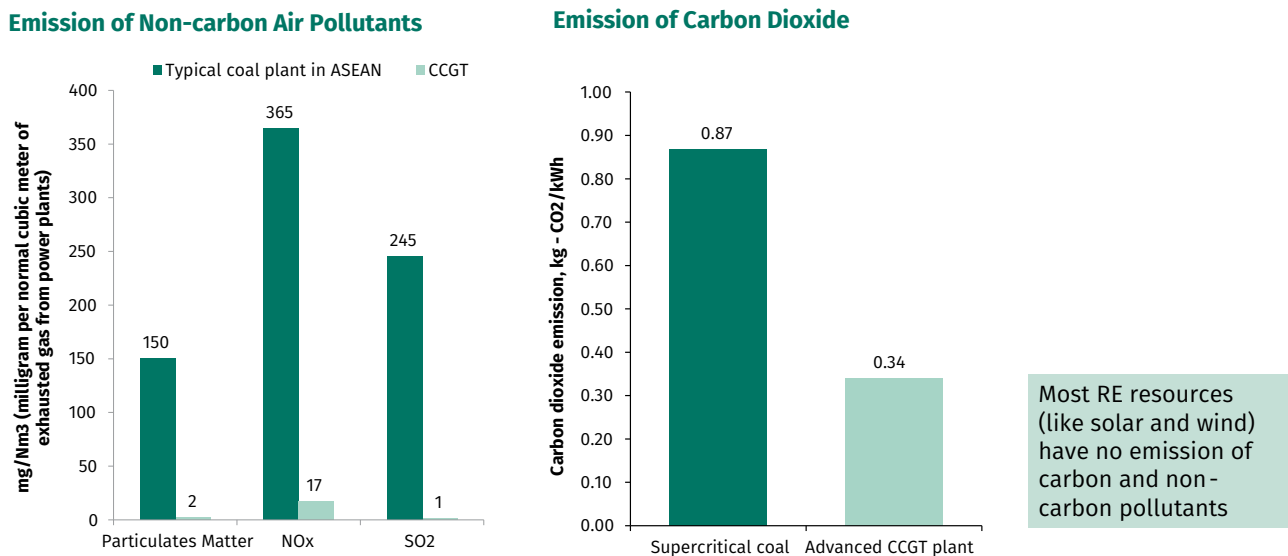
10. At a long-term Brent price of USD 65/barrel, diesel price is around USD 80/barrel, which is equivalent to USD 13/GJ. Assuming the heat rate of the diesel plant is 11.5 GJ/MWh, the fuel cost of running diesel plant is about USD 150/MWh. Thus, the fuel cost is about twice as much as the LCOE of a new solar or wind plant.

3.2.2. Sustainability

Environmental Sustainability

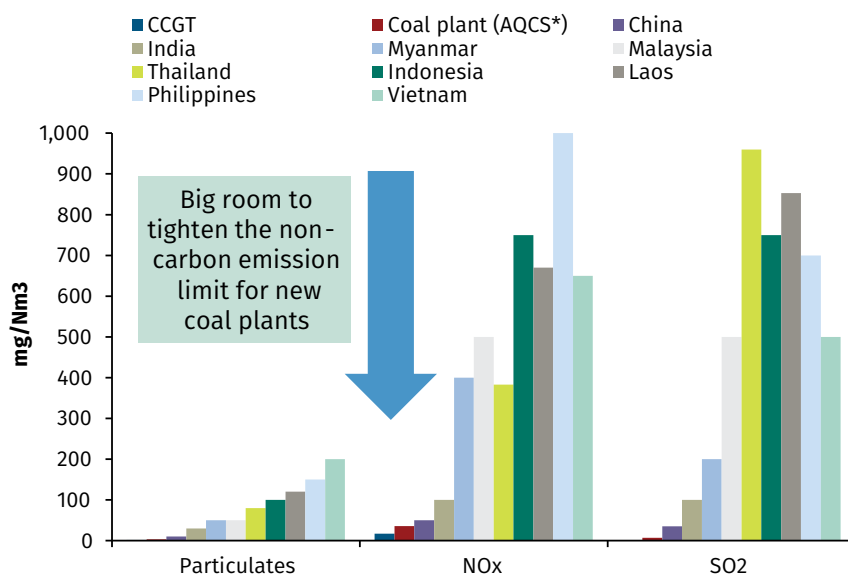
Environmental concerns have become increasingly important in decision making for governments and corporations. **Renewable capacity has positive attributes compared to thermal capacity due to zero emissions of pollutants** (Figure 15).

Figure 15: Emission of CO2 and Non-carbon Air Pollutants



Source: IPCC, WaterRock Energy Research and Analysis

Figure 16: Emission Limit of Non-carbon Air pollutants of Coal Plants in ASEAN



Source: Economic Research Institute for ASEAN and East Asia, WaterRock Energy Research

For non-carbon emission, coal-fired power plants (without properly installing Air Quality Control System, AQCS) emit a high level of non-carbon air pollutants (SO_x, NO_x, particulates and mercury), especially when low-quality coal with high sulfur content is used. In most ASEAN countries, non-carbon emission standards are set in the early 2000s and are much less stringent than other Asian developing countries like India and China (Figure 16). ASEAN governments should consider tightening the emissions limit for non-carbon air pollutants and early retirement of heavy emitters. For CO₂ emissions, there are no cheap ways to remove CO₂ from thermal capacity. Even though carbon capture and storage (CCS) has been widely discussed, the technology is still unproven and commercial application in the power sector is almost non-existent.¹¹

Financial sustainability

There is a growing number of countries, companies and financial institutions embedding practices to minimise financial exposure to coal-related projects and maximise flows to low carbon economic activity and assets.

Transitioning to renewable sources can enhance the financial competitiveness of the ASEAN bloc. Furthermore, more international corporations have sought to procure renewables for their operation in host countries. Creating barriers for them to procure renewables could slow down foreign direct investment in ASEAN.

11. Based on an [IEA](#) commentary "[Is carbon capture too expensive](#)" published in Feb 2021, there is no single cost for CCS/CCUS. For carbon capture, the cost can vary greatly by CO₂ source, and it could be USD 40-120/t CO₂ for processes with "dilute" gas streams, such as power generation. For the cost of transport and storage, this can also vary greatly on a case-by-case basis, depending mainly on CO₂ volumes, transport distances and storage conditions. Based on the "[Carbon Capture, Utilisation and Storage \(CCUS\): Decarbonisation Pathways for Singapore's Energy and Chemicals Sectors](#)" report published in Singapore's National Climate Change Secretariat website in July 2021, capture cost of CO₂ from coal plant is USD 41-51/tonne-CO₂ (Table 9 on page 26), transport cost is USD 0.2-40/tonne-CO₂ (Table 11 on page 31), and storage cost is USD 2-31/tonne-CO₂ (Table 12 on page 32). Thus, the total cost of CCS/CCUS for coal-fired power plant is more than USD 40/tonne. This is higher than the implied carbon tax to make solar and wind competitive against running the existing coal capacity as shown in footnote 11. Thus, the running cost of existing coal capacity with CCS/CCUS is more than building new solar and wind capacity.

3.2.3. Security

Energy security is a complex issue. It has a physical dimension related to the value of ‘keeping the lights on’, and it also has an economic dimension related to the relative undesirability of exposure to price and cost risks. There is also a time dimension, as short-term risks and long-term risks have different implications for exposure and response. Compared to coal and gas capacity, wind and solar can provide values for each aspect of the energy security risk matrix (Table 2).

Table 2: Forms of Energy Security Risk Matrix

| Energy Security Risk Matrix | Physical (loss of load/fuels) | Economic (high prices) |
|-----------------------------|--|--|
| Short-term | <ul style="list-style-type: none"> • Technical failure • Extreme weather events • Political disruption. <p>Local wind and solar greatly shorten the supply chain to reduce the risk of disruption.</p> | <ul style="list-style-type: none"> • Cartel production quota to push up prices • Balance of payment issue <p>Local wind and solar have zero fuel price and can mitigate tariff fluctuation.</p> |
| Long-term | <ul style="list-style-type: none"> • Resource depletion; Resource nationalization • Policy/regulatory failure <p>Local wind and solar can diversify the energy mix.</p> | <ul style="list-style-type: none"> • Fuel price shifts • New technologies <p>Local wind and solar already has the lowest LCOE in most ASEAN nations.</p> |

Source: WaterRock Energy Research and Analysis

Firstly, **wind and solar can diversify the energy mix and increase short-term and long-term physical energy security in ASEAN.** In recent years, most ASEAN countries have added a substantial amount of coal capacity to meet their incremental demand, making their energy mix heavily reliant on coal. Extreme weather events, which has become more frequent due to climate change, can potentially disrupt the supply chain of coal, leading to blackouts. For example, severe flooding in February 2019 in key coal-producing regions in Indonesia led to a government warning about potential power blackouts.

Secondly, renewables can also improve economic energy security by **mitigating fuel prices and tariff fluctuation.** Moreover, if fuels are imported, it can potentially lead to a balance of payment issue when regional fuel prices increase substantially. Investment of wind and solar capacity is mostly CAPEX-related and they have zero fuel cost. Such attributes of wind and solar capacity can help to reduce tariff fluctuation.

Thirdly, embracing renewables now also create opportunities for regulators and local investors/developers to gain knowledge on grid integration, deployment and operation, potentially positioning ASEAN as one of the renewable/new technology hubs in the long term. As the cost of renewables is expected to further decline over time, this approach points the ASEAN bloc in the right direction to fully exploit its renewable resource endowment.

4. ALTERNATIVE SCENARIOS WITH ECONOMIC ENTRY OF WIND AND SOLAR CAPACITY

We have modelled for alternative future power generation mix scenarios optimising for least cost, subject to demand requirements. Assumptions made for demand, supply, fuel and technology costs are discussed in the sections below and in Appendix B.

Key Findings

The power optimization model confirms that solar and wind are economic options to meet demand growth and reduce carbon emissions in both Indonesia and Vietnam. In other words, not only does it make sense from a climate perspective to add renewables capacity versus thermal, but it also makes economic sense. **Higher solar and wind capacity penetration can in fact reduce the average system cost in Indonesia and Vietnam.**

- **Should current thermal capacity under construction over the next 3 years be completed, demand growth in the forecast period of 2020-2030 can be fully met from renewables addition in 2025-2030.** This is particularly true for Indonesia as the local power sector is well supplied in the coming years. Pushing for more thermal capacity will exacerbate the oversupply and lead to higher system costs.
- **CO2 emissions from the power sector in Indonesia and Vietnam can peak around 2025.** Reducing the cost of building wind projects and pushing ahead with energy efficiency programs will be key to help achieve this.
- **As more solar and wind capacity enters the system, existing gas, large hydro, pumped storage and battery energy storage capacity will need to be run more flexibly.** They need to be ramped up and generate more during 5-10PM, which are the new peak hours after large amount of solar capacity enters the system.

4.1. KEY ASSUMPTIONS

We have used the latest available information to refine several key assumptions made in the PDPs: (a) the impact of COVID-19 on power consumption; (b) treating only projects under construction as committed; (c) retiring old coal capacity after 30 years;¹² and (d) allowing for economic entry of solar, wind and thermal capacity.

We have formulated two alternative scenarios with the following assumptions:

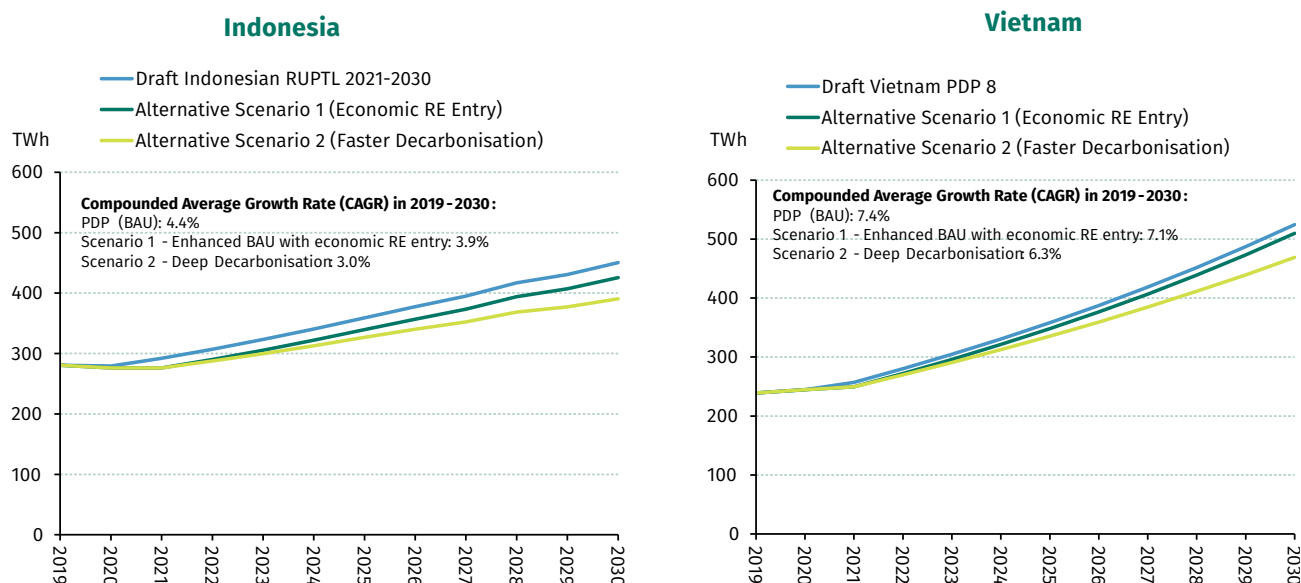
- **Alternative Scenario 1 (Economic RE Entry) :**
 - (1a) **Power demand** growth has been lowered to reflect the impact of the COVID-19 pandemic
 - (1b) **Committed capacity** entry and expected coal retirement
 - (1c) **Key parameters of new capacity** are based on the data shown in Table 1 and
 - (1d) **Economic entry** of solar, wind and thermal capacity can occur after 2023
- **Alternative Scenario 2 (Faster De-carbonisation):** relative to Scenario 1, this scenario assumes a lower demand growth and is more optimistic on the cost decline of renewables sources.
 - (2a) **Power demand** growth is 1% lower annually relative to Scenario 1 in 2022-2030, driven by a push on energy efficiency,
 - (2c) **The rate of decline for the cost of solar and wind doubles** relative to assumptions in Scenario 1 in 2020-2030

4.1.1. Impact of COVID 19 on Near-term Demand Growth

We have adjusted power demand growth downwards, as shown in Figure 17, to reflect the impact of the Covid 19 pandemic. In the faster decarbonisation scenario, we assume that the government will push forward energy efficiency programs and that the demand growth rate will be reduced by 1% annually relative to the BAU scenario.

12. This is a very conservative assumption. For coal projects built since 2010, there are arguments to retire them in 20 or less than 20 years. For our forecasting period of 2020-2030, the CO2 emission profiles in Indonesia and Vietnam have marginal changes even if we assume that the old plants are retired in 20 years. Details are discussed in Appendix C.

Figure 17: Gross Demand in Indonesia and Vietnam for Alternative Cases

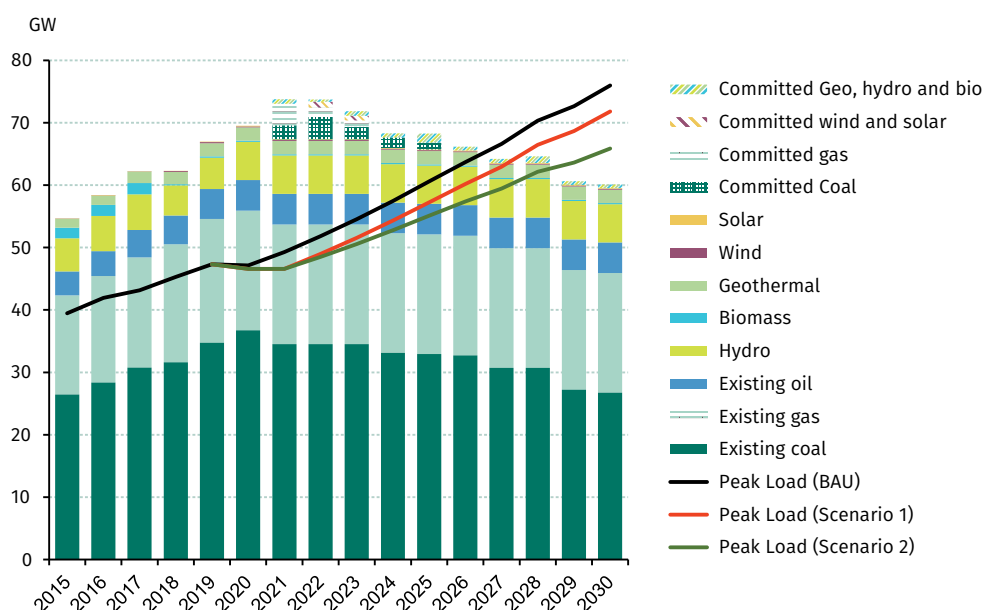


Source: PLN, EVN, BP, IEA, WaterRock Energy Research and Analysis

4.1.2. Committed Projects and Retirement of Coal Projects

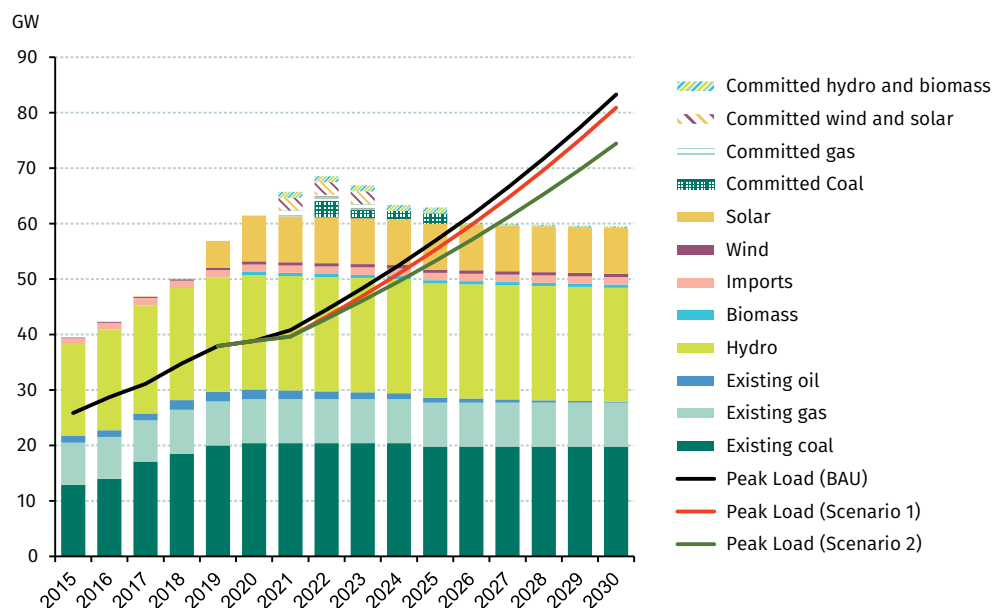
We assume that only coal capacities that are currently under construction are brought online in the alternative cases, with a delay of 0.5-2 years due to the COVID-19 pandemic. We also assume that old coal capacity will be retired after they reach their economic life of 30 years. (see Appendix C for further detail). Figure 18 and Figure 19 illustrate the supply and demand situations in Indonesia and Vietnam based on existing and committed capacity. In the next 3-5 years, Indonesia has sufficient supply while Vietnam will still need to add capacity to meet its rapidly growing demand.

Figure 18: Supply and Demand in Indonesia



Source: WaterRock Energy Research and Analysis

Figure 19: Supply and Demand in Vietnam

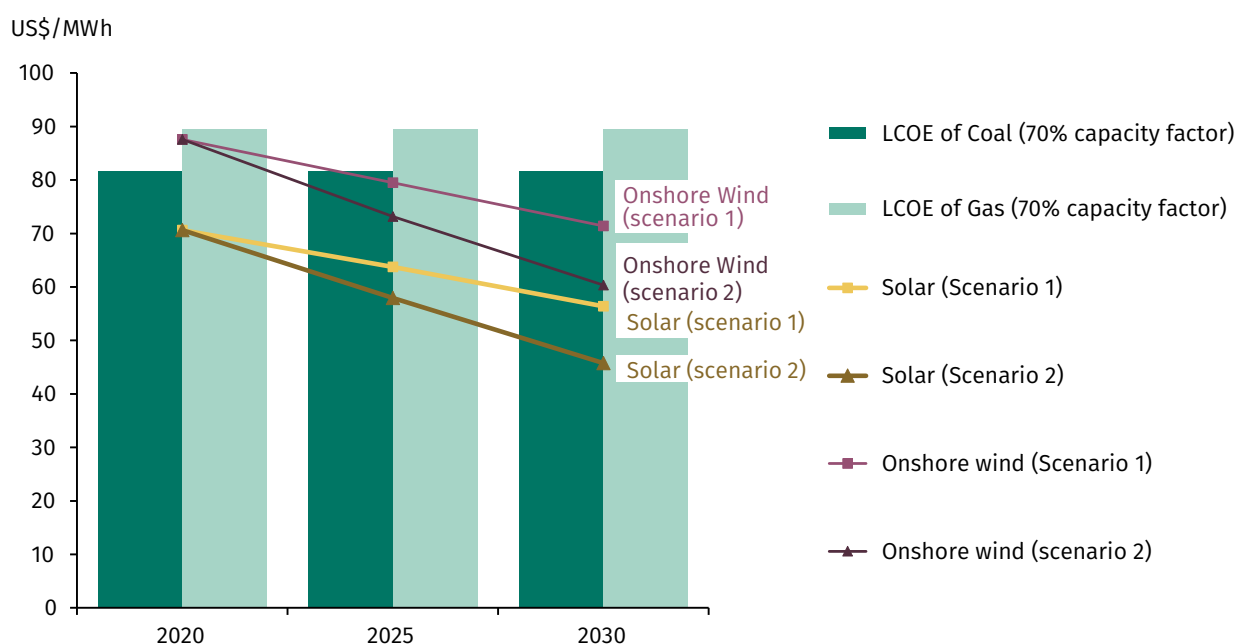


Source: WaterRock Energy Research and Analysis

4.1.3. Renewables cost assumptions

We assume that there are no key barriers for the economic expansion of solar and wind projects, such as transmission constraints. Under Scenario 2, the faster cost reduction assumptions make wind more economical than thermal capacity after 2025 (Figure 20).

Figure 20: Comparison of LCOE of Wind and Solar under Scenario 1 and 2



Source: WaterRock Energy Research and Analysis

4.2. KEY MODEL OUTPUTS

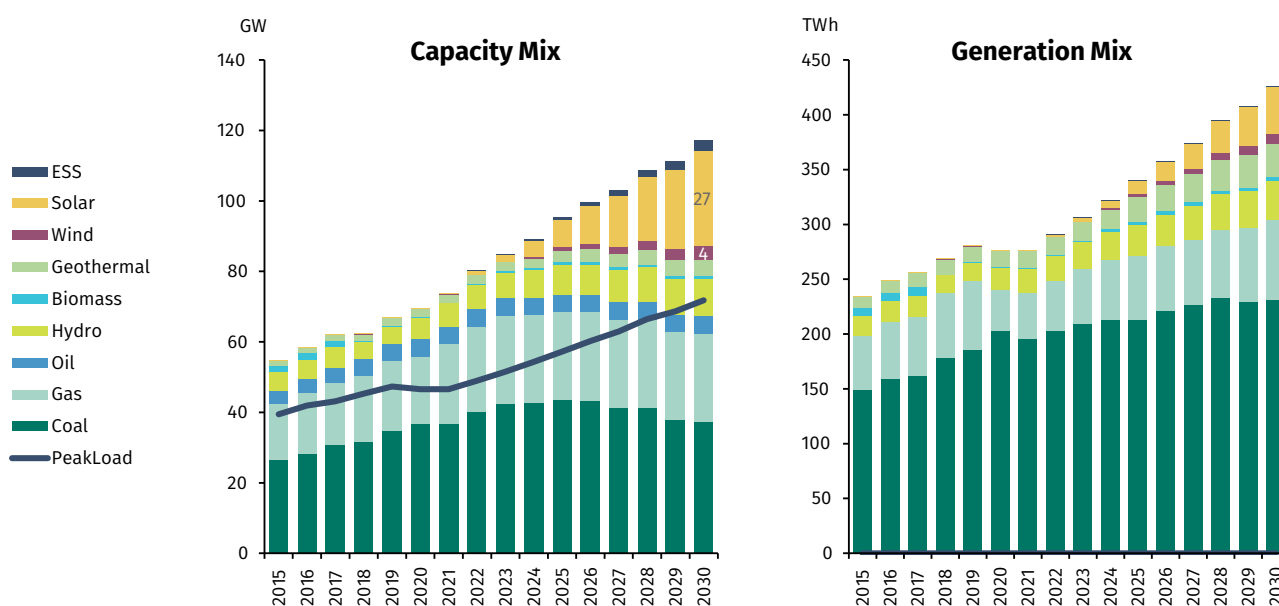
4.2.1. Indonesia

Scenario 1

The power optimization model builds a material amount of solar capacity under Scenario 1 (Economic RE entry), reaching 25 GW in 2030, about four times of the expected solar capacity under RUPTL 2021-2030 (Figure 21). More onshore wind capacity is also built, reaching 3.7 GW in 2030, higher than the 0.7 GW target capacity. There is also no addition of thermal capacity beyond those that are under construction. By 2030, solar and wind will account for 25% of the capacity share and 12% of the generation share.

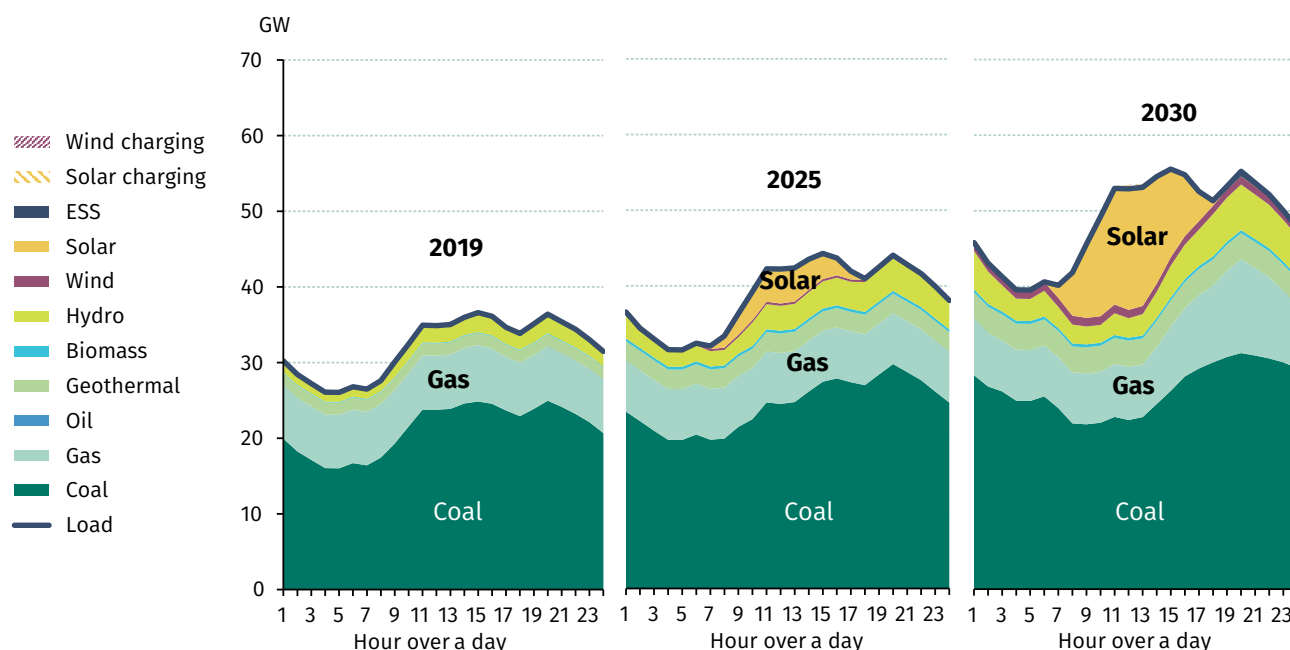
Figure 22 illustrates the dispatch of different technologies on an average hourly basis for Scenario 1. Most solar generation is concentrated from 10AM to 3PM, so its entry will gradually shift the peak hours to 5–10PM. The system can accommodate this level of solar penetration, although dispatchable capacity will need to be run more flexibly to meet the residual load during 5-10PM until storage solutions can be economically deployed at scale.

Figure 21: Capacity and Generation Mix in Indonesia Under Scenario 1



Source: WaterRock Energy Modelling

Figure 22: Average Hourly Generation in Indonesia under Scenario 1



Source: WaterRock Energy Modelling

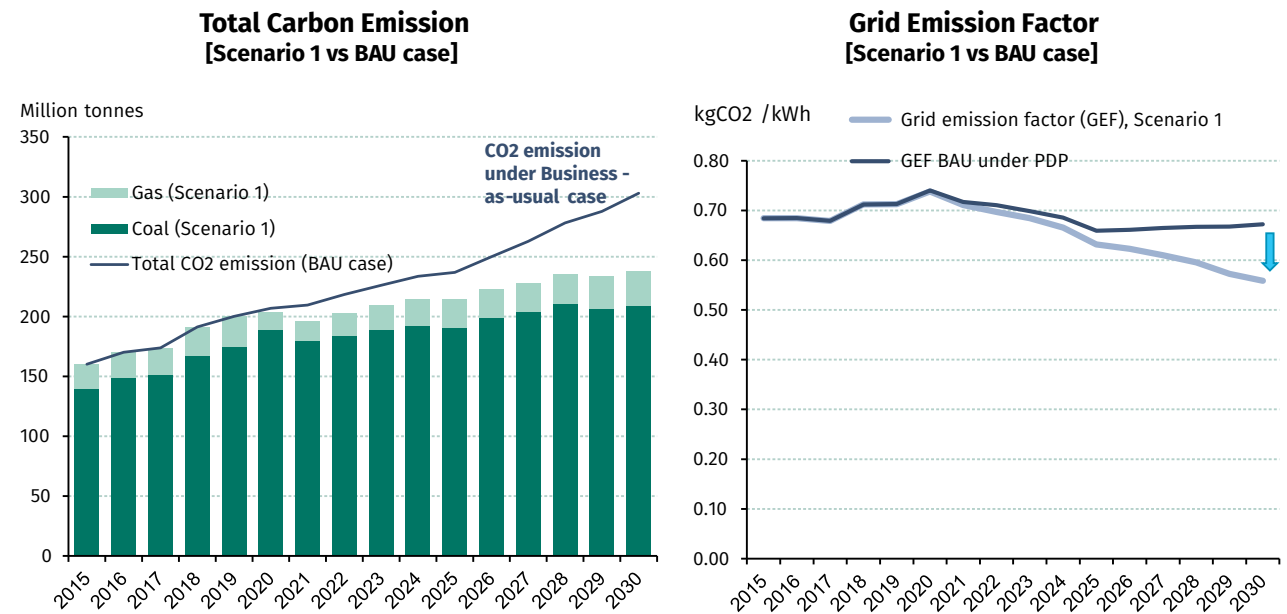
Whilst CO₂ emissions will still increase over the period, **total carbon emissions are about 24% lower than that of the BAU scenario in 2030. This is driven by a 5% lower demand and higher share of non-fossil fuel generation.**

The average grid emission factor (GEF), defined as the ratio of total CO₂ emissions and total power generation, is expected to decline slightly from 0.74 kgCO₂/kWh in 2020 to 0.56 kgCO₂/kWh in 2030. The reduction in GEF is driven by two key factors: (1) primarily, the share of non-fossil fuel generation increases from 12% in 2019 to 29% in 2030; and (2) more efficient coal capacity replaces the old and inefficient coal capacity. Under the BAU case, the grid emissions factor does not improve as thermal capacity remains key to meet incremental demand.

The total system cost¹³ reaches USD 34.3 billion in 2030, about 8.5% lower than that of the BAU case as it allows for the faster economic expansion of cheaper renewable capacity. The average system cost reduces from USD 90/MWh in 2021 to USD 80/MWh by 2030.

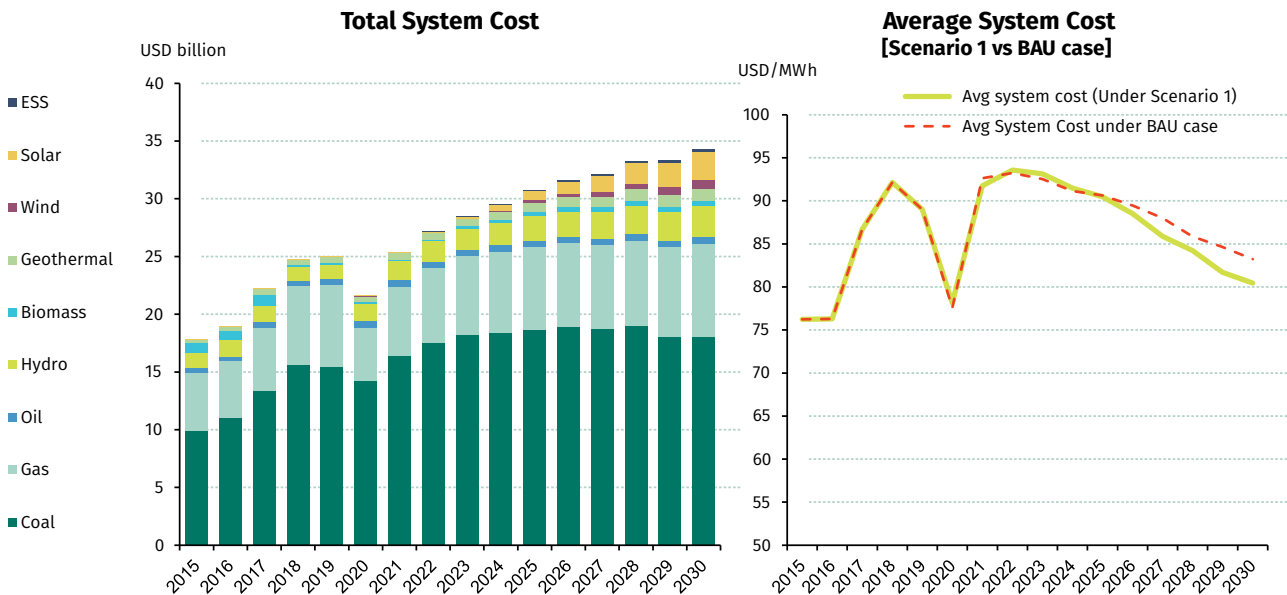
13. Includes all quantifiable costs that result from electricity production decisions, such as fuel cost, capital cost, operation and maintenance cost and CO₂ emission cost (if a carbon tax is imposed either explicitly by policymakers or implicitly by financial organisations). In our calculation, we have used a very conservative approach as we do not assume any carbon tax or any additional financing cost for coal.

Figure 23: Carbon Emission under BAU and Alternative Scenario 1



Source: WaterRock Energy Modelling

Figure 24: System Cost in Indonesia Under Scenario 1



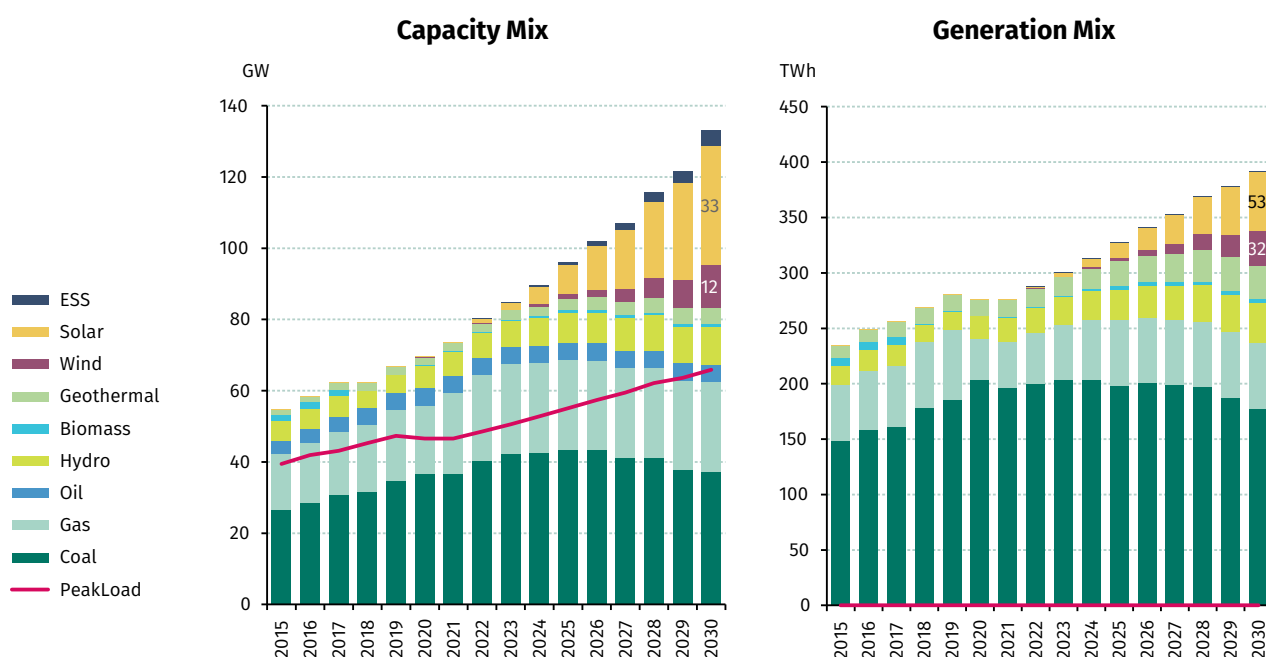
Source: WaterRock Energy Modelling

The power optimization model builds much more wind and slightly more solar capacity after 2025 in this Scenario – solar capacity reaches 28GW and wind capacity reaches 9GW in 2030 (Figure 25).

Faster entry of solar and wind helps to reduce CO₂ emissions, and the push for energy efficiency also helps to reduce demand growth and emissions. As illustrated in Figure 26, **the annual CO₂ emissions in 2030 are about 40% lower than that of the BAU scenario and about 24% lower than that of Scenario 1. Annual CO₂ emissions also remain about the same at 200-210Mt in 2021-2028 and start to decline after 2028.** The grid emission factor is reduced at a faster rate than in Scenario 1 from 0.74 kgCO₂/kWh in 2020 to 0.46 kgCO₂/kWh in 2030.

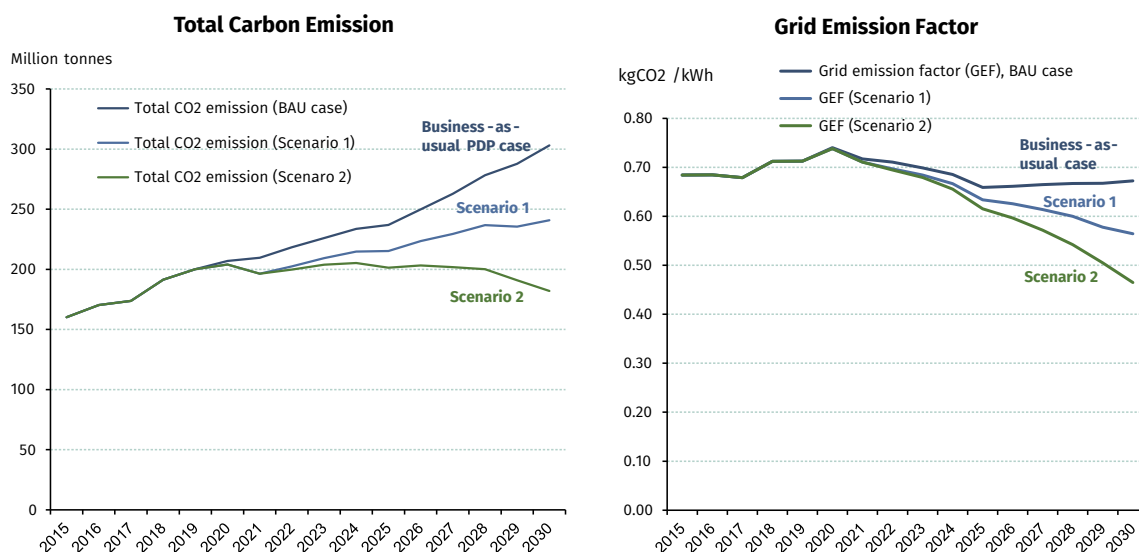
The total system cost reaches USD 33.5 billion in 2030, about 11% lower than that of BAU scenario and 2.3% lower than that of Scenario 1.

Figure 25: Capacity and Generation Mix Under Scenario 2



Source: WaterRock Energy Modelling

Figure 26: Carbon Dioxide Emission in the Power Sector in Indonesia under Scenario 2



Source: WaterRock Energy Modelling

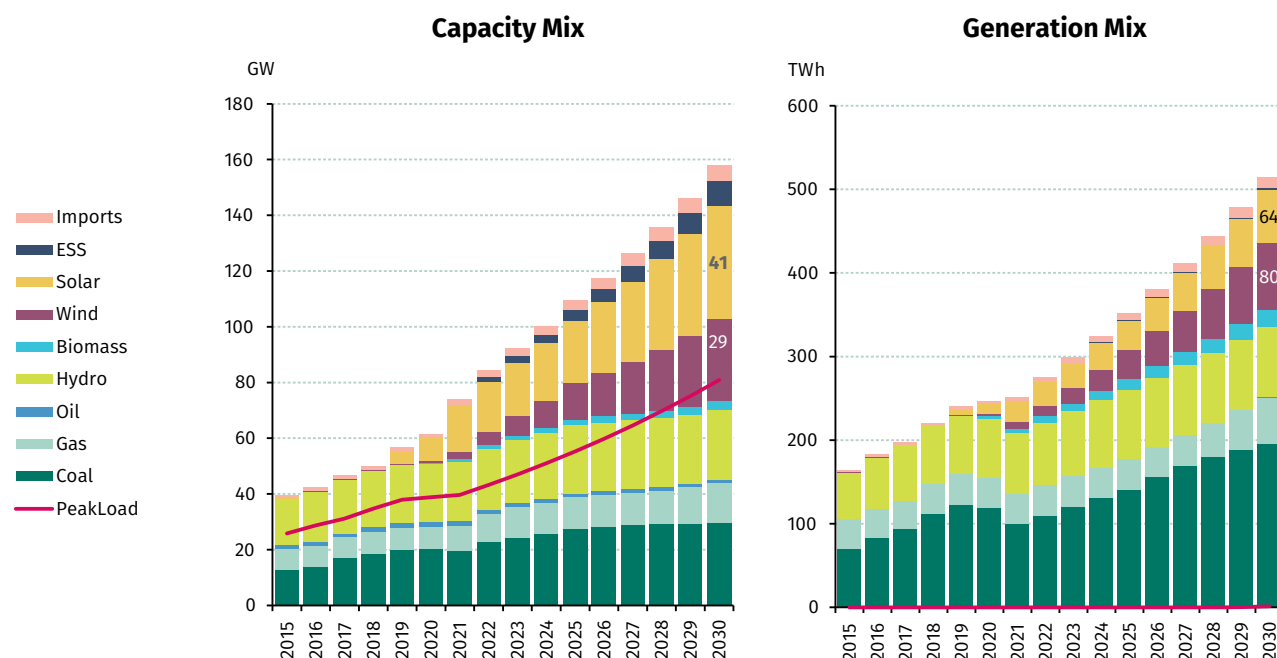
4.2.2. Vietnam

Scenario 1

The power optimisation model builds further solar capacity, with total solar capacity reaching about 41GW in 2030, about twice as much as the expected amount under PDP 8d (Figure 27). More onshore wind capacity is also built, reaching 29GW in 2030, higher than the 19GW target capacity under PDP 8d. By 2030, solar and wind will account for 44% of the capacity share and 28% of the generation share.

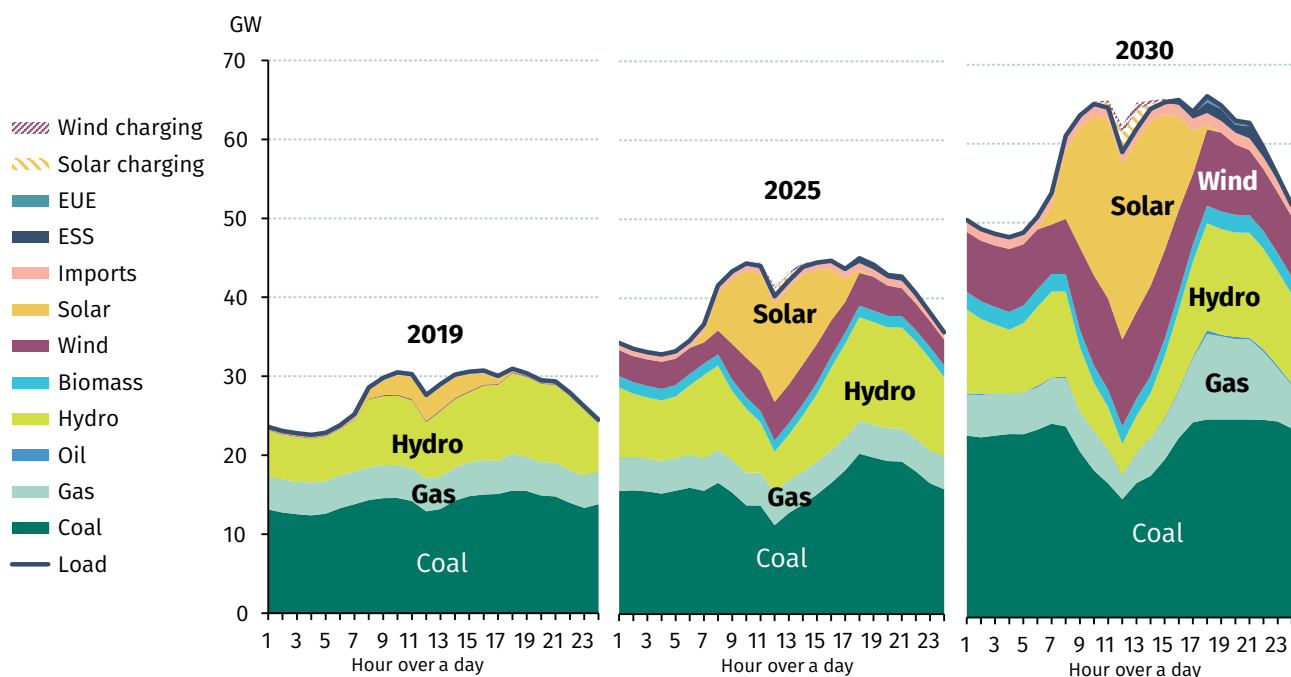
Similar to Indonesia, most solar generation is concentrated from 10AM to 3PM, so its entry will shift the peak hours to 5-10PM (Figure 28). More flexible capacity will need to be built for higher ramping requirements due to faster solar entry.

Figure 27: Capacity and Generation Mix in Vietnam Under Scenario 1



Source: WaterRock Energy Modelling

Figure 28: Average Hourly Generation in Vietnam under Scenario 1



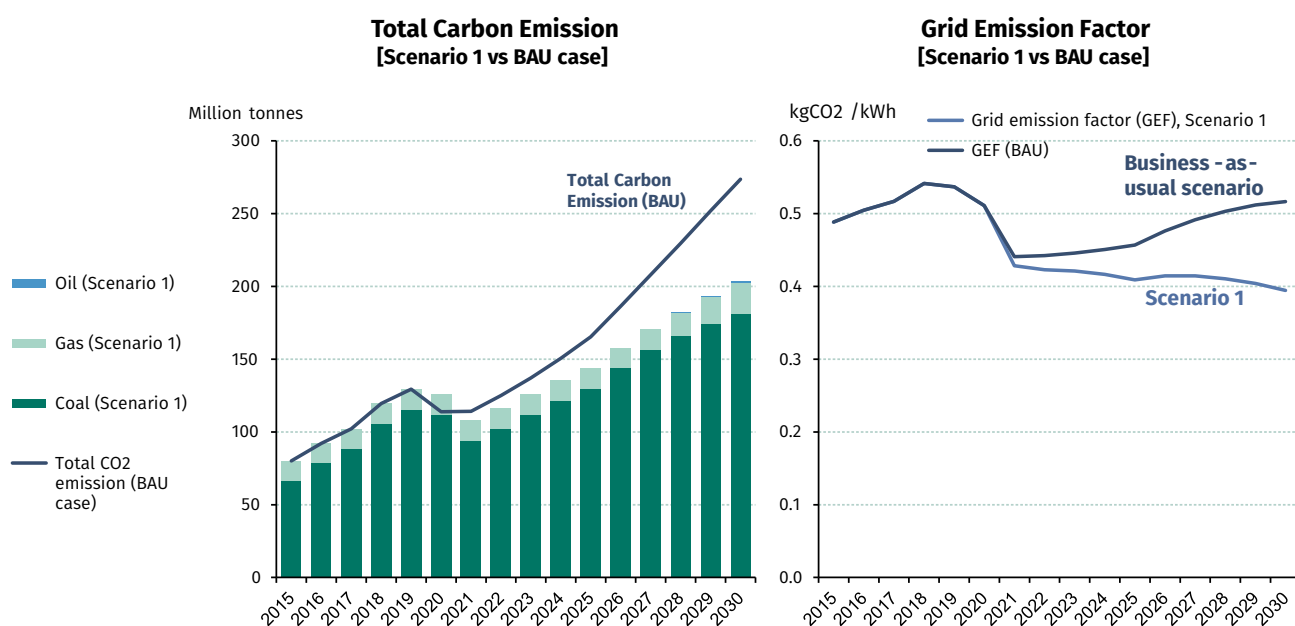
Source: WaterRock Energy Modelling

CO₂ emissions increase from 130 million tonnes (Mt) in 2019 to 204Mt in 2030 (Figure 29) as existing and the new 9GW committed coal capacity are run at a high-capacity factor to meet the strong demand growth in the next 10 years. **Driven by a higher share of non-fossil fuel generation, total carbon emissions under this Scenario are 26% lower than that of the BAU scenario in 2030.**

The average grid emission factor (GEF) is expected to decline from 0.51 kgCO₂/kWh in 2020 to 0.39 kgCO₂/kWh in 2030.

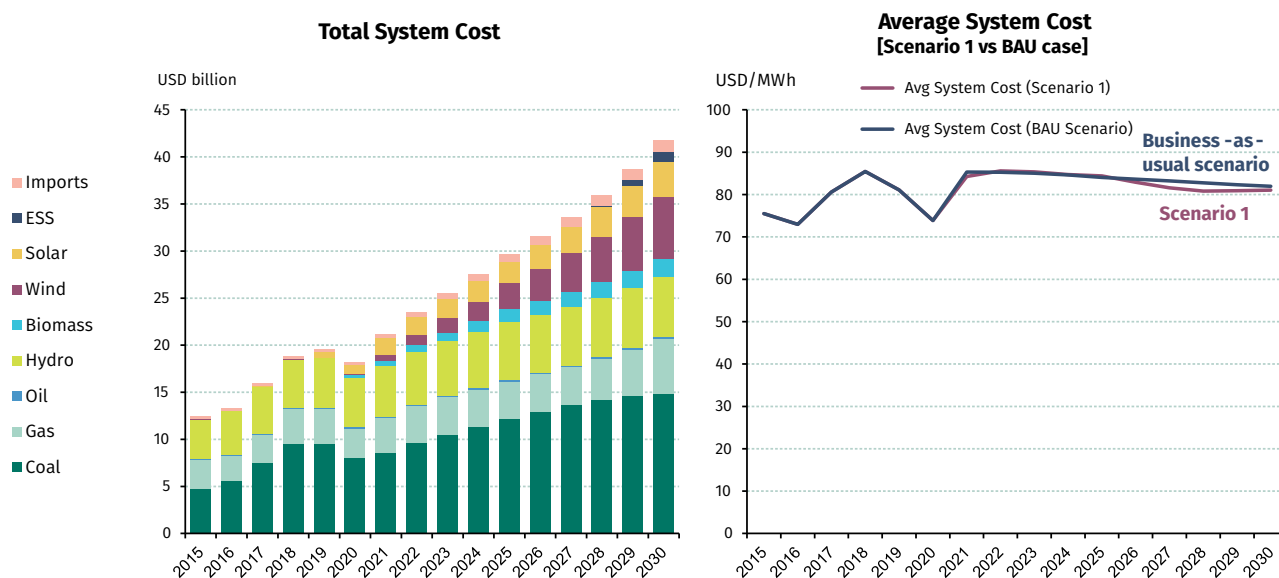
The total system cost reaches USD 41.8 billion in 2030, about 4% lower than the BAU scenario as cheaper solar and wind enters the system. The average system cost is reduced from USD 84/MWh in 2021 to USD 81/MWh by 2030.

Figure 29: Carbon Emission under BAU and Alternative Scenario 1



Source: WaterRock Energy Modelling

Figure 30: System Cost in Indonesia Under Scenario 1



Source: WaterRock Energy Modelling

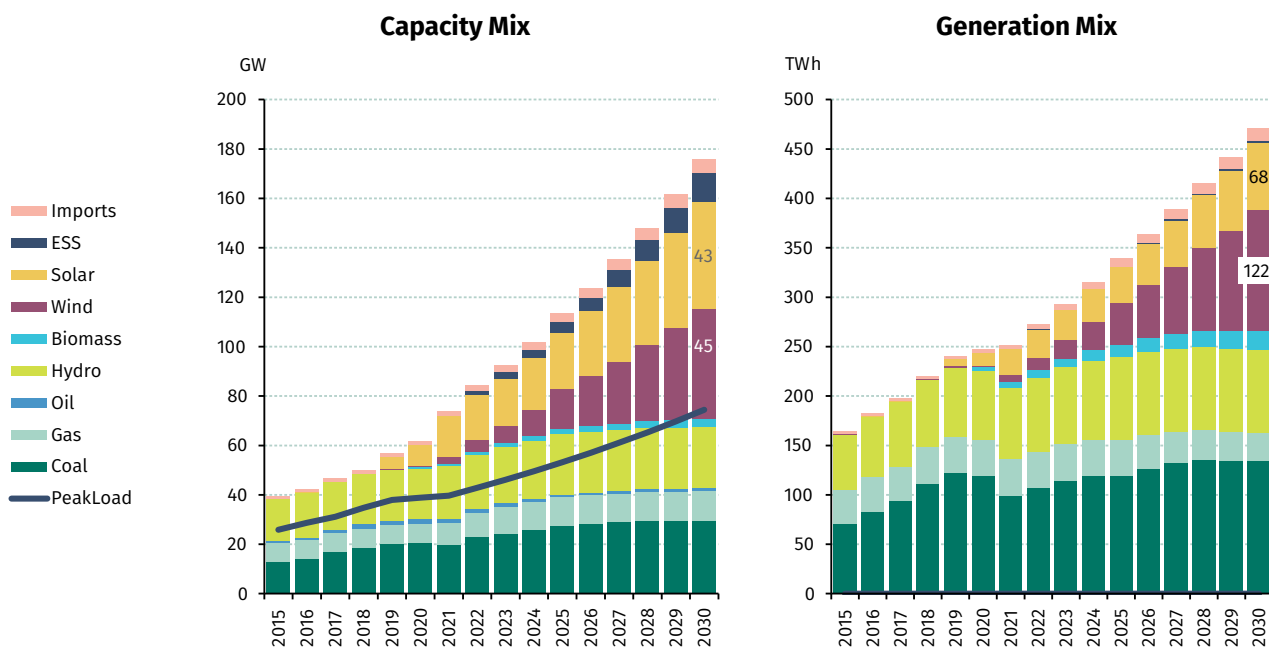
Scenario 2

Compared to Scenario 1, more onshore and offshore wind enters the system post 2025. Solar capacity reaches 43GW, onshore and offshore wind capacity reaches 39GW and 6GW respectively in 2030. Figure 31 illustrates the capacity and generation mix.

Faster entry of wind capacity helps to reduce carbon emission; the push for energy efficiency also helps to reduce demand growth and CO₂ emissions. **The annual CO₂ emissions in 2030 are about 51% lower than that of the BAU scenario and about 34% lower than that of Scenario 1.** Annual CO₂ emissions remain about the same at 135Mt in 2028-2030 (Figure 32); the grid emissions factor is reduced from 0.51kgCO₂/kWh in 2020 to 0.29kgCO₂/kWh in 2030.

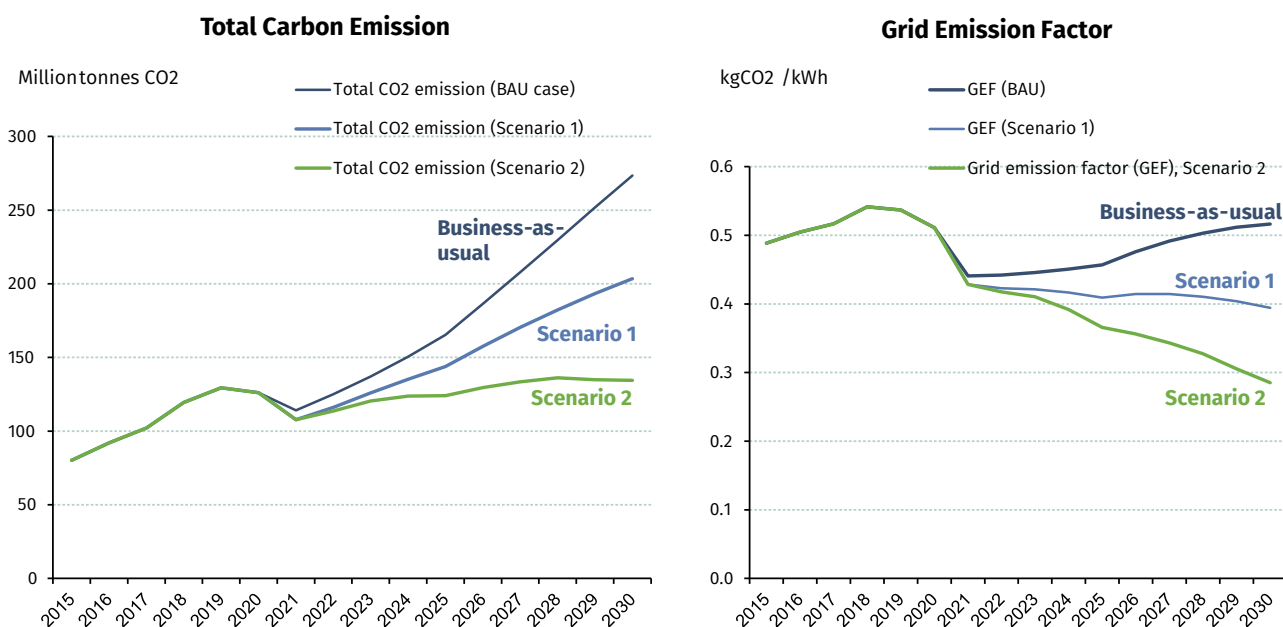
The total system cost reaches USD 39 billion in 2030, about 9% lower than that of BAU scenario and 6% lower than that of Scenario 1.

Figure 31: Capacity and Generation Mix in Vietnam Under Scenario 2



Source: WaterRock Energy Modelling

Figure 32: Carbon Dioxide Emission in the Power Sector in Indonesia under Scenario 2



Source: WaterRock Energy Modelling

5. KEY BARRIERS AND PROPOSED SOLUTIONS TO DE-CARBONISE THE POWER SECTOR IN ASEAN

As detailed in Chapter 3 and Chapter 4, solar and wind add value in many ways and it is **economical** to deploy renewables on a large scale in ASEAN. However, most ASEAN countries are yet to actively deploy renewables or they are being pursued well below the pace that is justified by economics. In their PDPs, most ASEAN governments have modest expansion plans for solar and wind. We highlight several key barriers and propose solutions to enable the economic entry of solar and wind capacity in Table 3.

Table 3: Key Barriers and Proposed Solutions

| Barriers | Description of the Barriers | Proposed Solutions |
|--|---|--|
| 1. Regulated power markets, including no non-discriminatory T&D access, no transparent dispatch Protocol, and subsidies to fossil fuels and thermal plants. | <p>ASEAN power markets, except Singapore and the Philippines, are largely based on an integrated market structure. There is no open access to T&D lines for renewable developers, and the T&D tariff is not independently set but bundled in the retail tariff. Thus, it is practically impossible to do off-site renewable corporate Power Purchase Agreements (PPAs). Renewable capacity expansion is also heavily dependent on the government plans, which are often overly conservative.</p> <p>The power dispatch protocols are opaque, and the power system operators typically dispatch power plants based on PPAs, increasing solar and wind curtailment risks.</p> <p>Subsidies are still provided to fossil fuels and thermal power plants in Indonesia, leading to inefficient investment signals and greatly reducing the incentives to improve energy efficiency.</p> | <p>The international best practice is to de-regulate the electricity market:</p> <p>Create a robust market structure by unbundling the competitive and non-competitive segments of the power system. T&D segment, system and market operations are monopolistic activities, so they need to be unbundled from the competitive generation and retail segments. Non-discriminatory access of T&D lines can then be provided to renewable developers.</p> <p>Tariff reform is required to independently set the T&D tariff. Subsidies for fossil fuel and thermal capacity need to be removed, thus providing the right investment signal and incentivise end-users to improve their energy efficiency.</p> <p>Wholesale competitive electricity markets can then be set up with independent systems and market power operators to adopt economic dispatch to reduce risk of grid curtailment.</p> |

| Barriers | Description of the Barriers | Proposed Solutions |
|---|--|---|
| | <p>Unclear regulation on project approval can delay renewable projects.</p> <p>Foreign ownership restrictions for renewable projects, such as the Philippines 40:60 rule¹⁴, dis-incentivise foreign investment.</p> | <p>Retail competition to be introduced over time.</p> <p>Streamline the regulatory process for approving renewable projects.</p> <p>Remove foreign ownership restrictions (if any) for renewable projects.</p> |
| 2. Lax environmental regulation and uncoordinated energy policies/ targets | <p>Environmental regulation on the emission of CO2 and non-carbon air pollutants are outdated.</p> <p>Energy policies from different government agencies can be unaligned, causing confusion in the market.¹⁵</p> | <p>Tighten the environmental regulation on non-carbon air pollutants from power plants to reflect public demand and the technological advancement of air control technologies.</p> <p>In Indonesia, Vietnam and many other ASEAN countries, there is a need for further cooperation between the energy policy making body and the environmental policy making body to ensure that concrete actions are implemented to meet climate change targets.</p> <p>International organizations can help to build up the capacity and capability of the energy and environment policy making bodies in ASEAN. Regional cooperation and knowledge sharing within ASEAN can also be facilitated.</p> |

14. Foreign equity is limited to 40% for wind and solar projects in the Philippines.

15. ADB has highlighted this as one of the core issues during their December 2020 assessment of the Indonesian energy sector, “Many electricity sector policies awaiting implementing rules and regulations are not aligned with each other, or contradict related non-energy regulations. Several official plans, including RUEN (Rencana Umum Energi Nasional, i.e. National Energy General Plan), RUPTL, and RUKN (Rencana Umum Ketenagalistrikan Nasional, i.e. National General Plan for Electricity), rely on unrealistic data input assumptions, and provide conflicting and unachievable targets.”

In Vietnam, at least three papers have identified the power dynamics of strong and weak institutions, and conflicts of interest, as a barrier in the formulation of a cohesive energy transition policy. EVN has been identified by ADB as a dominant actor in the energy sector. The Ministry of Industry of Trade (MOIT), as the owner of EVN, takes the lead in power-sector reform, regulation and supervision. Its multiple interests therefore may conflict at different levels with other regulatory bodies in Vietnam. Ministry of Environment and Natural Resources (MONRE) supports climate change action more than other policy makers. However, like MOIT, MONRE aligns with economic arguments for cost-efficiency and development, rather than energy transition related policies. The energy actors (i.e. state-owned enterprises) are “unsupportive or lukewarm in their support for GHG emissions reduction and do not consider this to be in their direct interest or their responsibility”, according to a 2017 FES Asia paper.

Sources: <https://www.adb.org/sites/default/files/institutional-document/178616/vie-energy-road-map.pdf>
<https://www.tandfonline.com/doi/full/10.1080/17565529.2020.1723469>
<https://library.fes.de/pdf-files/bueros/vietnam/13684.pdf>

| Barriers | Description of the Barriers | Proposed Solutions |
|--|--|--|
| 3. Misalignment of benefits and costs or adverse side-effects | <p>Environment costs of building or keeping coal plants are not taken into account while coal projects bring employment and investment for local communities and governments. Thus, local communities and governments may prefer to pursue coal projects or resist the call to retire old coal plants.</p> <p>Socialized benefits can also incur local costs. One example is related to the construction of transmission lines to connect to renewables in remote areas. These transmission lines can create NIMBY (“not in my back yard”) problems for affected residents and communities that do not directly share the benefits of renewable capacity.</p> | <p>Coal retirement- one solution is to provide “grants” or other commercial incentives contingent upon the retirement of coal plants and retraining of staff for new green jobs to ensure a just transition. Given potential budget constraints of ASEAN governments, international funding is required to help facilitate this, including from developed countries that have agreed to deliver and facilitate a just transition under the Paris Agreement.</p> <p>The Energy Transition Mechanism is another innovative solution that can be considered. Specific conditions, such as no new coal capacity, can be imposed to ensure that the local power system is truly transiting away from coal when international funding/support is provided.</p> <p>For the NIMBY issue on transmission capacity expansion, the redistribution of benefits or the introduction of additional beneficial local projects can help offset some of the adverse side effects of initial project in question.</p> |
| 4. Limited risk tolerance for potential RE investors and lenders. | <p>Investors may have limited ability to bear risk even if economics make sense. This may result from perceived high counter-party risk of the local utilities, exposure to “unpredictable” public policy shifts or lack of hedging or insurance.</p> <p>Some renewable developers may face project finance difficulties.</p> | <p>Governments need to help improve the financial position of the integrated utilities in ASEAN like PLN via tariff reform to remove power tariff subsidies.</p> <p>Ensure a stable and transparent regulatory framework/regime for renewables, and benchmark their renewable PPA templates to international best practices.</p> |

| Barriers | Description of the Barriers | Proposed Solutions |
|----------|-----------------------------|--|
| | | <p>International development banks should be encouraged to be more involved and provide seed financing or provide credit enhancement for renewable projects in ASEAN.</p> <p>International and local financial institutions can help to provide more long-term green financing at low rates.</p> |

CASE STUDY: TENAGA NASIONAL BERHAD

TNB, Peninsular Malaysia's vertically integrated electricity utility company, outlined a new sustainability pathway in August 2021 that targets net zero emissions by 2050. However, the company still faces multiple barriers in achieving that target, particularly over curbing near term emissions. In order to limit global warming to 1.5 degrees, science indicates that utilities in emerging markets need to phase out coal by 2040.

One of the key barriers for TNB and other renewables developers is the vertically integrated and regulated power market structure, which does not allow for non-discriminatory T&D access nor has a transparent dispatch protocol.¹⁶

Since 2010, the Malaysian government has started its power market reform in Peninsular Malaysia. In early 2020 (before COVID-19), the government considered granting green generators access to T&D infrastructure via an interim Third Party Access (TPA) framework using a Green Third-Party Contract (GTPA). However, such an arrangement has yet to be rolled out, possibly due to more urgent priorities during the pandemic. Without T&D access, renewable developers are not able to sign up long-term green corporate PPAs with end-users directly, hindering their capacity expansion.

16. In Malaysia, since 2016, the development of solar PV has been supported through the Large-Scale Solar (LSS) competitive tender programme for capacity greater than 1 MW and the Net Energy Metering (NEM) programme for rooftop solar capacities. The annual quota for the LSS tender and the solar cap for the NEM programme are administratively determined by the Malaysian government, but not driven by market forces.

We recommend that the Malaysian government re-launch the interim TPA framework to allow green generators access to the T&D infrastructure. In the medium-term, the government should push forward the tariff and market reform to have a robust tariff setting and open access regime for the power T&D lines based on best international practices¹⁷.

In Peninsular Malaysia, reform has also been implemented to improve the transparency and independence of the power dispatch process with the creation of a ring-fenced Single Buyer. The Single Buyer is the entity that carries out the New Enhanced Dispatch Arrangement (NEDA). NEDA provides a platform for non-PPA generators to bid into a market to sell electricity. Since its launch in June 2017, the rules of NEDA have been evolving:

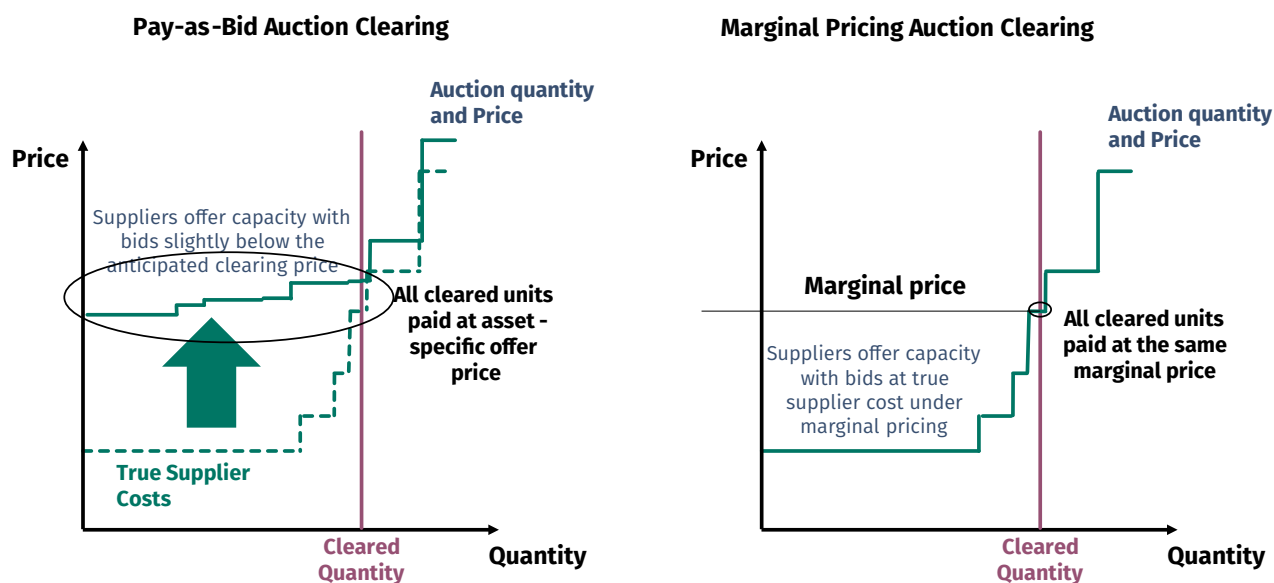
- **It has evolved from a pay-as-bid to a marginal pricing arrangement.** As illustrated in Figure 33, in a pay-as-bid arrangement, suppliers are paid based on their bid price; in a marginal pricing arrangement, suppliers are paid based on the market-clearing price, at a marginal cost of the last producing unit to meet electricity demand. This is **an improvement** as the latter increases competitions whilst reducing inefficiencies¹⁸ and is consistent with international best practices in other competitive electricity markets.
- As bidding under the new NEDA rule is cost-based, a capacity market¹⁹ needs to be introduced to cover fixed O&M and fund any material capital investment for marginal new capacity in the future. **We recommend that the government conduct a study into the need for a capacity market and its compatibility with other market reform initiatives.** A well-designed capacity market can help attract the entry of flexible capacities. This enables the power grid system to accommodate the high penetration rate of non-dispatchable solar capacity.
- Under NEDA, PPA and merit-order dispatch is used. Over time, **we recommend that the government shift the market towards economic merit-order dispatch.**

17. There is a rich literature on power tariff reform and tariff design. One example is the [“Cost Recovery and Financial Viability of the Power Sector in Developing Countries”](#) published by the World Bank in December 2017,

18. Under the old NEDA rule, generation is paid what it bids. Under pay-as-bid, hydro would have to guess that market price and bid accordingly rather than bidding to a rule curve. This creates extra work for no extra benefit. Furthermore, it is generally accepted that bidding behaviour under pay-as-bid arrangement can introduce inefficiencies, weaken competition in new generation and may impede expansion in capacity.

19. Under a cost-based energy market, the marginal units will not be able to recover their fixed cost (i.e. capital cost and fixed operation and maintenance cost). This gives rise to a “missing money” issue. The typical solution is to introduce a capacity market, which provides an additional stream of revenue to help investors recover their fixed cost. The capacity market is also often linked to reliability target and is used to ensure resource adequacy of a system is met. Typically, a centralized auction of capacity is done a few years ahead, and cleared capacity will be remunerated but also have the obligation to be available and to operate in such a way to provide at least as much reliability value to the system as they have committed to.

Figure 33: Pay-as-Bid vs Marginal Pricing Auction Clearing



Source: WaterRock Energy Research and Analysis

As more energy is procured through NEDA, and as this market mechanism further develops, it can potentially move towards a forward capacity plus energy market arrangement, similar to the US PJM (Pennsylvania-New Jersey-Maryland Interconnection) electricity market in the long run. Such market design can help to set up a robust market-based mechanism to facilitate the entry of flexible capacity, accommodating high solar penetration in the long term in Peninsular Malaysia.

6. CONCLUSION

Policymakers need to take a large range of factors into account as they make long term decisions on power generation mix. This report proposes a total value framework that considers the cost, sustainability and security elements respectively in this decision-making process.

The modelling from this report shows that, even based on highly conservative assumptions, Indonesia and Vietnam can achieve peak CO₂ emissions around 2025 without an increase in system cost. In the optimisation model, solar and wind capacities are substantially higher and the need for the adoption of energy efficiency programs is highlighted. These alternative scenarios for 2020-2030 will go a long way towards helping countries meet long-term net zero emissions ambitions.

Whilst there are multiple barriers to achieve this, they can be addressed via power market reform, tightening of environmental regulation, innovative and local solutions to “re-align” benefit and cost and credit enhancement to “de-risk” solar and wind capacity investment.

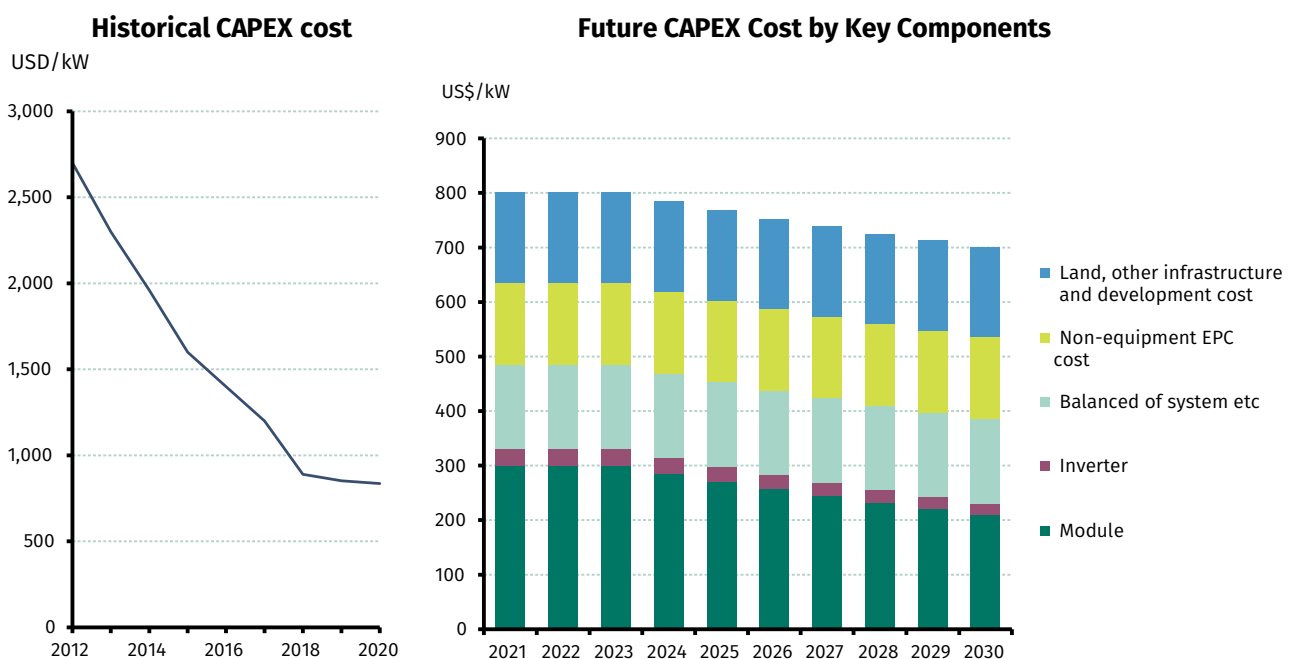
This report shows that ASEAN nations have the opportunities to realise their renewables potential without compromising growth, and that this is a path that will bear fruits in the long run both from an economic and social perspective.

APPENDIX A : COST IMPROVEMENT OF SOLAR AND WIND CAPACITY

Solar PV

The cost of installing a solar PV plant fell dramatically in 2010-2018 by an annual rate of more than 15%, driven by technological improvement and a bigger manufacturing scale. The cost reduction has been slower since 2018 as the share of non-technology related costs increase and due to the relatively high global demand for solar panels and inverters in the past few years. In the next 10 years, we expect that the total cost will continue to fall by an annual rate of 1.5%, driven by the expected cost reduction of solar panels and inverters.

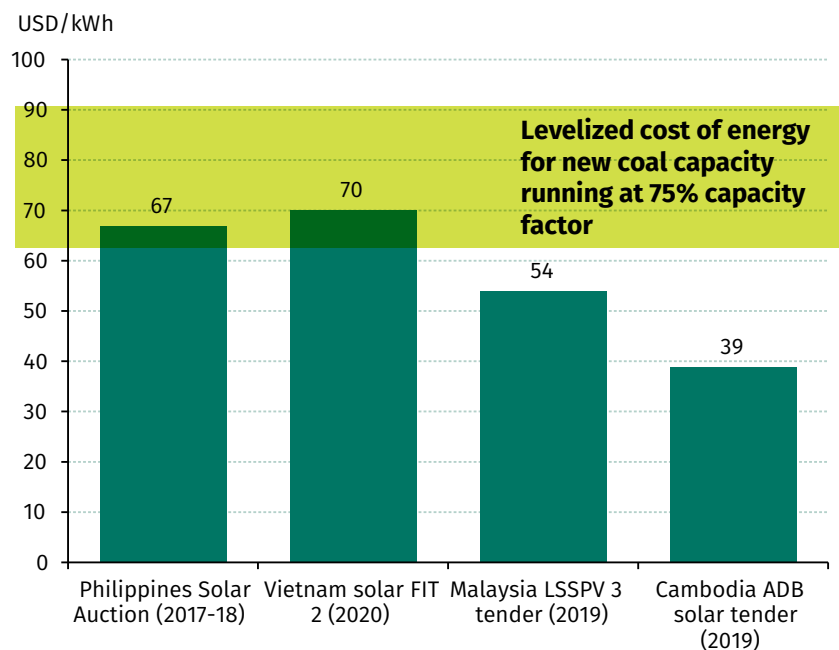
Figure 34: Overnight CAPEX of Installing Solar Plants in ASEAN



Source: IRENA, IEA, Vietnam PDP 8 draft, WaterRock Energy Research and Estimates

With the rapidly declining cost, solar has become economic in many ASEAN markets since 2018. Based on the competitive solar auctions in several ASEAN markets, the auction price outcomes are in the range of USD 40-70/MWh, which is cheaper than building a typical new coal-fired power plant in the power system.

Figure 35: Solar Auction Price Outcome in ASEAN



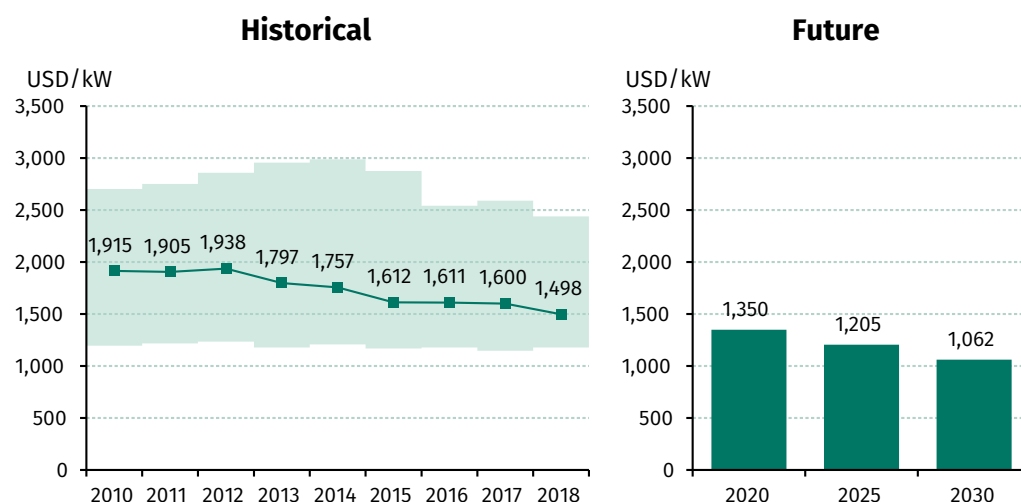
Source: Public news clips, WaterRock Energy Research and Analysis

Onshore Wind

Average capital costs of onshore wind (turbine and balance of system) have reduced at an average annual rate of 3.7% in 2010-2018 (Figure 36). Wind turbines have also become larger, which helps to increase the swipe area and average capacity factor.

The exact cost and capacity factors of onshore wind projects are site-specific and can vary substantially. We expect that the cost of onshore wind to decline at an annual rate of 1-3%.

Figure 36: CAPEX Cost of Onshore Wind

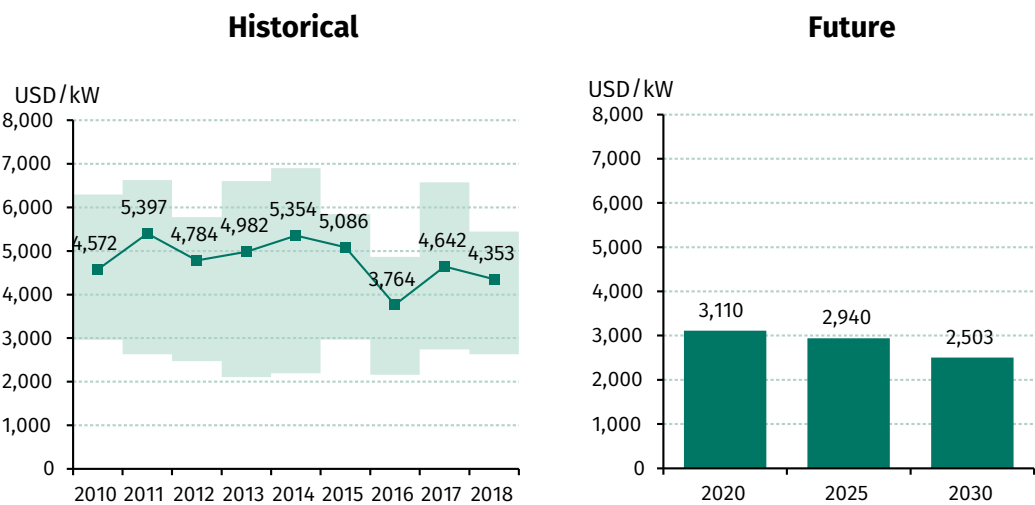


Source: Historical data are based on assessment from IRENA and the future cost is based on the mid-case onshore wind CAPEX cost in the Vietnam PDP 8 draft.

Offshore Wind

The offshore wind sector is still at a nascent stage in ASEAN and there is no offshore wind capacity in the region. The total cost of building offshore wind projects is still high, and total CAPEX cost has been fluctuating in 2010-2018. Nonetheless, as there has been a strong push to develop offshore wind capacity in Europe, UK, US and North Asia, the manufacturing scale of the offshore wind value chain is likely to increase substantially and there will be also technological advancement. These can help to reduce the cost in the coming years. In ASEAN, Vietnam has good offshore wind resources.

Figure 37: CAPEX Cost of Offshore Wind



Source: Historical data are based on assessment from IRENA and the future cost is based on the mid-case onshore wind CAPEX cost in the Vietnam PDP 8 draft.

APPENDIX B : CALCULATION OF LEVELIZED COST OF ENERGY

We provide more explanation on the different items in Table 1 of Section 3.2.1, and the process of calculating the levelized cost of energy. The after-tax weighted-average cost of capital (ATWACC) is an estimate of the cost for an investor to raise capital (both debt and equity). This represents the necessary return to raise the capital needed to make the investment, which is a fair return as anything less would not support the investment and anything above this amount reflects excess rents collected by the investor.

“Fixed O&M” is “fixed operation and maintenance” cost, and it refers to the operation and maintenance cost that cannot be changed in the short-term and does not relate to the generation volume, such as full-time staff cost, office services, long-term service cost for the power turbines, insurance cost etc. “Variable O&M” is “variable operation and maintenance” cost, and it refers to the cost that is related to the generation volume, such as water cost, the balance of plant, chemicals, and consumables etc.

“Capital Recovery Cost” is based on the summation of annual cost recovery and annual depreciation shield.

The annual cost recovery (not including the depreciation tax shield) in each year of the investment life cycle would allow the supplier to earn a fair return on the investment.

$$\text{Annual Cost Recovery} = \frac{\frac{\text{Investment} * \text{ATWACC} * (1+\text{ATWACC})^{\text{Years in Life Cycle}-1}}{(1+\text{ATWACC})^{\text{Years in Life Cycle}} - 1} * (1+\text{ATWACC})}{(1-\text{Tax Rate})}$$

The total investment is depreciated over the life cycle using straight-line depreciation, meaning the depreciation is equal in each year of the investment life. The annual depreciation tax shield is calculated based on the tax rate multiplying the annual depreciation and then gross-up with the corporate tax rate.

$$\text{Annual Depreciation Shield} = \frac{\text{Tax Rate} * \text{Annual Depreciation}}{(1-\text{Tax Rate})}$$

For fuel cost, coal price is based on USD 90/metric tonnes of FOB Newcastle coal and USD 9/tonne of freight cost. Delivered LNG price to the CCGT plant is based on oil-linked delivered ex-ship LNG price with a slope of 0.125, a constant of USD 0.5/MMBtu at Brent price of USD 65/barrel and LNG terminal fee of USD 1/MMBtu.

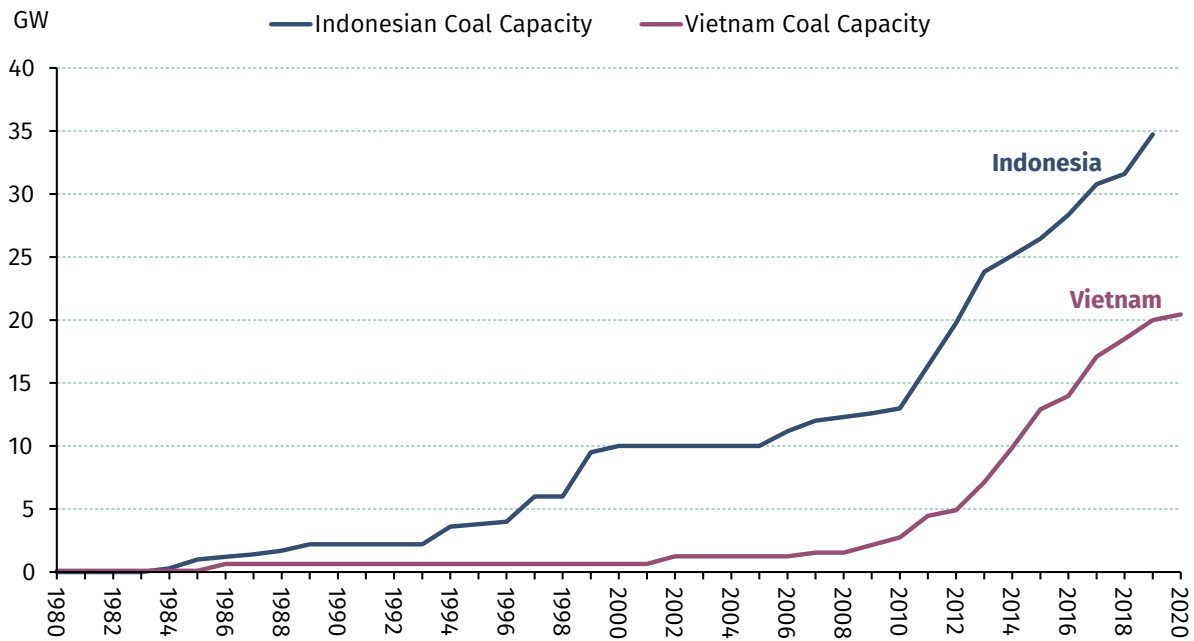
Levelized Cost of Energy of a Technology (LCOE) in USD/MWh =

$$\text{Heat Rate} * \text{Fuel Price} + \text{Variable O\&M} + \frac{\text{Fixed O\&M} + \text{Capital Recovery Cost}}{(\text{Capacity Factor} * 8760)}$$

APPENDIX C : ASSUMPTIONS ON CAPACITY ADDITION AND RETIREMENT OF COAL CAPACITY IN OUR ALTERNATIVE SCENARIOS

C.1 RETIREMENT OF OLD COAL CAPACITY IN INDONESIA AND VIETNAM

Figure 38: Existing Coal-fired Power Capacity in Indonesia and Vietnam



Source: Indonesian MEMR, Vietnam EVN, IEA, WaterRock Research

The first wave of coal capacity addition happens in 1990-2000 in Indonesia, and it is mainly built to avoid power shortages and replace oil plants. These old coal projects have reached 20-year life, but most of them are still operating in the market. As new coal units are being added quickly and solar and wind capacity can enter economically, these old coal units should be retired in the coming years.

- In Indonesia, coal capacity was increased from 2.2GW in 1990 to nearly 10GW in 2000. Many of those PPAs has expired or are about to expire. As those coal projects are generally sub-critical coal plant without the installation of the latest Air Quality Control System, they have an adverse side effect on emissions of CO₂ and non-carbon air pollutants. We assume that they are retired after reaching 30 years of economic life in our model.²⁰

20. In the draft RUPTL 2021-2030, PLN has proposed a retirement schedule of coal capacity in 4 phases. In 2021-2030, it plans to retire three coal-fired power plants (Muara Karang plant in Jakarta, Tambak Lorok in Semarang, Central Java, and a gas/coal-fired power plant in Gresik, a regency in East Java) by 2030 with a total capacity of 1.1 GW. In 2035, PLN plans to retire its conventional power plants which have a total capacity of 9GW. By 2040, supercritical coal power plants with a total capacity of 10GW, will be shut down. The final phase of coal retirement will see its ultra-supercritical coal power plants shut by 2056. The coal retirement in 2021-2030 is too conservative and assumes older coal capacity can operate for 40-50 years. Details on the assumption for the life-span of coal plants are also discussed in Appendix C.

- In Vietnam, less legacy coal capacity was built in the 1990s; its total installed coal capacity was only 0.645GW by 2000. Similarly, we assume that they will be retired after reaching 30-year life.²¹

There has been a second wave of coal capacity addition in Indonesia, Vietnam and other developing ASEAN countries since 2010. As “sustainability” becomes much more important in the domestic and global markets, it is sensible to assume that the second wave of coal projects have a 20-year or even less economic life span.

C.2 STATUS OF THE NEW COAL PROJECTS UNDER PLAN IN INDONESIA AND VIETNAM

For the alternative scenarios, we assume that only coal capacities that are currently under construction are brought online, with a delay of 0.5-2 years due to the COVID-19 pandemic. For coal projects under plan, we do not include them as “committed” plants. These planned coal projects will likely have difficulty of getting financing as the key lenders of the existing large coal projects in Indonesia and Vietnam are all under pressure to stop financing new coal projects.

- In April 2021, JBIC’s governor stated that JBIC would stop funding coal power projects overseas.²² There is also growing domestic and international pressure for the Bank to stop financing new coal projects.
- In South Korea, there is a pending bill in the National Assembly to ban KDB and other government-affiliated institutions from participating or financing overseas coal projects by excluding them from the business scope of these agencies.²³ A commitment to this effect was also made by South Korean President Moon Jae-in at the US-hosted Leaders Summit on Climate Change. China Eximbank is a signatory to the Green Investment Principles for the Belt and Road Initiative²⁴, and is under increasing pressure to stop or materially reduce its financing activities for coal-related projects.

The following sub-sections provide more information on the status of those coal projects.

21. As per the draft PDP8, there are no planned retirements for Vietnam’s existing coal power plants. In Vietnam, the oldest operating power plant is the 46-year old 50 MW Uong Bi Unit 5, commissioned in 1975. There is only a total of 545MW coal plants whose ages are more than 30 years, which are possible candidates for retirement. 81% of Vietnam’s operational coal capacity is below nine years old as of 2021.

22. This is based on a news clip from [NHK News](#).

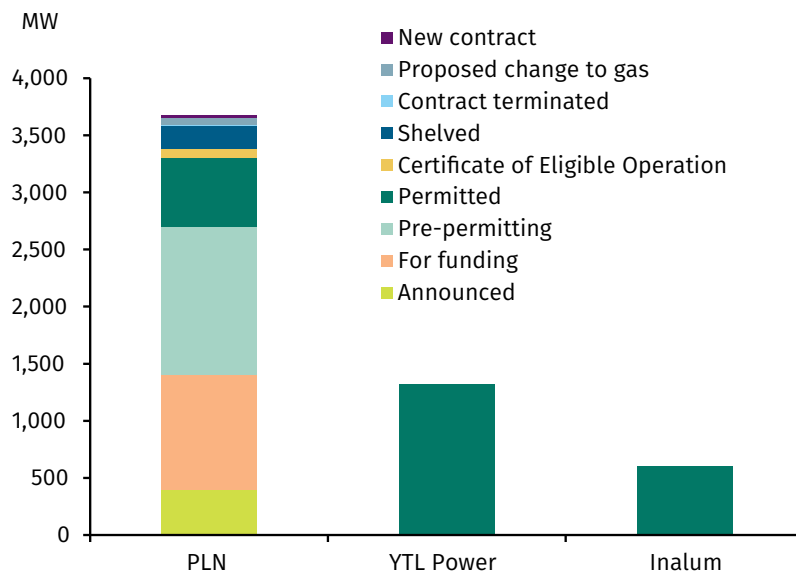
23. This is based on a “[Tracing 12 Years of Korea’s Coal Finance Addiction](#)” report.

24. The list of financial institutions (including China Eximbank) that signed up the Green Investment Principles for the Belt and Road Initiative (BRI) are in the [BRI website](#) [<https://green-bri.org/green-investment-principle-gip-belt-and-road-initiative/>].

C.2.1 Indonesia

There are still significant numbers of coal power projects which are awaiting construction in Indonesia (5,595 MW) and Vietnam (22,610 MW). Majority of these projects are still in the hands of state-owned entities such as the utilities PLN and EVN, public financing and private holdings companies.

Figure 39: Coal Projects under Pre-construction Phase in Indonesia



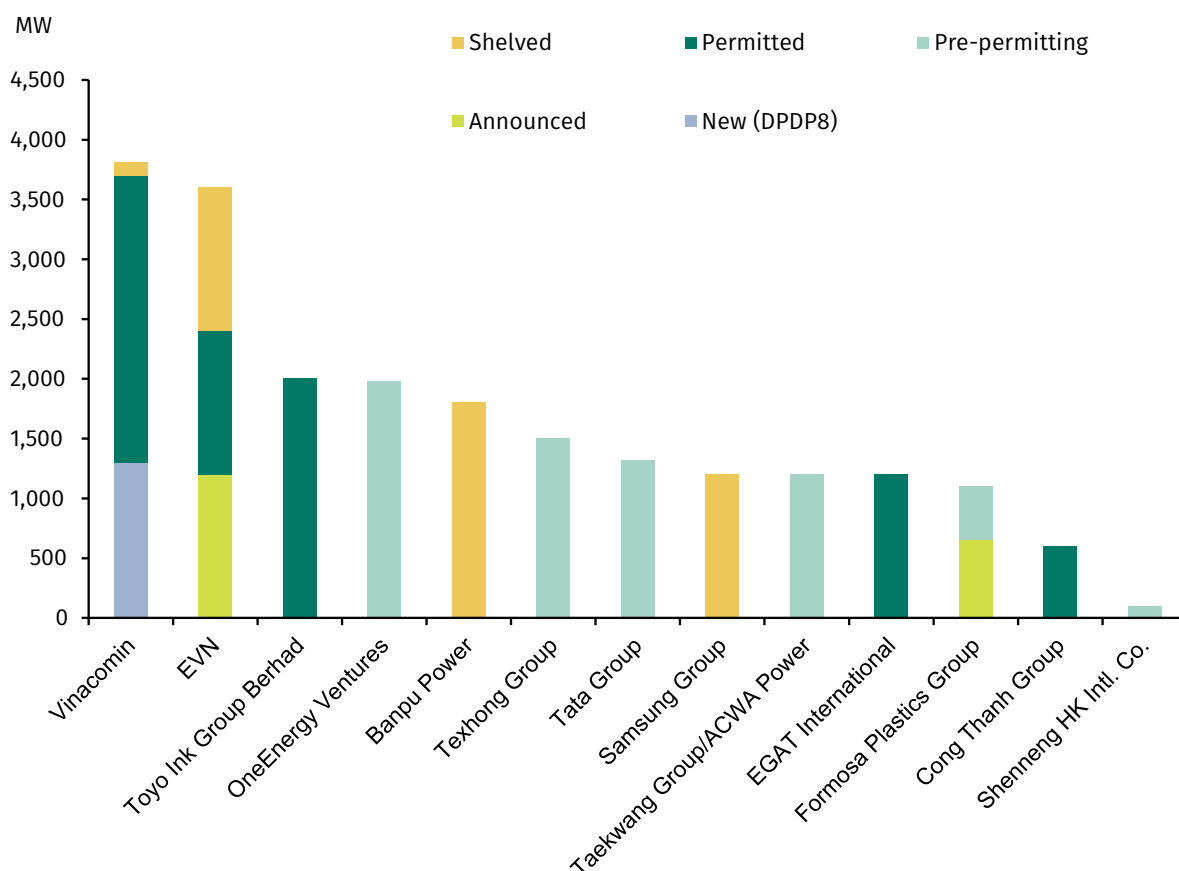
Source: WaterRock Energy Research and Analysis

In the case of Indonesia, 65% of the projects in the pre-construction pipeline are still held by PLN, the state-owned utility, in various stages of development. These include projects which are seeking funding or co-investors (1,000 MW), have not been granted permits yet (1,300 MW), have been granted permits (600 MW), or have had their contracts terminated or have been re-contracted after termination of contract with the previous partner (34 MW). Furthermore, 60 MW have been proposed to be converted to gas-powered plants. Only 81 MW have been issued a Certificate of Eligible Operation, the precursor to the construction phase. One project has the status of “announced” (400 MW Sulbagsel Unit 1 and 2) since it has just been included in the draft RUPTL 2020.

There are only two Indonesian projects in the pre-construction phase which were undertaken by private entities as parent companies. The 1,320 MW Jawa-3 FTP2, also known as Tanjung Jati A is owned by Malaysian holdings company YTL Power (80%) and Indonesia’s Bakrie Group (20%). Local companies Indonesia Asahan Aluminium (Inalum) and PT Butik Asam (PBTA) own the 2x300 MW Sumut 1 Unit 1 and 2. The aluminium refinery would use 600 MW for its own use. It is described as an independent power project (IPP). These two projects are already in the permitted status.

C.2.2 Vietnam

Figure 40: Coal Projects under Pre-construction Phase in Vietnam



Source: WaterRock Energy Research and Analysis

In Vietnam, a third of the coal projects in the pre-construction phase is controlled by the public entities Vinacomin (3,810 MW) and Electricity Vietnam (EVN) (3,600 MW).

- Vinacomin is a state-owned coal and minerals corporation while EVN is a public distribution utility. A total of 1,300 MW of projects held by Vinacomin have been included in the draft PDP8.
- EVN has announced it will convert 1,200 MW to gas projects.
- The rest of the pipeline of 14,000 MW is owned by private local and international entities.

Toyo Ink of Malaysia's 2,000 MW Song Hau II project is the third largest. It has been on a permitted status similar to EGAT of Thailand (1,200 MW) and local cement manufacturer Cong Thanh (600 MW). Other international companies currently have their projects in the pre-permitting process: OneEnergy (1,980 MW), Texhong (1,500 MW) and Shenneng (100 MW) of Hong Kong, Tata Group (1,320 MW) of India, Taekwang/ACWA (1,200 MW) which is a South Korean-Saudi Arabian joint venture, and Formosa Plastics Group (450 MW) of Taiwan.

OneEnergy, however, through its parent company China Light and Power (CLP) announced in its 2020 Annual Report that it is in the process of exiting from the 1,980 MW Vinh Tan III project. It previously withdrew from the 1,200 MW Vung Ang II project in October 2020.

Samsung Group's 1,800 MW Vung Ang 3 Units 1 and 2 projects have been delayed to be post-2030, plus 1,200 MW Vung Ang 3 Units 3 and 4 which have been cancelled and are not included in the draft PDP8. In June 2021, the Ha Tinh People's Committee submitted a proposal to the Ministry of Industry and Trade to switch Vung Ang 3 from coal to gas, and to increase its capacity from 2.4 GW to 4.8 GW. Banpu Power's 1,800 MW Long Phu 3 is also delayed to be post-2030 and is excluded from the draft PDP8.

C.3 OTHER NEW CAPACITY IN OUR SIMULATION MODEL

For other new capacities in our alternative scenarios, we assume the following:

- In Indonesia, the incremental gas, solar and wind capacity in 2021-2023 under RUPTL 2021-2030 is committed and delayed by half a year. Incremental hydro, geothermal and biomass capacity is assumed to be the same as RUPTL 2021-2030.
- Similarly, in Vietnam, we assume incremental gas solar, wind capacity in 2021-2023 in PDP 8 draft is committed and delayed by half a year. Incremental hydro and biomass capacity is assumed to be the same as PDP 8 draft.

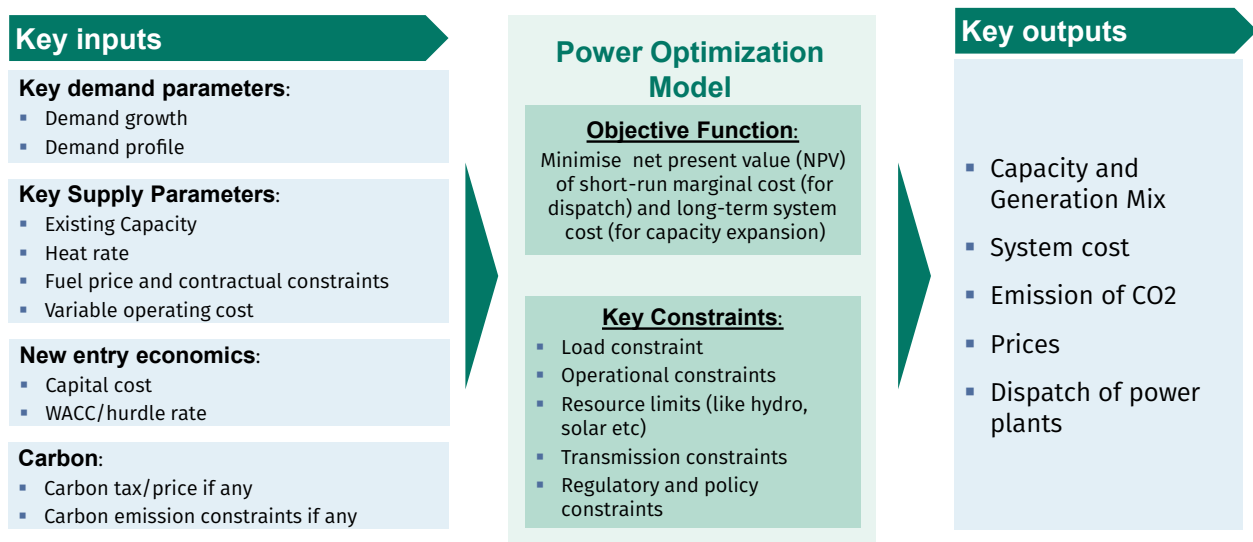
APPENDIX D: WATERROCK POWER OPTIMIZATION MODEL

D.1 BACKGROUND OF THE POWER OPTIMIZATION MODEL

WaterRock's Power Optimization Model is our proprietary tool to simulate representative hourly market operations, investment, and retirement over a 10-30 year time horizon, and was designed from the bottom up to analyze how key drivers of demand growth and decarbonized policies will affect future market outcomes.

The model focuses on energy market dynamics and carbon constraints, including both dispatch and develops an optimal long-term capacity expansion plan to meet hourly load and annual carbon emission constraints (if any) at least cost for the system. Figure 41 illustrates the input and output structure of the model.

Figure 41: Power Optimization Tool of WaterRock Energy



Source: WaterRock Energy

In the past three years, we have used the model to assist multiple investors to assess the economics of building solar capacity, LNG-fired CCGTs, LNG terminals, wind capacity and battery energy storage in Vietnam, the Philippines and Singapore. We were recently engaged by an ASEAN energy regulator to use the model to quantitatively determine the implications on its energy mix and cost for different long-term carbon emission profiles in the country.

D.2 INPUT ASSUMPTIONS

Based on our internal database and further research, we have the following key assumptions for the Power Optimization Model:

- **Demand.** The input assumptions of load in the model capture the representative hourly load profile in Indonesia and Vietnam. Demand growth is based on the different demand growth rates as discussed in Section 4.1.1.
- **Supply.** We model the whole Indonesian and Vietnamese power market. Their existing capacity is based on the data from the Power Development Plans. Assumptions on committed capacity are discussed in Section 4.1.2. For entry of new capacity, we use the assumptions on CAPEX, OPEX and fuel prices outlined in Table 1.
- **Carbon.** We do not assume that any carbon tax is imposed in the forecast horizon of 2021-2030, and there are no carbon emission constraints. For CO₂ emissions rate of fuels, we use data from the IPCC.²⁵

25. Table 2.2 Default Emission Factors for Stationary Combustion in the Energy Industry in the [2006 IPCC report](#). The latest 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories still maintains the same table.