Decarbonizing while growing

Energy transition in Southeast Asia's power sector



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Executive summary

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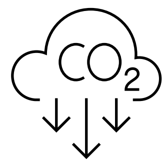
Southeast Asia's emerging economies have averaged 5% annual GDP growth over the past decade, while electric power demand outpaced the economy, growing at 5.7% per year on average. S&P Global expects the region's economies to continue expanding at a similar pace through 2050, which is significantly higher than the global average growth of 2.5%. This means that the size of the region's economies will triple before 2050.

The associated industrialization, urbanization, and rise in living standards will all drive electric power demand growth in the decades ahead. By 2050, S&P Global expects the region's power demand to triple from today's levels to 3,000 TWh. This incremental volume—2,000 TWh—is roughly equivalent to 80% of the European Union's power consumption today.

However, fossil fuel power plants are powering most of the region's economies today, contributing to 75% of power supply. Coal accounts for 55% of total generation. As such, Southeast Asia will face an uphill challenge as it looks to decarbonize during a rapid growth period.



Most Southeast Asian countries announced new climate targets, with net-zero targets between 2050 and 2065

Energy transition is now an imperative

Like most countries in the world, Southeast Asia's economies have made their own nationally determined contributions commitments during UN climate conferences, most recently updated in 2021 during the Glasgow negotiations.

Accordingly, governments in the region have made efforts to update their energy plans, aiming to promote renewable energy, slow down coal development, reduce operating coal capacity, as well as improve gas supply infrastructure and develop gas-fired power generation.

During the Glasgow climate conference in 2021, most Southeast Asian countries announced their new climate targets, with net-zero targets between 2050 and 2065. The new targets are more aggressive than before and will require an accelerated energy transition to be achieved.

In our 2021 outlooks, the power sector in Southeast Asia is expected to reduce grid carbon intensity by 53% by 2050, with economy-wide emissions peaking in the late 2030s. By 2050, our outlooks indicate that total emissions will fall back to 2021 levels, but still not reaching net zero owing to the lack of policy and financial support.

Significant challenges ahead

Southeast Asia will face an uphill challenge as it embarks on energy transition toward net zero, which will take place alongside continued strong economic growth as well as electrification.

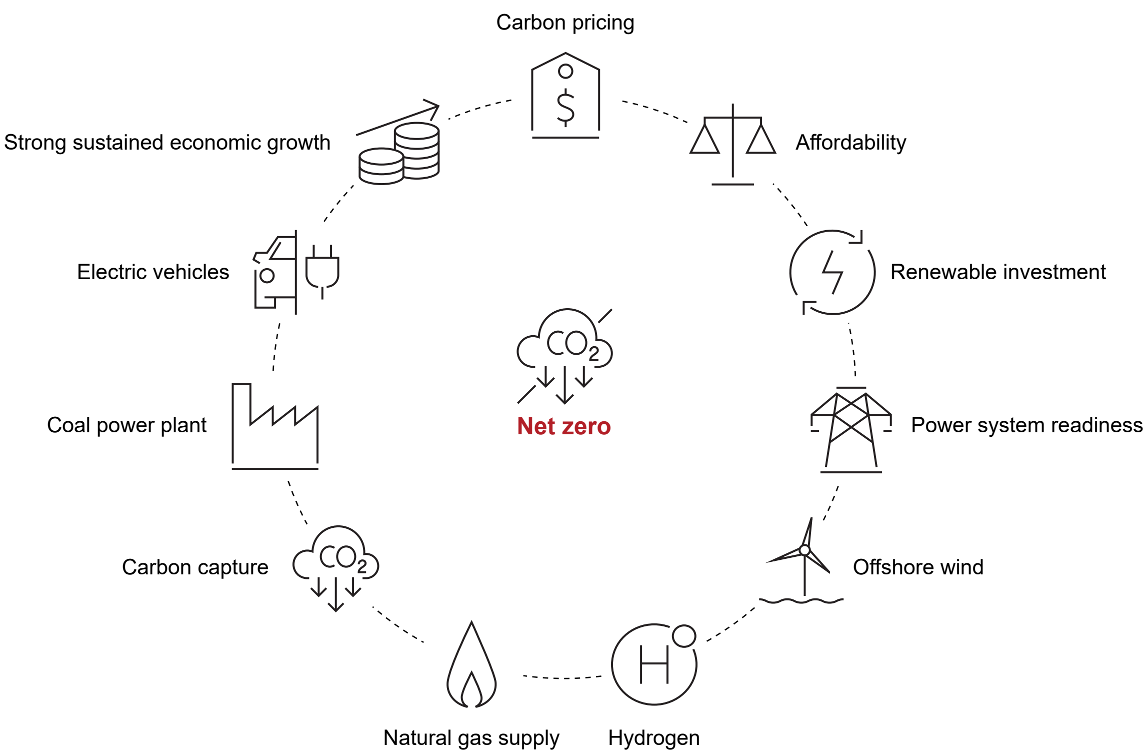
The incremental power demand will be met partially by conventional fossil fuel generation, which raises the question on the fate of coal-fired power plants, adequacy of natural gas supply, and the prospects for emerging technologies, such as carbon capture and storage, hydrogen, and energy storage.

Renewables will need to meet an increasing share of the load growth. However, concerns remain on the power system's readiness to accommodate more intermittent generation sources and the ability to attract more investments into the sector.

Against this backdrop, governments will be faced with a balancing act between energy transition and keeping power price affordable for consumers.

To help address the above and identify opportunities and risks for market participants, S&P Global Commodity Insights has issued a series of research, with the aims of answering some of the thorniest questions on energy transition in the region and drilling deeper into each of the market we follow. We welcome you to join us in this journey and provide your feedback along the way.

Decarbonizing while growing: Energy transition in Southeast Asia's power sector



As of Jan. 27, 2023.
Source: S&P Global Commodity Insights.

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Which ASEAN countries are the front-runners to decarbonize their power sectors?

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- Carbon dioxide (CO_2) emissions from the Association of Southeast Asian Nations (ASEAN) power sector will peak in 2029 and decrease by 20% in 2050 in the current forecast. The decarbonization progress appears slow as most countries have not yet developed firm measures to help them achieve the announced net-zero targets.
- To ensure the long-term success, the focus now should be the medium-term carbon reduction. By moving the emission peak years earlier, countries could win more time to achieve their ultimate net-zero goals.
- In the next decade, Singapore is undoubtedly positioned to be the leader in decarbonizing its power sector, followed by two front-runners—Malaysia and Thailand—that are able to cap power sector emission in eight years.

Given its location and proximity to oceans, ASEAN is one of the most vulnerable regions to the impact of global warming. In recognizing the risks, the region has set decarbonization targets, pledged reduction plans in their nationally determined contributions (NDCs), and passed laws and policies to address climate change.

This report will briefly describe the region's national emission targets and then take an in-depth view of the power sector, ranging from power development plans (PDPs) and future generation fuel mix to emission perspectives; in particular, which country's or countries' power sector will be the front-runners leading the decarbonization pathway in the next 10–15 years.

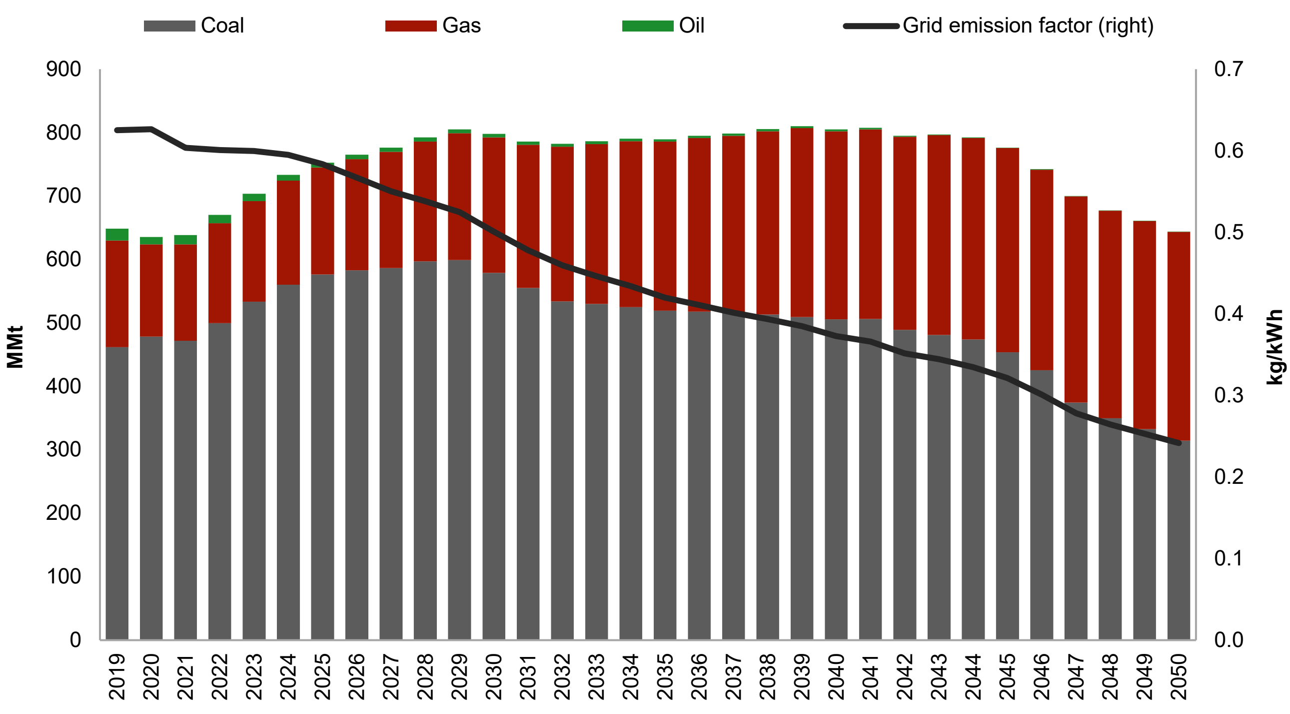
ASEAN power sectors' emission perspective in relation to their climate targets

Of the 10 ASEAN countries, 8 have announced national targets to achieve net-zero greenhouse gas (GHG) emissions or to become carbon neutral by 2050, corresponding to the 1.5°C target set by the Intergovernmental Panel on Climate Change (IPCC), except Indonesia, which committed to net zero by 2060, and the Philippines, the only ASEAN country that has not committed to a net-zero target.

However, despite these pledges, most ASEAN countries have not yet developed firm measures to help them achieve the targets. Also, an important part of net-zero actions is to reduce coal use in power generation, but current PDPs mostly do not reflect the coal phaseout plans, neither do they align with their net-zero targets.

Figure 1-1

Southeast power sector carbon emission outlook



Source: S&P Global Commodity Insights.

According to the current PDPs and the region's ability to deploy clean energy, there will still be substantial coal power capacity, mostly already under construction, to be added in the major power systems. Therefore, ASEAN is expected to witness coal-fired generation growth in next seven years. Post-2030, the reliance on coal will ease over time, with more renewable projects coming online. Accordingly, the power sector's emission would reduce but not reach net zero by 2050.

ASEAN power sector CO_2e emissions will continue to grow and peak at 805 million metric tons (MMt) in 2029. Emissions will then plateau between 2029 and 2040, as the region retires 20 GW of coal capacity (40% from Malaysia) in this period while adding 54 GW of new gas capacity to provide stable power output and to balance the renewables.

The region's total emission will move downward only from 2041, owing to accelerated renewable growth combined with a phase-down of coal in total power generation. The reduction will accelerate from 2045 owing to the implementation of multiple decarbonization measures in the region, including large-scale coal capacity retirement and the expectation of carbon capture and storage (CCS) technologies being installed largely on new thermal power plants. Grid emission factors will improve significantly from 0.54 kg/kWh in 2019 to 0.18 kg/kWh by 2050. Besides, progress in attaining the emission peak remains uneven among individual countries.

Front-runner club analysis

In the next 5–15 years, Singapore is positioned to be the leader in the decarbonization of the power sector. It is the only country that is projected to achieve a CO_2e emission reduction (9%) in 2030 compared with the 2019 level. It is followed by Malaysia and Thailand, each representing an emission growth of 11% and 12%. Indonesia, Vietnam, and the Philippines will lag owing to heavy dependence on coal-fired generation and reliance on external funding to support projects.

Singapore will lead in decarbonizing the power sector, followed by Malaysia and Thailand, while Vietnam and the Philippines lag behind

Singapore's power sector's CO_2e emissions are expected to peak in the mid 2020s, as the country not only set a net-zero target but also made tangible actions by deploying domestic renewable projects, planning for low-carbon/renewable imports, and applying carbon tax to incentivize low-carbon energy.

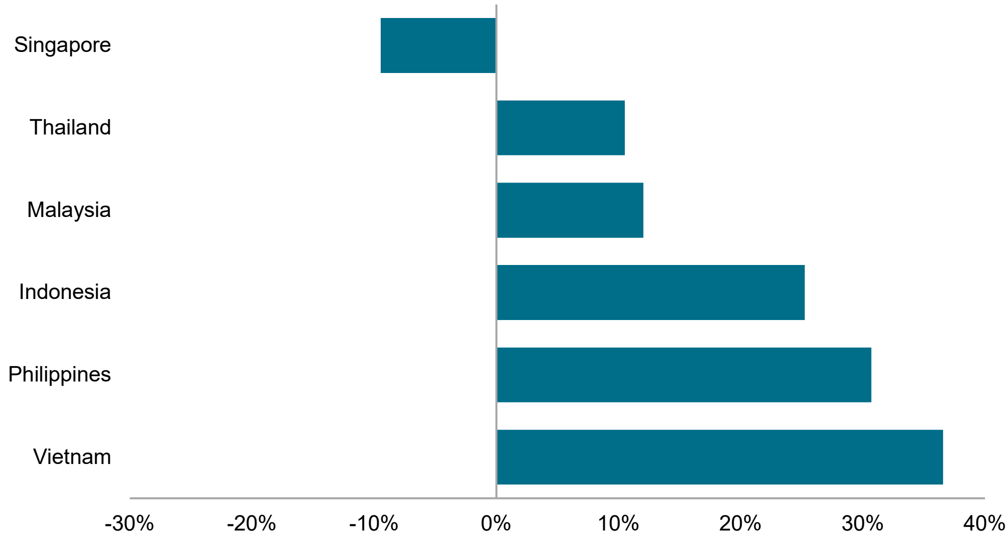
In alignment with the country's net-zero targets, the government launched various programs to aggregately deploy solar power. In addition, the country is actively exploring renewable import projects, with two rounds of requests for proposals (RFPs) launched to call for up to 4 GW of dispatchable low-carbon power imports, mostly to come online before 2035.

A positive decarbonization perspective will also be aided by efficiency improvements of gas-fired generators (some of which have already signed contracts with the equipment suppliers for upgrades) and the carbon tax that started with S$5 per metric ton of carbon dioxide equivalent between 2019 and 2023, with a plan to increase to S$50–80 by 2030.

Thailand is also in the front-runner club, after Singapore. Thailand's power sector's emissions will have a brief increase from oil during 2022–23 as some gas plants have temporarily switched to burning oil owing to gas price hikes. From 2024 onward, emissions will continue to grow but at modest rates as the country manages to cap the generation from coal-fired power plants.

Figure 1-2

CO_2e emission growth/reduction, 2030 versus 2019



Source: S&P Global Commodity Insights.

Thailand stopped building new coal plants and will continue to promote renewable energy. Thailand has launched the Bio-Circular Green (BCG) economic model as the national agenda to promote renewable energy, and the National Energy Policy Committee (NEPC) approved the New RE Quota for purchasing 5.2 GW electricity from renewables under a feed-in-tariff (FIT) scheme between 2022 and 2030. Coupled with the renewable expansion, Thailand has made significant progress toward smart grids and prepared the enactment of third-party access codes to the power grid systems. Thailand also intended to increase imports from Laos's hydropower and is accelerating legal and policy actions to implement enhanced carbon pricing.

Similar to Thailand, **Malaysia** is ranked high from a low-carbon perspective. The country has stopped building new coal-fired power plants and announced plans to retire the existing coal fleet in stages or once power purchase agreements (PPAs) with each facility expire. In addition, Malaysia is endowed with abundant gas resources, and it could quickly ramp up gas capacity to make up for the capacity loss from coal.

Malaysia has represented strong renewable energy demand. To promote renewables, the country has awarded 2.2 GW capacity in four rounds of large-scale solar (LSS) tenders and released the Malaysia Renewable Energy Roadmap (MyRER) to provide detailed plans for expanding the use of renewable energy sources and support further decarbonization of the electricity sector through 2035. As a result, emissions will slowly increase for a few years and reduce significantly owing to gas replacing coal alongside the renewable boom, presumably from 2030.

Followers weigh economic growth and decarbonization

Vietnam, Indonesia, and the Philippines are facing the same dilemma. They represent the strongest economic growth in ASEAN and require substantial new power capacity, including reliable thermal power plants, to sustain the growing demand. Meanwhile, they are the most coal-reliant countries and decarbonizing the existing power fleet appears to be a difficult task.

Vietnam has announced a net-zero target and made commitments to quit coal at COP26, but no strategic report has been issued to clarify the route to the net-zero target. The quit-coal statement was not joined by specific proposals. In fact, despite Power Development Plan VIII (PDP8) drafts showing that Vietnam's power system would center on gas and wind, the capacity of coal and wind moves up and down in different drafts, and the final release has been delayed repeatedly.

Furthermore, the expansion of renewable capacity in the past three years came with great challenges to Vietnam's grid system. Therefore, in January 2022 Vietnam's National Load Dispatch Center (NLDC) announced it would not add wind and solar power to the 2022 national plan. In view of the investment deficiency in the grid not being able to accommodate the renewable expansion, Vietnam is to consider opening the grid sector to private and foreign investors.

Neverthless, Vietnam has one wild card to play; its two big gas blocks: Block B and Cá Voi Xanh. Should prices of LNG imports continue to trend higher, Vietnam may try to push forward its domestic gas development more and accelerate the coal retirement accordingly.

Indonesia is heavily coal-reliant and has been slow to develop renewables. Therefore, CO_2e emissions will grow quickly through 2041 owing to increasing power generation from coal-fired power plants. In the next five years, more coal capacity will still be added, and coal generation share will remain high.

Indonesia is heavily coal reliant, making it challenging to decarbonize by phasing out coal

Various plans around coal have been announced, but key ones (PLN coal retirement plan will be after the completion of 16 GW planned mega coal projects; the country's low-carbon vision, LTS-LCCR 2050, still specifies that coal will continue to have an important role in the power sector; and recent New and Renewable Energy Bill classified liquified and gasified coal as "new energy" and is part of Indonesia's efforts to replace petroleum imports) delivered the same message that Indonesia is not ready to remove coal from the power sector in the medium term and even in the long term.

Meanwhile, instead of phasing out coal, Indonesia has been actively involved in biomass co-firing to phase down coal use. It also established a carbon tax, but the initial price of 30 Indonesian rupiah per kilogram of CO_2e, or $2.09, is viewed as being too low to incentivize decarbonization actions. All these actions could slow the emission growth rate before 2041 but would not move the peaking earlier.

The **Philippines** is the only ASEAN country that has not committed to a net zero target. It is well positioned for more renewable development in terms of policies, procurement, and economics. However, the only domestic gas source (Malampaya) is depleting, and the introduction of LNG has been slow. It appears difficult for the country to completely phase out coal soon.

In December 2020, the Philippines's energy secretary announced a moratorium of new coal plants. In 2021, power companies announced discontinuing some coal projects. However, at least half of the planned coal capacity stays on the table. Therefore, the Philippines's emissions will likely grow following the coal-fired generation growth through 2028. It remains to be seen if the newly elected President Ferdinand Marcos Jr would commit to favor renewables and roll out decarbonization measures.

Supporting the development of ASEAN economies: Understanding the strong power demand growth in the region

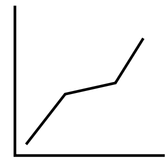
Hui Min Foong, **Research Analyst, Southeast Asia Power & Renewables**

Joo Yeow Lee, **Associate Director, Southeast Asia Power & Renewables**

- Power demand growth in Southeast Asia's key markets will continue to be strong, with Vietnam, the Philippines, and Indonesia leading with average growth rates of 5–6% in the coming decade. The region's demand growth is forecast to reach 4.5% in the next decade (2022–31)—nearly 1.5 times higher than the global average of about 3.1%.
- The sectors driving growth are changing: commercial and industrial sectors will drive future power demand growth, instead of the residential sector. Commercial and industrial demand will be driven by the general expansion of these sectors as regional economies strive to be more competitive, as well as changes in subsector composition and electrification of spaces and processes. Meanwhile, although residential demand contributed to nearly 40% of the total increase in demand in the past decade, this is forecast to moderate to 34% in future.
- Emerging trends, specifically transport electrification and implementation of energy efficiency frameworks, will introduce new growth and mitigation factors to the power demand outlook. Singapore aims for all vehicles to run on cleaner energy by 2040, Thailand aims for 30% of its automotive production to be zero emission, and Indonesia has announced a 2050 target for vehicle sales to be 100% electric.

Current power demand growth rate is double the global average

Southeast Asia's power demand growth has averaged an impressive 5.7% annually from 2010 to 2019, making it one of the fastest-growing markets in the world. In the same period, global power demand growth averaged at 2.5%, less than half that of Southeast Asia. Electricity supply remains the engine of economic growth in this region. Hence, Southeast Asia's strong economic growth and accompanying high EIs are the key driving forces behind the large overall increase in power demand.



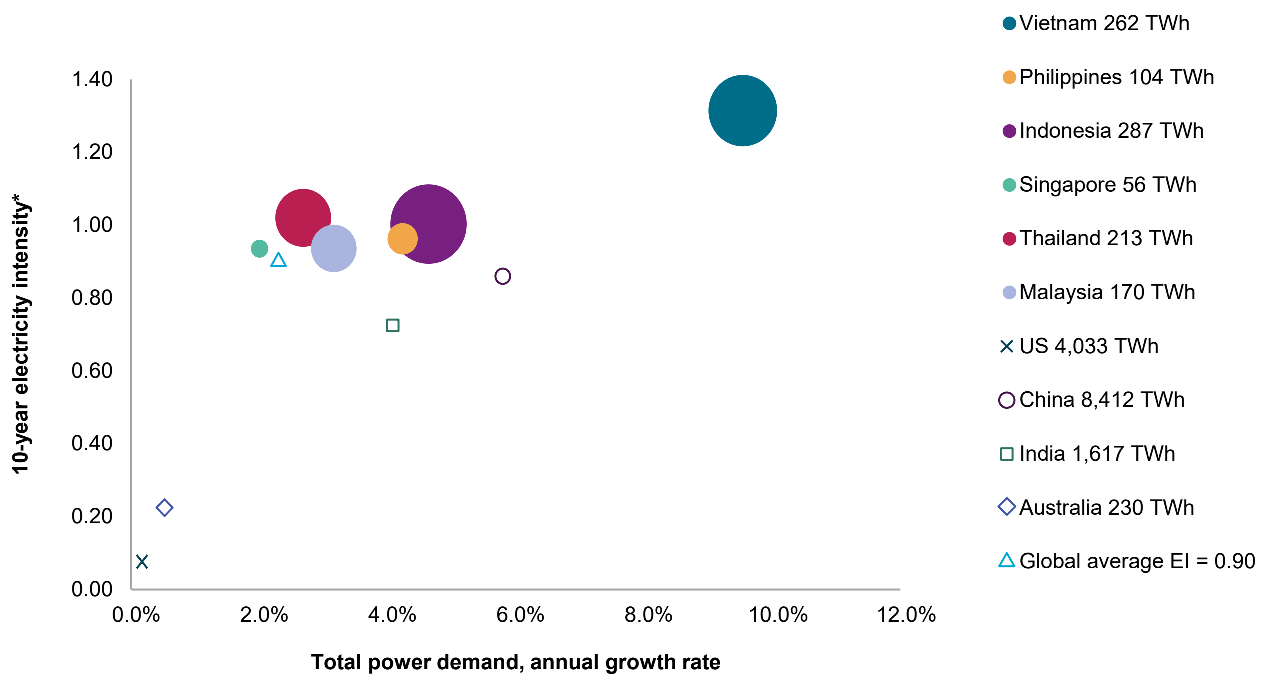
High electricity intensity shows regional demand growth outpacing GDP growth

The six key markets in the Southeast Asian region have averaged a high electricity intensity of 1.18, even including the COVID-19 impact in the past decade. Electricity intensity, or EI, is defined here as the ratio of power demand growth to GDP growth over a 10-year period (2012–21). Southeast Asia's EI of 1.18 is almost a third higher than the global average EI of 0.90 in the same period. High EI reflects an outsized increase in electricity demand in relation to economic growth, an indicator that power-intensive sectors are driving economic growth (e.g., during industrialization). It also indicates that electricity demand is elastic: in a market with an EI of 1, for every 1% increase in national income, the electricity demand likewise increases by 1%. Hence, increases in incomes and electricity access lead to an outsized surge in power demand in high-EI markets.

Southeast Asia features electricity demand growth that outpaces GDP growth; this is expected to persist in the medium term

Figure 2-1

2012-21 10-year electricity intensity



Note: Bubble size represents 2021 market size (total demand) for Southeast Asian countries. Market size for US, Australia, China, and India not represented.

Source: S&P Global Commodity Insights.

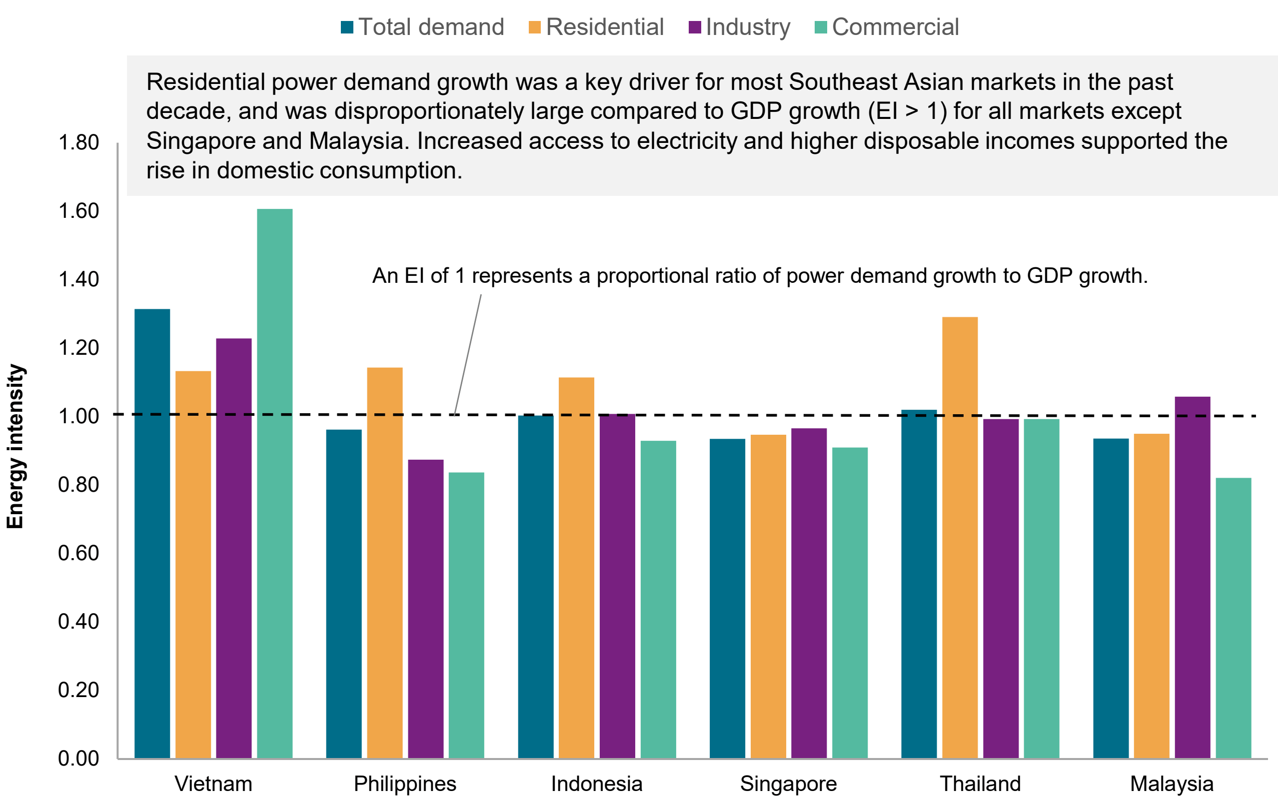
The sectors that have historically driven growth vary by market, with the three broad sectors of commercial, industrial, and residential power demand playing different roles. In Vietnam, commercial EI and growth were high, but industrialization was the main demand driver. Meanwhile in Thailand, Indonesia, and the Philippines, residential demand grew by 58% and was the main driver of growth. In contrast, residential demand was a less significant driver in Malaysia and Singapore. Per capita residential power consumption in Singapore and Malaysia was already the highest in the region in 2012 and grew moderately compared with other regional markets in the past 10 years. Industrial growth played a larger role in these two markets instead.

Southeast Asia's power demand growth forecast to remain strong at 4.5% (2022–31)

Southeast Asia's power demand growth will continue to be stronger than in most other markets. Regional power demand growth is forecast to reach 4.5% in the next decade (2022–31), nearly 1.5 times higher than the global average of about 3.1%. Following a rapid post–COVID-19 recovery, Vietnam, the Philippines, and Indonesia are forecast to lead power demand growth, each with growth rates of over 5% from 2022 to 2031.

Figure 2-2

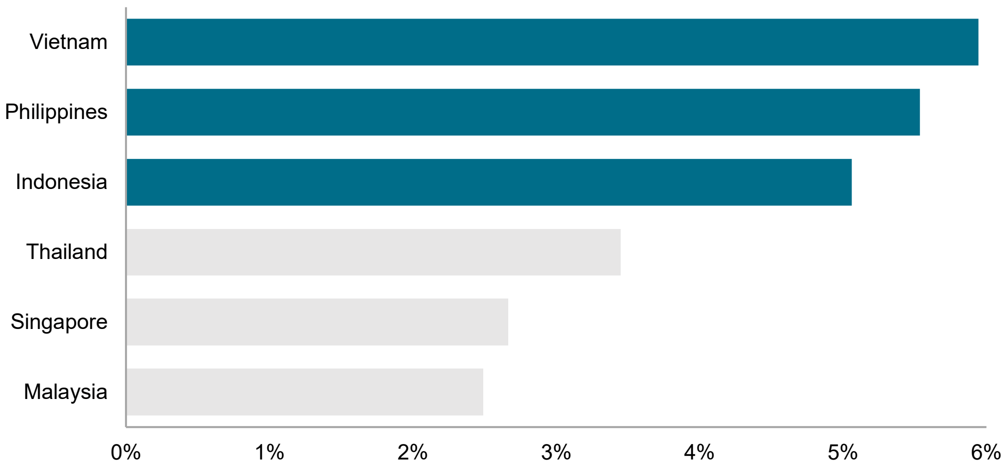
Historical 10-year EI by sector (2012-21)



Source: S&P Global Commodity Insights.

Figure 2-3

Forecast 10-year average total demand growth rate (2022–31)



Source: S&P Global Commodity Insights.

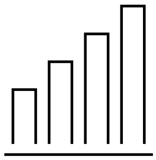
Commercial and industrial demand to drive future growth

While economic performance remains linked to power demand, the economic sectors driving demand growth will shift. This is a result of three key trends within the commercial and industrial sectors: general expansion of the two sectors, changes in subsector composition, and electrification of commercial and industrial spaces and processes.

Both commercial and industrial demand growth is set to increase in Thailand, the Philippines, and Indonesia, where overall demand growth is also forecast to exceed that of the previous decade. Unlike the other three industrializing markets, Vietnam's demand growth is forecast to moderate in all sectors as it continues on its industrialization pathway and its early-stage commercial development. In Singapore and Malaysia, commercial power demand growth is forecast to increase while industrial growth moderates.

Key contributors that will broadly support growth in the region include the newly implemented Regional Comprehensive Economic Partnership (RCEP) agreement and fixed investments into infrastructure. Other market-specific growth sectors and drivers vary, including Thailand's efforts to transition to "Thailand 4.0", Philippine's business process outsourcing industry, Vietnam's trade and exports growth, and Singapore's data centers.

Developments in technology are also introducing new dimensions to the power demand outlook. Emerging trends that governments have allocated substantial resources into supporting include transport electrification and energy efficiency considerations, which will be important disruptors in the coming decade.



Power demand growth in Thailand, the Philippines and Indonesia are forecast to exceed the previous decade's levels

The electric vehicle revolution: The impact on power systems in Southeast Asia

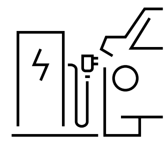
Hui Min Foong, Research Analyst, Southeast Asia Power & Renewables

- The adoption of EVs introduces a new power demand growth sector that has the potential to reshape load profiles. The rate of EV growth directly determines the scale of impact on power systems; clear government policy direction and individual market characteristics can act as catalysts.
- EV power demand is forecast to reach 89 TWh by 2050 in the region, from a negligible amount today.
- Price incentives are needed to align EV charging periods with peak renewable generation timings, especially if EVs are to run on cleaner energy.

Governments across Southeast Asia are promoting the shift from internal combustion engine (ICE) vehicles to electric vehicles (EVs). Thailand aims for 30% of new vehicles to be electric by 2030, Singapore for 100% cleaner-energy vehicles by 2040, and Indonesia for 100% of new motorcycles and cars to be EVs from 2050. As governments continue to announce new targets and solidify their EV road maps, the future of electric mobility in Southeast Asia is coming into focus.

The adoption of EVs introduces a new power demand growth sector that has the potential to reshape load profiles. With the growth of renewables, incentives are needed to sync EV charging with peak renewable generation timings. While the pace of change will depend on policy support and individual market characteristics, the overarching trend of gradual vehicle electrification is clear.

EV adoption rates determine scale of power system impact



The rise of electric vehicles will introduce a new power demand growth sector and concurrently introduce potential benefits for the power system

The rise of electric vehicles (EVs) impacts power systems in two main ways—introducing a new power demand growth sector and providing a potential load-balancing effect. The rate of EV growth directly determines the scale and pace of these power system impacts.

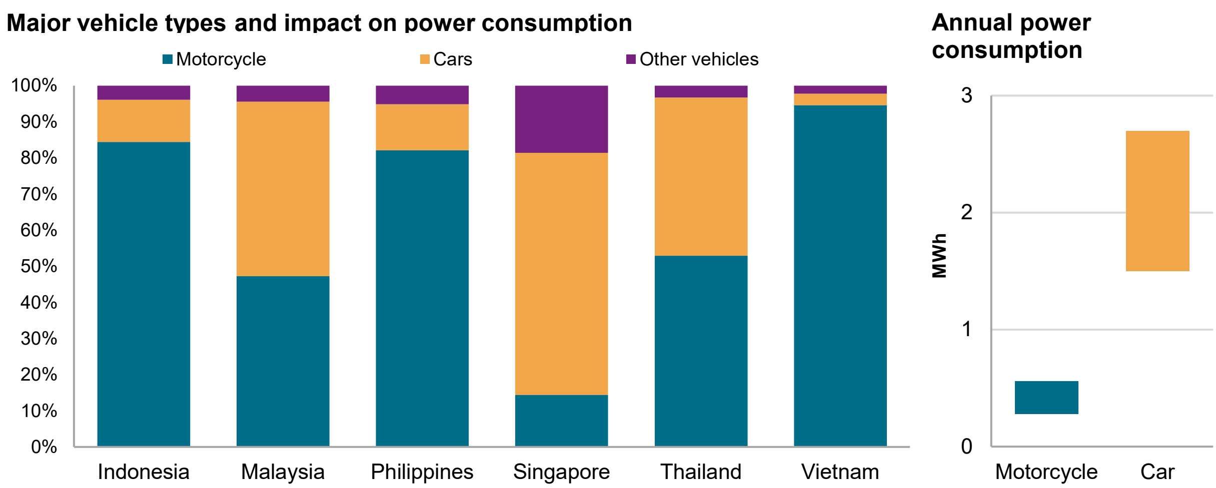
The decision to select EVs over internal combustion engine (ICE) vehicles is influenced by many factors, such as policy support, technology costs, price parity between ICE vehicles and EVs, and overall country-level decarbonization efforts. Policy measures can include both pull and push factors, such as subsidies or other fiscal incentives for EVs or outright ICE vehicle bans. Shifting the EV adoption curve forward or back by several years can drastically impact the size of power demand from EVs in a given year, especially during the rapid growth stage along the adoption s-curve of new technologies.

Cars versus motorcycles: Vehicle mix impact on EV adoption rates and power consumption

Electric motorcycles will take the lead in markets like Indonesia and Vietnam, where motorcycle ownership far exceeds car ownership. Compared with markets with higher car ownership, markets with high motorcycle ownership could experience a faster switch to EVs and therefore see an impact to power systems in the nearer future.

Electric motorcycles have smaller battery sizes compared with electric cars, making charging quicker and more convenient. The simple fact that the batteries are smaller in electric motorcycles reduces the major stumbling blocks of excessive battery prices and charging times faced by EVs.

Figure 3-1



Source: S&P Global Commodity Insights.

The average annual mileage of a motorcycle is about 70–80% of that of a car. In addition, their smaller sizes mean electric motorcycles require less power than cars to travel the same distance, at about 0.04 kWh/km for an electric motorcycle, compared with about 0.15 kWh/km for an electric car. The combination of lower mileages and lower power consumption per kilometer traveled means that smaller batteries and less charging time are needed.

In addition, innovations like battery swapping stations also increase convenience and are currently being trialed in several Southeast Asian markets. This circumvents the problem of long charging times entirely. Price parity for motorcycles may also come earlier than that for cars, given the smaller battery sizes for motorcycles.

These factors lower the barriers to adoption for prospective users and can help bring forward the adoption timeline of electric motorcycles, hence increasing EV-driven power demand in motorcycle-dominated markets in the nearer future.

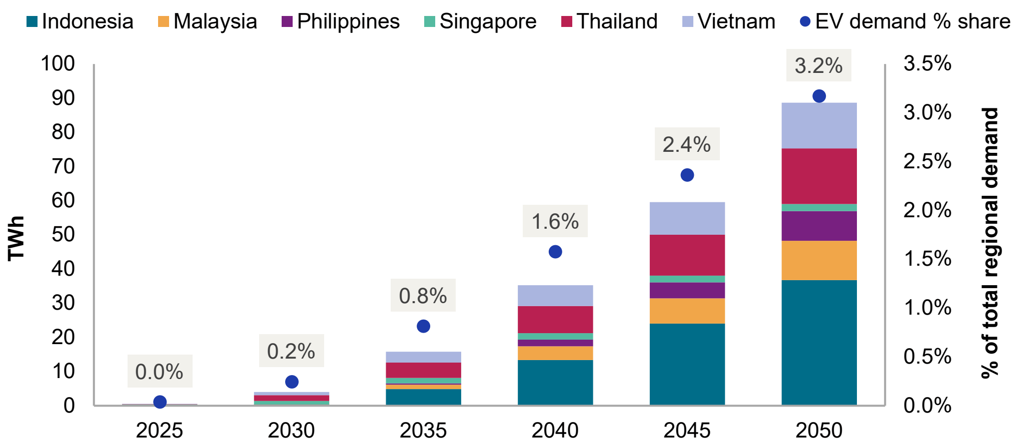
A new power demand growth sector that has the potential to reshape load profiles

EVs present an emerging demand subsector forecast to reach 89 TWh in the region by 2050, from a negligible amount today. Under current conditions, the share of EVs in the region is forecast to reach just about 27% by 2050, following an s-curve adoption pattern. There is headroom for total EV power demand to be even higher depending on the rate of EV adoption: adoption rates can be sped up significantly with strategic government policy and earlier price parity between ICE vehicles and EVs. While higher EV penetration is forecast in markets like Singapore and Thailand, Indonesia's EV power demand retains the largest share in the forecast owing to the sheer size of the market and vehicle population.

EVs are unlikely to be a major power demand sector in itself, but they will be an important driver of growth, contributing to a projected 5.4% of total power demand growth from 2022 to 2050. The scale of power demand from EVs in 2050 is forecast to be about 3.2% of total Southeast Asian power demand. Again, there is significant potential for higher EV power demand if adoption rates are accelerated even slightly.

Figure 3-2

Electric vehicle annual power consumption

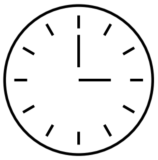


Source: S&P Global Commodity Insights.

Flattening the peak-load profile

EV charging has the potential to change the shapes of load profiles. Overnight charging results in higher load at night and may be the preferred option, especially in markets like Thailand where off-peak nighttime power tariffs are about half that of on-peak prices. Higher loads at night and a flatter load profile can reduce the amount of ramping up and down required and hence results in a higher overall utilization rate of power plants.

The extent of potential price reductions from using off-peak pricing is significant—in Thailand, time of use (TOU) tariffs are 2.6 baht per kWh off peak versus 5.8 baht per kWh peak for residential use under 12 kV. This means that charging an electric car could cost 5,200 baht instead of 11,600 baht ($148 versus $330) each year, on an average annual power consumption level of 2,000 kWh. Taking Thailand as an example, based on its current vehicle population and assuming 10% EV penetration, the load profile will change if all users were to charge overnight to accommodate slow charging and benefit from off-peak prices.



Aligning EV charging with peak solar output timing can flatten out the duck curve and benefit the power system

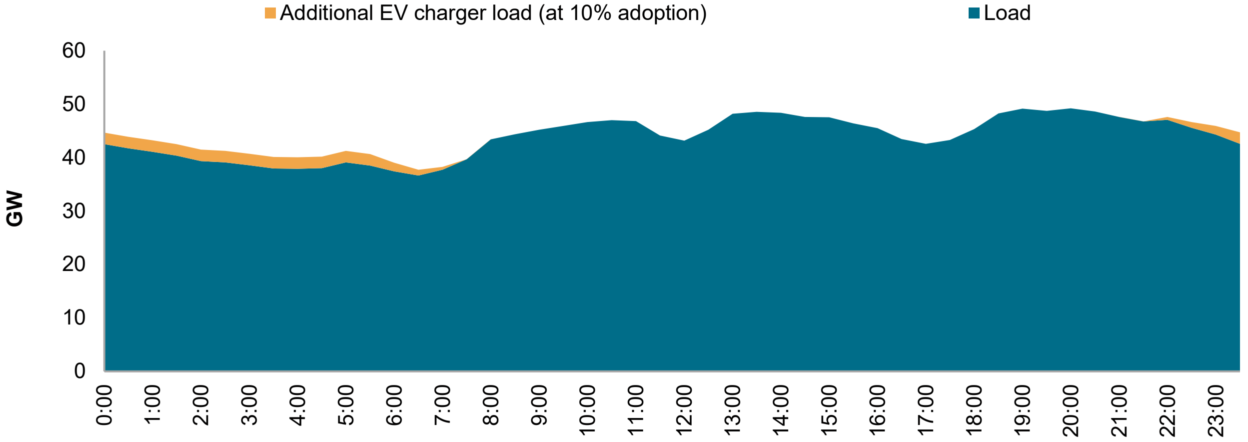
Aligning peak charging timing with renewable generation

Solar and wind are forecast to reach about 33% of total generation in Southeast Asia by 2050. As renewable penetration grows, the available power supply at any given hour will be increasingly influenced by the level of solar irradiance or wind speed at the time. These environmental conditions vary on an hourly basis and also more generally on a seasonal month-to-month basis. Without optimization systems in place, this variability will likely result in a mismatch between peak EV charging times and peak renewable power output timings.

Emissions reductions from EVs can only be maximized if they are charged on renewable power. In addition, syncing EV charging with peak solar output timings can have the added benefit of helping to flatten out the duck curve by increasing power demand during peak solar generation periods. EV charging can be incentivized during peak renewable generation hours through, TOU incentives, which can reflect cheaper prices during peak renewable generation timings. In parallel, more advanced charger technology with built-in timers would allow users to automatically and conveniently charge during low price periods.

Figure 3-3

Thailand sample daily load profile



Source: S&P Global Commodity Insights.

The role of coal-fired power plants in Southeast Asia accelerated energy transition

Allen Wang, Senior Director, Asia Pacific Regional Integrated Service

Cecillia Zheng, Associate Director, Southeast Asia Power & Renewables

- Over-reliance on coal is impairing the region's power supply and is destined to make a structural coal reduction. The recent roaring coal prices, owing to tight supply, have led to some SEA coal-fired power plants shutting down or down-scaling, resulting in increased risk of power shortages, especially in heavily coal-reliant countries. As SEA governments remain committed to decarbonization, and against a backdrop of declining renewable power cost that makes it an economic option, investment will continue to flow away from coal power into renewable business.
- Lack of effective coal retirement mechanisms and proven coal power alternatives are slowing down SEA's coal reduction roadmap. Coal power assets in SEA are young, about one-third of the 95 GW coal capacity is five years old or younger.
- Role of coal-fired power plants has gradually shifted from providing energy security and affordability to energy security and system stability. Coal power plants in SEA have traditionally been a major contributor to supplying low-cost power for baseload demand, as well as diversifying power source to provide energy security. However, all the coal capacity retirement scenarios indicate that the future role of coal power certainly will change under the current technical options: co-firing, repositioning, and others. Its energy affordability role would gradually disappear, while its energy security role will remain but weaken.

The enablers for structural coal reduction have emerged already

All SEA governments remain committed to tackling climate change

Nine SEA countries have announced national targets to achieve net-zero greenhouse gas (GHG) emissions or to become carbon neutral. Coal reduction has been recognized by the policy makers as a crucial part of the decarbonization journey for the region. They are actively assessing all available solutions and have been planning for much lower coal share in their respective PDPs.

Corporates have shifted away from coal value chain

Financial institutions have become more reluctant to invest in new coal projects. Concerns have been raised by asset owners or investors on the risk of prolonged or uncertain project development timeframes, the early closure that coal assets may have to face, or projects becoming stranded should quit-coal actions become more radical. In 2021, the three biggest coal assets sponsors for SEA—China, Japan and Korea—have announced they will stop funding new coal plants overseas, and major regional banks, such as Rizal Commercial Banking Corp (RCBC), CIMB, DBS, OCBC, and Maybank, gradually joined the quit-coal alliance by announcing a stop in coal financing.

Accordingly, original equipment manufacturers (OEMs) and engineering, procurement, and construction (EPC) firms are scaling back their coal plant manufacturing operations, in view of the possible lack of new business in the future.

Phasing out coal could be an economic option to decarbonize

The majority of SEA countries will see cost parity between coal and renewable power following the downtrend of renewable cost in the next few years. If adding the factor that the energy storage would be needed to make the intermittent renewable generation comparable to stable/firm coal generation, cost parity should be reached starting in the mid-2030s. It will not revert the trend that renewables will be one of the lowest cost options.

Phasing out coal could be an economic option, following the downtrend of renewable cost

Challenges to phase out coal plants

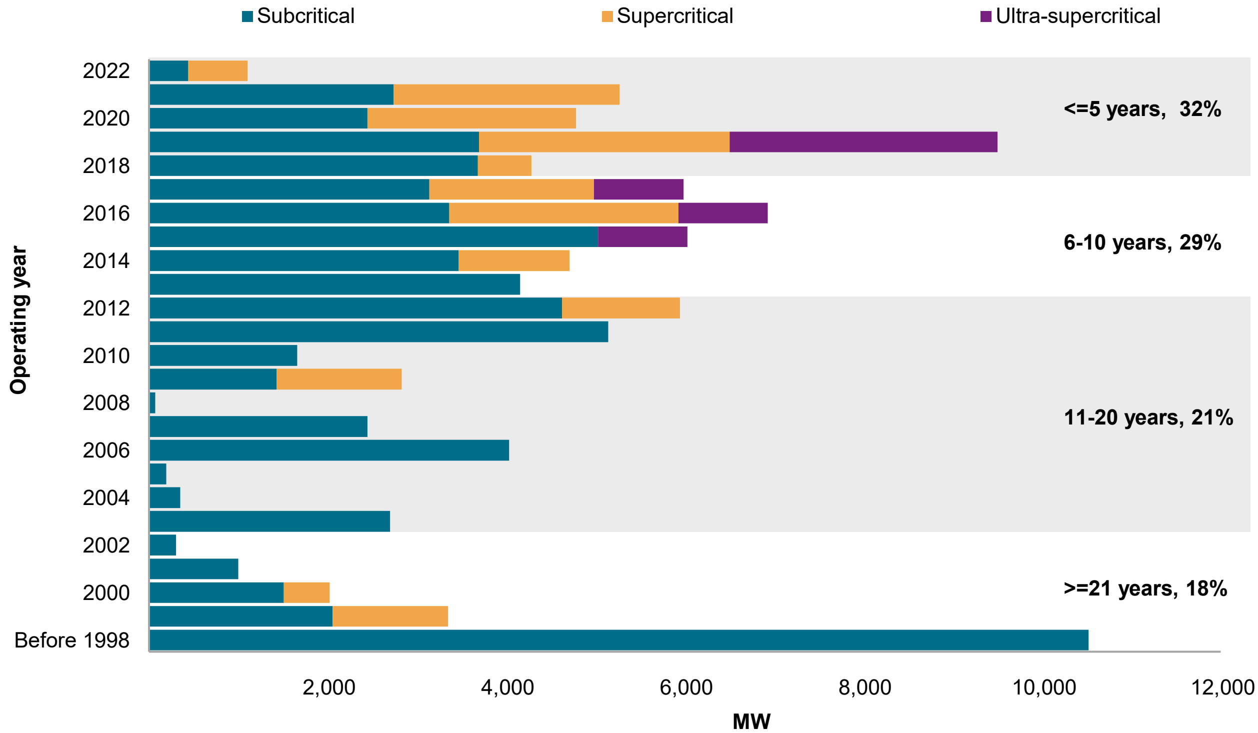
Effective coal retirement mechanisms are still missing in SEA countries

SEA market coal plants often have PPAs of 25 years and designed technical lifespan of 40 years. Retirements earlier than 25 years will give financial challenges to the plant investors and the utility that signed the offtake contracts. Retirements earlier than 40 years indicate a potential waste of the power-generation resource and a gap from the original power supply planning. Therefore, an effective retirement mechanism that is both financially viable and does not put the power system at risk is required.

In fact, coal plants in SEA in general are quite young. By January 2022, about one-third of the coal capacity was five years old or younger, and half of the less-than-five-year-old power plants are with more efficient technology, super critical or ultra-super critical, that could achieve an efficiency of 46% or higher.

Figure 4-1

SEA coal power capacity addition



Source: S&P Global Commodity Insights.

In addition, 31 GW of coal capacity that is under construction or at advanced stage likely will come online by 2027. The new coal plants are from Vietnam, Indonesia, and the Philippines. These three countries represent strong economic growth and require substantial new power capacity to sustain the growing demand. It is very challenging for them to simply cancel that coal capacity.

Looking for coal alternatives in SEA countries

The early retirements of coal plants would be a critical challenge for energy security and power system reliability. The retirement should be backed up by other power generation capacities. A sustainable energy transition would require technical expertise and financial assistance to support the development of alternative power sources, renewable energy plus storage, and/or gas capacity.

Sustainable energy transition would require technical expertise and financial assistance to support development of alternative power sources

Investment in renewables needs to ramp up rapidly to support the retirement of coal power capacity. Green bonds and loans in SEA, being the emerging and popular means to support climate or environmental projects, have grown by seven times to $15.6 billion in 2021. However, the current green funding size is way insufficient. To achieve the current government renewable targets by 2030, close to 100 billion of green fundings on renewable projects is needed in the next eight years, although the targets were not aggressive enough to partner with coal retirements. In addition, as the investment is expected to cover both the renewable power source and the associated power infrastructure, especially the power grid, governments or state-owned utilities mostly cannot afford such investments.

Role of coal-fired power plants in the energy transition era

Technical options to enable coal plants in decarbonization

- Co-firing coal with other low-carbon fuels, such as biomass or ammonia, evidently could reduce the CO_2e emissions that would have been released without the blending.
- Upgrade those aged plants by adopting high-efficiency, low-emissions (HELE) conditions. HELE technologies could practically reach an efficiency of at least 46%. Given that the majority of current coal power assets in SEA are subcritical, with an average efficiency of 32–38%, adopting HELE technology can help reduce an average of 15–30% of CO_2e emissions. In the longer term, HELE technologies would make the plants a better choice for the carbon capture, utilization, and storage (CCUS) installation or retrofitting, hence potentially increasing the lifetime of those steam plants.
- Reposition some of the coal power assets to be non-spinning reserve capacity. It is proposed to better utilize the coal plants that are young and efficient from retirement.

Figure 4-2

Coal capacity reduction scenarios

	BAU case	Accelerated case	Slow case
Government targets	The currently announced government coal reduction targets will be partially met	All countries strive for their claimed net-zero target. New and more aggressive coal reduction polices are announced.	Considering slow renewable development, risks in securing natural gas supply, conservative concerns on energy security, and the successful technical solutions on co-firing or efficiency improvements to keep coal capacity online.
Coal retirements	The majority of the coal capacity retires in 30–32 years, except for Malaysia where retirement happens after 25 years at the PPA expiration	Indonesia, Vietnam and the Philippines all claimed to phase out unabated coal capacity by 2040, and they should accelerate the retirement schedule 7–10 years ahead of BAU case.	Current retirement pattern will continue, roughly 30–40 years in Thailand and Malaysia and 45 years in Vietnam, Indonesia, and the Philippines.
New coal plants construction	Limited to those that already started construction or have reached financial close. The planned projects without financial close are cancelled.	Considering at least 30 years are required for power sector emission to reach net zero from peaking, countries aiming for 2050 net zero will have to stop adding new coal capacity, although Indonesia is an exception with its targets for net zero being 2060 and coal cap from 2030.	Coal-fired power projects at the advanced development stage will come online. Planned projects located in areas where no other large power sources are available will also move forward.

Note: BAU = business-as usual
Source: S&P Global Commodity Insights

Coal capacity outlook and scenarios

We assessed five major SEA countries—Indonesia, Vietnam, Malaysia, Thailand and the Philippines—and explored three different coal capacity phase-out scenarios.

Figure 4-2 compares the assumptions of government targets, coal retirement strategies, and new coal plants construction plans in the three scenarios.

Figure 4-3 illustrates the operating coal capacity movement path in different scenarios.

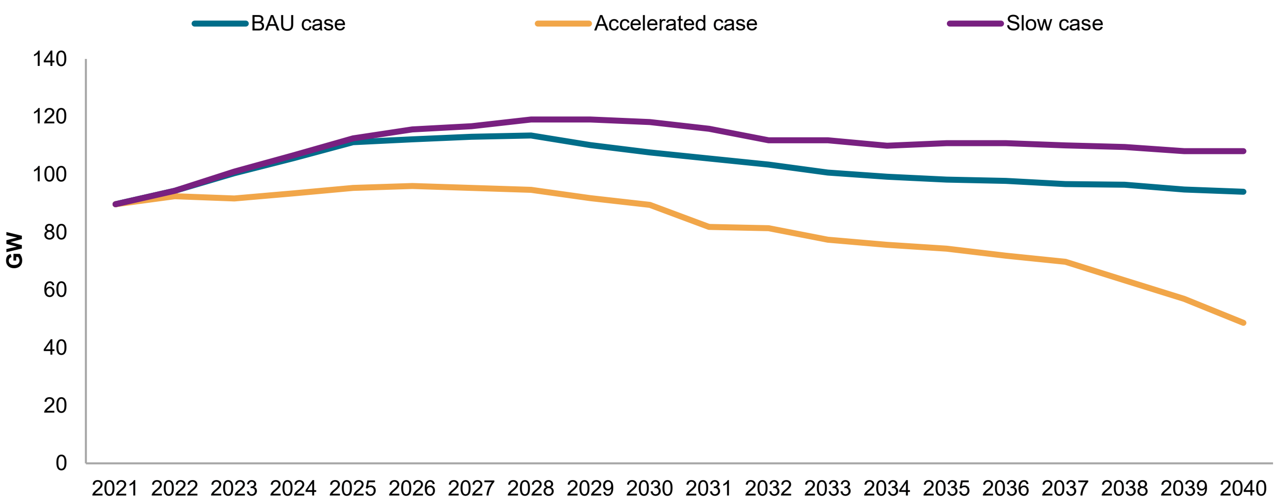
Four years from now, coal capacity addition will be limited in BAU and Slow cases, and coal plants continue to supply baseload power in this period, running at 50–70% across all countries.

From 2026 to 2030, new coal capacity will move forward only in the Slow case, likely in Indonesia and Vietnam, and retirement emerges. Biomass co-firing will expand, and HELE conversions will start.

2031–40 will witness a sharp fall in coal capacity in the Accelerated case, with about 40 GW of coal capacity to be retired or repowered. While retirement in the other two cases is slower. In all cases, energy transition or decarbonization will move ahead, while coal power plants will make the contribution too. The fundamental change will happen only after 2040, when the region can possibly introduce another reliable power source, maybe nuclear, to replace coal power without any disturbance to power system; transmission and distribution (T&D) conditions can largely be improved to accommodate more renewables or distributed generations, or CCUS technology is commercially available to partner with the remaining thermal plants.

Figure 4-3

SEA coal retirement scenarios



Note: BAU = business-as-usual
Source: S&P Global Commodity Insights.

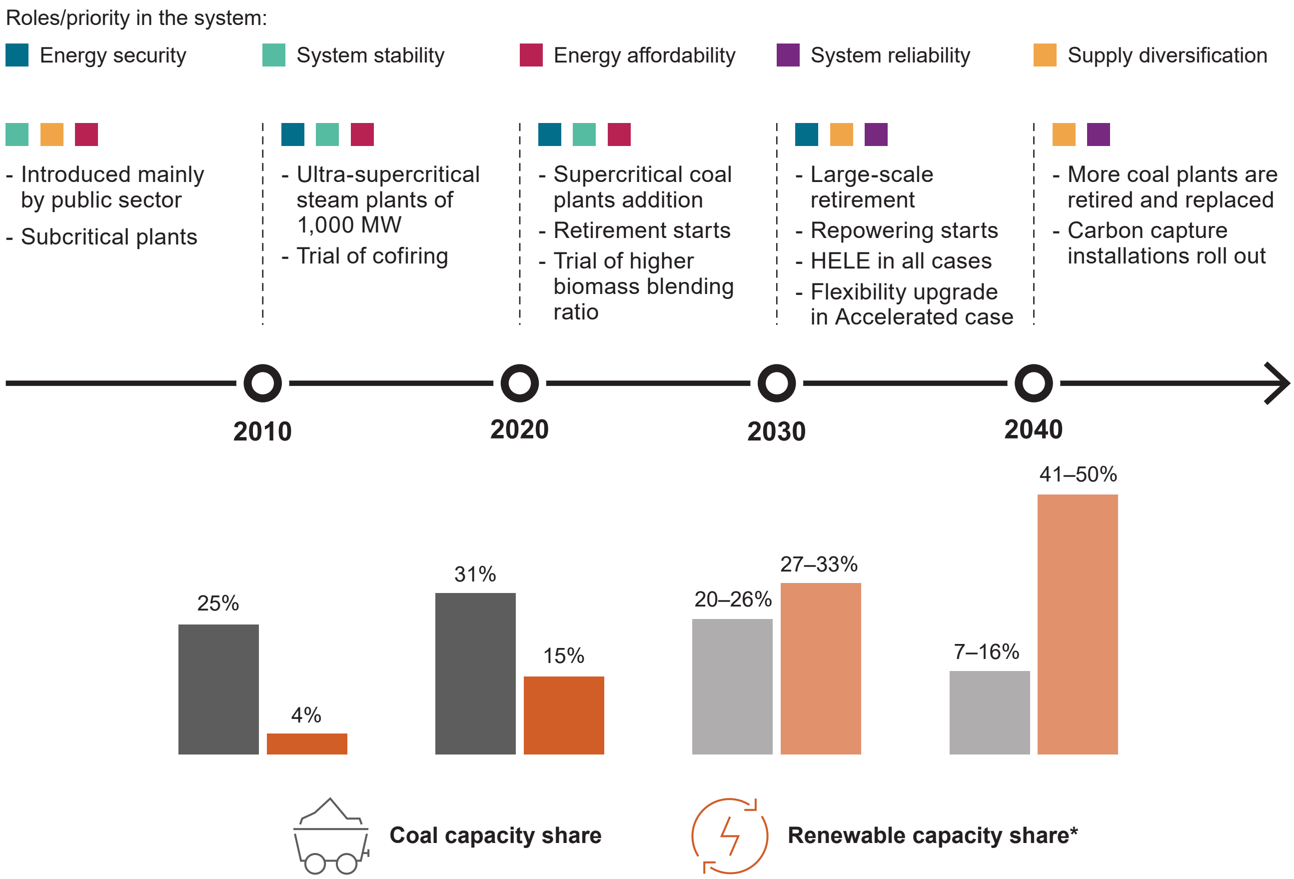
Evolving role of coal-fired power plants in the energy transition

Coal power plants in SEA have traditionally been a major contributor to supply low-cost power for baseload demand, as well as to diversify power source to provide energy security. However, the future role of coal power certainly will change amid the energy transition. Its energy affordability role would gradually disappear as renewables have become more cost-competitive in many markets, and its energy security role will remain but weaken. In order to stay online, coal power will gradually act more as a system regulator or even as a non-spinning reserve capacity.

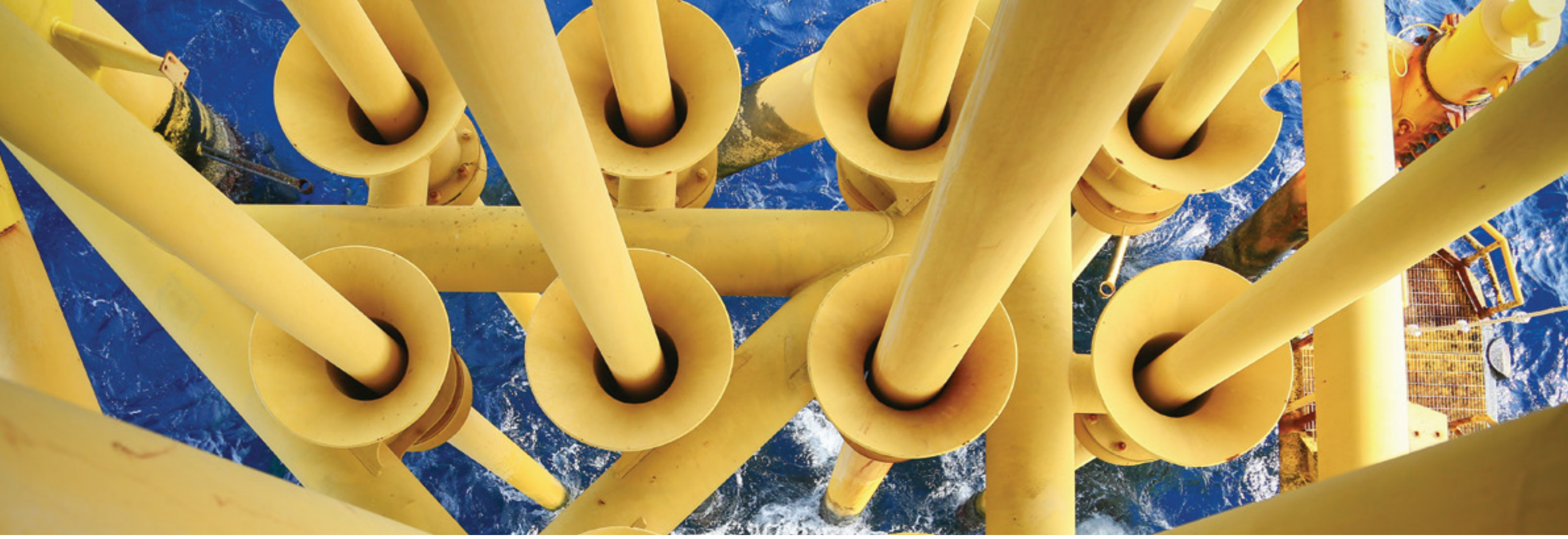
To sum up, although most of the decarbonization pathway would expect to retire all or reduce large coal-generation capacities aiming to reduce emissions, the current energy transition process in SEA will likely not move away from the coal plants immediately. Instead, the role of coal power plants in the next 20 years will evolve amid the energy transition. The role of providing diversification and energy security will remain, while the role of providing energy affordability will gradually disappear, and in order to stay online, coal power should actively seek a new role in supporting system reliability amid the rising renewable penetration.

Figure 4-4

Evolving roles of coal-fired power plants



As of Feb. 14, 2023.
Renewables exclude hydro; HELE = high efficiency low emissions.
Source: S&P Global Commodity Insights.



Securing natural gas supply to power Southeast Asia's energy transition

Johan Utama, **Principal Analyst, Southeast Asia Gas & LNG**

- Europe's quest for LNG to replace Russian pipeline gas will continue to prop international LNG prices until significant tranches of new supply can be brought onstream by 2025–26. The difficulty in securing LNG volumes at affordable prices means a slowdown in Southeast Asia's LNG demand growth.
- Despite the immediate challenges, Southeast Asia gas and LNG demand is still expected to grow strongly in the long term. Robust electricity demand growth, coal phaseout, the investment and time needed to build out sufficient renewable capacity and grid capability all point out to an increase in gas power generation during the energy transition.
- Southeast Asia still has significant domestic gas resources, with the top 10 non-producing gas projects containing 45 Tcf of recoverable gas. The high commodity price environment and the prospect of energy transition can help to push governments and national oil companies to overcome the challenges that have hindered the development of most of these projects.
- Ultimately, the timely development of gas supply and accompanying infrastructure, both for international and domestic volumes requires a firmer and more consistent power system planning. Gas and power market pricing schemes must also be reviewed to allow each market to transition to a pricing structure that enables development of domestic resources and provide financial space to kickstart low-carbon solutions like carbon capture and storage.

Southeast Asian markets struggle to secure volumes at affordable prices

Europe's quest for LNG to replace Russian pipeline gas will continue to prop international LNG prices until significant tranches of new supply can be brought onstream by 2025–26.

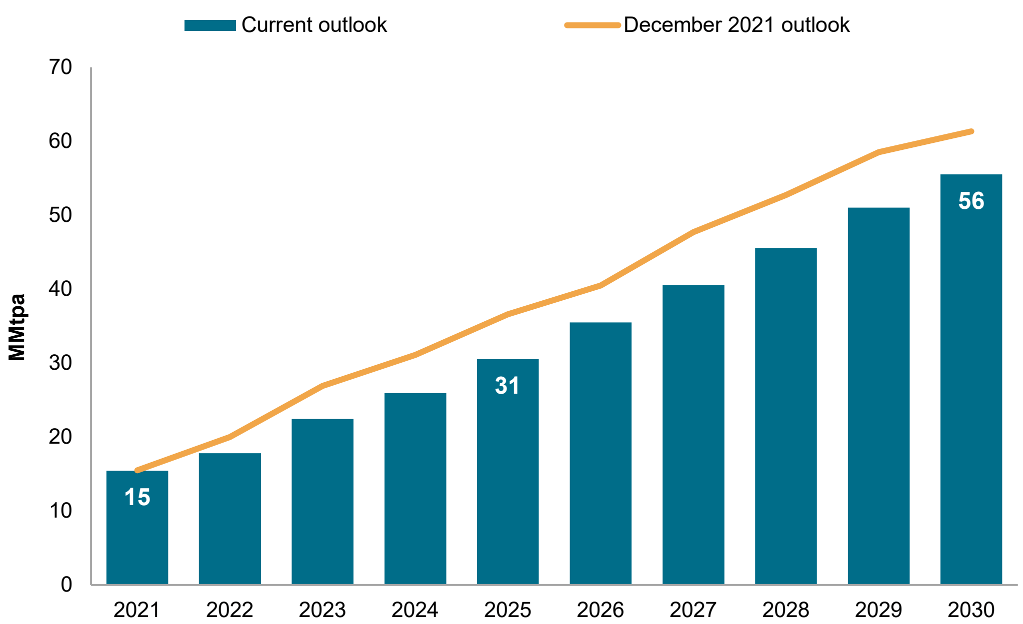
To replace sharply declining Russian piped gas supply, European gas buyers are turning to LNG and outbidding Asian buyers, driving prices higher. This competition for LNG supply is expected to sustain elevated prices in the medium term, until significant tranches of new supply can be brought onstream by 2025–26. The difficulty in securing LNG volumes at affordable prices means a slowdown in Southeast Asia's LNG demand growth.

The price of oil-indexed LNG has increased on the back of oil prices rising to around $100/bbl, impacting existing importers. But even at this oil price level, spot LNG prices at $40–60/MMBtu are well beyond the 11–15% slope range of oil-indexed contracts. This price disparity incentivizes LNG sellers to continue selling on the spot market, making it difficult for buyers to sign term contracts at affordable prices. Upcoming LNG importers without any contracts such as the Philippines and Vietnam may find delaying the start of their imports more favorable if spot cargoes are too expensive.

High prices have resulted in difficulty securing LNG volumes at affordable prices, slowing Southeast Asia's LNG demand growth

Figure 5-1

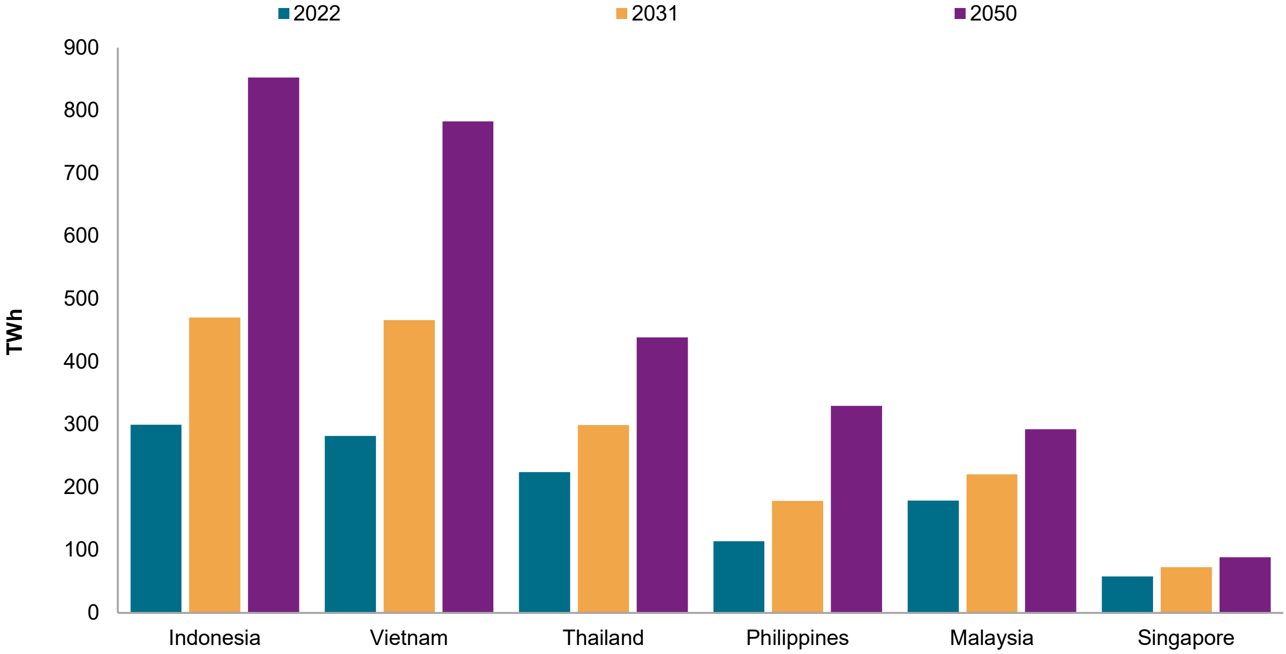
Southeast Asia LNG demand



Source: S&P Global Commodity Insights.

Figure 5-2

Power demand growth outlook



Source: S&P Global Commodity Insights.

Closing the supply gap in the short-term will be difficult, and demand is likely to be lower than previously forecast. But Southeast Asia's gas demand growth will continue. Robust electricity demand growth, coal phaseout, the investment and time needed to build out sufficient renewable capacity and grid capability all point out to an increase in gas power generation during the energy transition. In our current outlook, the region's LNG demand would still grow from 15 MMtpa to 56 MMtpa by 2030.

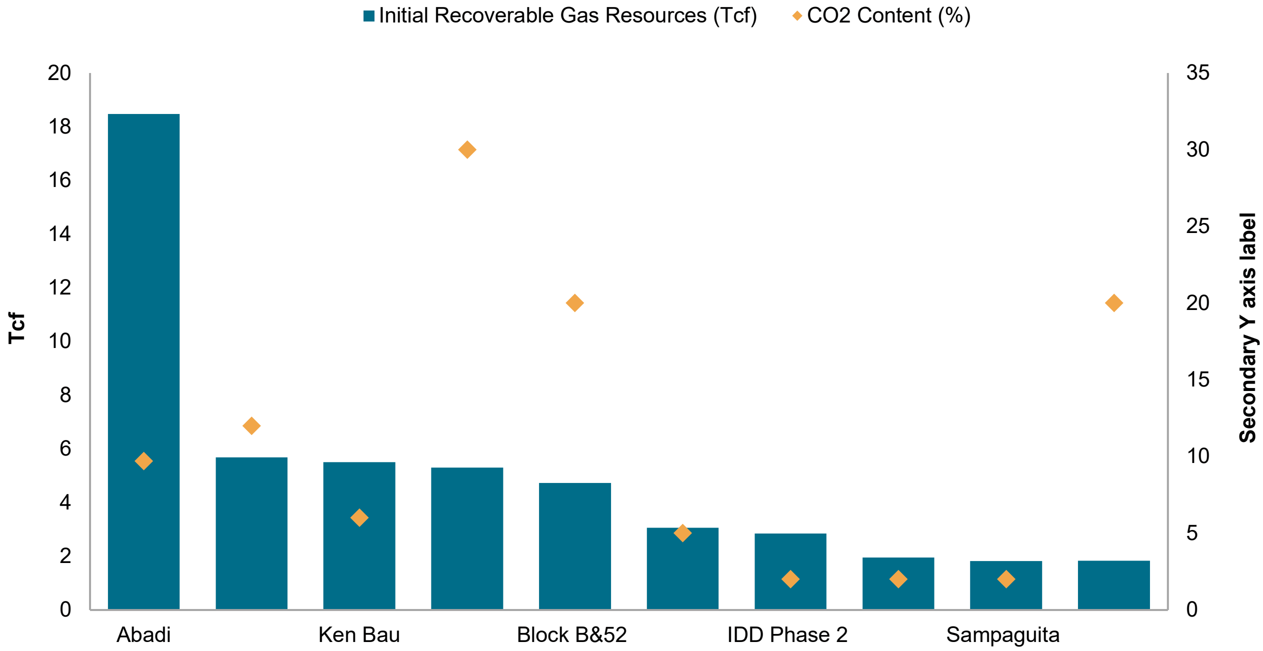
Southeast Asia's case for strong gas demand growth

In recognition of their vulnerability to the warming climate, most Southeast Asian countries have updated their climate targets in the run up to the COP26 conference in 2021, aiming for net-zero between 2050 and 2065.

Plans to move away from coal generation have been a common feature among the region's climate strategies, but Southeast Asia's strong power demand growth will require adding more capacity on top of replacing coal. In the past decade, the region's power demand has grown 5.7% annually, more than double the global average of about 2.5%, while growth to 2031 is forecast to reach 4.5%. The options to fulfil this demand will increasingly fall on gas and renewables as financing options to build new coal plants become scarce.

Figure 5-3

Southeast Asia's largest non-producing gas projects



Source: S&P Global Commodity Insights, formerly IHS Markit

High levels of renewable capacity addition are planned, with more than 50 GW of solar and wind capacity targeted to be added across Southeast Asia by 2030. To be able to handle the intermittency that comes with increased reliance on renewable generation, all countries also require hefty investments to upgrade their grid.

Vietnam has shown the issues that can happen when the development of solar and wind capacity outpaces grid enhancements. Out of 40 GW of the current solar and wind capacity in Southeast Asia, 66% of the capacity is concentrated in Vietnam. A rush of development was triggered after the introduction of a lucrative feed-in-tariff, and more than 16 GW of solar capacity was added during 2019–20. However, the grid was not ready to integrate such influx of intermittent generation, resulting in high curtailment levels negatively impacting investors' revenue. It is estimated that Vietnam Electricity needs to dedicate about $3.6 billion per annum over the next five years for grid enhancements, compared to a total capital spend of $2–3 billion over the past few years.

EVN needs to dedicate about $3.6 billion per annum over the next five years for grid enhancements

Robust electricity demand growth, coal phaseout, along with the investment and time needed to buildout sufficient renewable capacity and grid capability all point out to an increase in gas power generation during the energy transition.

An opportunity to accelerate development of domestic resources

Southeast Asia still has large amounts of gas resources. The top 10 non-producing gas projects in the region have around 45 tcf of net recoverable gas between them. With 1 Tcf of gas being comparable to 18 years of 1 MMtpa LNG supply, sufficient to power a 900 MW combined cycle gas turbine (CCGT) for the same period, development of these resources is critical to fuel the region's energy transition.

Unfortunately, most of these projects have stalled. Many of the projects share similar key challenges, the first being high CO_2 and the additional cost of handling it. The only two projects in the chart above that are seeing clear progress are in Malaysia, despite having fields with relatively high CO_2. This is because PETRONAS has realized that development of its large gas fields with high contaminants is crucial to maintain the utilization of its key asset, Malaysia LNG (MLNG), and it is working with its partners to fast-track CCS infrastructure using depleted fields as storage. Work on Malaysia's regulatory and incentives framework to support these CCS developments is also ongoing.

The second key challenge facing upstream development is a lack of market or difficulty in finalizing offtake agreements. For example, both Cai Voi Xanh and Ken Bau are in the central coast of Vietnam, while Vietnam's gas market is concentrated in the south. With no gas market nearby, these projects need to be developed with an integrated power development but are faced with difficulty in securing PPAs and a public-private partnership regulation that is less friendly to international investments.

The third key challenge is international players exiting the region. Shell, Chevron, and Murphy are seeking to exit from their positions in Abadi, IDD, and the Kelidang cluster, respectively. Although the underlying factors are not the same, these projects share a lack of robustness that made them prone to substantial delays and struggle against more promising projects in a global upstream portfolio.

Addressing these challenges are not easy but lowering the barriers for the projects can be achieved through policy changes. For instance, adjusting domestic gas price expectations, providing incentives, and implementing carbon pricing can help accommodate CCS costs. The ability to limit the carbon intensity of upstream developments can be especially attractive and it is evolving to be a key requirement for many international players.

These changes are already taking place. As spot LNG prices continue to stay high and long-term contracts are difficult to secure, markets will look for alternatives. The development of a shared carbon capture facility and the regulatory framework supporting CCS in Malaysia may be replicated across the region that will allow more upstream investments to take place. The increase in dialogue between governments to reach a consensus on shared resources, such as between Thailand and Cambodia, is another signal that changes are afoot.

Lofty renewable targets in Southeast Asia: How to attract more private investments?

Joo Yeow Lee, Associate Director, Southeast Asia Power & Renewables

- Returns on equity for renewable projects have declined since the earlier feed-in-tariff (FIT) days and are forecast to continue declining. The initial FITs were set at attractive levels, accounting for the infancy of the solar PV and wind sector in the region. However, as the markets matured, and the renewable sector within the country develops, governments' support for the sector through FITs diminished, and shifted in favor of tenders.
- Renewable development environment remains challenging, although there have been some improvements. In most other aspects, things have remained relatively unchanged for renewable project development as compared with the earlier days.
- Changes are necessary to ensure that the sector remains attractive to private investments.

Southeast Asia's renewable growth story began just over a decade earlier, kickstarted through the implementation of FIT mechanisms across the region. The growth rates were high owing to the low starting base, but the absolute annual capacity additions were relatively low, at several hundred megawatts for most of the decade, given the size of the power system, which more than doubled from 140 GW to nearly 290 GW over the same decade. The size of the capacity additions increased drastically when Vietnam's FIT deadline loomed in 2020 and 2021 for solar PV and wind, respectively.

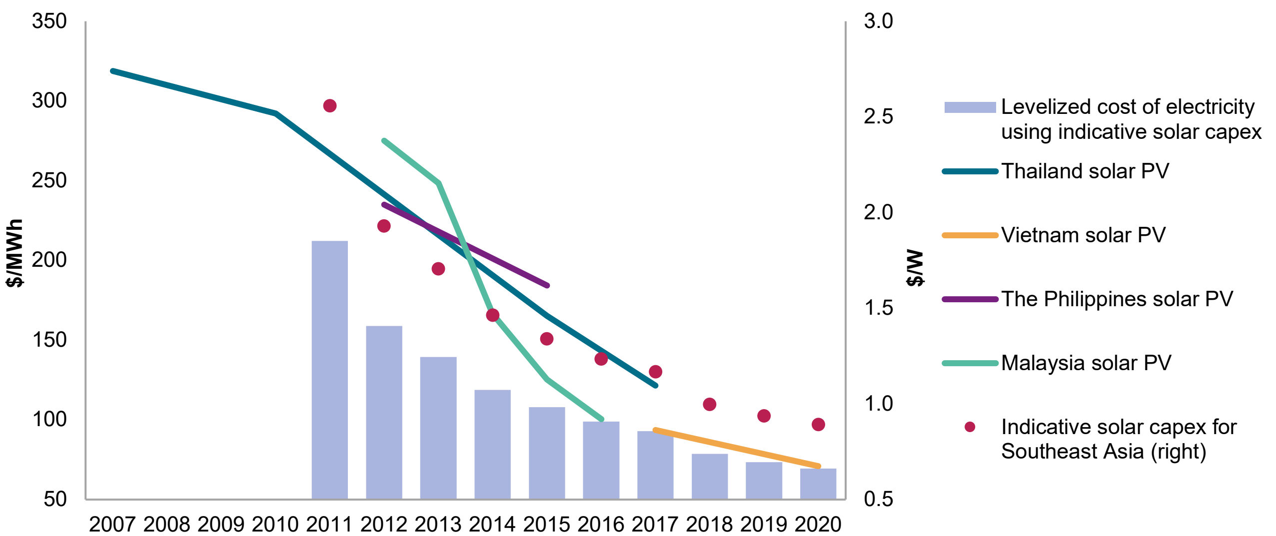
Feed-in-tariffs were set at attractive levels

The first country in Southeast Asia to introduce FITs was Thailand, back in 2007, while the last country that had FITs to support solar PV and wind developments was Vietnam, ending in 2021. The initial FITs were set at attractive levels, accounting for the infancy of the solar PV and wind sector in the region, at a time when there was nearly negligible capacity in operation, except for some rooftop solar PV capacity. In most countries, the FITs were accompanied by capacity quotas/targets, which were rapidly taken up. This reflected the attractiveness of the FITs, but the government also recognized the burden of supporting these renewables at that level and its impact on the cost of power. As a result, the governments reduced the FITs at a relatively quick pace, ranging anywhere from 8% to 43% over each FIT adjustment, with an average reduction of 24%.

Although the rate of FIT reduction appears to be high and at times even outpacing the decline in cost to develop solar PV projects, this did not result in the project developers' margins getting squeezed to razor-thin levels. This was because, at the onset of the FIT regime, these FITs were set without many available local benchmarks and had to compensate the developers for the risk of undertaking projects when the sector was still just starting out in the region. As a result, the starting FITs were significantly greater than the levelized cost of electricity (LCOE), and based on our estimates, even the large reductions did not bring them below the LCOE for solar PV.

Figure 6-1

Evolution of solar feed-in-tariff and capex

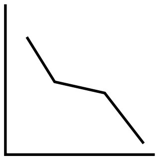


Source: S&P Global Commodity Insights.

Recent and future projects will face lower returns

As the markets matured, and the renewable sector within the country develops, governments' support for the sector through FITs diminishes. Across the region, many countries that have successfully kickstarted their solar PV and wind sector have shifted in favor of tenders, especially amid an environment of rapidly declining awarded prices being reported globally. These tenders have been accompanied mostly by some form of price cap or requiring renewables to compete against the grid parity generation cost. Whether the countries implement tenders or reintroduce FITs (which will be at a declining rate), what is clear is that the remuneration for solar PV and wind projects will be declining and likely at a rate faster than their cost to develop, thereby putting a squeeze on margins. S&P Global estimates that the equity internal rate of return (IRR) will decline substantially, falling to the single-digit level.

High prices across the supply chain will also impact the projects currently under development. After the dramatic cost decline in the past decade, the recent boom in demand, surging raw material costs, and disruptions in the supply chain have led to global prices for solar modules rising by 14% year-on-year in 2022. This is in addition to freight premiums, which reached a high of more than five times the pre-pandemic levels back in 2021 and has remained elevated since, owing to higher freight demand, logistical challenge, and heightened fuel costs, impacting the overall delivered equipment cost. These high prices across the supply chain are currently expected to persist till end-2023 before prices return to 2020 levels from 2024 onward. This increase in project cost was not limited to solar PV projects, as major non-Chinese wind turbine suppliers reported an increase in average selling price increase of close to 25% between 2019 and 2022.



Recent and future projects face lower returns owing to high prices across the supply chain

Some improvements made, but much has remained unchanged

Some progress has been made in reducing the development time for new solar PV and wind projects. This has been achieved through having consistent procedures across tenders, such as the four large-scale solar PV tenders in Malaysia, which makes the process of submitting the proposal for every subsequent tender easier. The Philippines has implemented an Energy Virtual One-Stop Shop system, to allow the submission of all necessary documents and information, for synchronized processing through a single portal for new power generation permits. More route-to-markets have also been introduced in the Philippines, with the emergence of projects relying solely on the merchant market to reach financial close, or a mix of corporate power purchase agreements from offsite renewable generation via the green energy option scheme and/or merchant market and/or contract with distribution companies. There is also the planned introduction of third-party grid access in Malaysia and in Thailand, which will facilitate offsite corporate renewable PPAs in the future. Vietnam, on the other hand, is looking to launch the pilot of the direct power purchase agreement scheme, which is akin to the corporate power purchase agreement in most other jurisdictions. These will be in addition to the government-led renewable tenders. Although these are all being planned, there remains a lack of transparency on when new route-to-markets will be added, or when planned tenders and/or capacity additions will take place, which would facilitate better project planning for developers. This means that the repercussions from missing scheduled commissioning and having the PPA canceled or having a planned project canceled owing to a change in government planning will be severe, as the project faces an uncertain revenue stream. In most other aspects, things have remained relatively unchanged.

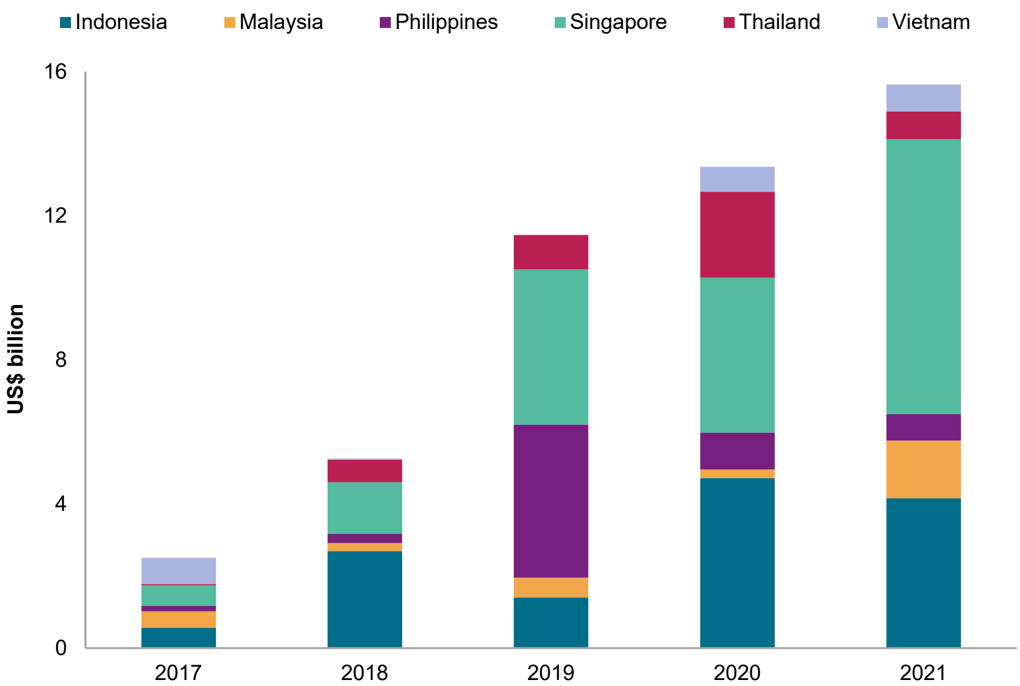
Changes need to be made for the sector to remain attractive to investments

The equity IRR is expected to decline further in the future, and this will impact the solar PV and wind capacity additions. The emergence of green debt as an avenue to finance new renewable projects is just one piece of the puzzle to help the region meet its ambitious renewable targets and transition the power sector toward net-zero. More effort is required to mitigate risk for prospective developers so the sector's attractiveness for investments can be improved. Even if some shortcomings remain as they take longer or are too challenging to be addressed, S&P Global forecasts strong solar and wind capacity additions, more than tripling the current capacity by 2030.

The region will need to compete globally to attract investment in the renewable sector. Countries have fared poorer than average in terms of market stability. However, as this is based mostly on overall risk, it will require a fundamental change not specific to the power sector. The contract terms are a critical area for improvement in Vietnam, which is the only country in the region that fares poorly, largely owing to the inequitable risk allocation in favor of the offtaker, made worse by the ongoing curtailments owing to the mismatch in provincial supply and demand and grid congestion. The offtaker status could be improved with more route-to-markets opening, as there is a wider range of offtakers to contract with, and many corporate offtakers would be deemed more favorably

Figure 6-2

Southeast Asia green bond and loan issuance



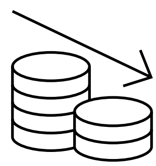
Note: Excludes sustainability-linked bonds/loans. Includes issuances of green bonds and loans with use of proceeds for projects within Southeast Asia.

Source: S&P Global Commodity Insights.

than the single buyer who tends to be supported by government subsidies owing to regulated prices being below the cost of electricity supply. Ownership hurdles need to be addressed, as both Malaysia and the Philippines have foreign ownership restrictions, limiting the entry opportunity of foreign independent power producers (IPPs). In addition, both Malaysia and Indonesia have local content requirements in place, which limit the sourcing of equipment and engineering, procurement, and construction services from potentially lower-cost countries.

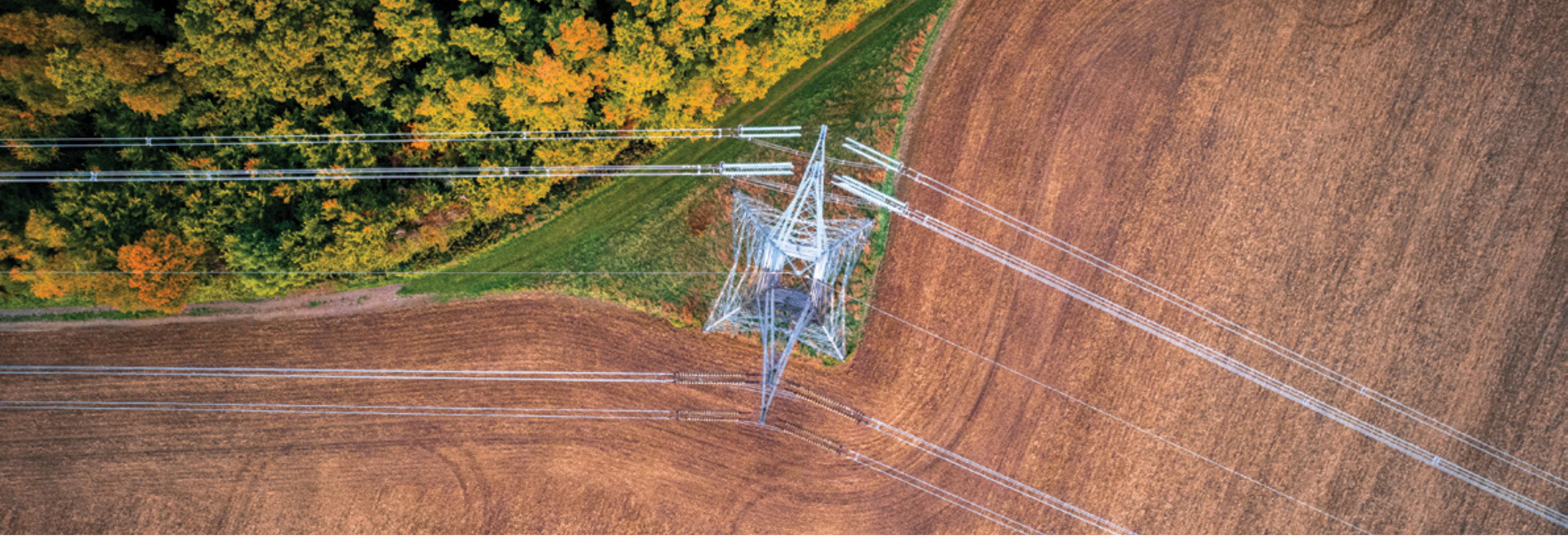
On a macro level, planning the power system based on renewable energy zones will provide a clear road map for investors and reduce the investment uncertainty in the areas where additional solar PV and wind capacity can be developed over the planning horizon, with minimal curtailment risk, as investments in the transmission infrastructure and flexible generation should also be planned in parallel. These plans will also need to be relatively consistent from revision to revision to provide certainty to investors beyond the short term and to reduce uncertainty.

Alongside the capacity plan, the policy roadmap for the introduction of new route-to-market needs to be clearly illustrated with a timeline. This will prevent the stranding of any assets for an unknown protracted period, in the event there are delays to the commissioning, which nullifies the PPA. This is because the project developer can plan for such contingencies through other route-to-market. In addition, corporate PPAs will likely also allow the renewable projects to have a higher selling price. This is because the demand for renewables will likely outweigh the supply in the short to medium term as renewable commitments from corporations grow, and when the option becomes available, it will likely only allow a limited amount of new renewable capacity to be developed annually, to avoid grid congestion issues. This will also improve the offtaker status for the countries, as it opens up the offtake to strong corporate buyers.



Record low awarded prices provide lessons that can be adopted across the region to derisk renewable projects

As demonstrated from the record low awarded price across the region, in both the first and second Cambodian National Solar PV Park tender of $38.77/MWh and $25.70/MWh, there are many lessons that can be learned and adopted across the region, to derisk the solar PV and wind projects. First, as land ownership is highly fragmented in the region and there are differing requirements and jurisdictions of multiple levels of government, state entities are better positioned to carry out the land acquisition and bear this portion of the risk for the project. This is similar to additional transmission infrastructure for the connection to the national grid. These will benefit from renewable energy zone planning and will facilitate faster project development and a significantly lower likelihood of delays. Second, the PPA risk allocation is equitable, allocating the risk arising from various events to the party that can manage it. For example, there is a minimum generation clause that allocates the power plant operational risk to the project owner, while the deemed dispatch clause owing to grid congestion, puts the offtake risk on the offtaker. These are important, especially with the proliferation of more renewables which may impact their dispatch. Lastly, PPA included clearly defined default and termination compensation terms, which provide a fair amount of protection for the developer. The PPA terms are critical in ensuring the bankability of the project and, consequentially, the ability of the project to access international capital.

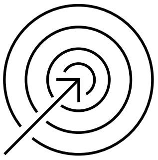


Are Southeast Asia power systems ready for the rise of renewables?

Joo Yeow Lee, Associate Director, Southeast Asia Power & Renewables

- All countries will require enhancements to their grids to accommodate more solar and wind capacity, but Vietnam and Indonesia will face the toughest challenge to accommodate more renewables. The two countries have the most ambitious renewable target and greatest renewable potential, respectively, and are starting at two extreme ends of the spectrum, with Vietnam having more intermittent renewable capacity than the entire remainder of Southeast Asia and Indonesia having one of the smallest in the region.
- The creation of renewable energy zones will help coordinate power system planning and allow for faster-pace development of solar and wind capacity. Staying consistent in planning is also critical for the governments in the region. This would be highly beneficial as it will help optimize the limited investment capital available for investments in grid enhancements by concentrating the capital on areas that have better renewable resources and more economically efficient transmission investment outcomes.
- Flexible generation is not a newly established technology, but the status quo needs to be changed to enable its development in Southeast Asia. There is currently no clearly defined remuneration mechanism for the delivery of frequency regulation services for batteries, as the only revenue stream is through the sale of electricity, which needs to change. Gas-fired generation is technically capable of playing a role in managing the intermittency, but the current contracting structure, based on a high level of utilization and fuel contracting with high fixed offtake obligations, does not allow for it to play a flexible role.

Like most countries in the world, Southeast Asia's economies have made their own nationally determined contributions commitments during the UN climate conferences, most recently updated in 2021 during the Glasgow negotiations. During the Glasgow climate conference in 2021, most Southeast Asian countries announced their new climate targets, with net-zero targets to be achieved between 2050 and 2065. The new targets are more aggressive than before and will require an accelerated energy transition to be achieved. Currently, governments in Southeast Asia have plans to add more than 250 GW of solar and wind capacity over the next two decades, and this will likely be increased further when their PDPs are updated in the coming years.



Governments in Southeast Asia plan to add more than 250 GW of solar and wind capacity over the next two decades

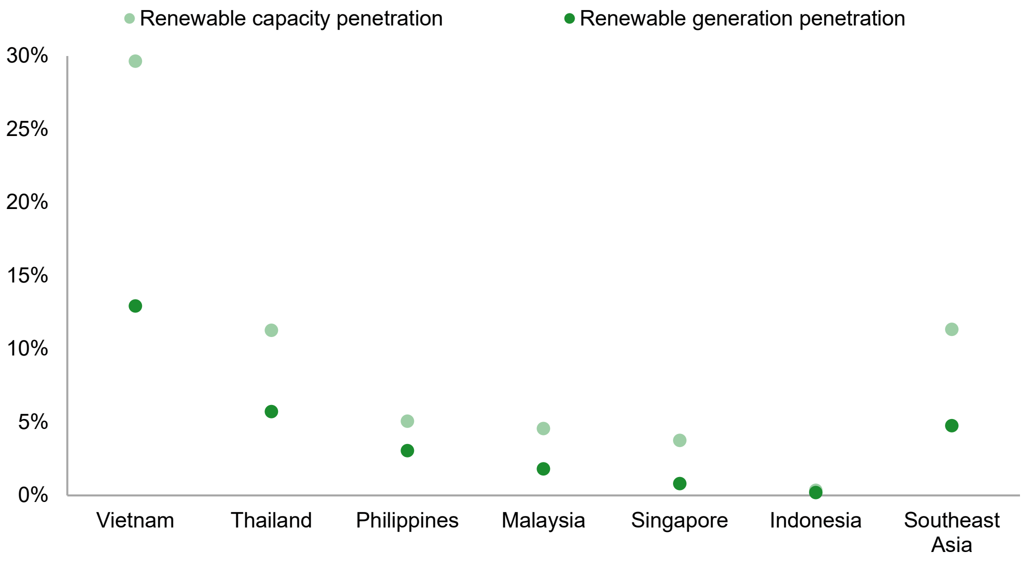
Grid readiness for more intermittent renewables to be added to the power system

The current solar and wind renewable penetration across Southeast Asia is still relatively low, at 5% and 11% of total generation and installed capacity, respectively, compared with leading countries like Germany, which have already reached levels of 34% of generation and 55% of capacity from solar and wind. This level of renewable penetration is somewhat skewed by the large share of intermittent renewable capacity contributed by Vietnam, which over the past three years has added more than 20 GW of solar and wind capacity. Vietnam's renewable penetration is more than double the region's average, at 13% and 30% for generation and capacity, respectively. Although the level of solar and wind penetration is still relatively low, some countries are already facing challenges in dealing with the intermittency and grid congestion impeding the utilization of solar and wind generation.

Vietnam and Indonesia will face the toughest challenge to accommodate more renewables. The two countries have the most ambitious renewable target and greatest renewable potential, respectively, and are starting at two extreme ends of the spectrum, with Vietnam having more intermittent renewable capacity than the entire remainder of Southeast Asia and Indonesia having one of the smallest in the

Figure 7-1

Solar and wind renewable penetration in Southeast Asia



Source: S&P Global Commodity Insights.

region. Despite the differences, they face grid congestion and challenges dealing with the intermittency from renewables, which will hinder future growth of solar and wind capacity.

Grids in Malaysia, the Philippines, and Thailand do not face any challenges to accommodate the operating intermittent renewable capacity thanks to a low renewable penetration and robust requirements before capacity could be developed. Going forward, as solar and wind additions pick up pace (either through increased tender sizes or more aggressive government plans/targets), similar to the rest of the region in their energy transition journey, locations with sufficient grid capacity will dwindle, and similar grid enhancements will be needed.

Countries in Southeast Asia are currently targeting to add close to 50 GW of solar and wind capacity by 2030, and this target is slated to be increased further. Most of the countries have either experienced first-hand the impact to the grid and power system caused by the rise of intermittent renewables or have witnessed the issues faced by their regional neighbors. Each country is facing a different situation in terms of the current state of their grids to handle the existing and planned intermittent renewable additions, but they have all incorporated the lessons from the region into the PDP, which is to upgrade the grid infrastructure to facilitate the connection for more renewables, in line with their ambitious targets. The plans for renewable additions need to keep pace with the grid upgrades to ensure that the additional renewables can be utilized.

The plans for grid upgrades to support more renewables will come at a high cost. This is because, unlike conventional generators, which can be located closer to the load centers, renewables have a significantly larger land requirement and will need to be developed further away, where land is cheaper. Therefore, as the share of renewables in the generation mix increases, so will the investments in transmission infrastructure. Many of the Southeast Asian countries currently have government-regulated power tariffs, which are set at levels below the cost of supply; therefore, it will definitely be challenging to finance increasingly larger grid investments.

Regulation and policy readiness to aid renewables addition

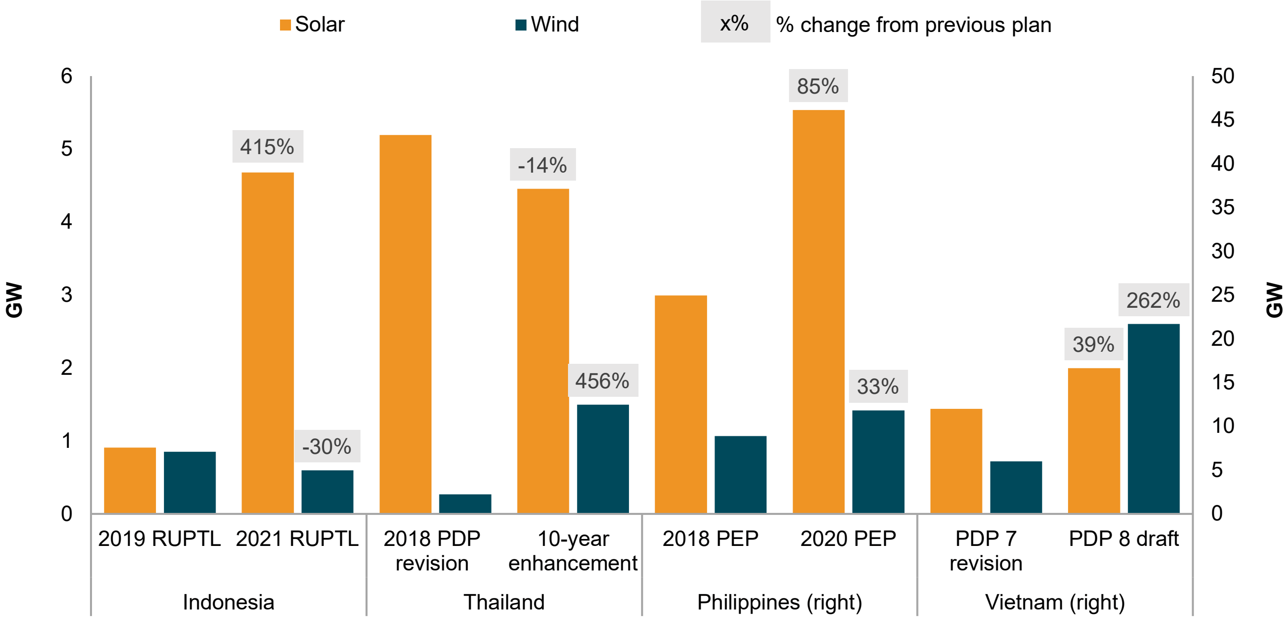
Capacity expansion planning has historically been weighted on total supply adequacy rather than reliability and flexibility

Most of the legacy PDPs for Southeast Asian countries mainly focused on generation capacity additions to serve the strong power demand growth. Capacity expansion planning was weighted on total supply adequacy rather than supply reliability and flexibility. In recent years, more plans are proposed to accommodate the addition of more intermittent renewables across all the Southeast Asian countries' national PDPs. However, beyond enhancements to the transmission and distribution grid, it remains to be seen what the countries will be doing from the regulation and policy perspective to facilitate the development of more flexible generation sources of power demand and supply.

Currently, the main regulatory and policy tool being utilized to ensure that additional intermittent renewable generation does not impact the power system comes from requiring grid impact studies or power system studies before the development approval is given. Both the project developer and the transmission and distribution company are responsible for carrying out these studies together. Such studies have been in place for countries like Malaysia (large-scale solar photovoltaic [PV] tender), the Philippines (Energy Regulatory Commission interconnection agreement), and Thailand (grid connection code) and utilized effectively, as no grid-related curtailment/congestion issues have been reported. Most recently, following the grid issues faced in Vietnam, there is now a clear set

Figure 7-2

Change in solar and wind targets for 2030 across successive power development plans



Note: PDP = Power Development Plan; PEP = Philippines Energy Plan.
Source: S&P Global Commodity Insights.

of grid-related conditions placed alongside each newly proposed solar and wind project, when they are seeking to be added to the approved national project list.

Long-term power/energy development plans are useful in guiding necessary investments and the corresponding policy and regulatory changes to achieve the target fuel mix. However, in Southeast Asia, many long-term plans have a horizon of up to 25 years and are being updated frequently. The most frequent updates to PDPs are being done annually, and even the less frequent updates are occurring before a quarter of the planning horizon is over—even though the plans cover an outlook of between 10 and 25 years and typically consist of relatively significant changes. Frequent revisions to the development plans would not be an issue if the changes were not drastic, however, this has not been the case for many countries.

The PDPs across the countries in Southeast Asia, appear to still be based mostly on planning based on conventional generation. Although they do mention the need for increased flexibility to allow more intermittent renewables to be added to the generation mix, there is little mention of the addition of flexible generation. This will need to be addressed in future plans, to provide more clarity for potential independent power producers to attract investments in such flexible generation sources.

Staying consistent in planning and the creation of renewable energy zones will help coordinate power system planning and allow for faster-pace development of solar and wind capacity. This would be highly beneficial as it will help optimize the limited investment capital available for investments in grid enhancements by concentrating the capital on areas that have better renewable resources and more economically efficient transmission investment outcomes. In addition, this will provide a clear road map for investors and reduce the investment uncertainty on the areas where additional solar and wind capacity and flexible generation can be developed over the planning horizon.

Technology readiness to handle the increasing intermittency in the power system

The recognition of the need for more flexibility in the power system across most PDPs in Southeast Asia bodes well for the accommodation of more intermittent renewable capacity. However, for many of the plans, this is the very first time this has been included and it remains a relatively new concept for much of the region. The supporting mechanisms, such as capacity payment/market, ancillary service market, or frequency regulation service, are not implemented or are still at a very early stage.

Flexible generation is not a newly established technology, but the status quo needs to be changed to enable its development in Southeast Asia. There is currently no clearly defined remuneration mechanism for the delivery of frequency regulation services for batteries, as the only revenue stream is through the sale of electricity, which needs to change. Gas-fired generation is technically capable of playing a role in managing the intermittency, but the current contracting structure, based on a high level of utilization and fuel contracting with high fixed offtake obligations, does not allow for it to play a flexible role. The current gas generation fleet is also not suitable to play a peaking role. Its efficiency and corresponding fuel cost are greatly affected by lower utilization—as much as 300% higher than a baseload plant.

Figure 7-3

Readiness to accommodate more intermittent renewables

● Low ● Medium ● High

Readiness category	Readiness subcategory	Indonesia	Malaysia	Philippines	Thailand	Vietnam
Grid readiness	Grid ability to accommodate current renewables	Low	High	High	High	Low
	Grid upgrades and renewable addition plans aligned	Low	High	High	High	Medium
Policy and regulation readiness	Grid impact studies/power system studies required to approve new intermittent renewable projects	Low	High	High	High	Medium
	Plans to increase flexible generation (gas and/or batteries)	Low	Medium	High	Low	High
	Consistency in plans	Low	High	Medium	Medium	Medium
Technology readiness	Battery adoption readiness	Low	Medium	High	Low	Medium
	Flexible gas generation adoption readiness	Low	Medium	Medium	Medium	Medium

As of Feb. 2, 2023.
Source: S&P Global Commodity Insights.

Seizing offshore wind investment potential in Southeast Asia

Joo Yeow Lee, Associate Director, Southeast Asia Power & Renewables

Vince Heo, Director, Asia Pacific Power & Gas

- Vietnam and the Philippines have raised their ambition for offshore wind, capitalizing on their vast resource potential. According to the latest draft version of Power Development Plan VIII (PDP8), Vietnam aims to achieve up to 7 GW of offshore wind capacity by 2030, up from 6 GW in the PDP7 (onshore and offshore wind combined). While there is no explicit offshore wind capacity target set for the Philippines, the Department of Energy (DOE) raised the wind capacity target for 2040 from 12 GW to 17 GW in the latest National Renewable Energy Program.
- International developers are actively seeking a partnership with Vietnamese firms, with two-thirds of offshore wind project pipelines jointly owned by international and local companies. European companies are particularly active, making up 52% of total attributable capacity of offshore wind projects in a pre-construction stage.
- The new tariff proposed by Vietnam Electricity (EVN) will make most transitional wind projects unprofitable. The proposed tariff at 7.9 cents/kWh will reduce post-tax equity IRR to 5–9%, down from 11–15% under the previous feed-in tariff (FIT), making the profitability of transitional wind projects not commensurate with a hurdle rate by many developers.
- Risk mitigation in financial structuring is required to unlock low-cost international capital. Vietnam needs massive financing for offshore wind, which could not be provided by local lenders alone. Credit enhancement mechanism such as sponsor support or Export Credit Agency (ECA)- backed financing will be needed to attract international lenders

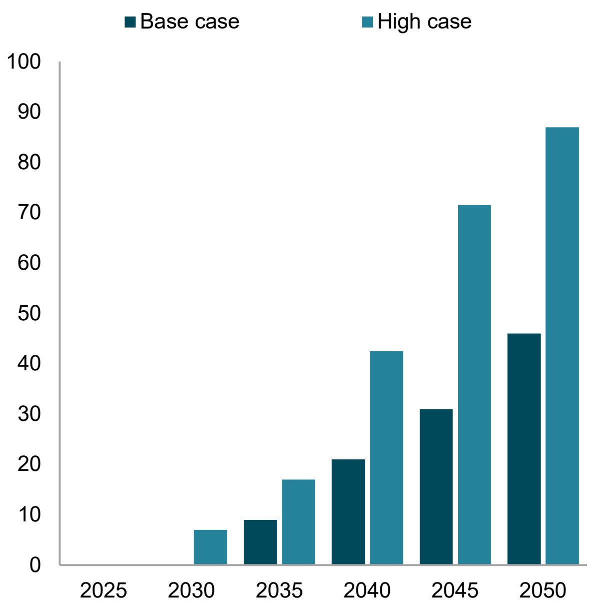
Vietnam and the Philippines have been gaining traction among offshore wind developers and investors. About half of electricity generation in these economies still comes from coal, while growth in electricity demand is among the highest in the region. Offshore wind is well positioned to cater to the rising demand or to displace old coal-fired power plants owing to their large capacity and high capacity factor relative to solar or onshore wind. Yet, offshore wind in both markets is nowhere close to reaching a commercial stage—no single de facto offshore wind project is in full operation yet, the permitting process in many development stages is still obscure, and mobilizing resources from the international capital market remains challenging. Developers need to be wary of various challenges in permitting, supply chain, and financing when crafting a go-to-market strategy.

Vietnam and the Philippines have raised their ambition for offshore wind, capitalizing on their vast resource potential

Vietnam has an ambitious offshore wind capacity target of adding between 46 GW and 87 GW by 2050, with the first tranche of up to 7 GW planned to come online between 2026 and 2030. There is strong interest from major players such as Ørsted, Mainstream Renewable Power, Copenhagen Infrastructure Partners (CIP), and Equinor to preempt the vast market potential in Vietnam. However, frequent restatement of near-term targets and unclear rules in permitting, as well as a lack of a road map for the transition from FIT to tender, are posing uncertainty to many developers.

Figure 8-1

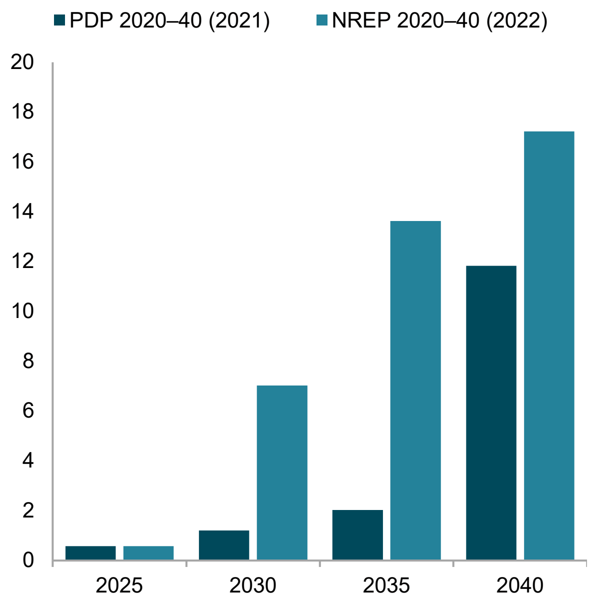
Vietnam's offshore wind target (GW)



Data compiled December 2022.
Based on the November 2022 draft PDP8.
The Vietnamese government defines offshore wind as wind projects developed in water depth of at least 20 m.
Source: S&P Global Commodity Insights.

Figure 8-2

Philippines' wind target (GW)



Data compiled December 2022.
NREP: National Renewable Energy Program.
No explicit offshore wind targets in Philippines.
Source: S&P Global Commodity Insights.

While there is no explicit offshore wind capacity target set in the Philippines, the DOE raised the wind capacity target for 2040 from 12 GW to 17 GW in the latest National Renewable Energy Program. The DOE is also responding to a growing interest from predominantly local players in offshore wind, with a draft executive order issued in November 2022 to strengthen and rationalize the regulatory framework for the immediate development of offshore wind projects. The market demand will also remain robust—the current Renewable Portfolio Standard (RPS) stipulates a minimum 1% increase in renewable generation per annum (and this is likely to be increased to meet the 50% of generation from renewables by 2040), underpinning the growth potential for offshore wind. Developers can explore various route-to-market options, including RPS, utility/corporate PPA, and merchant, capitalizing on a favorable market environment for companies.

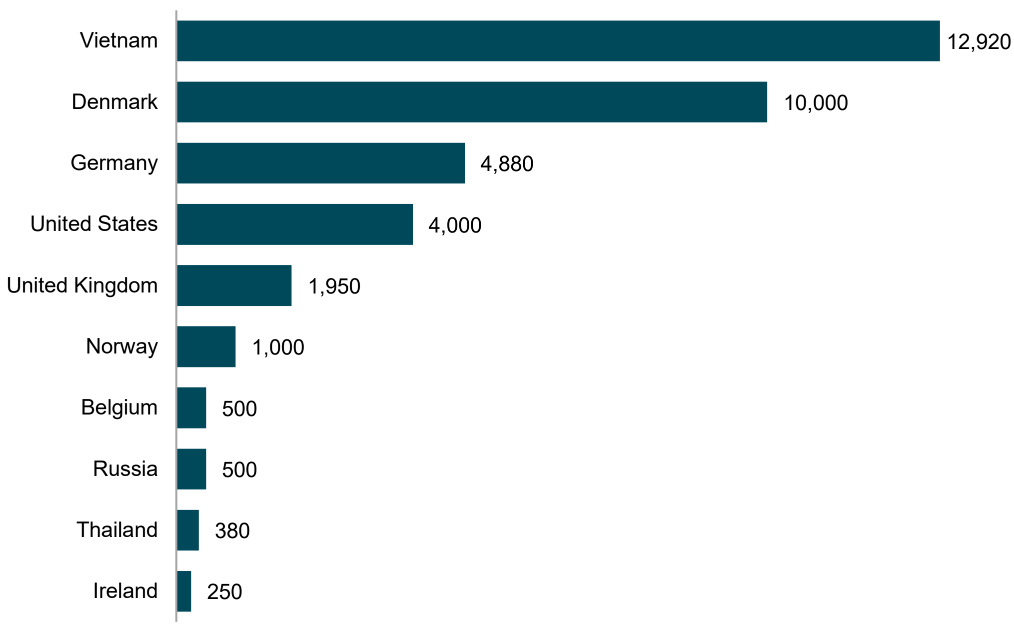
Vietnam has ambitious offshore wind targets of between 46 GW and 87 GW by 2050

Vietnamese firms sought after by international developers

International developers are actively seeking partnership with Vietnamese firms, with two-thirds of offshore wind project pipelines jointly owned by international and local companies. Companies headquartered in Europe make up 52% of total attributable capacity for offshore wind projects in a preconstruction stage, with firms from Denmark taking 10 GW in net capacity. It is also worth noting that the role of regional players—mainly Singapore-, Philippine-, or Thai-based developers and IPPs holding power assets across Asian markets—is not prominent in offshore wind projects, unlike their active role in solar or onshore wind projects. This is primarily owing to their limited experience in offshore wind relative to their European peers.

Figure 8-3

Vietnam: Announced offshore wind projects by developer headquarters (MW)



Data compiled November 2022.

Data exclude intertidal projects. The share of attributable capacity is assumed to be equal by equity sponsors in the same project where information is not available.

Source: S&P Global Commodity Insights.

The new tariff proposed by EVN will make most transitional wind projects unprofitable

In Vietnam, the initial FIT of 9.8 cents/kWh, which expired on 31 October 2021, brought a couple of intertidal wind projects into commercial operation. These projects are often constructed with concrete foundations and do not require subsea foundations, thus their capex is 30–70% lower than the equivalent offshore wind projects in a deep-sea on a unit-capex basis. Based on S&P Global Commodity Insights analysis, these intertidal wind projects are expected to achieve 11–15% post-tax equity IRR, a range that is deemed commensurate with the hurdle rate of many developers.

However, there are other intertidal wind projects with 3.5 GW capacity that had signed PPAs but missed the deadline for FITs. On 7 January 2023, MOIT approved a price framework for transitional offshore wind projects alongside ground-mounted solar, floating solar, and onshore wind (Decision No.21/QD-BCT), with an FIT for offshore wind at 7.7 cents/kWh (1,816 Vietnamese đồng/kWh). This FIT is about 20% lower than the previous FIT at a time when many developers are faced with rising cost inflation, making almost no projects commercially viable.

Under this tariff, many projects may not be able to proceed to commercial operation, and some developers and investors may have to hold their projects until the new auction scheme is announced. Corporate PPA, albeit at the demonstration phase, should also be construed as another route-to-market in the absence of the next FIT structure.

Risk mitigation in financial structuring is required to unlock low-cost international capital

Current PPA templates do not offer bankability by international standards

Most solar and onshore wind projects in Vietnam have been financed by local banks so far, because current PPA templates do not offer bankability by the international standard. However, Vietnam needs massive financing for offshore wind, which could not be provided by local lenders alone. Based on S&P Global Commodity Insights calculation, as much as $17 billion in lending will be needed to meet the draft PDP8 target of building 7 GW worth of offshore wind projects by 2030. With the benchmark lending rate expected to rise in order to fight inflation, which surpassed 5% last year, the Vietnamese offshore wind industry needs access to low-cost international capital to unlock its potential.

Attracting international lenders in high-risk emerging markets will call for additional risk mitigation, since they have more limited risk appetite than domestic banks. Some innovative financing vehicles have been explored in collaboration with domestic financial institutions to facilitate derisking instruments:

- Credit enhancement through arranging additional sponsor support has become a common approach by multilateral banks to facilitate project financing from international lenders.
- Export credit agency could also unlock international capital in high-risk emerging markets.
- Other debt instruments such as concessional loans and grants from donor nations could also catalyze a diverse pool of capital needed for Vietnam.

Post coal-to-gas switch, what's the next fuel option for Southeast Asia?

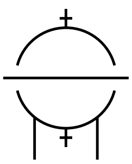
Joo Yeow Lee, Associate Director, Southeast Asia Power & Renewables

- Decarbonization post the scheduled coal-to-gas switch will incorporate the use of hydrogen, to allow continued use of thermal power plants. Fossil fuel generation will remain a sizable part of the region's generation mix, contributing to just under 50% of total generation by 2050. Therefore, many countries in the region intend to tap into hydrogen as a fuel for power generation, to allow continued use of existing and currently under construction power plants, with some upgrades/retrofits
- Hydrogen will be a relatively more expensive fuel with prices estimated at $40/MMBtu compared to coal and gas, and is a costly option for power generation for the region. This is equivalent to around five times the 2022 average delivered gas price in Southeast Asia, and even with cost declines, the delivered cost of renewable hydrogen is forecast to reach $3.5/kg ($27/MMBtu) by 2040.
- Hydrogen blending expected in the region, albeit still in small proportions. Across Southeast Asia, S&P Global Commodity Insights' base case outlook of renewable hydrogen generation reaching 2.5% of the total generation by 2050, which translates to 77 TWh, with four countries adopting renewable hydrogen into the fuel mix.

Decarbonization post coal-to-gas switch will incorporate the use of hydrogen

Southeast Asia as a region has achieved 5.7% annual power demand growth in the past decade, more than double the global average. This growth has been mainly powered by around 94 GW of new fossil fuel generation capacity, or 60% of the total capacity additions added over the last 10 years. Looking ahead, S&P Global forecasts that power demand growth in the region is expected to remain at a robust 3.2% per annum out to 2050, to support the continued development of the regions' economies. This power demand growth, coupled with the decarbonization targets across the region has already led to many governments instituting plans to switch from coal to gas, as the latter produces around half the carbon emissions of the former per unit of electricity generated.

However, the existing coal and gas generation fleet is still relatively young, with nearly 50% of current operating capacity being 10 years old or younger. These assets typically have a relatively long technical life of 25–40 years, and there is more than 40 GW of new capacity that is currently under construction, which will likely come online in the next five years. As a result, fossil fuel generation will remain a sizable part of the region's generation mix, contributing to just under 50% of total generation by 2050. Even with the coal-to-gas switch, the emissions remain substantial, owing to the growing power demand, giving rise to the need to adopt lower carbon fuel, as variable dispatchable generation is still required even with the rapid growth of renewables and energy storage.



Many countries in Southeast Asia intend to tap into hydrogen as a fuel for power generation

Many countries in the region intend to tap into hydrogen as a fuel for power generation. This will allow them to continue utilizing existing and currently under construction power plants, with some upgrades/retrofits required to allow for the blending of either hydrogen or ammonia, instead of requiring entirely new builds or the early retirement of a substantial amount of capacity, which may give rise to supply security concerns.

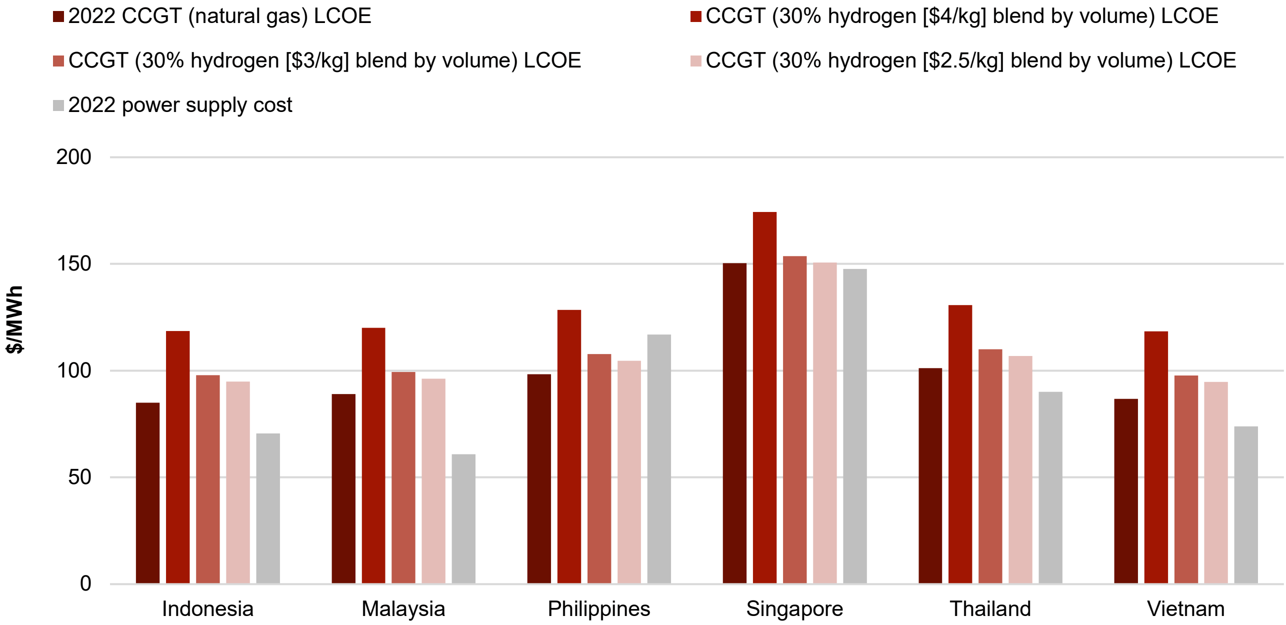
Hydrogen is a costly option for power generation

There is a myriad of technologies to produce and transport hydrogen, some of which have already been developed, while some are still being studied. The differing production technologies result in different 'colors' of hydrogen, of which green hydrogen is the focus, since many of the abovementioned plans and activities aim at utilizing it.

Australia is one of the leading countries in terms of capacity in the pipeline, with 78 GW at various development stages. Owing to the proximity to Southeast Asia, it is the likely supply source for any imports of green hydrogen, especially given the high cost of transport. Currently, the estimated average cost of green hydrogen production in Australia is around $3.5/kg, and at least another $1.6/kg for it to be delivered to the region, which translates to nearly $40/MMBtu. This is equivalent to around four times the 2022 average delivered gas price in Southeast Asia and is still higher than the highest recorded monthly average imported LNG price in the region of $35/MMBtu amidst the Russia-Ukraine war. Even with cost declines, the delivered cost of liquid hydrogen is forecast to reach $3.5/kg ($27/MMBtu) by 2040. It is important to note that the above estimates only reflect the cost, and not the price of delivered green hydrogen, which will likely be at a premium, owing to the growing demand globally, as it has been identified as a tool for decarbonization.

Figure 9-1

Levelized cost of electricity and power supply cost



Data compiled Feb, 15, 2023.

LCOE is determined based on the latest technology CCGT either in operation or under development, and generating at fleet average capacity factor.

Source: S&P Global Commodity Insights.

This high cost of imported green hydrogen will be detrimental to the adoption into the region's generation fuel mix. In most markets in Southeast Asia, the levelized cost of electricity for a combined cycle gas turbine utilizing natural gas as a fuel, is already higher than the average power supply cost, having a premium of between 2–46%. This means that this generation source is likely one of the more expensive sources in the entire fuel mix. Therefore, the adoption of hydrogen, even at a 30% blend by volume appears untenable, as it will raise the levelized cost by 20–40%, and drive up the power supply cost, and will raise affordability concerns. This is exacerbated further, if the intention is to fully switch to hydrogen to decarbonize thermal generation, as this will raise the levelized cost of electricity anywhere from 2.5x to 4x the current level.

Hydrogen blending expected in the region, albeit still in small proportions

Despite the higher cost of utilizing renewable hydrogen as a fuel source for power generation, adoption is still expected through blending with natural gas to mitigate the impact from a most costly fuel and also due to technology readiness for power generation equipment and other related infrastructure. The addition of renewable hydrogen into the generation mix is one of many tools that will be needed for decarbonizing the power sector. This is already acknowledged by companies in the region, as both national oil and gas companies and independent power producers have plans to develop renewable hydrogen production either domestically or abroad, to secure supply for their power generation needs.

Singapore, which does not have the resources to produce renewable hydrogen at scale, has already announced its National Hydrogen Strategy where it targets up to 50% of power generation to be fuelled by hydrogen by 2050. The adoption of this more costly fuel will likely be supported with revenue from the carbon tax, as the government has made a commitment that it will be used for decarbonization and not for additional government revenue collection.

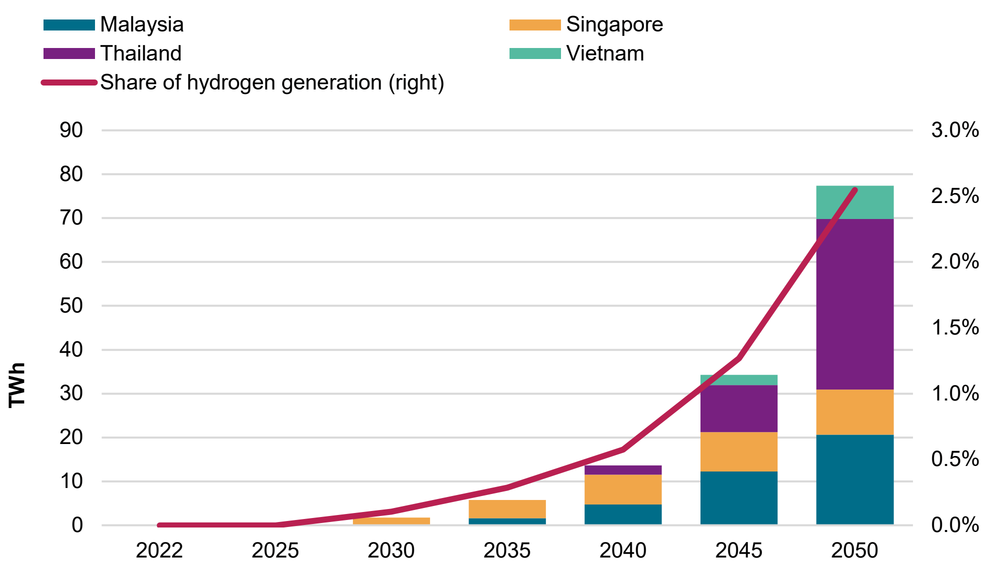
2.5% of the region's generation will come from hydrogen by 2050

An increasing amount of generation in Singapore is expected to come from burning a blend of hydrogen and natural gas. This has been explicitly mentioned in the emission standards for power generation units consultation that is currently ongoing, where new and repowered plants to be at least 30% hydrogen compatible by volume and have the ability to be retrofitted to become operationally 100% hydrogen-compatible in the future to the extent possible. The very first hydrogen-ready 600 MW combined cycle gas turbine by Keppel has already reached a final investment decision in 2022. The company has also partnered with Pertamina Power Indonesia and Chevron Corporation through a joint study agreement to explore the development of green hydrogen using renewables (geothermal) located primarily in Sumatra, Indonesia, to potentially secure supply.

Across Southeast Asia, S&P Global Commodity Insights' base case outlook of renewable hydrogen generation reaches 2.5% of the total generation by 2050, which translates to 77 TWh, with four countries adopting renewable hydrogen into the fuel mix. There is upside potential, which will be dependent on policy support and a potential decline in cost of renewable hydrogen, which may be contingent on cost reductions in transportation and production, as well as the possibility for domestic production. There will be more investment opportunities for hydrogen infrastructure and technology deployment in Southeast Asia, as countries incorporate hydrogen in their power generation plans.

Figure 9-2

Renewable hydrogen generation



Data compiled Feb, 15, 2023.
Source: S&P Global Commodity Insights.

Southeast Asia's continued reliance on fossil fuel generation: Is carbon capture the solution?

Joo Yeow Lee, **Associate Director, Southeast Asia Power & Renewables**

- Carbon capture will be one of many solutions to reduce carbon emissions from fossil fuel generation. This is necessary, as the reliance on fossil fuel generation remains significant over the coming decades, to meet the regions' growing power needs, as the economy continues to grow rapidly. By 2050, fossil fuel generation will still contribute to half of Southeast Asia's generation mix according to our base case outlook.
- The cost of carbon capture applied to the power sector is expected to decline more rapidly starting in the 2040s. The current application of carbon capture to gas and coal power plants is only 4% of the global carbon capture projects currently in operation, as the carbon emission concentration from such plants is relatively lower compared to other applications.
- The addition of CCS is not suitable for all coal and gas capacity. This will be dependent on remaining plant life, technology type and utilization level, meaning that at best, just under 70% of the fossil fuel generation emissions can be captured. Financing and/or pricing mechanisms will still need to be implemented to facilitate CCS deployment, to either levelized the playing field with standalone coal or gas generators, or make the investment to retrofit with CCS and attractive one.

Carbon capture will be one of many solutions to reduce carbon emissions from fossil fuel generation

As fossil fuel generation continues to feature prominently in the generation mix over the next three decades, while the countries target to achieve net zero or carbon neutrality by 2050, there has been a slew of options being studied and piloted to decarbonize fossil fuel generation both in the region and globally.

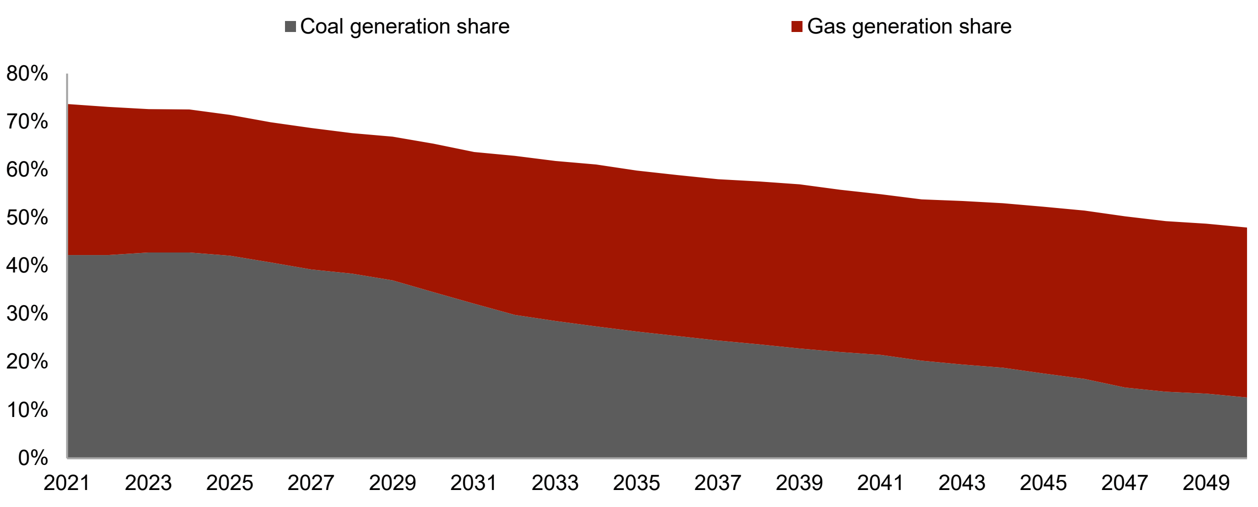
Indonesia is pursuing the option of cofiring of biomass together with coal. Indonesia's state utility company Perusahaan Listrik Negara (PLN) has been aggressively seeking biomass cofiring solutions. This was clearly articulated in the 2021 electricity supply business plan and has been tested since 2020 across 52 coal-fired power plants. Currently, cofiring is done commercially at 15 plants, and the latest trial has demonstrated that up to 20% blending made no significant operational difference for a coal-fired power plant. Vietnam also mentioned blending biomass with coal in its August 2022 draft PDP; however, this is at an even earlier stage than where Indonesia is at currently.

Many countries across the region intend to tap into hydrogen as a fuel for power generation, with some even intending to produce it for domestic consumption and exports In Malaysia, Tenaga Nasional Berhad (TNB), together with IHI and PETRONAS, has also conducted cofiring of ammonia with coal successfully at its test rig facility. Vietnam in its November 2022 draft PDP8 is targeting to fully switch from gas to hydrogen and coal to ammonia in the longer term. These have provided a strong basis for the planned developments in Southeast Asia.

Carbon capture technology is the most mature technology among the options above. Currently, there is around 50 million metric tons per annum (MMtpa) of carbon capture capacity in operation globally. However, the majority of carbon capture capacity is being utilized in the gas processing and oil and gas refining industry. The addition of CCS in the power sector is only included in Indonesia's electricity supply business plan and has been discussed in Singapore's 2050 energy scenarios.

Figure 10-1

Southeast Asia share of coal and gas generation



Data compiled Dec. 1, 2022.
Source: S&P Global Commodity Insights.

The cost of carbon capture applied to the power sector is expected to decline more rapidly starting in the 2040s

Based on our global carbon capture project tracker, only 4% of the current projects are utilized in coal- and gas-fueled power generation plants, while close to 70% are utilized in gas processing and oil and gas refining. Carbon capture projects in natural gas processing facilities have been the main driver of growth over the past decade. This was necessary to remove CO_2 from the produced gas to meet pipeline specifications, and there was also value from utilizing the CO_2 for enhanced oil recovery (EOR). This was on top of the relatively lower cost of capture, owing to the high concentration stream of CO_2, which reduces the energy requirement to separate CO_2 from flue gas.

Over the coming decade, based on the projects currently being developed, there will be a sizable increase of carbon capture projects in the power generation sector, as compared with natural gas processing and oil and gas refining. Post-2030, CCS costs are forecast to decrease more rapidly, as the build-out increases. The S&P Global Commodity Insights Inflections scenario estimates five doublings of capture capacity between 2030 and 2050, presenting an opportunity for more sizable cost reductions through learning by doing and economies of scale, on top of the development of new capture technologies.

The cost of power generated from coal and gas power plants with the addition of CCS is expected to gradually decline over the coming decades. This is largely due to cost decline from the technology cost as the global build-out increases. On top of technology cost declines, the cost of transportation and storage of the captured CO_2 is anticipated to fall, as projects are scaled up from demonstration scale to regional commercial hubs utilizing depleted oil and gas wells, which are available in the region. Based on those cost declines and incorporating our current fuel cost forecast, the LCOE from gas generation, with the addition of CCS, will average around 10% lower than coal with the addition of CCS throughout the outlook horizon in Southeast Asia. The gap between the two will narrow to around 5% by 2050, as coal and gas generation LCOEs decline by 24% and 11%, respectively. This is despite a faster cost decline in CCS capex for gas-fired generators vis-à-vis coal, owing to the significantly smaller share of the LCOE from capex of around 24% versus 47%. In contrast, fuel cost contributes to nearly two-thirds of the LCOE for a gas generator, compared with a quarter for a coal generator, and this exacerbates the narrowing difference in LCOE, arising from rising gas prices versus the decrease in coal prices, although it will be partially mitigated by improvements in gas-fired power plant efficiency.

The addition of CCS is not suitable for all coal and gas capacity taking into consideration the impact on cost

This will be dependent on remaining plant life, technology type, and utilization level, meaning that at best, just under 70% of the fossil fuel generation emissions can be captured.

A sizable part of the cost of adding CCS is the capex on the equipment, which impacts coal-fired power plants more than gas-fired power plants. As a result, a longer economic life is necessary to depreciate the cost over, so as not to impact the LCOE as much. Therefore, it makes more economic sense to either add CCS to a new-build fossil fuel plant or retrofit CCS equipment onto a relatively young plant. In addition to the age consideration, more efficient generation technology will be preferred, as adding CCS will impact the plant efficiency.

The addition of carbon capture equipment onto a fossil fuel generation plant also impacts the plant's operating capability and efficiency. This is due to the power required for the carbon capture equipment and the increase in the minimum load that the plant needs to operate at, thus limiting the type of roles that generators with carbon capture equipment can play.

Financing and/or pricing mechanisms need to be implemented to facilitate CCS deployment

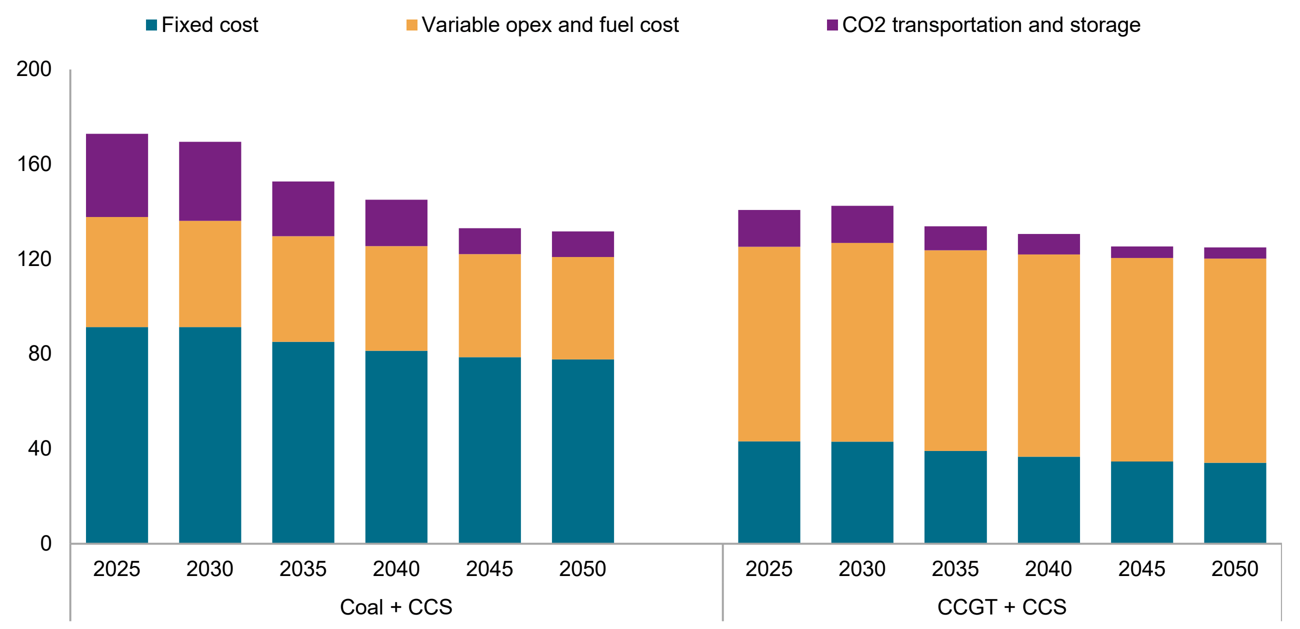
A carbon tax of between $100 and $200 per metric ton of CO_2 is necessary to level the playing field

In a region where a majority of countries do not have any carbon tax implemented, it remains challenging for low-carbon generation technologies to be adopted for fossil fuel power plants to compete against the business-as-usual option, even as their cost gradually declines. Taking into consideration the sensitivity analysis in the section above, a carbon tax of between $100 and $200 per metric ton of CO_2 is necessary to put the addition of CCS on a level footing with the stand-alone coal- or gas-fired generation.

In 2021, the Asian Development Bank (ADB) announced the Energy Transition Mechanism (ETM), which is a transformative, blended-finance approach that has the objective to retire existing coal-fired power plants on an accelerated schedule and to replace them with generating capacity using cleaner sources. However, there will still be a sizable fossil fuel generation fleet, as the region still needs a large amount of dependable power capacity. Therefore, allowing and supporting new PPAs to provide revenue certainty, which commensurate the increased cost from adding CCS, will make the additional investment to retrofit an existing power plant with CCS an attractive one.

Figure 10-2

Coal and gas generation cost with CCS (real 2022 $/MWh)



Data compiled Dec. 1, 2022.
Source: S&P Global Commodity Insights.

Balancing affordability and the power sector energy transition in Southeast Asia

Cecillia Zheng, Associate Director, Southeast Asia Power & Renewables

Choon Gek Khoo, Research Analyst, Southeast Asia Power & Renewables

- Countries in the region mostly regulate electricity prices at a lower level to support economic growth. Power retail tariffs in Peninsular Malaysia and Thailand have been at 9.5–12.5 US cents/kWh in the past 10 years, and in Vietnam and Indonesia they have been below 8.2 US cents/kWh during the same period. However, the current pricing mechanisms are not sustainable and have led to huge financial burdens on utilities and national budgets.
- Consistent policy support is vital to attract funding and to set up an orderly and sustainable energy transition path to improve energy affordability. Major transition paths include retiring coal power and introducing renewables and other new technologies, and these paths are proved prohibitively expensive. To build sustainable and low-carbon power systems in Southeast Asia, including generation and grid expansion, $56–97 billion investment per year would be required, and that will require higher private participation to supplement the insufficient public funding.
- Innovative cost control and new payment funds are important to balance the rising prices and electricity affordability. More effective policy tools are expected to cut costs while exploring new payment sources, such as carbon prices and other green funds, and appropriately respond to the short- to medium-term price hike and strive for long-term price stabilization. Eventually, should both the avoided cost and additional benefits be considered, the whole energy transition process would generate economic benefits in the longer term.

Energy affordability remains a major concern in most Southeast Asian countries

In the past decade, Southeast Asian countries have made significant efforts to extend electricity access to all users, with major countries achieving close to 100% electrification rates. Despite the substantial investment in the power sector, from generation to T&D infrastructure, the power retail tariffs are mostly regulated and have remained relatively low over the years.

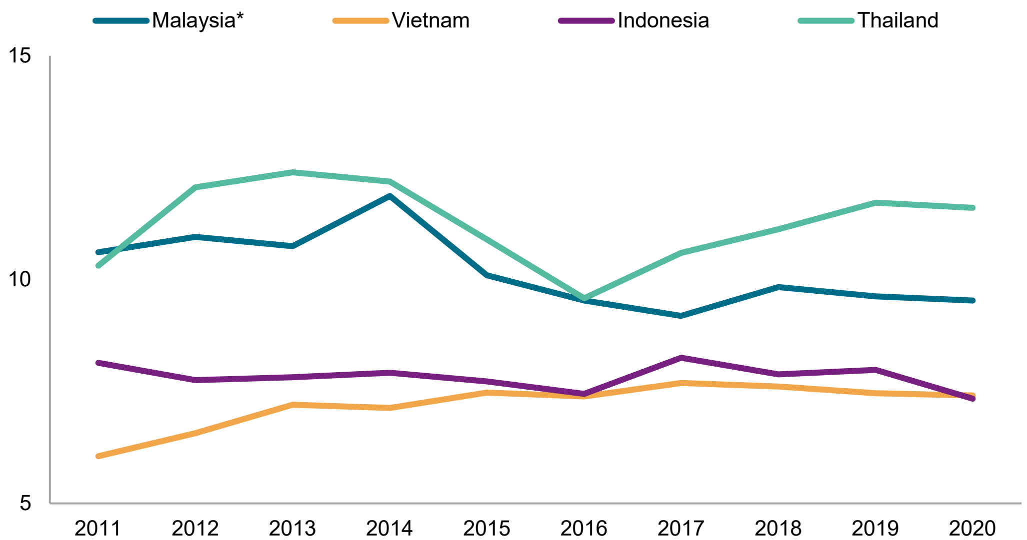
The power tariffs (in US cents per kilowatt-hour) in Peninsular Malaysia and Indonesia are lower now than 10 years ago. This is because the tariffs in local currency terms increased by a small amount, and the small tariff increases have all been offset by the depreciation of local currencies. Tariffs in Vietnam and Thailand increased by 22% and 13%, respectively, in the past 10 years, lower than the overall increase of the living costs (consumer price index) at 42% and 14%, respectively, in the same period.

The most important reason to keep power tariffs low is that the industrial sector is the most sensitive to price changes; thus, keeping power tariffs low is critical to attracting foreign investment for emerging Southeast Asian countries such as Malaysia, Vietnam, Indonesia, and Thailand that are under industrialization process. Another reason to maintain low tariffs is to help the large low-income population in the region.

However, power pricing reforms in these emerging Southeast Asian countries remained stagnant. Regulated power prices are sometimes lower than the power supply cost, resulting in financial losses for utilities and the need for national subsidies. The current pricing mechanisms become unsustainable and are under scrutiny for market reform, a major part of which is to privatize the power sector and implement a market-based pricing mechanism. As fossil fuels will account for a significant share of total power generation in the medium term, the variation of fuel prices will have a big impact on power costs

Figure 11-1

Average power retail tariffs (US cents per kWh)



Data compiled Nov. 12, 2022.

*Average power selling prices for Tenaga Nasional Berhad (TNB).

Source: S&P Global Commodity Insights.

Additionally, as the region is gradually phasing out energy subsidies and unlikely to introduce a new scheme to tackle rising power costs, this will impair electricity affordability at a time when most countries are willing to transition to more cost-reflective pricing. Theoretically, pricing reform will introduce market-based prices into the system, with consumers bearing the cost, but this is difficult for developing countries that have regulated prices. Thailand and Malaysia have been exploring the fuel pass-through mechanism, trying to ensure that power prices reflect costs and to keep utilities profitable while supplying affordable power. The mechanisms work smoothly, but during the COVID-19 pandemic these two countries were not able to increase power tariffs, and the loss was shared by the utilities and state budgets. Pricing reform is an important component of power sector market reform, and it likely will take a long time for the region to fully liberalize its power markets.

Energy transition is confirmed but in funding hunger

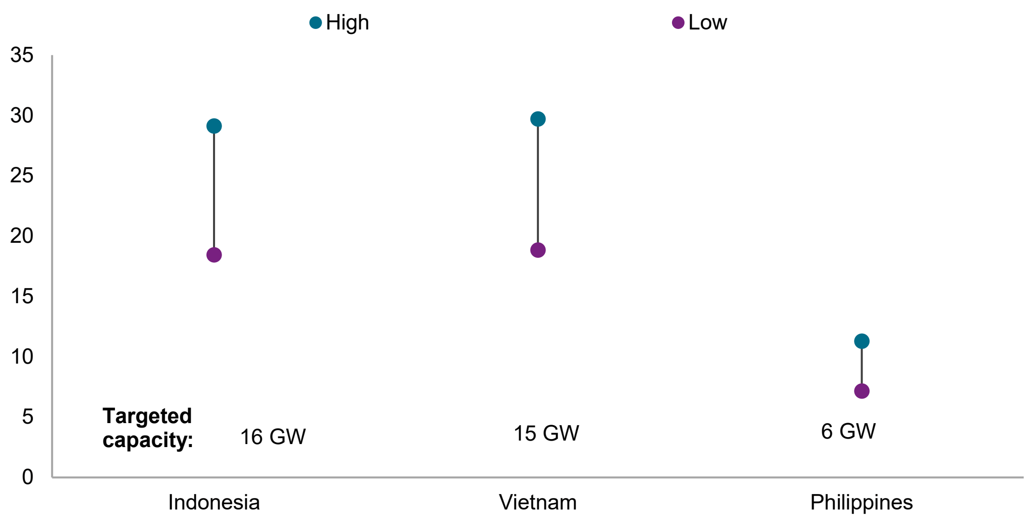
Southeast Asian countries are endowed with a variety of fossil fuel resources. As the governments of Southeast Asia appear to be committed to the energy transition, it will have significant implications for the evolution of the power market and economic growth. The major energy transition paths involve retiring coal-fired power generation and introducing renewables and other new technologies, which have proven to be not only technically challenging but also prohibitively expensive.

Energy transition pathways are not only technically challenging but also prohibitively expensive

Below are the cost estimates of the early retirement mechanism to retire coal plants at 15 years old, compared with the fact that plants in this region usually operate for 40 years or longer, 37 GW of coal plants commissioned between 2015 and 2022 were from coal-dependent countries such as Indonesia, Vietnam, and the Philippines. These are very young power fleets that will not retire unless an early retirement mechanism is implemented, which is estimated to cost $7–30 billion, excluding additional investment to build replacement capacity.

Figure 11-2

Net present value (NPV) of coal plants' early retirement cost range (billion $)



Data compiled Nov. 12, 2022.

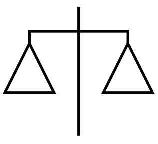
Assuming purchase coal plants (commercial operation date [COD] 2015–22) by end-2022 and retire them at the age of 15 years.

Source: S&P Global Commodity Insights.

Aside from deploying renewable energy resources to reduce the countries' reliance on fossil fuels, Southeast Asian countries have a variety of decarbonization plans in place, including carbon capture systems installed in power plants, biomass or ammonia cofiring in coal plants, and hydrogen blending in gas-fired power plants. However, research and development (R&D) and commercialization of new technologies are both technically and financially challenging. Building a sustainable and low-carbon power system in Southeast Asia, including generation and grid expansion, is forecast to cost $56–97 billion per year, and that will require higher private participation to supplement the insufficient public funding.

Simultaneously, policy supports that consistently meet affordability, reliability, and emission reduction challenges are vital to providing investors with confidence and attracting low-cost financing. Governments are encouraged to implement more policies and measures to attract private investment to complement the tight public funding. Additionally, a sustainable energy transition will inevitably raise power supply costs, and the region must examine how higher power prices will shape the future fuel mix and initiate concerted actions to turn risks into opportunities.

Actions to balance rising prices and electricity affordability



A balance needs to be struck between implementation costs and ensuring long-term affordability

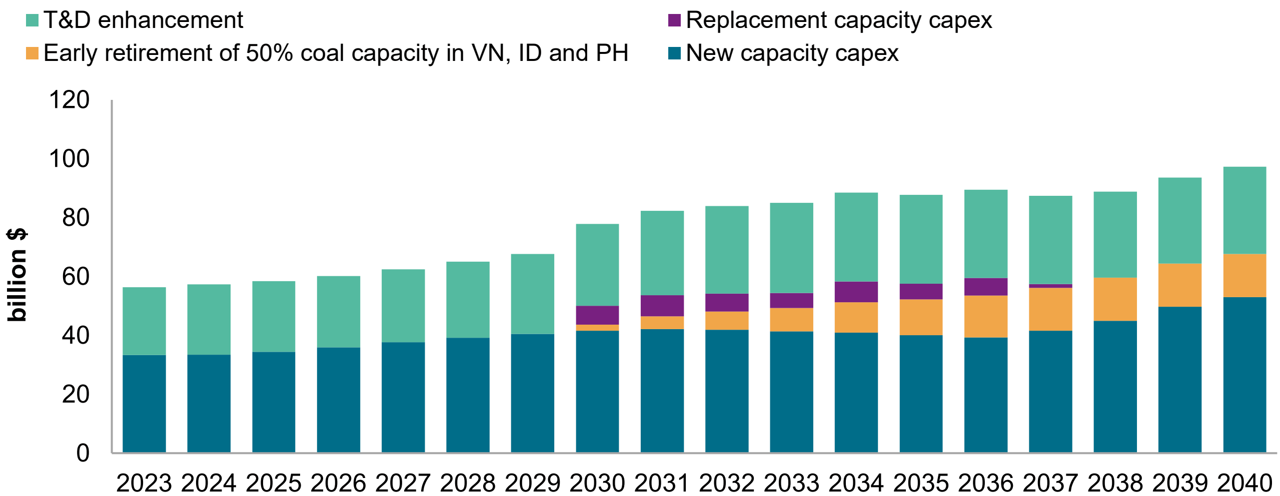
The energy transition will continue, and further price increases are inevitable. Hence, investors and developers would be encouraged to bring up concerted solutions that could help mitigate the short-term increases in energy prices while striking a balance between implementation costs and ensuring long-term affordability of electricity for consumers.

Adaptations measures—controlling cost with innovative financing while expanding new payment funds—are recommended to cope with short-term price hike, as well as to strive for long-term price stabilization.

As the energy transition to a low-emission economy continues or even accelerates, with both avoided costs and additional benefits being considered, the whole energy transition process would generate greater economic benefits in the longer term.

Figure 11-3

Major Southeast Asia countries' capex required



Source: S&P Global Commodity Insights.

One missing key enabler: How to price carbon in Southeast Asia

Cecillia Zheng, **Associate Director, Southeast Asia Power & Renewables**

Yuejia Peng, **Associate Director, Climate and Energy Transition**

- Most countries in Southeast Asia have no carbon pricing mechanisms in place. This is hindering the energy transition in Southeast Asia's power sector. Optimal carbon prices are required in the region to promote emission-free technology and ultimately to help achieve net-zero targets.
- There is a direct correlation between carbon price and thermal generation cost. A relatively low carbon price of between $12–40 per metric ton would enable coal-to-gas switch in the region owing to the increasing cost of financing coal projects and equipment. The effectiveness of a carbon price to decarbonize the power sector is also dependent on other incentives to expand renewable energy and various mechanisms to cap or reduce coal use.
- Significantly higher carbon prices would facilitate the adoption of newer technology such as carbon capture and the blending of hydrogen. By 2030, carbon prices at $60–70 per metric ton would make carbon capture more economically competitive versus unabated coal plants, while prices above $100 per metric ton would make carbon capture more economically competitive versus unabated combined cycle gas turbine.

Figure 12-1

Southeast Asian countries' progress of implementing carbon pricing

Data compiled Jan. 09, 2023.
Source: S&P Global Commodity Insights: 2008668.

Southeast Asian countries mostly have pledged net-zero targets by around 2050 and have expanded efforts to decarbonize their energy systems. In addition to various renewable incentives and mechanisms to reduce coal use, the region has also been actively exploring carbon pricing options.

Carbon pricing status in Southeast Asia

There exist two main approaches to price carbon, namely carbon tax and emission trading system (ETS). A carbon tax directly sets a per ton tax rate on carbon emitted but does not fix the emissions level, while an ETS, or a cap-and-trade system, sets the emission cap by giving emission permits, which could be traded on the carbon market. Subsequently, the supply and demand for the permits will determine the carbon price in an ETS system.

While a proper carbon pricing system could help accelerate the decarbonization process, only three countries; Malaysia, Singapore and Thailand, have implemented carbon pricing. The remaining Southeast Asian countries have no carbon pricing mechanism in place, leaving a large policy gap.

Benefits and challenges to implement carbon pricing in Southeast Asia

Carbon pricing helps to promote low-carbon technologies, raise funds, finance "climate aligned" projects, and ultimately incentivize emission reduction and help the implementation of national determined contribution (NDC) goals. Carbon pricing will also benefit Southeast Asia as it helps the exporting industries prepare for the adverse impact posed by the European Union's Carbon Border Adjustment Mechanism (CBAM). In addition, given the huge nature-based avoidance potential and the untapped renewable potential in the region, setting up a voluntary carbon market (VCM) would positively incentivize more decarbonization projects to be developed for carbon credit trading.

However, challenges remain, which inhibit the implementation of carbon pricing. Firstly, the region's power sector is mostly regulated, and governments are still subsidizing power prices in some areas despite years of the effort to right price power. The nature of the regulated power sector has proven to be incompatible with voluntary emission trading, and the VCM's development accordingly will be delayed owing to slow progress of power market reform. Second, imposing carbon prices is risky for the countries with weak power systems, which either have a thin reserve margin that might result in potential capacity shortage, or do not have strong grid network to support higher renewable integration. Lastly, the biggest challenge is to set appropriate carbon price, which will require balancing affordability concerns and incentives for low-carbon technologies.

Impact of carbon price on thermal power plants' LCOE in Vietnam

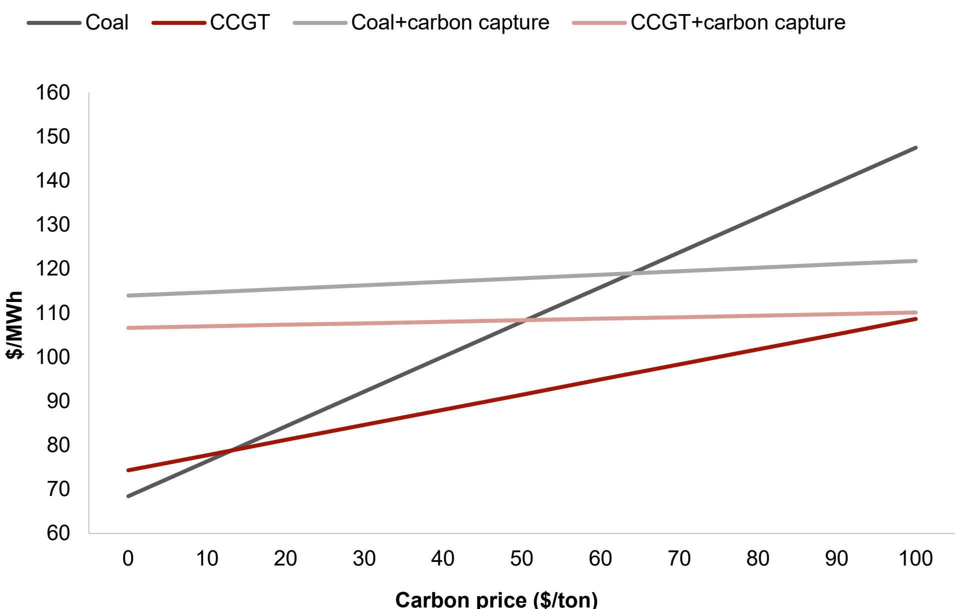
There is a direct correlation between carbon price and thermal generation cost. The analysis of the impact of a carbon price on Vietnam's thermal power plants' LCOE finds that a carbon price set at a $13/ton will trigger a coal-to-gas switch, and $64/ton will incentivize expensive carbon capture applications for coal-fired generators, while at the same time keep the power system stable and reliable.

In addition to coal-to-gas switching and adding carbon capture technology, the carbon price can incentivize the development of low-cost renewable capacity, and that will lead to two additional benefits. Firstly, moving forward, renewable power will become cheaper than thermal power, therefore a higher share of renewables will help reduce the overall power system's cost, and accordingly help to reduce emissions; secondly, higher renewable penetration will need more flexible back-up power, and automatically promote coal to gas switch.

$13/ton will trigger a coal-to-gas switch, and $64/ton will facilitate carbon capture applications for coal-fired generators

Figure 12-2

Vietnam thermal plants' LCOE versus carbon price



Data compiled Jan. 07, 2023.

Source: S&P Global Commodity Insights.

Optimal carbon pricing to support Singapore's energy transition

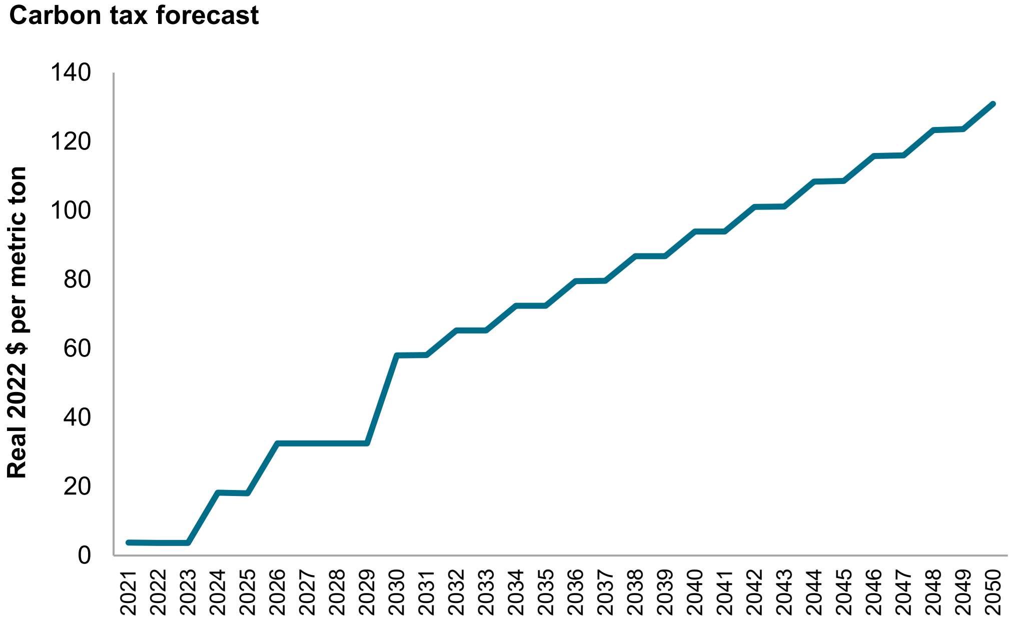
To forecast the optimal carbon tax to decarbonize Singapore's power sector, S&P Global modeled the net-zero scenario by 2050 following the country's goal, as well as other announced plans, such as renewable targets, low-carbon power imports, hydrogen, and carbon capture, to determine the future generation technology mix.

Subsequently, the cost to the power system was determined, and the premium vis-à-vis the business-as-usual case was derived. As announced by the Singapore government, the carbon tax will not be a source of additional government revenue, instead they will only be used for decarbonization and energy transition. Therefore, based on the announced carbon tax trajectory and the commitment on the use of carbon tax revenue in addition to the 2050 net-zero target, an optimal carbon tax pathway for the power sector is determined. With the support of carbon tax, carbon capture will be added in power equipment from late-2030s when the technology application to the power sector matures, and hydrogen blending ratio will gradually rise over the years as cost of the fuel declines.

Carbon pricing is necessary for the decarbonization of the power sector

Carbon prices might increase the power supply cost in the short time, but with well-designed redistribution mechanism, they'll benefit the entire power sector for longer term. The lack of carbon pricing is hindering the energy transition in Southeast Asia's power sector, and optimal carbon prices are required in the region to promote emission-free technology and ultimately to help achieve net-zero targets.

Figure 12-3



Data compiled Jan. 03, 2023.
Source: S&P Global Commodity Insights.

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