Analysing Energy Transition Risk in the Philippines Power Sector

from the British people

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Acronyms

BNEF - Bloomberg New Energy Finance
CAPEX – Capital Expenditure
CCGT - Combined Cycle Gas Turbine
CPA - Critical Point Analysis
CSP - Competitive Selection Process
DOE - Department of Energy
EPC – Energy Performance Certificate
ECR - Energy Regulatory Commission
ESG - Environmental, Social and Governance
FiT - Feed-in-Tariff
FPV - Floating Solar Photovoltaic
IEA - International Energy Agency
IEMOP - Independent Market Operator of the Philippines
IGCC - Integrated Gasification Combined Cycle
IPP - Independent Power Producers
LCM - Least-Cost Models
LCOE - Levelized Cost of Electricity
LNG - Liquefied Natural Gas
LROE – Levelized Revenue of Electricity
MGEN - Meralco Powergen Corporation
MMS - Market Management System
MGEM - Meralco Powergen Corporation
NREB - Natural Resources and Environment Board
NREL - National Renewable Energy Laboratory
NGCP - National Grid Corporation Philippines
O&M - Operation and Maintenance
OPEC - Organization of the Petroleum Exporting Countries
PEMC - Philippine Electricity Market Corporation
PPA - Power Purchase Agreement
PSA - Power Sharing Agreements
PV – Photovoltaics
RCOA - Retail Competition and Open Access
REA - Renewable Energy Act
REC - Renewable Energy Certificates
RoR - Run of River
RPS - Renewable Portfolio Standards
SEA – South East Asia
SEC - Securities and Exchange Commission
TCFD - Task Force on Climate-related Financial Disclosure
UPERDF - University of Philippines Engineering Research and Development Foundation
USAID - United States Agency for International Development
WACC - Weighted Average Cost of Capital
WESM - Wholesale Electricity Spot Market

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Key points

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- The speed of the energy transition in the Philippines will be driven by a combination of endogenous and exogenous factors. Specifically,
  - The rate of technology innovation in power generation technologies.
  - Divestment, restrictions, and cost of capital from capital market and financial regulator policies.
  - Carbon pricing and air pollution policies.
  - A shift in foreign restrictions to ownership.
  - Grid absorption capability and management.
  - Institutional inertia.
  - Availability of viable land due to land scarcity and convertibility issues.
  - Volatility and trends in coal and gas prices.
  - Regulatory incentive improvements.
  - Retail competition's interaction with low-cost renewable energy.

- Merchant generators in the Philippines could face a "missing money problem" due to bilateral contracts

- Proactive policymaking is needed to minimise stranded cost risk and ensure a least-cost power system. Specifically,
  - Fast-track auctions to ensure new capacity decisions are cost-competitive and complementary to grid flexibility.
  - Enforce mandatory removal of cost pass-throughs to end-users.
  - Improve tariff setting to ensure least-cost and flexibility generation.
  - Build on the current moratorium by implementing a permanent moratorium on new inflexible power.
  - Increase clarity on who pays for stranded asset risk.

- Greater bond disclosures can help protect retail investors from stranded asset risk.

Executive summary

The objective of this report is to analyse energy transition risk for power generation in the Philippines. This report is funded by the UK government and is the result of a stakeholder engagement process with investors and policymakers in the Philippines power sector. The report has the following findings and recommendations.

Deflationary renewable energy will transform power markets throughout the world

Power generation throughout the world is being transformed by deflationary cost trends in renewable energy. Over the last decade, the levelized cost of electricity (LCOE) of onshore wind and solar photovoltaics (PV) have declined 70% and 90%, respectively. These deflationary trends, coupled with similar declines in battery storage and offshore wind, mean it now costs less to build renewable energy than to operate coal and gas in several jurisdictions. While these trends are happening to varying degrees in different markets, the cost declines in low carbon technologies should be seen as a mega trend that will fundamentally change the generation mix of power markets throughout the world. Although Southeast Asia is seen as the last growth market for fossil fuel power, deteriorating economics is likely to undermine demand for coal and gas in the region in the future. The Filipino government has made good progress to take advantage of these deflationary cost trends. Due to improved competition policy, growing public pressure for lower power prices and a desire for more domestically secure capacity, the government is targeting 22 GW of renewable energy capacity by 2030 or 35% of total generation from renewable energy over the same period.

The transformation and materialisation of energy transition risk in power generation depends on risk-sharing improvements in the Power Purchase Agreements

Analysing energy transition risk is challenging, especially in the power sector. Market structures and procurement policies will likely determine who is directly or indirectly at risk from a disorderly transition in the power sector. Unlike the single-buyer markets of Indonesia, Vietnam and Thailand, the Philippines power market has been unbundled and opened for private investment. The wholesale power buyers include over 120 distribution utilities and 25 retail electricity suppliers. Power is traded as a commodity through a wholesale power market. An important aspect of the Filipino power market is the preponderance of long-term bilateral contracts for conventional thermal generators. These contracts guarantee the generator capacity fees and realized variable costs, thereby securing full cost recovery, including investment returns, and function as a constrained capacity market.

The speed of the energy transition in the Philippines will be driven by a combination of endogenous and exogenous factors

Determinants that could either accelerate or slow down the energy transition in the Philippines will be influenced by supply and demand side variables. Based on our analysis of the Philippines power market, these factors will come from internal and external factors, and include: 1) the rate of technology innovation in power generation technologies; 2) how access to capital is influenced by fossil fuel divestment and other restrictions as well as the cost of capital determined by capital market and financial regulatory policies; 3) carbon pricing and air pollution policies; 4) a shift in limits on foreign ownership; 5) grid absorption capability and management; 6) institutional inertia; 7) availability of viable land due to land scarcity and convertibility issues; 8) fuel price volatility and trends in coal and gas market; 9) regulatory incentive improvements; and 10) how retail competition interacts with low-cost renewable energy.

Stranded asset risk for coal generators in the Philippines will likely materialise independent of additional policy support for renewable energy

We reviewed several least-cost models (LCM) to better understand transition risk affecting power generation assets in the Philippines. The least-cost models we identified as being influential in the Philippines were developed by: Bloomberg New Energy Finance (BNEF), the University of Philippines Engineering Research and Development Foundation (UPERDF), National Renewable Energy Board (NREB) and Meralco Powergen Corporation (MGEM). Our analysis of these LCMs found a diminishing role for coal and an increasingly important role for renewable energy. All models reviewed in this report also emphasised the need for flexible generation instead of baseload capacity. Coal power is inherently inflexible compared to other dispatchable generation technologies. This is why the recent moratorium on new coal build announced by the Department of Energy (DoE) was appropriate. In the context of the Filipino power market, stranded asset risk materialises when competitive regulated tariffs are not sufficient to deliver a commercial return.

Mer**chant generators in the Philippines could face a “missing money problem” due to** bilateral contracts

Critical point analysis (CPA) was used to understand the competitive interactions of new entrant generation technologies, such as wind and solar, and conventional generators, such as coal and gas. Three critical points were identified: 1) when the LCOE of renewable energy is lower than the marginal costs of gas peaker capacity; 2) when the LCOE of renewable energy is lower than revenues they obtain from in-market sources; and 3) when the LCOE of a hybrid solar and Combined Cycle Gas Turbine (CCGT) system outcompetes the LCOE of new coal. To analyse critical points 1 and 3, we relied on BNEF model outputs, as their LCM was more transparent than the other LCMs surveyed. To analyse critical point 2, we used a simulation model of the Wholesale Electricity Spot Market (WESM). This model was provided by the Philippine Electricity Market Corporation (PEMC), which governs the WESM. Our review shows critical point 1 has already been met and highlighted how near-zero marginal cost renewable energy can undercut conventional generators. According to BNEF data, the LCOE of new coal is below the LCOE of a CCGT for the foreseeable future, but when a CCGT is hybridised with solar it could be cheaper than coal.

Outputs of the WESM model highlighted that critical point 2 may take longer, due to a market flaw resulting from a preponderance of long-term bilateral contracts for conventional generators. Our analysis of the WESM model shows that conventional generators bid opportunistically into the market, offering prices that are much lower than their variable costs. This results in a situation where conventional generators with bilateral contracts depress wholesale power prices by bidding into the market at a cost much lower than their actual operating cost, which forces the market to take electricity from a generator that might not be the lowest cost. Our analysis shows that this bidding behaviour may make renewable energy merchant generation unviable, despite increasingly being a least-cost option. This market dynamic could create a "missing money problem" which would have serious implications for policymakers who are trying to create market structures that would support the development of a least-cost pathway and investors who are trying to make renewable energy investments bankable.

Proactive policymaking is needed to minimise stranded cost risk and ensure a least-cost power system

There are 7,641 islands in the Philippine archipelago. As a consequence, the Philippines has two distinct markets for power: grid-connected and off-grid. Grid-connected regions are served by the Luzon, Visayas and Mindanao transmission grids, while off-grid regions are served by decentralised sources of power such as PV and diesel. It is highly unlikely these stakeholders are going to ensure a least-cost outcome given their differing mandates. The cased study on Meralco, a large power distribution company in the Philippines, is a good case in point. Meralco's current procurement policy is based on the LCOE of thermal generation, which may result in a least-cost outcome for its captive customers, but not for the whole system. As such, we offer the following policy recommendations:

- Fast-track auctions to ensure new capacity decisions are cost-competitive and contribute to grid flexibility. The Philippines has had recent success in its competitive selection processes including open bidding instead of bilaterally negotiated contracts. The next step towards enabling lower prices is to ramp up the country's auctions policy - the Green Energy Action Program - to include geographic and resource-specific auctions as a mean of maximizing price competition and improving transparent procurement across the archipelago.
- Impose the mandatory removal of cost pass-throughs to end-users. The standard PSA between a utility and an IPP stipulates that fuel costs are automatically passed through to consumers, and that they are subject to changes based on the prevailing coal price index. To protect end-users from high prices in periods of volatile and low demand, a curtailment clause should be implemented to encourage proactive management of financial obligations to generators during exceptional circumstances.
- Improve tariff setting to align with least-cost and flexible system operations. The Energy Regulatory Commission (ERC)'s tariff-setting methodology should be redesigned as it does not provide cost-efficient market-based incentives for least-cost power options. The ERC's reliance on outdated regulatory incentives has meant that power tariffs are still based on a fixed set of financial assumptions that are no longer relevant to more dynamic competitive power market norms. Tariffs should be reformed so that ratepayers do not pay more because of forecasting errors by grid operators or policy planners. Currently, the utilities are not incentivized to hedge against USD inflation or exchange rate volatility.
- Build on the current moratorium by implementing a permanent moratorium on new commitments to inflexible generation project. While the Department of Energy (DOE) no longer provides a supply mix, it previously targeted an energy mix of 70% "baseload" capacity, 20% "mid-merit" capacity, and 10% "peaking" capacity. According to the DOE, 80% of the country's baseload capacity is inflexible as the regulatory design incentivizes baseload. A parallel

point is mentioned in a 2019 World Bank report which notes a lack of investment in mid-merit and peaking power plants. The lack of balance in the generation mix is coming at a high cost. Depressed demand requires more use of mid-merit plants. During the economic lockdown, there was more use of flexible power and a drop in inflexible coal utilization from 70.3% to 52%. In current demand conditions, coal plants have mid-merit plant load factors which are lower than baseload plant load factors leading to an increased cost per kilowatt hour (kWh) for end-users, as stipulated in the Power purchase agreements (PPA). These costs could be avoided with a permanent moratorium on coal.

- Increase clarity on who pays for stranded asset risk. Legacy plant operators and investors often claim that energy transition is triggering higher costs. Instead, as older facilities lose competitiveness, non-performing stranded assets are paid for by either end-users, investors or creditors. With the deflationary nature of renewable energy and storage costs, as well as the clamour for cheaper power, future non-performance and the stranding of assets will be a reality, resulting in a stranded asset cost burden for the same stakeholders.

These recommendations all require Filipino policy makers to proactively intervene to avoid stranded assets and ensure least-cost energy.

Enhanced disclosure by bond issuers can help protect retail investors from stranded asset risk

Filipino financial regulators have provided notable leadership in climate risk disclosure. The Securities and Exchange Commission (SEC) has imposed mandatory Environmental, Social and Governance (ESG) reporting for publicly listed companies. Bangko Sentral Ng Pilipinas (the central bank of the Philippines) has also approved the Sustainable Finance Framework to safeguard the financial system from the evolving material hazards of transition risk, including non-performing stranded asset risk. The next step is to protect retail investors by requiring bond disclosures that take into consideration the heightened risk-profile of fossil fuel investments. Reviewing a recent domestic bond prospectus with a focus on pandemic risk, regulatory risk and project risk, our analysis found that the risk disclosures are neither up to date nor adequate for retail investors. We recommend financial regulators introduce policy and enhanced fiduciary responsibility to improve bond disclosures to protect retail investors from stranded asset risk.

Introduction

As part of a UK government-funded project[1] to support the Philippines in navigating the risks and opportunities associated with the transition to a low carbon economy, CTI, in collaboration with IEEFA and ICSC, held a series of events to gather stakeholder views on energy transition challenges and opportunities in the power sector. This report summarises some of these perspectives.

The project had three general objectives:

1. Gather views from stakeholders on the inflection points that determine the viability of investments in new and existing power generation projects, comparing the economic cost and financial liability of import-dependent and inflexible coal power in the face of cheaper alternatives such as renewables.
2. Propose recommendations for policymakers to encourage a flexible, efficient, and technology-neutral power market that delivers least-cost power to consumers and industry.
3. Issue guidance for financial regulators to ensure bond issuance documentation clearly stipulates the risks of new coal investments to protect investors.

The aim was to secure consensus among developers, investors, policymakers and civil society on the most effective approach to measuring the speed and scale of energy transition risk in the power sector. The latest consultation held in July 2020 focused on the implications of Covid-19. This report is a cumulation of these engagements to help the Filipino government manage energy transition risk to minimise stranded assets and promote a transition to least-cost low carbon sources of power generation.

The report has the following sections: (1) global context of energy transition risk in the power sector; (2) an overview power generation trends in Southeast Asia (SEA); (3) an overview of power market structures and regulations in the Philippines; (4) renewable energy policies in the Philippines; (5) determinants of progress on the energy transition in the Philippines; (6) energy transition risk assessment through a LMC review and CPA; (7) discussion of implications of the LMC and CPA; and (8) policy recommendations.

Sections 1-5 provide context of the energy transition both worldwide and in SEA by providing a comprehensive overview of market structures, renewable policies and the determinants of the speed of the energy transition in the Philippines. To date, the energy transition has progressed slowly in SEA, but this is changing quickly due to endogenous and exogenous forces. Section 6 details our methodology for measuring and managing energy transition risk in the Philippines. This methodology was informed by the intensive stakeholder engagement process. Sections 7 and 8 discuss the results of the methodology and offer policy recommendations to ensure stranded asset risk is minimised and a least-cost transition to a low carbon economy is realised that benefits the Filipino consumer with

[1] *This project is part of the UK [Knowledge, Evidence and Engagement Programme (KEEP)](). KEEP is a research and engagement facility that enables HMG climate leads to commission bespoke evidence and engagement activities to improve the delivery and increase the ambition of UK international climate finance activities, supporting developing countries to tackle climate change.*

affordable power prices. Special attention is paid to policy guidance on bond disclosures, which have financed coal-fired power in the Philippines without paying due consideration to the risks associated with investing in this type of power generation technology.

1 Global context

In this section, we provide an overview of how deflationary trends in renewable energy are transforming power markets throughout the world.

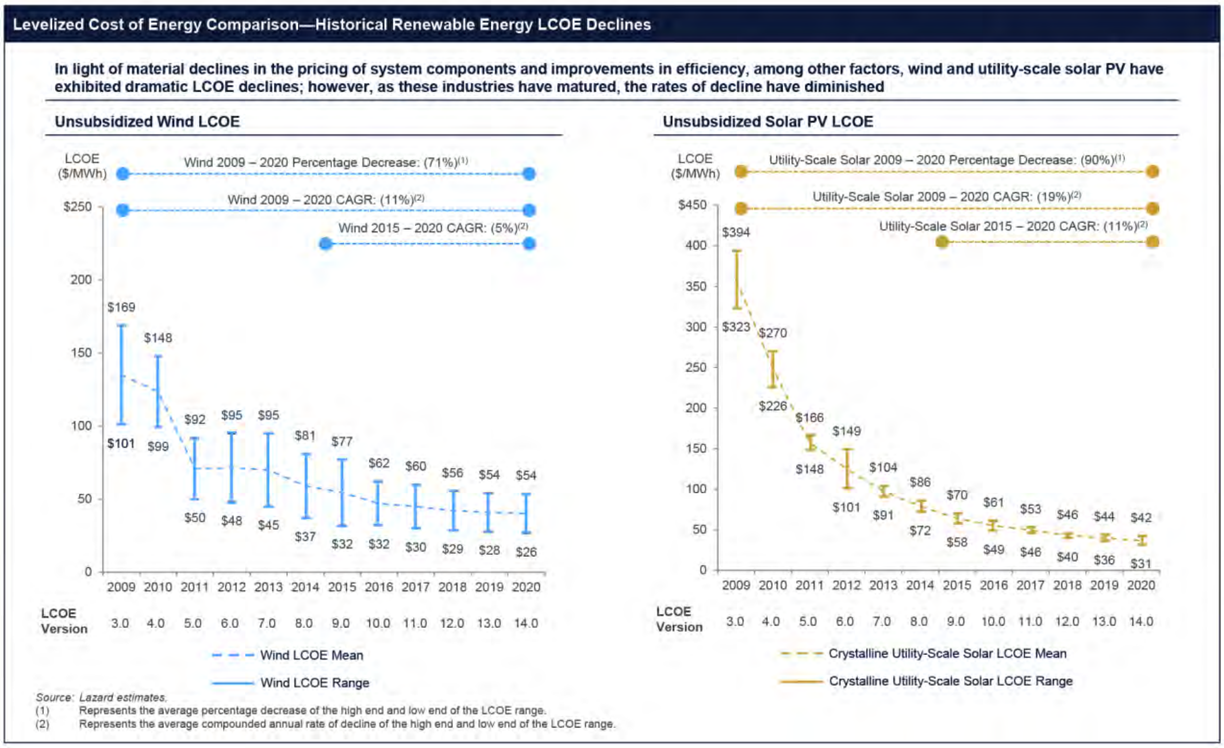
Measuring and managing energy transition risk is a complex endeavour, especially in the power sector. Over the last decade, the cost of innovative new power generation technologies such as onshore wind and solar PV have declined 70% and 90%, respectively.[2] Similar declines are also being observed in associated technologies, such as battery storage and offshore wind. This deflationary cost trend has increasingly resulted in renewable energy LCOEs[3] that are lower than the marginal cost of coal and natural gas generation.[4] These cost declines in low carbon technologies should be seen as a mega trend that will fundamentally change the generation mix of power markets throughout the world. For Southeast Asian energy growth markets, however, these trends are strongly affected by local context due to differences in market structure and different regulatory and policy environments.

[2] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Jun/IRENA_Power_Generation_Costs_2019.pdf

[3] *The LCOE is a standard analytical tool used to compare power generation technologies and is widely used in power market analysis and modelling. The LCOE is simply the sum of all costs divided by the total amount of generation. The LCOE calculations in this model are based on a discounted cash flow model where costs (CAPEX and O&M) of developing and running renewable energy assets are discounted using a real weighted average cost of capital (rWACC). These costs are then divided by the discounted (also using rWCC) lifetime production (in kWh) of the asset to obtain the LCOE value. The rWACC is calculated using a split between debt and equity to finance the project; this is usually 80% debt and 20% equity for OECD countries. The percentage split for debt is then multiplied with the cost of debt, and the inflation rate is subtracted from the total. The percentage equity split is multiplied by the return on equity minus the inflation rate. The sum of these two values yields the rWACC.*

[4] https://carbontracker.org/reports/how-to-waste-over-half-a-trillion-dollars/

FIGURE 1. LCOE COMPARISON - HISTORICAL RENEWABLE ENERGY LCOE DECLINES



Source: [Lazard (2020)]

Accurate analysis of energy transition risk in the power sector requires much nuance due to the heavily regulated nature of power production and consumption. This is especially the case regarding the calculation of stranded asset risk. The traditional stranded asset theory stipulates that assets becomes stranded when they are no longer able to earn an economic return due to the transition to a low-carbon economy – is less applicable in the context of many power markets. This is because governments often use the sovereign balance sheet to underwrite risk or have policies that provide significant and guaranteed returns for coal developers and financiers. This dynamic means that price discovery – an economic term to describe the setting of the value of an asset in the marketplace through the interactions of buyers and sellers – is often limited in regulated and semi-regulated markets. In such markets, stranding occurs through a change of regulation. Financial market constraints often support a bias toward heavy reliance on guaranteed long-term offtake contracts that lock-in payments to generators regardless of eventual market conditions. As a result, instead of encouraging a market-driven transition to more cost-effective generation, stranded asset risk is more likely to cascade through the economy and force consumers and taxpayers to bear the burden of poor planning decisions through higher energy costs and increased public debt.

It should also be noted that energy transition risk is often mischaracterized as a long-term risk. This framing is flawed because although completion of a transition to a low carbon economy might take decades, accelerating market developments catalysed by transition impact the energy markets on a much shorter time scale than the transition itself. For example, the European electricity market was obliged to write down over $150bn of assets between 2010-2016, at the time renewable energy made up just 4% of electricity supply.[5] These dramatic revaluations in power assets are not only limited to competitive or "liberalised" markets. For example, the timing of the South African government's response to transition risk will be critical to the health of the country's state-owned enterprise utility, ESKOM, which is heavily dependent on at-risk coal assets resulting in a fast-deteriorating financial position and serious problems with power supply reliability.[6]

It is our view that coal power is increasingly a high-cost option in the context of Southeast Asian markets and has the potential to reduce the economic competitiveness and fiscal resources of nations that continue to rely on the fuel for power. However, the transition away from coal will unlikely happen at the scale and speed required if Southeast Asian governments:

1. are unconvinced by the evidence base that a coal-free grid is going to deliver reliable, safe and secure power at least-cost; and
2. fail to introduce competitive, transparent and non-discriminatory policies.

How governments respond to these challenges will have far-reaching implications for the economic competitiveness and energy security of nation states.

[5] https://carbontracker.org/reports/lessons-from-european-electricity-for-global-oil-gas/
[6] https://www.climatepolicyinitiative.org/publication/understanding-the-impact-of-a-low-carbon-transition-on-south-africa/

2 Power generation trends in Southeast Asia

In this section, we provide a brief overview of power generation trends in Southeast Asia (SEA). Southeast Asia has been one of the fastest growing regions in the world, supported by the strong demographic trends of a young population. Today, Southeast Asia has a combined GDP of almost US$3 trillion, and the ten countries account for around 650 million people or 8.5% of the global population, with 70 million people yet to gain access to energy. The population growth trajectories for the region are a key driver for power sector investment. Southeast Asia's energy requirements have grown by 60% over the last 15 years and are forecast to grow another two-thirds by 2040. According to the International Energy Agency (IEA), the pace of growth will be twice that of other regions with demand growing to more than 2000 terawatt-hours over the next 20 years.

As the global economy re-starts post-COVID-19, Southeast Asia is expected to benefit from a high growth trajectory with strong energy demand. At that time, cost-effective power will be more important than ever for end-users, and particularly manufacturers looking to diversify their supply chains. Achieving a flexible low-cost energy mix will also be important for governments that have historically subsidized power due to the narrowing fiscal space. In this scenario, power tariffs could be a pressure point post-COVID, especially for countries that import most of their fuel needs and either pass the cost onto consumers, or that have fuels which are subsidized by the government and thus taxpayers.

Although Southeast Asia is seen as the last bastion of growth for thermal power, the deteriorating economics of fossil fuel power and the investment context may undermine thermal power's future in the region. Two key issues will determine the economics of whether thermal power can continue to operate in a country's energy system post-COVID: 1) whether a country is an importer of fossil fuels and must accept fuel price and foreign exchange volatility as well as the risk of fuel supply disruptions; and 2) the ability of end-users to cope with high prices and volatility and the burden of ongoing subsidies.

Dramatic advances in new energy technology are fundamentally reshaping the energy landscape, including in Southeast Asia. This market transformation has significant implications for energy security, especially for importing coal countries like the Philippines and Vietnam. Increasing domestic renewable energy and storage solutions provide options for domestic diversification away from fossil fuel imports, while cutting exposure to volatile commodity markets and enabling price stability.

Vietnam is one example of a country that is taking steps to transition its energy market away from fossil fuels to take advantage of global shifts in technology. Due to the long project development timelines of domestic thermal power projects and the high cost of imported fossil fuel power, Vietnam is shifting towards renewable energy to supply growing power demand. Vietnam surprised the market with a tenfold expansion in installed solar capacity during 2019 and is now building a strategy for new offshore wind which can be completed in half the time it takes to build a fossil fuel project, while bringing significant cost reductions and domestic energy security. Unlike Vietnam, most Southeast Asian countries are yet to maximize the advantages of deflationary renewable energy, despite having renewable energy targets. In the Philippines, renewable energy capacity has fallen short of the country's target of 24% despite the energy supply growing at a rate of 7% over the past ten years.

That said, in response to improved competition policy led by the DoE, growing public pressure for lower cost of power and the country's desire for flexible and more domestically secure capacity at affordable prices, the government initially decided to triple renewable energy capacity by 2030 to over 15,000 megawatts (MW) from the initial 5,000MW. Considering that the National Renewable Energy Program is targeting 35% renewable energy in the mix by 2030, the target is now 22,000MW of new renewables capacity. The Department has recognized that with rapid technological development globally in low-cost renewable energy, a higher mix of renewables can put electricity prices on a deflationary pathway, and improved access and reliability will be within reach.

3 Overview of the Philippines power sector

The Philippines power sector is unique in the region for two reasons. Firstly, unlike the single-buyer markets of Indonesia, Thailand and Vietnam, the Philippines power market has been unbundled and is open for private investment. In fact, all power investments in generation, transmission and distribution are now undertaken by private energy companies. The wholesale power buyers include over 120 distribution utilities that sell to captive customers in their franchise areas and over 25 retail electricity suppliers that sell to over 2,000 large commercial and industrial consumers. In fact, the Philippines power industry law mandates that eventually all power consumers shall have the ability to choose their power supplier. These consumers shall continue to depend on their franchised distribution utilities for "wires service" but will have the ability to choose their power supplier.

Secondly, there is a WESM where electricity is traded as a commodity. WESM aims to establish a competitive, efficient, transparent and reliable market for electricity. WESM has been operating in Luzon since June 2006 and in Visayas since December 2010. Thus, with over 10 years of operation, including under the extreme pandemic conditions this year, the WESM has established itself as a robust power market. The latest information from the government indicates that by 2021, the WESM will be operational in Mindanao, thus making it a nationwide competitive power market.

Trading in the WESM is organised through a reverse auction. Generators submit online hourly energy offers (i.e. volumes and prices) through the Market Management System (MMS). Offers are submitted by accessing the Market Participant Interface of the MMS through the generators' computers installed with digital certificates. The Market Operator, currently the Independent Market Operator of the Philippines (IEMOP), ranks the generator offer prices from lowest to highest and matches their corresponding volume offers with the demand of power customers through the MMS. The last generator to be dispatched to meet the load sets the price for all generators dispatched at the time interval. Dispatch hierarchy is as follows:

1. Minimum stable load (P-MIN) of baseload power plants – minimum stable loading as determined during testing and commissioning. Based on WESM data between March 17, 2019 to November 30, 2020, on average, P-MIN is 37% of nominal capacity of coal power plants.
2. Security-related Must-Run power plants and/or ramp-limited conventional power plants as determined by National Grid Corporation Philippines (NGCP).
3. Must-Dispatch (solar, wind and run of river hydro).
4. Priority-Dispatch (biomass FIT power plants).
5. Non-Scheduled Dispatch (biomass non-FIT power plants).
6. Bids and offers of conventional power plants, including baseload power plants above P-MIN

There is an enhanced WESM design now under trial runs with full operation scheduled in 2021.[7] The changes include:

1. Shortening of dispatch interval from one hour to five minutes.

[7] https://www.wesm.ph/market-development/enhanced-wesm-design

2. Economic scheduling of P-MIN or removal of its privilege for automatic nomination at the head of the dispatch.
3. Co-optimized energy and reserves that will ensure optimal scheduling of energy and ancillary services.
4. Adoption of ex-ante pricing. These enhancements aim to address market operational audit findings and introduce new features and functionalities such as simplified compliance reporting process and demand side bidding.

The power dispatch hierarchy under the enhanced WESM design is as follows:

1. Security-related Must-Run power plants and/or ramp-limited Conventional power plants as determined by NGCP.
2. Must-Dispatch (solar, wind and run of river hydro).
3. Priority-Dispatch (biomass FIT power plants).
4. Non-Scheduled Dispatch (biomass non-FIT power plants).
5. Bids and Offers of conventional power plants.

An important aspect of the Philippines power market is that generation is currently dominated by historical bilateral contracts, especially for conventional thermal generators. These contracts guarantee the generator capacity fees and realised variable costs, thereby guaranteeing cost recovery and function as a constrained capacity market.

4 Renewable energy policies in the Philippines

The initial impetus for market entry by renewables developers came from the Renewable Energy Act (REA) which was ratified in December 2008. This legislation introduced two major mechanisms: a Feed-in-Tariff (FiT) system and Renewable Portfolio Standards (RPS). These mechanisms accelerated renewable energy adoption. REA also included additional mechanisms, such as a net-metering system and green energy option programme.

REA included a diverse set of fiscal incentives: 1) a 7-year income tax holiday; 2) a 10% income tax rate after the ITH; 3) net operating loss carryovers for income tax calculations; 4) accelerated depreciation; 5) duty-free importation of RE equipment; 6) zero-rating for value-added tax purposes; and 7) discounted realty tax rates. In the off-grid areas, a cash incentive equivalent to half of the savings from replacing high cost diesel with RE can be realized by private investors.

4.1 The FiT System

4.1.1 FiT objectives, targets, rates, and qualification

The purpose of the FiT system was to increase renewable energy grid penetration by: 1) to ensure developers have bankable contracts with stable cash flows and 2) to spread the risk of variability, where reserves could readily serve as the firm-up capacity.

The first set of FiT rates for solar, wind, run-of-river (RoR) hydro and biomass, was approved by the Energy Regulatory Commission (ERC) in 2012. Installation targets were first set by the DoE in consultation with the NREB. The NREB, after consultation with industry, proposed rates for approval by the ERC. The rates, applicable for 20 years and subject to yearly inflation and foreign exchange adjustments, were calculated using average costs and included plant, transmission connection, and operating costs. These costs were provided by industry associations, approved by NREB and thus guaranteed a rate of return for renewable energy projects. During these consultations, the matter of setting these rates via competitive auctions was floated, but this was opposed by industry, which claimed this would make project finance prohibitively expensive. The ERC further evaluated the costs presented and decided on the risk premia to which each technology was entitled. Each set of rates as proposed by the NREB, were also subject to digression, to account for steadily declining technological costs, especially for solar and wind.

The entitlement to FiT rates was based on a ‘race to the finish’ methodology, which absolved the DoE of deciding on qualification after the pre-development stage of competing project applications. This meant that to qualify, developers first had to prove that the project was almost finished. This introduced an added risk to developers, many of which had to resort to balance sheet financing as a bridge to project finance. This procedure led to about 300 MW of ‘stranded’ solar projects, mostly on Negros Island in the Visayas region.[8] Not only did these projects not qualify for FiT rates, their operation as

[8] https://www.nrel.gov/docs/fy18osti/68594.pdf

merchant plants was also hampered by intra-island and inter-island transmission constraints.

4.1.2 Cost recovery

The FiT rates are paid through market prices per a qualified generator, and the balance is paid annually via a FiT-all allowance, estimated by the National Transmission Corporation (TransCo), the country's grid operator, on a per kWh basis. This allowance is approved by the ERC and collected by Transco from utility and non-utility off-takers under a universal charge and disbursed to the generators. Differences between the estimates and realized market values are included in the following year's allowance. Importantly, the generators are entitled to interest charges for delayed disbursements.

4.1.3 Renewable energy share, tariff, and overall social impacts

As of the end of 2018, the quota for solar and wind installation was exceeded, while biomass and RoR hydro were just 14.6%, 36%, and 52% respectively. By the end of 2019, the remaining allocation for biomass had already been filled, and the DoE had lifted the deadline for RoR hydro to meet its quota, primarily because the projects were hampered by delays due to transmission connection issues. Also, by the of end 2018, the FiT enabled 2.7% of total power generation and accounted for roughly half of total renewable energy generation.

The view of power consumers is that the FiT system via the FiT-All allowance has imposed additional costs on end-users. This is because the Fit-All allowance is an additional one-line item on their electric power bills. The study by the Philippine Electricity Market Corporation (PEMC) has found that the merit-order effect reduced rates, swamping the feedback effect of an increase in the FiT premia (the difference between the guaranteed revenues and spot market revenues). Specifically, the FiT and prioritized dispatch have led to reductions in wholesale electricity spot prices by PHP1.47 per kWh for consumers, which led to savings or avoided costs of PHP44.3 billion from November 2014 to October 2015.[9] Moreover, the study potentially understates the positive impact on rates because it only considers the savings in the actual spot purchases and disregards fuel cost savings. The FiT reduced the price of electricity by reducing the dispatch of oil. Even then, we are still underestimating the benefits of FiT because the dispatch gives way to bilateral contracts, which includes oil. Therefore, to those who are not familiar how the spot market works might think that the benefits of FiT is minimal. Thus, the current energy plan, with the concurrence of the NREB, has preferred to achieve its desired RE generation share target of 35% by 2030 through a Renewable Portfolio Standard (RPS) rather than by other means.

4.2 The Philippine Renewable Portfolio Standard

4.2.1 Concept and Target

The RPS is considered a more market-oriented mechanism compared to FiT because participants are allowed to choose the least-cost pathway to comply. The RPS mandates

[9] https://ieefa.org/wp-content/uploads/2019/09/Prospects-Improve-for-Energy-Transition-in-the-Philippines_September-2019.pdf

participants to increase their share of renewable energy by 1% every year. The 1% share is calculated as actual renewable generation plus renewable energy certificates (RECs) over total sales. It is important to note that actual increments in generation and RECs purchases are not expected until 2023, because the participants are entitled to RECs from FiT-qualified generation, in proportion to their share in total energy sales, starting in 2018.

4.2.2 Coverage and mechanics

The RPS applies to the following mandated participants: 1) all distribution utilities with respect to their captive customers; 2) all retail electricity suppliers; 3) generation companies with respect to their actual supply to directly connected customers; and 4) other entities recommended and approved by the NREB and the DoE, respectively. Generation from the following technologies are eligible for compliance: biomass, waste-to-energy, wind, solar, RoR hydro, impounding hydro systems, ocean energy, hybrid systems to the extent of their renewable energy component, geothermal energy and other technologies identified by the DoE. Generation from these technologies are eligible for compliance under the following circumstances: 1) existing and new generation facilities under the FiT system; 2) additional capacity resulting from an RE generation facility; 3) additional capacity resulting from upgrades; 4) new capacities resulting from fuel hybridization; 5) renewable energy facilities under the net metering program (certificates due to the distribution utilities); 6) renewable energy facilities set up for use by the owner of premises; and 7) mothballed RE facilities that are restored.[10]

4.2.3 Compliance, monitoring, and COVID-19

RECs are issued based on the following guidelines.

1. Bilateral contracts: the certificates are issued to the purchaser only to the extent of actual energy received, and the portion sold on a merchant basis accrues to the generator.

2. FiT contracts: the facilities will continue to be eligible under the RPS.

3. Competitive procurement: via competitive bilateral procurement under CSP rules explained in the power sector overview section.

Proof of compliance is via the surrender of RECs (one per MWh) to the Registrar, with the deadline for surrender a year after the compliance period. A key provision is that compliance is not supposed to have any adverse impacts on captive ratepayers of distribution utilities. Furthermore, the ERC is required to set a price cap for the RECs. The DoE has stated that the commercial opening of the REM has been reset from June this year to June 2021 owing to the disruption from COVID-19. However, because of the advanced compliance from the FiT-generated certificates, the deadline for compliance with RPS requirements for 2020 remains on 25 December 2021. More significant is the postponement until further notice, of RPS compliance in the off-grid areas.

[10] *Department Circular No. 2017-12-0015: Promulgating the Rules and Guidelines Governing the Establishment of the Renewable Portfolio Standards for On-Grid Areas*

4.3 The Green Tariff Program

The Green Tariff Program is the Philippines' renewable energy auction program. The program is meant to facilitate RPS compliance via auctions of aggregated peak and off-peak demand, especially for the distribution utilities and their captive markets. The compliance process comprises the following features:

1. An auction process is administered by the Green Energy Auction Committee (also known as the RPS Composite Team) under the RPS rules.
2. Demand is aggregated on a voluntary basis, with resulting bilateral contracts undergoing pro-forma approval by the ERC.
3. Auctions are held annually and result in a green tariff for each winning supply bidder.
4. The ERC sets an annual tariff cap (maximum) for variable (e.g. variable wind and solar) and non-variable power supply (e.g. firm capacity with storage, etc.), for each RE technology.
5. The current leadership of DOE is not in favour of extending the FiT program and intends to replace it with the Green tariff program. The DOE has announced it will implement it by June 2021.

5 Determinants of speed of the energy transition in the Philippines

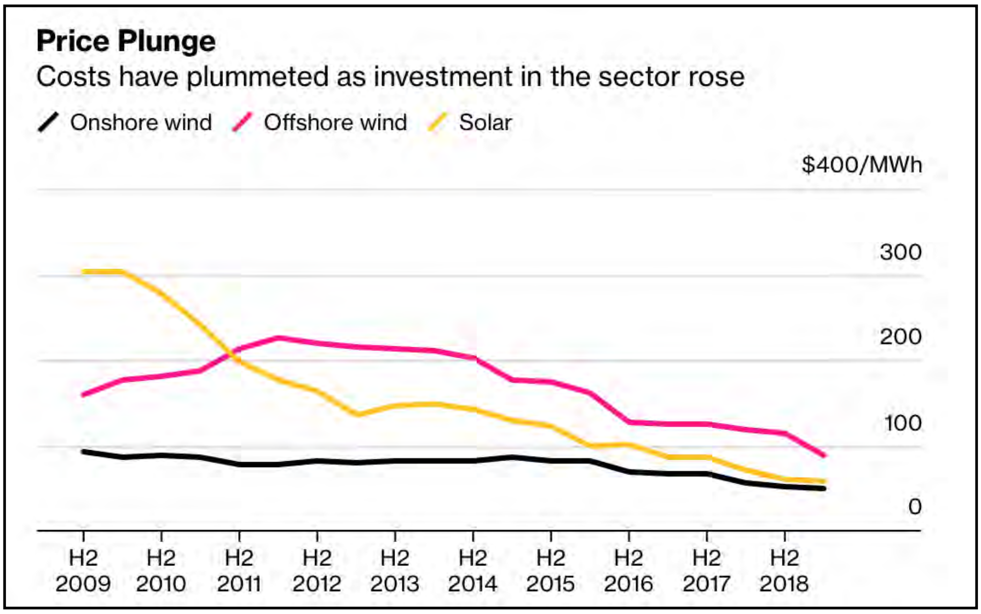
Regional variations and local contexts will affect the speed of the transition in the power sector. Based on our analysis, the determinants of the speed of power sector transition on both the supply and demand side in the Philippines include: 1) rate of global technology innovation with local applications; 2) divestment, restrictions and cost of capital; 3) carbon pricing and air pollution controls; 4) shift in foreign restrictions to ownership; 5) grid absorption capability and management; 6) institutional inertia; 7) availability of viable land due to land scarcity and convertibility issues; 8) coal and gas prices; 9) regulatory incentive improvements and 10) retail competition's interaction with low-cost renewable energy. These factors are discussed in detail below.

5.1 Rate of technological innovation

The energy sector is going through a comprehensive technological transformation that is fundamentally changing the economics of power. These advancements are driving the economics of variable renewables, permitting them to meet or under-cut previously accepted grid parity pricing norms.[11] This is resulting in lower power prices for consumers and improving returns for investors in renewable power assets.[12] In the context of the Philippines, the CEO of Ayala-owned AC Energy stressed that since 2016, solar and wind technology have scaled up significantly due to lower costs. This was the catalyst for AC Energy's pivot to renewable energy in the Philippines and around the region. In another case, Meralco has underwritten an 85MW solar power supply deal for PHP 2.99 per kWh. Other technology options are also proving economical. For example, geothermal projects can supply power at costs ranging from PHP 3.5 to PHP 4.5 per kWh. Run-of-river hydro costs range from PHP 3 to PHP 6.5 per kWh.[13] This cost range could be improved by removing the permitting red tape, which currently results in project approval taking an estimate of 4 to 5 years. These prices, coupled with the recent success of offshore wind, point to continued renewable energy cost deflation. If the example of global markets is any indication, the Philippines is now moving to the point where serious questions about the economics of new imported coal generation must be reassessed.

[11] *Levelized cost of producing power is equal to or less than the price of power from the grid.*
[12] https://www.forbes.com/sites/davidrvetter/2020/05/28/just-how-good-an-investment-is-renewable-energy-new-study-reveals-all/?sh=282e21f4d278
[13] https://ieefa.org/wp-content/uploads/2018/08/IEEFA_Unlocking-Rooftop-Solar-in-the-Philippines_August-2018.pdf

FIGURE 2. RENEWABLES PRICE REDUCTION 2008-2018



Source: BNEF (2019)

5.2 Divestment, restrictions, and cost of capital

Just as power markets have endorsed new technologies due to the rise of renewables, capital markets are responding by repricing the cost of capital allocated to the power sector. This is evidenced by the shift of capital away from coal power assets and decisions by large insurers and asset owners to exit participation in coal-linked financing or underwriting. The immediate impact is that it will be even more difficult to raise equity and debt financing for coal projects in terms of higher interest rates and/or shorter debt tenors. In addition, there is evidence indicating that it has already become more difficult for current holders of coal-linked financial assets to securitize or divest related financial asset portfolios due to a decline in liquidity as investor preferences shift.[14]

According to IEEFA, over 130 globally significant banks and insurers/reinsurers, with assets under management or loans outstanding in excess of US$10 billion, have coal exit policies with many starting to include oil and gas.[15] Asian banks such as Standard Chartered and DBS Group Holdings, have now placed restrictions on funding coal and other fossil fuels. Even U.S. giant JPMorgan Chase, known as the largest and most enthusiastic lender of fossil fuels, has now signalled an end to coal finance. Momentum-wise, every two weeks, a bank, insurer or lender announces new restrictions on coal.[16]

BlackRock CEO Larry Fink, through an open letter in 2020, said that Blackrock would end support for thermal coal and screen fossil fuel investments more closely.[17] Specifically, he wrote: "because capital markets pull future risk forward, we will see changes in capital allocation more quickly than we see changes to the climate itself. In the near future —

[14] *https://ieefa.org/ieefa-asia-asian-financial-institutions-also-beginning-to-exit-coal-financing/*
[15] *https://ieefa.org/finance-exiting-coal/ either bold or unbold – make consistent footnotes 15 and 16*
[16] https://ieefa.org/finance-exiting-coal/
[17] https://www.blackrock.com/corporate/investor-relations/larry-fink-ceo-letter

and sooner than most anticipate — there will be a significant reallocation of capital [...] Over time, companies and countries that do not respond to stakeholders and address sustainability risks will encounter growing scepticism from the markets, and in turn, a higher cost of capital. Companies and countries that champion transparency and demonstrate their responsiveness to stakeholders, by contrast, will attract investment more effectively, including higher-quality, more patient capital." In other words, the risk-profile of fossil fuel investments are changing, which will likely result in a higher cost of capital.[18]

TABLE 1. MAJOR COAL POLICY ANNOUNCEMENT IN THE PHILIPPINES

DATE	ANNOUNCEMENT
2016	Norway's Norges Bank Investment Management (NBIM) divested from Aboitiz Power and included it an exclusion list as a result of an investment criteria to reduce exposure to coal assets.[19]
2018	AC Energy, Ayala Corporation's subsidiary, set a goal to sell US$1 billion worth of coal assets by 2025[20] to rebalance its portfolio while raising capital for regional expansions that targeted renewable technologies. AC Energy sold its stake in the 552 megawatt (MW) GNPower Kauswagan's (GNPK) coal-fired power project to its partner, Power Partners Ltd., and more recently completed a partial sale of its 600MW AA Thermal coal-fired power plant to Aboitiz Power Corp.[21]
2018	The Securities and Exchange Commission (SEC) issued the ASEAN green bonds standards.
2019	The SEC launched ESG reporting guidelines, which will be mandatory for publicly listed companies in 2020. The guidelines include four of the globally accepted frameworks for reporting sustainability and non-financial information: the Global Reporting Initiative's Sustainability Reporting Standards, the International Reporting Council's Integrated Reporting Framework, the Sustainability Accounting Standards Board's Sustainability Accounting Standard and the recommendations of the Task Force on Climate-related Financial Disclosure (TCFD).[22]
2019	The Philippines issued USD 2.02 billion of green bonds, the third largest issuer in Southeast Asia after Singapore (US$6.20 billion) and Indonesia (US$2.88 billion).

[18] https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/01/Energy-Transition-Uncertainty-and-the-Implications-of-Change-in-the-Risk-Preferences-of-Fossil-Fuel-Investors-Insight-45.pdf

[19] http://bworldonline.com/content.php?section=TopStory&title=norway-fund-excludes-aboitizpower-from-investment-list-on-new-criterion&id=130252

[20] https://asian-power.com/power-utility/commentary/southeast-asian-power-companies-are-seizing-renewable-opportunities

[21] https://www.philstar.com/business/2020/04/20/2008519/ayala-fully-abandon-coal-investments-2030

[22] https://apps004.sec.gov.ph:8500/pr-2019/sec-institutes-sustainability-reporting-for-listed-companies/

April 2020	Ayala Corporation, through its subsidiary AC Energy, is driving the energy transition in the Philippines, with a divestment plan by 2025[23] and a full coal exit by 2030.[24]
April 2020	The Monetary Board of the Central Bank of the Philippines (Bangko Sentral ng Pilipinas) approved the Sustainable Finance Framework25 to safeguard the financial system from the evolving material hazards of physical climate risk and transition risk including stranded assets. Under the Sustainable Finance Framework, banks will have three years to comply and integrate transition plans, with timelines, into their corporate governance and risk management framework. Banks are expected, in the next six months, to provide board-approved transition plans to the Central Bank.
June 2020	The largest conglomerates in the Philippines announced their sustainability commitments via a webcast. The Aboitiz Group through its holding company Aboitiz Equity Ventures (AEV) announced that it has become the first and only company in the Philippines to register as a supporter of the Task Force on Climate-Related Disclosures (TCFD) in line with its commitment to environmental, social and governance (ESG). San Miguel Corporation (SMC) pledged to contribute to the energy transition through investments by SMC Global Power, their power subsidiary, in renewable energy and battery storage. SMC has announced a pipeline of 10,000MW of renewables investments over the next 10 years, with 1200MW to be completed by 2024, focused on hydroelectric and wind. It also plans to be at the forefront of battery storage technology, raising USD 500 million in investment. SMC Global Power is also focused on grid infrastructure investment opportunities in the Philippines that would address voltage and frequency instability problems.

Sources: See footnotes 18-24

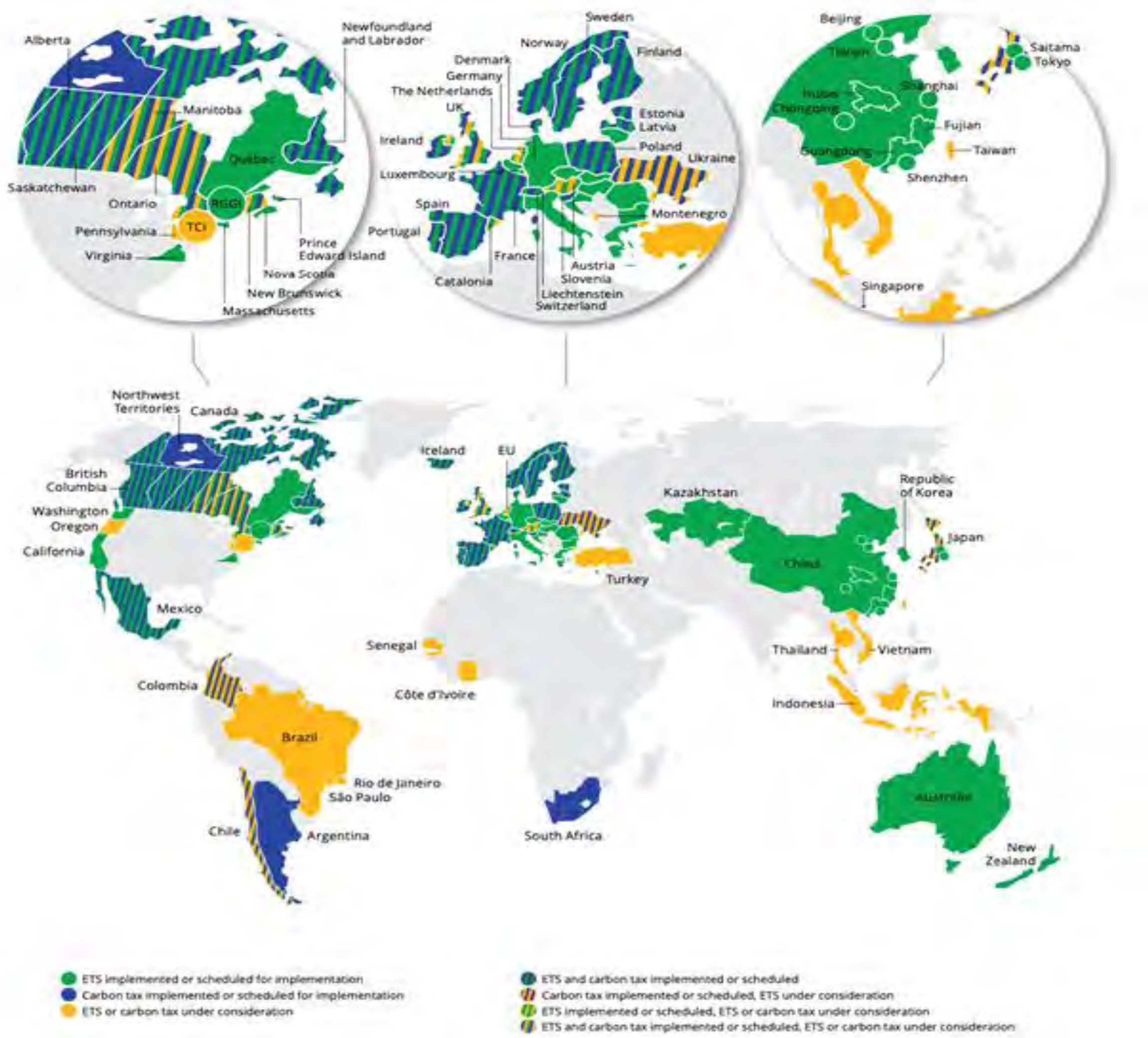
5.3 Carbon price (carbon tax) and pollution controls, raising operating costs

Governments and policy leaders have spent years assessing the potential of market-based mechanisms to encourage a more economically efficient response to climate change. The central premise is that the right price signals—obligating producers and consumers to internalize the cost of dangerous climate change impacts—will steer the market to the most efficient energy transition pathway. This has resulted in the development of a range of policy options including carbon trading and taxes that can be used to price in climate risks According to the World Bank, there are now 61 carbon pricing initiatives in place or scheduled for implementation globally, consisting of 31 emissions trading systems and 30 carbon taxes.[26]

[23] https://www.acenergy.com.ph/wp-content/uploads/2020/04/AC-ENERGY-ES-Policy-Statement-FINAL-for-web-v2.pdf
[24] https://www.dealstreetasia.com/stories/ayala-coal-185126/
[25] https://drive.google.com/file/d/1gXlU1PAbvFWHTzhMaLqpxghptWN4Nk4r/view
[26] *https://openknowledge.worldbank.org/handle/10986/33809*

This naturally begs the question of whether the current period of light touch policy on climate could be replaced by a more urgent stance, requiring the Philippine Government to implement more forceful market-based regulatory strategies to keep pace with global and regional peers. To date, Government regulations have ignored the public cost of health impacts borne by taxpayers and the cost of abating the Philippines' greenhouse gas emissions. On a 10-year view, investors, owners, and funders of coal assets may need to assess whether their forecasts for operating costs should take into account a shadow carbon price or a carbon tax to model new outcomes where the government forces market participants to internalize some of the adverse health, weather, and pollution known to be linked to the impact of coal power.

FIGURE 3. CARBON PRICING INITIATIVES IMPLEMENTED, SCHEDULED FOR IMPLEMENTATION AND UNDER CONSIDERATION (ETS AND CARBON TAX)



Source: World Bank (2020)

The Department of Finance is currently studying carbon pricing options.[27] So far, the Philippines has two main environmental regulations: the Clean Air Act of 1999 (Republic Act No. 8749) and the Clean Water Act of 2005 (Republic Act No 9275). It is important that investors take into account penalties for violating the provisions of the Clean Air Act of

[27] https://www.bworldonline.com/finance-dept-studying-carbon-emissions-tax/

1999 and Clean Water Act of 2005 and the additional costs of adhering to such regulation. So far, the Clean Air Act has resulted in the implementation of fuel standards, but an emissions-charge system has not yet been implemented. Unfulfilled mandates are the responsibility of the Environmental Management Bureau under the Department of Environment and Natural Resources. As a result, any tightening of environmental policies may create unexpected financial risk for investors who have not incorporated higher operating costs in their investment assumptions.

In addition to producing considerable amounts of carbon emissions and air pollutants, coal-fired power projects produce coal-ash leachate that is known to affect groundwater quality.[28] Coal-fired power plants also use a significant amount of water to turn turbines and cool thermoelectric plants.[29]

5.4 Foreign restrictions on ownership

There has long been a debate about whether energy transition could be accelerated if the Philippines' restrictions on foreign ownership were eased. For example, it can be argued that foreign ownership restrictions may reduce foreign direct investment crowding-out effects and that the net effect of these restrictions on the recipient country's welfare may be negative[30]. On the other hand, it can also be argued that lifting foreign ownership restrictions can play a role in attracting low-cost foreign capital.

More specifically, restrictions on foreign proprietorship can discourage overseas investors in the same way that domestic content rules can drive up the cost of generating equipment. In other words, does restricting foreign ownership deter foreign capital? The Philippines restricts foreign participation in renewable energy power companies to 60% Filipino and 40% foreign ownership, while fossil fuel generation plants have no restrictions, allowing for 100% ownership. The Constitution gives the Philippines government dominion over natural resources such as the sun, water (including non- consumption) and wind. Specifically, "the State shall not be alienated from potential energy sources such as kinetic energy from water, marine current and wind; thermal energy from solar, ocean, geothermal and biomass".[31] Moreover, there is a restriction on foreign land ownership.

In Chile, there are generally no restrictions on foreign ownership of electricity companies or assets. There are also no restrictions on land ownership. However, all corporate developers must be registered and established under Chilean law. The only restriction on foreign ownership covers transmission and hydro-generation assets.[32] In Brazil, foreign ownership of electricity companies or assets is permitted if the foreign entity registers, is located and established under Brazilian law. This means that foreign investors can participate in auctions. However, there are restrictions on foreign ownership in relation to

[28] *National Service Centre for Environmental Publication, Effects of Coal-Ash Leachate on Ground Water Quality*
[29] *National Service Centre for Environmental Publication, Effects of Coal-Ash Leachate on Ground Water Quality*
[30] https://www.sciencedirect.com/science/article/pii/S0301420716304470
[31] https://www.sec.gov.ph/wp-content/uploads/2019/12/2019OpinionNo19-24.pdf
[32] https://uk.practicallaw.thomsonreuters.com/w-019-3060?transitionType=Default&contextData=(sc.Default)

the acquisition of rural properties in Brazil, which can affect the economics of renewable energy projects.[33]

These examples support the argument that it may reduce the cost of capital should the Philippine government reconsider ownership either by lifting foreign ownership restrictions or limiting ownership of the power purchase agreement to 15 or 20 years for some energy sources such as solar PVs and kinetic energy from water and wind. This reduction in the cost of capital will favor high capital expenditure investment such as renewable energy.

5.5 Grid Absorption Capability and Management

The ability of the grid to absorb the type and quantity of power generated in line with future system needs is a critical indicator of system performance. In order to encourage capital efficiency and improve system design options, it is crucial to map generation options to grid capacity needs and to promote understanding of how new technologies such as storage and transmission system services can shape future technology investment choices.

The Philippines is not the only market to have suffered from sub-optimal transmission planning and investment in the wake of adding variable renewable energy to the generation mix. Indeed, this problem is common to many resource constrained power systems that have prioritized generation investment over grid investment. Given that leads and lags are common in high growth power systems affecting both conventional and renewable assets, market participants will naturally need to address appropriate risk mitigation strategies. In many systems, curtailment can be a low-cost transition solution, but investors in least-cost renewable assets understandably need confidence that they will be treated fairly in the event of market disruptions.

The Greening the Grid report by National Renewable Energy Laboratory (NREL) provides comprehensive modelling of the Philippines Luzon-Visayas grid, producing suggestions for transmission network enhancements to support a variable renewable energy (solar and wind) uptake of up to 50%.[34] Implementing the NGCP Transmission and Development Plan 2020-2040 could ensure the success of subsequent renewable energy generation development in the Philippines and that all developers will respond with more price competitive investment options. Box 1 shows an extract from the National Grid Corporation of the Philippines' (NGCPs) Transmission Development Plan 2020-2040.[35]

[33] https://uk.practicallaw.thomsonreuters.com/8-545-7207?transitionType=Default&contextData=(sc.Default)&firstPage=true
[34] https://www.nrel.gov/docs/fy18osti/68594.pdf
[35] *https://www.ngcp.ph/operations#development*

Box 1. NGCP Grid Transmission Line Planning & Renewable Energy

NGCP is currently adapting a market-based planning methodology that will consider the design of the wholesale electricity supply market (WESM) and how variable renewable energy and conventional power plants are being scheduled for supply.[1] NGCP will include in the model the renewable energy variability and the dynamics of the wholesale supply market's generation production cost, demand variance, and outages of network elements. This is to identify possible transmission congestion, lending a more realistic view of the impact of generation projects on the transmission network. The generation projects will be assessed alongside the targeted generation mix and forecast demand. The planning methodology should identify areas suitable for generation projects in coordination with transmission planning options.

The reference methodology is from "Greening the Grid Project" by the United States Agency for International Development (USAID) and NREL that conducted a renewable energy integration study for the DOE. The project observed the effects of integrating high levels of variable renewable energy on system operations using a production cost model that simulates the dispatch scheduling of the wholesale electricity spot market. The project also developed a siting algorithm for variable renewable energy projects and compared different siting scenarios, notably high potential areas versus minimized transmission upgrades. This approach can show how to maximize the transmission system's capability by optimally locating new power plants.

USAID and NREL found that Luzon-Visayas Grid in the Philippines could support a variable renewable energy (wind and solar) power generation mix of more than 50% by 2030.

In Luzon, grid development is currently driven by plans for large capacity coal-fired and natural gas power plants mainly concentrated in Batangas, Quezon, Bataan, and Zambales. A new 500 kilovolt (kV) transmission system for bulk power delivery within Metro Manila and three additional 230 kV drawdown substations will improve power quality and reliability. Looping configuration development for the 230 kV and 500 kV system, as well as the installation of reactive power compensating equipment at various substations, is also needed to enable the supply of power to customers from either direction of the loop. Part of the long-term plan is a 500-kV backbone extension for both the western and eastern sides of northern Luzon to serve as a power generation highway.

In Visayas, the reinforcement of the existing 138 kV Cebu-Negros-Panay submarine cable interconnection, the development of a 230 kV transmission backbone from Cebu up to Panay Island (Cebu-Negros-Panay 230 kV backbone), and the development of the new 230 kV backbone up to Bohol are intended to accommodate conventional and renewable generation projects. To complement the development of a 230 kV Visayas backbone, gradual establishment of a looping configuration for the 138-kV transmission system to improve system reliability will also be implemented.

In Mindanao, several coal-fired power plants with the potential for a large expansion of capacity and forecasted load growth require the development of various 230 kV transmission lines—including the 230 kV Mindanao backbone that will serve as the island's bulk power highway from north to south Mindanao, upgrading and extension of 138 kV lines, and looping of 69 kV lines. The implementation of the Mindanao-Visayas Interconnection Project (MVIP) will also allow export of power to the other major grids. In the long term, additional drawdown transformers for bulk power delivery in various substations and the interconnection of various islands to the main grid are expected.

5.6 Institutional inertia

Institutional inertia can be an obstacle to a timely and orderly energy transition. Permits for generation are required from all levels of Philippines government (i.e. from the barangay, municipal, provincial, regional, and departmental authorities), such as the local government units, Board of Investments (BOI), Department of Agrarian Reform (DAR), DOE, National Commission on Indigenous Peoples (NCIP), National Water Resources Board (NWRB), Bureau of Customs (BOC), Department of Public Works and Highways (DPWH), and the ERC with overlaps between the needs of some of the agencies. While the implementation of the Energy Virtual One-Stop Shop (Evoss) is in process, there is currently a lack of harmonization and standardization of administrative processes across these levels.[36] This can result in a stop-start process that can require additional application requirements, leading to what can appear to be a repetitive process for developers.[37]

One example to consider is the Sabang micro-grid that was successfully commissioned at the end of 2019. It took 6 years for this project to obtain the necessary approvals, endorsements and permits. IRENA reported in one public forum that a solar developer revealed that no less than 160 signatures were needed for its solar project before it was able to start construction. The permitting process for that project took almost three years while actual construction took less than a year.[38] It is notable that there has been a lag in new installations from December 2015 to June 2019. This is a result of new rules and legal challenges stemming from the government's attempts to increase competition through the implementation of regulations to encourage more transparent bidding. In May 2019, the Supreme Court ruled that single-bid power sharing agreements (PSA) applications submitted after 7 November 2015 were to be voided for failure to conduct the Competitive Selection Process (CSP). This ruling gives renewed clarity on the need for power stakeholders to adhere to the CSP to enable more competition and transparency, allowing more affordable technologies to compete.

Despite the administrative issues highlighted above, there have been some improvements in the administration of new generation capacity projects. For example, the Anti-Red Tape Authority (ARTA) is a government department created to ensure that government officials work in a set and timely manner, adhering to deadlines. It was implemented by the current Duterte Administration through the Implementing Rules and Regulation (IRR) of Republic Act No. 11032, also known as the Ease of Doing Business and Efficient Government Service Delivery Act of 2018. This Act imposes administrative and criminal liability on government workers for up to 6 (six) years in jail and P500,000 fine amongst others.

In one case, a local project developer claimed that it took three years for the DOE to provide a Renewable Energy Operating Contract (REOC), which is a permit to build, before approaching ARTA. Ten days after filing with ARTA, the respective REOC was released.

[36] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Mar/IRENA_RRA_Philippines_2017.pdf
[37] http://www.wfw.com/wp-content/uploads/2018/08/WFWBriefing-Renewable-energy-Philippines.pdf
[38] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Mar/IRENA_RRA_Philippines_2017.pdf

In addition to ARTA, in order to expedite applications for permits, the Government of the Philippines passed Republic Act 11234 in July 2018 to create an online platform called the Energy Virtual One-Stop Shop (Evoss), which is managed by the DOE and monitored by a Steering Committee chaired by the President of the Philippines.[39] This platform aims to enable developers to submit documents, apply for permits, pay fees, monitor status of approval and receive permits. Considering the required permits from various government agencies, Evoss facilitates both information sharing and standardization.

A change in the ERC's governing board also presents an opportunity to standardize processes and improve appraisal of PSAs. For example, after a Supreme Court ruling that all PPAs after 7 November 2015 are avoid as a result of failure to adhere to competition policy, in late 2019, the ERC included a "fixed bid price" in cooperation with MERALCO, the largest utility company, which is inclusive of fuel cost and other variable charges in a CSP, which can allow better economics for consumers.[40] This runs contrary to all previous PSAs, which automatically pass through all fluctuations in fuel costs and FX fluctuations to consumers and/or the cross-subsidy, also paid for by consumers.

5.7 Viable land due to land scarcity and convertibility issues

Land availability is frequently cited as an impediment to power sector development in the Philippines. There are competing needs for land-use such as urbanization, energy production, and growing food. Unlike the often-underpopulated plains of China and India, the Philippines has a high population density, at 358 people per square kilometre, and the geography of island archipelagos with little flat land.

Land-use competition has driven up the price of land and consequently the cost of land-based projects. A 100MW solar PV installation requires 250 acres or 100 hectares, equivalent to 1 sq. km. In the Philippines, land conversion can take up to three years because land must not have had any economic purpose for three years to be considered idle, which then allows it to be converted.[41] This significantly increases early stage project development costs. In countries like the Philippines with competing land-use such as urbanization, energy production and food cultivation, high land costs have been a catalyst for floating solar photovoltaic (FPV) and offshore wind due to the ability to deploy them in otherwise un-used locations such as irrigation ponds, mine lakes, water retention ponds, wastewater treatment ponds, industrial reservoirs, and hydroelectric dams. According to MGen, floating solar projects are not as expensive as the land-based solar farm.[42] The table below highlights the diverse land requirements of wind and solar projects.[43]

[39] https://www.officialgazette.gov.ph/downloads/2019/03mar/20190308-RA-11234-RRD.pdf
[40] https://ieefa.org/wp-content/uploads/2019/09/Prospects-Improve-for-Energy-Transition-in-the-Philippines_September-2019.pdf
[41] https://ieefa.org/wp-content/uploads/2020/06/Is-Combined-Floating-Solar-and-Hydro-the-Energy-Solution-for-ASEAN_July-2020.pdf
[42] https://www.philstar.com/business/2019/10/17/1960761/mgen-eyes-floating-solar-plant-laguna
[43] https://www.nrel.gov/docs/fy19osti/71814.pdf

TABLE 2. SOLAR PHOTOVOLTAIC TECHNICAL POTENTIAL

SCENARIO	LCOE	LCOE	SUITABLE LAND	CAPACITY	GENERATION
Relaxed	USD50 to USD100 per MWh	PHP2.5 to PHP5 per kWh	1,164.2 km²	41.9 GW	68 TWh
Moderate			464.8 km²	16.7 GW	27.2 TWh
Restricted			142.2 km²	5.1 GW	8.3 TWh
Urban			102.9 km²	3.7 GW	6 TWh

Source: NREL, 2019

TABLE 3. WIND TECHNICAL POTENTIAL

SCENARIO	LCOE	LCOE	SUITABLE LAND	CAPACITY	GENERATION
Relaxed	USD40 to USD100 per MWh	PHP2 to PHP5 per kWh	13,601.0 km²	421.6 GW	68 TWh
Moderate			7,144.5 km²	3,402.8 GW	27.2 TWh
Restricted			3,180.8 km²	5.1 GW	8.3 TWh

Source: NREL, 2019

5.8 Coal and fossil gas prices

One frequently under-analyzed flaw in the Philippines' power project evaluation results from the handling of fuel costs. Coal project feasibility documents have often suffered from unrealistic fuel cost benchmarks that overlook market conditions and risks associated with market volatility. Coal price assumptions used in recent PSAs in the Philippines are still higher than current low coal prices. While it would be tempting to regard this coal price weakness as a possible benefit for project economics, it also signals financial risk as many projects are dependent on Indonesian coal suppliers that are operating at close to or below breakeven — a situation that is not sustainable.

For example, the previous Atimonan coal power purchase agreement (PPA) draft set the Newcastle Index at USD 50.38 per metric tonne with a freight price of USD 5.90 per metric tonne, and a forex rate of PHP 46.07 per USD. The current Newcastle Index coal price, which is considered low due to a drop in commodity prices globally, is USD 52.79 per metric tonne[44], the lowest since June 2016, and down 24% from a peak in mid-January this year of USD 69.59 per tonne. The exchange rate has not been at PHP 46.07 per USD since June 2016. Depreciation since then means that it is more expensive to buy imported fossil fuels. In short, the current low coal price may still translate to higher prices than is assumed in the PSAs, leaving end-users to pay for ERC-approved mispricing. Eliminating

[44] https://www.reuters.com/article/column-russell-coal-asia/column-seaborne-thermal-coal-prices-slide-as-india-takes-coronavirus-hit-russell-idUSL3N2CG1DL

the pass-through for imported fuel costs avoids the ups and downs of volatile commodity markets, providing valuable price stability.

In the past, power sector planners often assumed that biasing the system toward baseload fossil fuel generators would deliver benefits from scale. This engineering planning norm is now being reconsidered in light of evidence that too high a new fossil fuel mix results in system lock-in due to inflexible contractual obligations that require base load dispatch even when new lower cost renewables can reduce system prices. Unfortunately, this "lock-in" problem is worse for countries that import coal due to negative effects on the trade balance.

The concept of large-scale system lock-in has particularly important implications for countries that may be evaluating a pivot to gas-fired power. The DOE is expected to finalize discussions about importing fossil gas, or liquefied natural gas (LNG), this year, but there are serious implications for investment and energy security. The Chair of the Senate Committee on Energy has already flagged logistical constraints as an issue for all imported fuels, including oil and gas, and implications for energy security.

Importing fossil gas is neither an incremental decision nor is it economical without scale. A long-term commitment to imports of liquified natural gas (LNG) requires a carefully orchestrated investment program involving the many players required to develop the required regasification units, associated pipelines, retail connections, and storage units. The price tag for this infrastructure typically runs billions of dollars and requires intensive market consultation if a retail gas market is part of the plan. This will require the same capital recovery guarantees as coal- and oil-fired generation unless developers are asked to take market risk. Before deciding to pursue fossil gas, it is prudent to understand what the economics of imported gas will look like in eight to 10 years vis-à-vis other technology options, and whether the experience of COVID-19 encourages power sector planners to specify greater domestic energy security and system flexibility. In many fast-growing markets, the deflationary price trajectory of renewable electricity generation and storage presents a better value proposition than the cost of generating and moving electricity from a large fossil-fuelled power plant.

5.9 Regulatory improvements

Timely support for transitioning the energy system to the cost-effective technologies that are currently reshaping global power markets would foster more reliable, competitive and flexible power. Opposing regulatory incentive improvements is the concept of baseload, which has enjoyed benefits of automatic pass-through of fuel and foreign exchange fluctuations as well as guaranteed capacity payments. The guaranteed capacity fee is designed to ensure independent power producers (IPPs) can fully recover their capital costs, repay their loans on a timely basis, and generate profit. However, as a consequence, low utilization translates into a scenario where consumers must pay for baseload IPP capacity covered by guaranteed capacity payments, even if the power is not dispatched, which ultimately punishes the end-users. This means that neither the financial sector nor the power sector is liable for the risk they take in designing a system that absolves the decision-makers of any market risk, as these costs are passed on to end-users who are ill-equipped to manage such risk. Recognizing this problem, Meralco, the largest utility company in the Philippines, has taken steps to improve procurement practices by requesting a fixed price and thus removing automatic fuel pass-through and including a curtailment clause (locally known as a carve-out provision) to protect end-users from paying for unused power.[45] PSA contracts prior to 2019 and contracting by other distribution utilities do not include these adjustments to the procurement terms.

The Philippines' power market has been shaped by regulatory incentives focused almost exclusively on baseload generation capacity rather than system-level resourcing. This power system design strategy has left power system planners vulnerable to a new and complicated challenge due to the system's lack of flexibility. The baseload concept reflects the minimum production level at which a coal plant can operate without having to be switched off. The reason this is important is that it is expensive to turn off a coal plant. Most coal plants are sized and scaled to meet the lowest point of power demand in order to run continuously. As demand increases, systems designed to prioritize baseload would be expected to increase output from coal plants rather than call on other options. However, if demand surpasses the economic output from coal plants, the utility company would have to buy from mid-merit or peaking plants typically fired by gas or oil, which is normally more expensive. Unfortunately, 2020 has taught us that peak demand trends can be unpredictable. During the first phase of the COVID-19 pandemic, MERALCO experienced a peak demand drop of almost 40% to 4,516MW in March 2020 and 4,289MW in April. The Department of Energy revealed that during the economic lockdown, electricity demand fell by 30% in Luzon, 17% in the Visayas, and 25% in Mindanao.[46] The impact on system operations and economics was immediate. With a large volume of unused baseload capacity, consumers faced unexpectedly high costs due to inflexible capacity payments.

As such, it is clear that baseload is a business and economic concept, rather than a technical one. In other words, coal needs baseload, and not the other way around. Given the availability of new technology solutions, it is clear that the reliance on outdated baseload planning disciplines will result in sub-optimal system design outcomes that overlook the opportunity for market improvement through the integration of competitive low-cost generation, flexible generation, demand management, and energy efficiency.

Finding the right pricing signals to drive technology adoption to solve the integration of a high share of variable renewable energy into the grid will be critical for the development of a more flexible power system. The DOE's proposed Green Energy Tariff Program is effectively an auction, which can improve transparency for grid access and thus makes it easier to raise finance at a viable rate — a step that could ensure that new renewables can provide price relief to Filipino power consumers.

In a critical reform, the DOE has also recently recognized the need to price system services. This includes contingency and regulating reserves classified as primary, secondary, tertiary (dispatchable), reactive power support and blackstart. These services are critical to balancing load requirements in a more flexible system. As a result, this initiative will effectively create a new and much needed sub-market via an ancillary

[45] https://ieefa.org/wp-content/uploads/2020/06/Philippines-Power-Sector-Can-Reach-Resilience-by-2021_June-2020.pdf
[46] https://ieefa.org/wp-content/uploads/2020/06/Philippines-Power-Sector-Can-Reach-Resilience-by-2021_June-2020.pdf

service or reserve power auction. Storage investment is driven by one of several value streams including cutting transmission charges and providing grid resilience. Battery storage can also be used to provide firm renewable power. Specifically, a storage system can address the variable nature of solar and wind, which are not always available when needed, or they are available in quantities that cannot be used in full at a particular time.

5.10 Retail competition's interaction with low-priced renewable energy

Accelerating policies on retail competition, known as Retail Competition and Open Access (RCOA), lessens the certainty of recovery of generation investment costs, re-aligns the interests of developers and consumers, and can influence risk-adjusted returns by raising required returns on capital invested in generation relative to the returns needed in markets in which capital recovery is "guaranteed" by cost-of-service regulation.[47] Nonetheless, it enables ratepayers, depending on a stable level of demand and consumption to be served by least-cost generation supply along with other value-added services.

After administrative and institutional delays, retail competition was finally implemented by the ERC in December 2013, starting with commercial and industrial ratepayers with an annual peak demand of over 1 MW (mandatory contestability), then moving down to 750 kw (voluntary contestability), and then 500 kw to the household level.

In Japan, where retail competition is universal, stranded coal risks are entirely borne by private developers.[48] To protect captive customers from the burden of high average rates resulting from low-capacity utilization that in turn results from the migration to other suppliers by contestable customers, Meralco, as early as 2012, started inserting 'carve-out clauses' in its PSA's with IPP's. These clauses give the utility the right to transfer capacity and energy supply to affiliates or other third parties at the same price conditions. Since then, the carve-out clause has evolved to take into consideration retail competition and the impact of competition from deflationary renewable energy projects.

Stranded contracts may arise if underlying demand falls due to the implementation of RCOA. Through RCOA, customers like industry can choose not to be supplied by their respective distribution utility; they can opt to buy electricity from a retailer. In due time, RCOA-empowered retail electricity suppliers (RES) can aggressively supply more of the demand. RCOA is the fastest way to an efficient market as it empowers customers to transact directly with the retail electricity supplier, rather than going through the ERC approval process. This means RCOA might cause a reduction in contracted capacity required by a distribution utility like Meralco. In other words, RCOA might trigger the 'carve-out' clause in the PSA, which Meralco added to the PSA, because adding the right mix of renewables to any electricity system has the potential to erode utilization rates of coal power.

It's noteworthy that Meralco, in essence, had the foresight to put a carve-out clause in the PSAs, recognizing the inevitability of stranded asset risk. For example, a carve-out

[47] https://hepg.hks.harvard.edu/files/hepg/files/retail_choice_in_electricity_for_emrf_final.pdf
[48] https://www.smithschool.ox.ac.uk/research/sustainable-finance/publications/satc-japan.pdf

clause exempts the distribution utility, in this case Meralco, from the consequences of reducing contracted capacity from the proposed Atimonan coal-fired power plant. Section 10.3.1 of the PSA states that "*subject to the provisions of the Section 10.3.2 below, Meralco shall, from time to time, be entitled to a reduction in the Contract Capacity and Associated Energy equivalent to the reduction in the demand of its captive customers by reason of the enforcement of Retail Competition and Open Access, the Renewable Energy Law and other Laws and Legal Requirements.*" Section 10.3.2 states that "*Meralco shall give a written notice to the Power Supplier of such reduction at least five (f5) Days prior to the first Day of the next Billing Period. Upon receipt by Power Supplier of such written notice, Meralco shall cease to have any rights and obligations under this Agreement in respect of such Reduction in Contract Capacity and Associated Energy.*"

The meaning of this decision became clear in 2017 when Meralco lost 20% of energy sales from the loss of half of its contestable load. Its captive market is said to be 60% and this will continue to decline as the peak demand threshold for contestability further reduces as a result of retail competition. This tells us that customers with consumption of 500kW and above can/do/may choose to buy from one or more power providers, effectively buying less or disconnecting from the utility company. Retail competition may be accelerated due to low-priced renewable energy. This may be a good indicator of the future market structure where power generators may be required to have assets that can compete on both the retail level and wholesale level, while utilities must have generation that is competitive with retail rates. If retail players are able to buy from the wholesale market, then utilities may want a portfolio of low-priced renewable energy and wholesale market purchases to be able to adequately compete.

6 Least-Cost Model review and Critical Point Analysis

To evaluate potential energy transition pathways for the Philippines' market, we reviewed several LCMs to understand differences in least-cost pathways. Critical Point Analysis (CPA) was also used to understand the competitive interactions of new entrant generation technologies. Considerable efforts were made to understand and correctly report LCM assumptions and constraints.

6.1 Least Cost Model

The objective of LCM is to minimize the present value of total system costs to meet (and shape) electricity demand over the time horizon. LCM typically uses linear programming to simultaneously model dispatch and investments in power plants. In doing so, LCM calculates short-term or long-term optima and estimates the corresponding capacity mix as well as prices, generation, and cross-border trade for separate market areas. LCMs require forecasts of: (1) power demand over space and time; (2) investment and running costs of power generation technologies based on evolving market conditions; and (3) resource adequacy and reliability constraints.[49] All these data requirements are subject to risks and uncertainties.[50]

LCMs typically include the following features: long-term adjustment of capacity mix, inflow pattern and load profiles, system service provision, combined heat and power plants, hydro reservoirs and pumped hydro storage, imports and exports, cost-optimal investment in interconnector capacity, thermal plant start-up costs, curtailment of variable energy and balancing power requirements.

Notwithstanding the risks, uncertainties and limitations associated with LCMs, this analysis is an effective tool for policymakers and investors. For investors, LCMs help guide investment and operational decisions. Given power generation facilities are capital intensive long-life assets, if a technology is not in the solution set, it implies the technology is not competitive and poses a significant investment risk. For a regulator, LCM can estimate incremental costs or tariff impacts of policies and mandates and provide guidance to developers, especially RE, that have no access to the tool and its data requirements.

6.1.1 Least-Cost Model examples

The main LCM providers the authors identified are: BNEF, the UPERDF, NREB and MGEM. We also use a bespoke dispatch model developed by the PEMC to highlight the importance of policy making for the deployment of renewable energy. We have chosen these models due to their influence on investor and policymaker decisions in the Philippines.

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[49] *When computing power was slow and expensive, planners resorted to screening curves, where fixed costs and variable costs are plotted against output, and only the technologies in the lower envelope were considered.*

[50] *For example, the central planners may address uncertainty with Monte Carlo simulations. These Incorporate risk and uncertainty into the evaluation of potential resource portfolios to the extent that is reasonable. Go beyond traditional approaches to stress testing the least-cost solution against only a short list of key uncertainties, by using more robust analytic approaches. The incorporation of renewable energy technologies certainly adds to the need to apply good planning practices with uncertainty.*

6.1.1.1 BNEF

BNEF's New Energy Outlook (NEO) is an annual long-term global forecast for the future of energy, with emphasis on the electricity system. NEO focuses on the parts of the energy system that are driving rapid change in markets, grid systems and business models. This includes the cost of wind and solar technology, battery storage and electricity demand. In the near term, the report's market projections are based on policy targets and BNEF's proprietary project database that provides a detailed understanding of planned new builds, retrofits and retirements, by country and sector. In the near-term NEO is based on policy targets and internal project databases, while over the medium to long-term NEO is driven by the cost of building different power generation technologies to meet projected peak and average demand. NEO provides projections of capital and operating costs of power generation technologies and power demand over a 30-year model horizon.[51]

In NEO, power generation rises to three and a half times 2019 levels from 100 to 350 Terawatt hours. Renewable energy as a percentage of total power generation is around 35% by 2030, consistent with the DoE's RPS target. Coal capacity peaks in 2023 after rising by 44% from 2019 levels from 9 to 13 GW. Coal capacity steadily declines from 2038 to 9 GW by the mid-2040s. Due to the declining capacity, coal generation falls from over 50% today to just over 10% in the 2050 generation mix.

6.1.1.2 UPERDF

The University of the Philippines Engineering Research and Development Foundation (UPERDF) model is a long-term simulation of the Luzon Electricity grid. The model provides a forecast of Luzon electricity demand to 2040, as well as a least-cost generation capacity expansion plan for 2021 to 2040 and an assessment of the short-term viability of existing infrastructure. The electricity demand in the ESM is forecasted using econometric modelling, while the long-term generation expansion plan is formulated using the Low Emissions Analysis Platform (LEAP), a software tool developed by the Stockholm Environment Institute. Baseline capital costs are based on data from the US Energy Information Administration Bureau (USEIAB) data[52] and projections based on the NREL data.[53] Importantly, the ESM only considers the Luzon grid. The outputs of UPERDF are similar to BNEF in terms of the growth of solar, wind and natural gas. In terms of coal capacity, there are no more additions after 2021. The power demand forecasts have been adjusted for the effects of COVID-19.[54] Demand in 2020 is assumed to decrease by 13.8% from 2019 levels. Demand in 2030 and 2040 is 9.2% compared to pre-pandemic model forecasts.

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[51] https://about.bnef.com/ NEO 2019 Deep Dive: the Philippines
[52] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf
[53] https://www.nrel.gov/docs/fy19osti/74273.pdf
[54] *N.B. there are limitations in the data since the official report has not yet been released by the University of Philippines.*

6.1.1.3 NREB

The NREB model aims to help power development planning by providing a least-cost, optimal supply mix for the Philippines over the 2020-2040 period. The model uses detailed hourly power demand forecasts from the DOE, broken down into the main regions of Luzon, Visayas and Mindanao. The demand forecast draws from historical time series and is adjusted based on relevant national data, including NEDA's projections on GDP, price levels of fuels, development plans of distribution utilities, as well as stakeholders and DOE insights on economic activities and potential disruption to future power demand.

The NREB modelling exercise includes two scenarios: the first assumes renewable energy generation as a percentage of total generation increases to 35% by 2030. The second assumes no 2030 target but includes the RPS mandate of 1% per year share of renewable energy generation as a percentage of total generation out to 2030. For the first scenario, NRB finds renewable energy generation share increases from 29% share in the generation mix in 2021 to 55.9% in 2040. Renewable energy capacity additions are dominated by RoR hydro and solar. The generation share of coal declines from 62.4% in 2021 to 28.5% in 2040. There are no coal capacity additions after 2020, with utilization rates of coal remaining stable over the model horizon. Capacity factors for new gas fell from 88.7% in 2023 to 47.6% in 2040. In the second scenario, there are no onshore wind capacity additions and renewable energy generation is just 27.6% by 2030 and 32% by 2040.

6.1.1.4 MGEN

MGen is the power generation subsidiary of Meralco. It runs its own LCM, but does not disclose the full results and the underlying assumptions. It uses scenario analysis to examine the incremental cost impacts of various policies, such as the FiT and RPS. Its presentation during a stakeholder consultation in the course of this project also showed parity-price pairs between coal and CCGT, under various capacity factors. Because we have no access to the assumptions or the model, we are unable to determine whether such capacity factors are model-generated or arbitrary, and thus cannot make any further comments. The only information shared with the authors is that the model uses available international data cost projections, adjusted for local EPC quotations. For the purposes of this study, however, the most important finding in their latest run, is that coal capacity additions are possible as late as 2028.

6.1.1.5 WESM

The WESM model is designed to estimate future WESM prices given the future load levels and configuration of power plants. It takes into consideration the dispatch hierarchy and uses the marginal costs of the future power plants to determine their dispatch. The LCMs described above can provide the input information on future load levels and the future configuration and costs of power plants, while the WESM model can show the prospects for commerciality of renewable energy projects based on merchant power sales. Even under the current power dispatch hierarchy, renewable energy generation enjoys an advantage over non-renewable or conventional power generation. Conventional power plants must compete among themselves on the basis of bid prices to be included on the dispatch at each time interval. Renewables on the other hand will be dispatched ahead of conventional generation. It is noted that the bilateral contracts of conventional power plants do not affect their dispatch, and such power supply contracts will only come into play during the price settlement with their counterparties that is done after the trading day and settled outside of the market. The enhanced WESM design will improve the dispatch position of all renewables as even the P-MIN of baseload power plants is removed from the top of the dispatch hierarchy. This frees up a lot of capacity that renewable energy can fill. Thus, any and all renewable generation will likely be dispatched, except in the case of extreme power load disruptions, the likes of which have not been seen even with this year's pandemic impacts. If their dispatch is secure, renewable generation only has to determine the likely market prices to calculate project viability on a merchant basis. If the WESM can provide a revenue stream above the LCOE plus the acceptable return on equity, then that provides a case for a merchant power sales strategy for renewables.

6.1.2 Summary of Least-Cost assumptions

The table below summarises information associated with BNEF, the UPDF, NREB and MGEM.

TABLE 4. INFORMATION ON THE MODELLER ASSUMPTIONS

MODELER	COVERAGE	DEMAND GROWTH	COST SOURCES	LAST COAL ENTRY	CONSTRAINTS	SOFTWARE
BNEF	Country	Own estimates	Inhouse estimates	2023	Full market	Inhouse
UPERDF	Luzon	Sectoral growth econometric model; government projections; adjusted for COVID-19 and energy efficiency effects	USEIAB (2020); NREL[55]; Korea Hydro and Nuclear Power Company	2021	RPS and LNG infra	LEAP
NREB	Country	Historical annual average growth	DoE and regulated power supply agreements	2020	RPS	Plexos
MGen	Luzon	Inhouse estimates	Inhouse estimates; confidential	2028	Unknown	Plexos

[55] The NREL assumptions show constant fossil fuel costs up to 2050.

Source: ICSC's elaboration based on BNEF, UPERDF, NREB, MGen

TABLE 5. ADDITIONAL INFORMATION ON THE MODELLER ASSUMPTIONS

MODELER	HORIZON	RESOURCE ADEQUACY	BEHIND-THE-METER IMPACTS	BATTERY STORAGE	NUCLEAR INCLUSION	INCREMENTAL COST OF RPS
BNEF	2020-2050	Resource margins that decline from 30-15%	Yes	Yes	No	Minimal to none
UPERDF	2020-2040	Loss of load probability (LOLP) of a day in a year	Not modeled	No	Yes	Minimal
NREB	2020-2040	Unknown	DoE and regulated power supply agreements	No	No	Minimal

Source: ICSC's elaboration based on BNEF, UPERDF, NREB

6.2 Critical Point Analysis

CPA identifies the capital and operating costs of different power generation technologies to understand the relative competitiveness of these technologies over time. We have identified three points which have the biggest implications for investors and policymakers in the Philippines market. The extent to which these implications impact investor and policymaker decision-making depends on the market context. If the LCOE of renewable energy costs are lower than that of coal, the capacity utilization of coal generation is likely to go down, and if these are merchant generators, there is a clear stranded cost risk. However, if the coal generators are covered by bilateral contracts, which is often the case in the Philippines - with the exception of some low-speed diesel and peaker or open-cycle gas - fuel savings accrue either to the off-taker or the generator, depending on the contract provisions. According to Meralco, if the spot price is lower than fuel costs, they pay the spot price plus the capacity costs, thus benefiting ratepayers. To analyze critical points 1 and 3, we relied on BNEF as their LCM was more transparent than the other LCMs surveyed. To analyze critical point 2, we used a simulation model of the WESM. This model was provided by the PEMC, which governs the WESM.

6.2.1 Critical Point 1

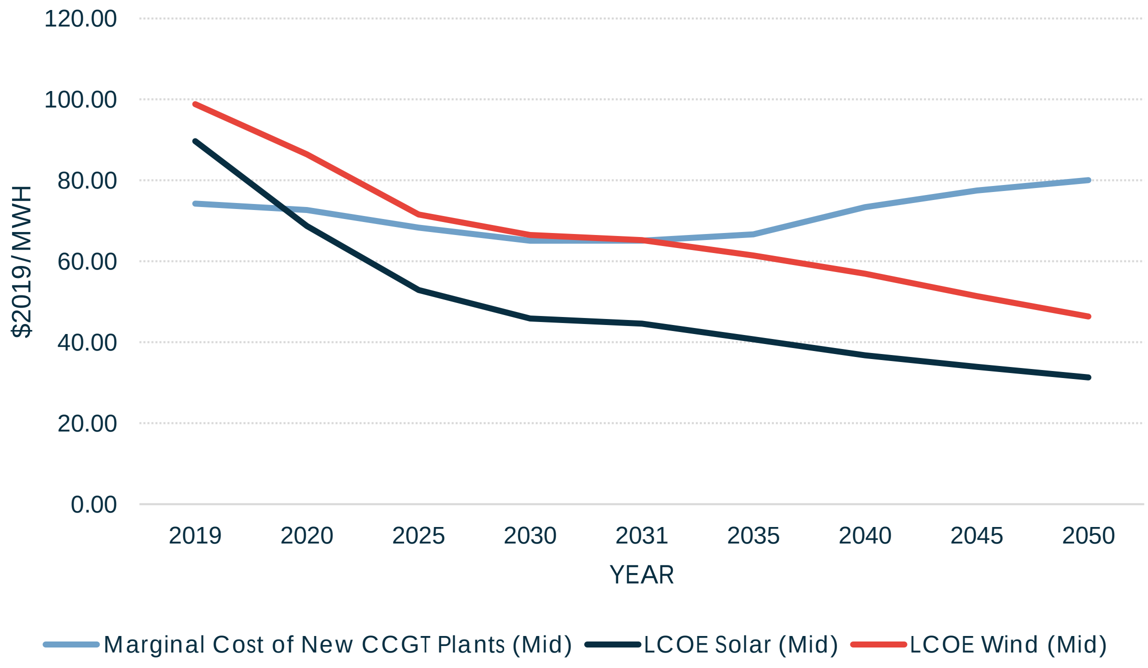
Critical point 1 is when LCOE of renewable energy is lower than the marginal costs of gas peaker capacity. This is the entry point for renewable energy, as gas peaker capacity is typically the most expensive form of power generation. According to NEO, the LCOE of solar is already lower than the marginal cost of existing fossil peaking power plant. Indeed, based on IEFFA analysis, this was reached much earlier in the small Philippine island grids where the marginal costs of diesel generation exceed the LCOE of solar generation.[56]

This situation has three important implications for investors and policymakers. Firstly, when this point is met it saves ratepayers money.[57] Since this critical point was met in 2020, ratepayers should benefit from the increasing competitiveness of solar.

Secondly, this situation also threatens the cost-recovery of merchant peakers, exacerbating what is called the 'missing money' problem. This problem is when electricity prices cannot rise high enough to recover fixed costs and as a consequence, investors make a loss in the long run. This situation is also a problem for policymakers, as it may lead to a shortage in critical capacity required to meet resource reliability requirements.[58]

Thirdly, policymakers should ensure the deflationary trends in solar are reflected in the FiT rates to ensure the FiT is cost-effective and minimises the cost to ratepayers. The early FiT rates for solar were more than twice the LCOE today. The FiT rates reflected the reduction in cost as more solar players came into the market which eventually lowered the LCOE.

FIGURE 4. LCOE OF SOLAR AND WIND VS MARGINAL COST OF NEW CCGT PLANTS



Source: ICSC's modelling

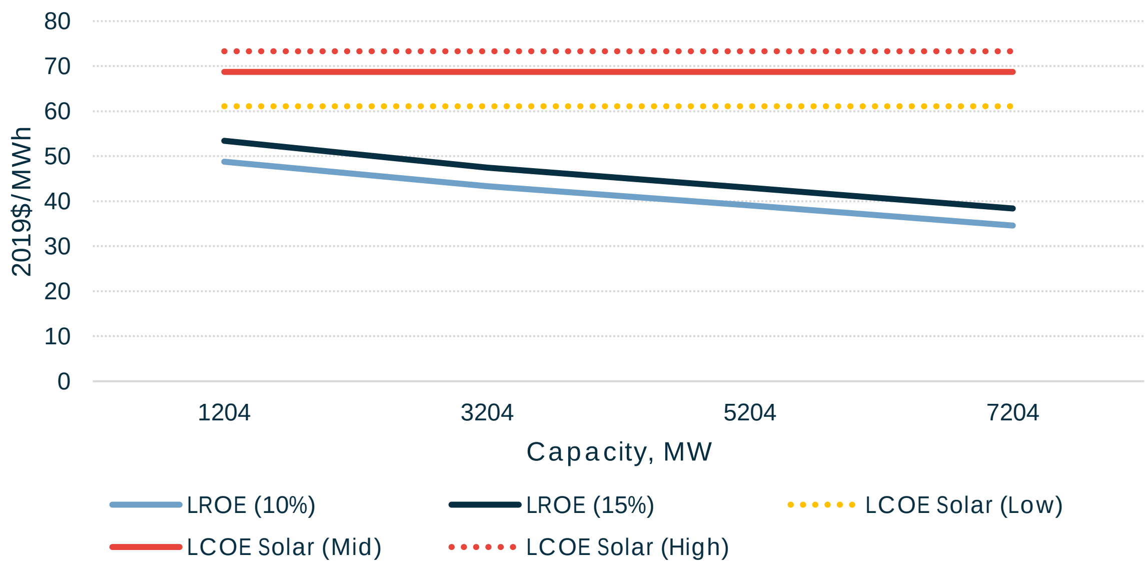
6.2.2 Critical point 2

Critical point 2 is where merchant renewable energy projects cover their LCOE (i.e. the LCOE is lower than in-market revenues). Our analysis, based on data provided by the WESM, shows that levelized revenues for renewable energy projects would never be above levelized costs. This creates a missing money problem, whereby investors may not

56 https://ieefa.org/wp-content/uploads/2017/05/Electricity-Sector-Opportunity-in-the-Philippines_May-2017.pdf
57 *This is providing peakers bid their true marginal costs and are not bound by take-or-pay fuel provisions*
58 https://economics.mit.edu/files/16650

cover their costs over the long-term. The reason for this model outcome could be due to the merit-order effect, due to the increased supply of renewable energies. In practice, this situation could also be exacerbated by self-scheduling. Self-scheduled units depress wholesale electricity revenues by bidding into the market at a cost much lower than their actual cost of operating, which forces the market to take electricity from a generator that might not be the lowest cost. The implication of this analysis is that while LCM show that mandates for renewable energy capacity are redundant, due to the fact that solar is the lowest cost power generation technology, they do not capture market dynamics. For this reason, it is likely renewable energy projects still need out-of-market revenues to be investable.

FIGURE 5. LEVELIZED REVENUE OF ELECTRICITY (LROE) VS. LEVELIZED COST OF ELECTRICITY (LCOE)

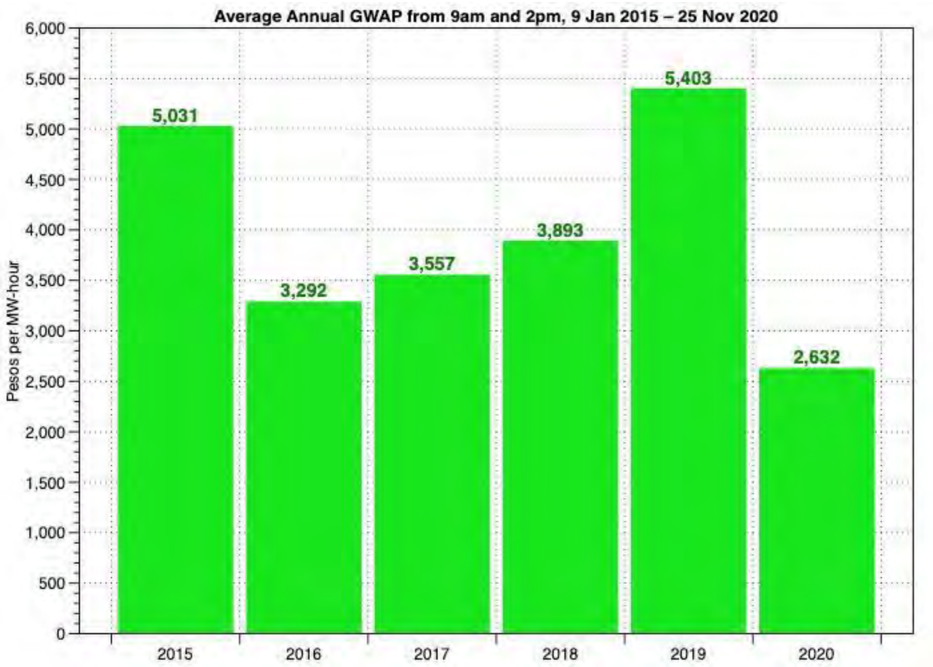


Source: ICSC's interpretation based on WESM modelling

ICSC's modelling shows that the LROE will never be higher than the LCOE regardless of how much capacity is installed. This is largely due to the fact that the analytical tools used set fixed marginal costs over the planning horizon. While this is a rational assumption, it neglects the realities of volatile fossil fuel costs and falling costs of renewable power plants, particularly solar and wind. A cursory examination of generator weighted average prices (GWAP) in 2018 and 2019 shows that during the solar hours (aproximately between 9AM and 2PM) the average GWAP was PhP 3.90 per kilowatt-hour and PhP 5.40 per kilowatt-hour respectively. In both years, the GWAPs were higher than the LCOE of solar power.

There are a number of new developments in the energy sector that support the energy transition. These are the recently-announced moratorium on new coal power plants, the higher proposed RPS target of 2.52 percent instead of 1 percent that is in the updated National Renewable Energy Program to be adopted in the Philippine Development Plan, the new law on energy efficiency for commercial and industrial power consumers, the new mandate for commercial buildings to have solar and/or other renewable energy power supply and the accelerated timeline for the Green Energy Auction announced by the DOE.

FIGURE 6. GENERATOR WEIGHTED AVERAGE PRICES (GWAP) 2015-2020 – PHILIPPINE PESO



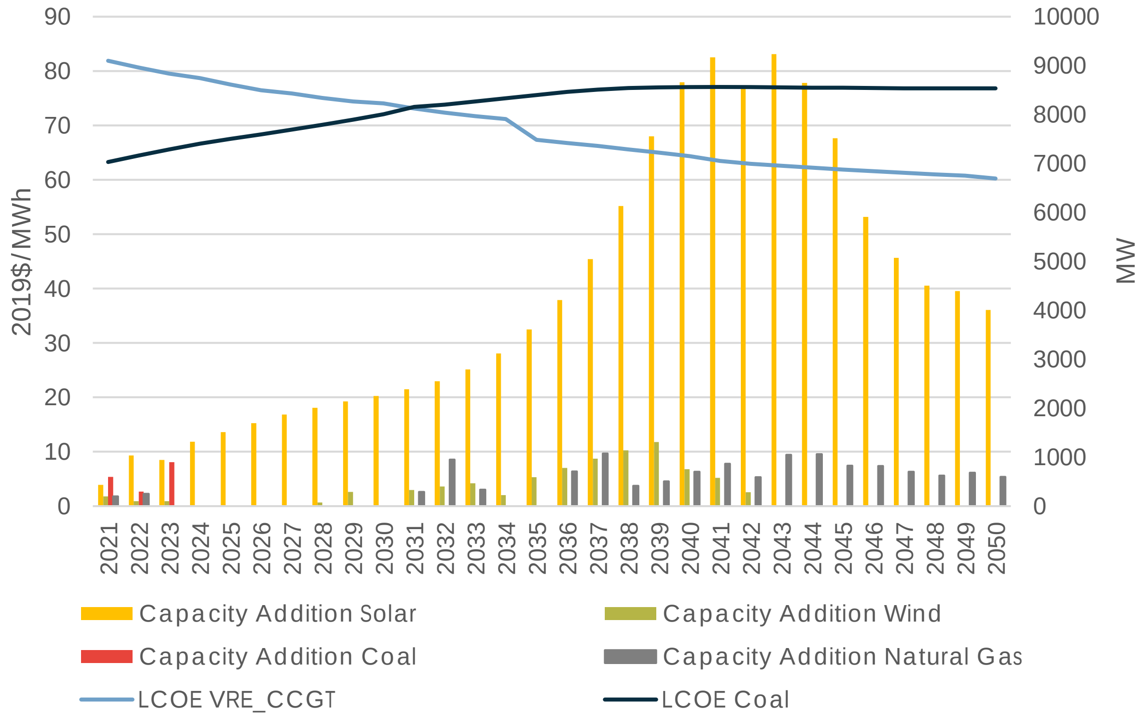
Source: GWAP published by PEMC/IEMOP

6.2.3 Critical point 3

Critical point 3 is when the LCOE of a hybrid solar and CCGT system outcompetes the LCOE of new coal. According to BNEF data, the LCOE of new coal is below the LCOE of a CCGT throughout the model period (from 2019 to 2050). The reason for this situation is likely due to increased amounts of solar generation which decreases the utilisation rates of conventional generators and thus increases their LCOE as fixed costs are spread over a smaller number of hours. Despite this, our analysis shows the LCOE of a hybrid CCGT could be cheaper than coal.[59] This can be consideration for policymakers for market design to encourage new renewable energy investments. As detailed in Figure 6, by 2031 the LCOE of hybridised CCGT is cheaper than the LCOE of new coal. At this point, new merchant coal will be at risk of becoming a stranded asset.

[59] Our modelling is based on our interpretation of BNEF data. Capital costs of unit capacities of CCGT and VRE are taken into account, as is the marginal cost of CCGT but is applied only when VRE generation is not available.

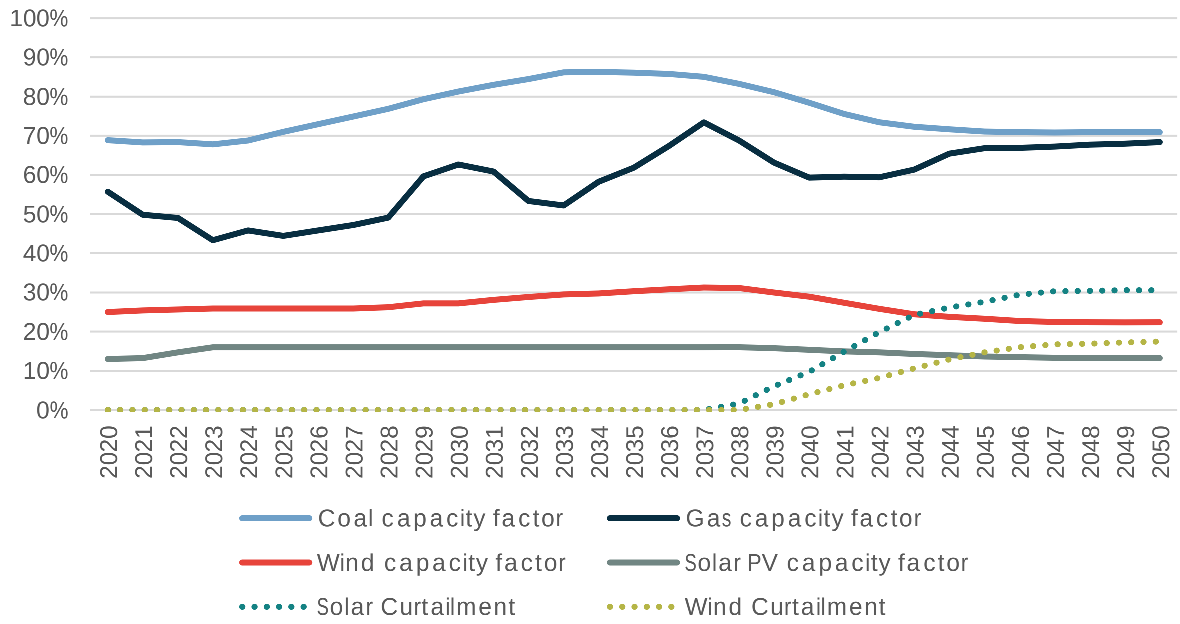
FIGURE 7. HOW CCGT AND VARIABLE RENEWABLE ENERGY (VRE) HYBRID DETERS NEW COAL ENTRY



Source: ICSC's modelling

In the 2030s is also when the utilisation rate of coal capacity starts to decline as the LCOE of solar and wind are low enough such that capacities in excess of peak demand can still be economically installed, but in turn generate more than what the grid can absorb. In short, the LCOE of solar and wind are still lower than the marginal cost of gas and coal, even with growing levels of curtailment. As illustrated in Figure 7, the utilization rates of both coal and gas decline, as the curtailment of solar and wind start in 2037. Based on our interpretation, BNEF projections do not yet take into account economic uses of the excess renewable energy, such as green hydrogen. While the curtailment of solar and wind implies that installed capacity of VRE exceeds peak demand, the current model assumes that there is a limit to renewable energy capacity that can be curtailed economically. While the capacity utilization of CCGT increases in the early 2040s in the model as the amount of wind and solar curtailment stabilizes, it is important to recognize that renewable energy can be used for green hydrogen in both transportation and manufacturing.

FIGURE 8. WIND AND SOLAR CURTAILMENT AND DECLINE OF COAL WITH CCGT UTILIZATION



Source: ICSC's modelling based on BNEF data

6.3 Meralco procurement case study

The country's largest utility is now procuring baseload capacity of 1.8 GW (with guaranteed plant capacity factor at 87.67%) for its captive customers, with projected commercial delivery months of 1.2 GW for December 2024, and the remainder for May 2025. The table below shows the bid parameters, and our comments. At the November deadline on November 13, 18 entities submitted expressions of interest, mainly coal and LNG proponents. Though we are not privy to names of the entities, this procurement is timely in applying the methods articulated in this section.

Current Meralco procurement parameters

PARAMETER/SCHEDULE	REQUIREMENT	COMMENTS
Schedule	Pre-bid conference: December 17 Bid submission: January 25	
Contract period	20 years	
Unit age	Units must not have been installed earlier than 2020	DoE has signed on to need for new greenfield capacity
Bid type	Pay-as-bid; with the minimum capacity offered at 150 MW per bidder	Captures any realized 'producer surplus' which is good for ratepayers
	Bid price to indicate headline rate (initial prices) and levelized cost; bid	

	has to hurdle reservation caps for both, to qualify; reservation caps to be revealed only during opening of bids	
Evaluation	Awards to be based on stacking of levelized costs; marginal bidder has to agree to reduction of bid capacity after capacity requirement is breached	
Tariffs	Two-part tariff consisting of fixed and variable costs. Capital recovery fee component of fixed cost, in local currency, constant for contract period No take-or-pay on variable costs (fuel and variable operating and maintenance) costs. Fuel handling and freight costs to be included in either variable and/or fixed operating and maintenance costs.	Proponents assume currency risks; no take or pay fuel costs allowed. This disallows minimum natural gas off-take costs borne by Meralco payers from its current contracts supplied with gas by the Malampaya consortium, that expire in 2024; Fuel from Malampaya will be replaced by imported LNG and supply would to generators would no longer be subject to take-or-pay
Levelized cost calculation	Levelized fuel costs are to be based on simple average of four-quarter estimates in US$ from 3rd quarter 2022 to 2nd quarter of 2023, adjusted for 2% annual inflation, for the whole contract period Actual fuel payments are based on initial estimates, and realized indexed and lagged ratios	Ratepayers assume some currency and world price fossil fuel risks; While the fuel-cost adjustment procedure implies bids mainly from new coal and CCGT, it provides leeway for other technologies, for whom projections could be waived, because the fuel-displacement model discussed above would render VRE as a more stable variable cost in lieu of risky fossil fuel costs;'
Carve out	If capacity requirement is reduced owing to retail competition or RE policy (mandates) capacity will be returned to proponent	Standard Meralco contract provision

The major point in evaluating this procurement via the methodology developed above, consisting of least-cost simulations enriched by critical points analysis is that a bilateral contracting procedure fails to capture portfolio effects. This is true of a bilateral contracting procedure that is based solely on levelized costs for baseload thermal plants, regardless of how competitive the bidding process is.

Moreover, it is important to note that this methodology does not take into consideration that the economics of establishing LNG in a time of energy transition may not be an economical or cost-effective choice. The arc of new technology development (renewable energy and storage) does conflict with the economic lives associated with required investments in LNG infrastructure such as gasification and storage facilities, and pipelines, which is typically a 25-to-40-year capital lock-in to meet transition return objectives. As witnessed this past decade in technology development, there are likely more cost-effective system options for balancing variable renewable energy than LNG that can be included in future analysis.

7 Discussion of Least Cost Model and Critical Point Analysis

The LCM and CPA both highlighted a diminishing role for coal and increased role for renewable energy.

7.1 Least Cost Model

The challenge for policymakers and investors is to identify and prepare for a least-cost pathway to meet future demand. LCM guides policymakers and investors in finding these least-cost paths while identifying risks and estimating costs. This report compares the outputs from several influential LCMs. All of these LCMs find the need for flexible generation instead of baseload capacity and the expansion of renewable energy. BNEF was the most comprehensive and transparent model available to researchers. With exception of the inclusion of the 1% per annum RPS, it is based on least-cost principles. BNEF projects that renewable energy will be 35% of total power generation by 2035, with solar dominating capacity addition in the mid-2020s. UPERDF also projected the dominance of solar after the last coal capacity addition in 2021. Unlike BNEF and UPERDF, NREB projected a significant role for RoR hydro. NREB also had the most aggressive outlook for renewable energy, making up 56% of total generation by 2040, with no new coal capacity from 2020. While it was impossible to analyze model results and assumptions due to a lack of transparency, MGEN results show that the last coal addition will be in 2028.

7.2 Critical Point Analysis

The CPA was based on BNEF data and supported the result of the LCM. Three critical points were identified, exhibiting the competitive interactions of new entrant generation, such as wind and solar, and conventional generation, such as coal and gas. Critical point 1 is when LCOE of renewable energy is lower than the marginal costs of gas peaker capacity. This critical point has already been met and highlighted how near-zero marginal cost renewable energy can disrupt conventional generators. Critical point 2 is where the LCOE of renewable energy is lower than revenues they obtain from in-market sources. This analysis was based on a model provided by the WESM and highlighted that this critical point will never be reached due to the preponderance of bilateral contracts which effectively crowd out normal cost-based price discovery. This missing money problem has serious implications for policymakers who are relying on a wholesale market structure to realise a least-cost pathway and investors who are trying to make bankable renewable energy investments. Critical point 3 is when the LCOE of a hybrid solar and CCGT system outcompetes the LCOE of new coal. According to BNEF data, the LCOE of new coal will be below the LCOE of a CCGT for the foreseeable future, but when a CCGT is hybridised with solar it could be cheaper than coal.

8 Policy recommendations

The Philippines energy market has been shaped by regulatory incentives focused almost exclusively on generation capacity rather than system-level resourcing. The government now has an opportunity to redesign the market to benefit from new low-cost renewable technologies and, in so doing, driving down costs for consumers. In this section, we detail several policy recommendations to help manage transition risk without putting undue pressure on power generators, distributors, or consumers.

Fast-track auctions so that new capacity decisions are more cost-competitive and complementary to transmission and storage plans

The country has had recent success in its competitive selection processes including open bidding instead of bilaterally negotiated contracts. The next step towards enabling lower prices is to ramp up the country's auctions policy - the Green Energy Action Program - to include geographic and resource-specific auctions as a means of maximizing price competition and improving transparent procurement across the archipelago.

The auction process could be augmented with resource mapping, using terrestrial and spatial analysis and technical application, to help identify the best usable energy technology for an allocated area. For example, mapping could identify the sites most suitable for on- or offshore wind, land-based or floating solar, or hydro resources. This mapping exercise could be scaled from a site-specific project to examine the whole country's resource potential. This process could be used to match high priority sites with the transmission planning process to enable timely grid access.

Auctions could also be extended to include storage installations. High-capacity storage provides many key services to a well-managed grid including the reduction of transmission charges and improved grid resilience.

The latest Transmission Development Plan (TDP) of the NGCP devotes an entire Chapter 7 on battery energy storage. The TDP recognizes that battery energy storage is a market-tested technology that has various applications for a transmission system, including the provision of ancillary services, deferment of transmission facility upgrades and transmission congestion relief. The first grid-scale battery energy storage in the Philippines was a 10-MW unit installed in 2016 in Zambales by AES. The TDP has identified 450 MW of battery energy storage requirements in several substations nationwide.

India is ahead of the game in Southeast Asia, installing its first grid-scale lithium-ion battery energy storage system (10MW/10MWh) in February 2019. According to the CEO of Tata Power Delhi Distribution Limited, the storage system has been valuable in addressing "key challenges in the areas of peak load management, system flexibility, frequency regulation and reliability of the network".[60] Also, in February 2019, the Solar Energy Corporation of India (SECI) announced tenders for 3,600MWh of energy storage to be connected to the

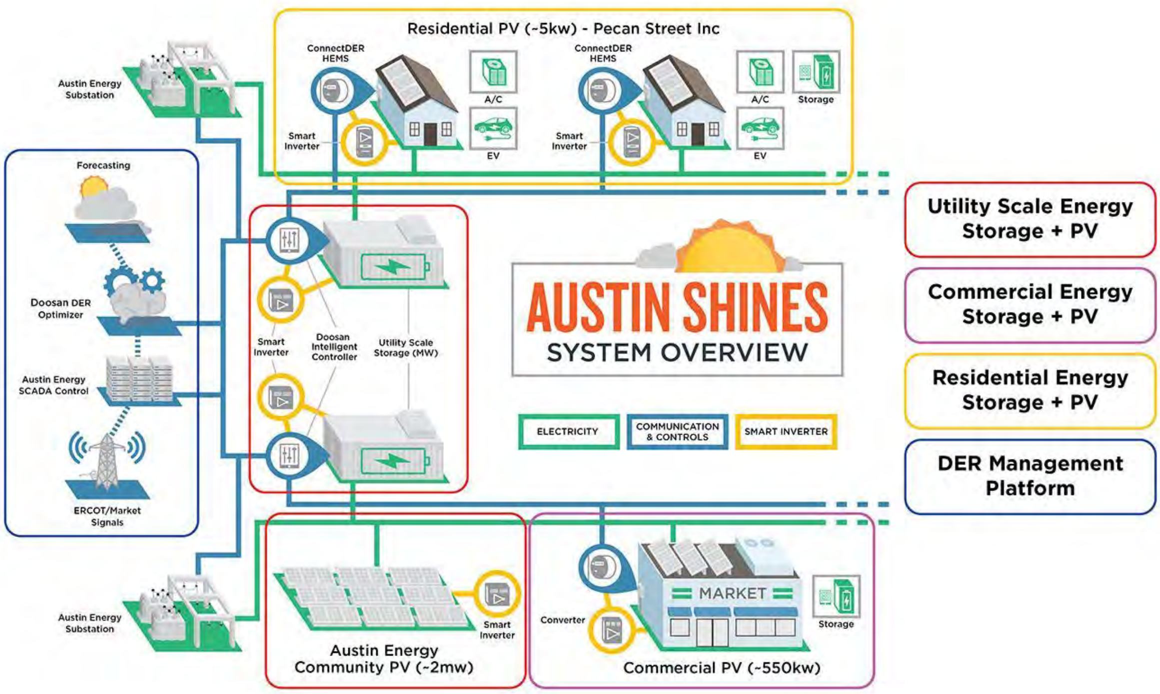
[60] https://www.energy-storage.news/news/indias-first-grid-scale-storage-project-10mw-li-ion-system-will-pave-way-fo

Interstate Transmission System (ISTS).[61] This extra storage will primarily be used to integrate renewable energy with ancillary services, micro grids, telecommunications, and railways.

Firming up renewable energy with storage is also having growing market impact in the United States. Arizona's "Solar after Sunset" program[62], designed to provide energy "after the sun goes down", and Hawaii's "Renewable Dispatchable Generation" program[63] which rewards dispatchability, are two recent storage initiatives.

Battery storage can also be used to meet peak demand needs as seen in California where a two-unit gas peaking plant was recently replaced with a battery system.[64] Figure 8 illustrates the many battery storage uses and combinations highlighted in the U.S. Department of Energy's SHINES program as part of a modernization initiative to improve the resilience, reliability and security of the power grid.

FIGURE 9. POTENTIAL BATTERY STORAGE USES AND COMBINATIONS



Source: [Austin Energy, 2020]

Increase competition and include standard force majeure provisions to ensure risk sharing

Due to the drop in demand during the COVID-19 lockdown and the prolonged economic disruption, some power distributors are now being forced to pay for unused power as a

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61 http://ficci.in/spdocument/23144/FICCI_EY_Battery-Storage-paper.pdf
62 https://www.businesswire.com/news/home/20190221005255/en/APS-Customers-Solar-Sunset-Major-Clean-Energy-Projects
63 https://www.greentechmedia.com/articles/read/hawaii-shared-renewables-program-incentivize-dispatchable-peak-capacity
64 https://ieefa.org/wp-content/uploads/2019/06/Advances-in-Electricity-Storage-Suggest-Potential-Rapid-Disruption-of-U.S.-Electricity-Sector-1-1.pdf

result of contracts that obligate users to pay for generation capacity regardless of whether there is demand for the power.

The Philippines largest distribution utility Meralco sought to invoke force majeure clauses in its IPP contracts[65] in May 2020 to relieve it from payment obligations to a range of IPPs. In response, the Philippine Independent Power Producers Association (PIPPA) rejected efforts to invoke the force majeure clauses, stating that they would be unable to cover ongoing fuel and operational costs as well as bank loans if capacity payments were not maintained. Although the decision ultimately rests with the ERC, there is a case to be made for use of force majeure clauses to protect end-users from the inflexible standard clauses of PSAs.

Electric cooperatives which serve consumers on small islands or regionally isolated grids are also looking for ways to manage pressing fixed costs due to the impact of COVID-19. Some 59 electric cooperatives would like to invoke *force majeure* clauses to alleviate higher per kWh costs due to increased fixed charges resulting from the unexpected drop in demand. In contrast to Meralco, however, only two of the 59 cooperatives have been able to negotiate with their power suppliers to date. The electric cooperatives lack the size and thus negotiating power of a dominant grid operator like Meralco.

The asymmetry in market structure between large grids and local cooperatives results in unbalanced outcomes where remote communities with little ability to hedge costs are left fully exposed while urban and industrial consumers may be protected. Despite its regulatory oversight role, during Congressional sessions in May and June 2020, the ERC indicated it was unable to give a blanket advisory on *force majeures* because the implementation of the COVID-19 quarantine was different for each area.

However, in recognition of regulatory assistance required, the Senate Committee on Energy has prepared an upcoming competition bill (SB1653) to:

- improve options on force majeure clauses and protect the interests of end-users;
- ensure equitable risk sharing between end-users and power generators; and
- incentivize utilities and power generators to procure flexible and least cost generation.

Impose the mandatory removal of cost pass-throughs to end-users and carve-out (curtailment)

The standard PSA between a utility and an IPP stipulates that fuel costs are automatically passed through to consumers, and that they are subject to changes based on the prevailing coal price index. There is little evidence that realistic market forecasts are used as a cross-check on over-optimistic fuel cost assumptions that are often accepted at face value.

As a case in point, in the previous draft of Quezon Province's Atimonan power station's PSA, the fuel price using the Newcastle Index was set at USD 50.38 per metric ton, with a

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[65] *A force majeure clause relieves a party from performing its contractual obligations due to an unforeseeable event.*

freight price of USD 5.90 per metric ton and a forex rate of PHP 46.07 per USD. Such rates are gross under-estimations. Due to the drop in commodity prices, the prevailing Newcastle coal price is now USD 52.79 per metric ton.[66] This is the lowest rate since June 2016, down 24% from a mid-January 2020 peak of USD 69.59 per metric ton. The exchange rate was last at PHP 46.07 per USD in June 2016. Depreciation since then means it is now more expensive to buy imported fossil fuels than ever before.

An example of the negative effect of automatic fuel pass-through can be illustrated in Panay Energy Development Corporation (PEDC)'s 167.4MW coal plant in Panay, which was expected to deliver power at PHP3.96 (USD0.08) per kWh based on a 2016 PPA price. Instead, on average, power from PEDC has cost PHP2 per kWh more than the agreed price, sometimes reaching PHP7.11 per kWh. This variance in price was permitted under market rules via the "pass-through provision" which allows fluctuations in fuel price and FX rates to be passed onto consumers and industry. As a result, from May 2018 to May 2019, the variability of coal prices led to consumers paying over PHP 788.7 million (equivalent to USD15 million) more than what was originally estimated.

PPAs based on guaranteed capacity payments give priority to the interests of funders and ignore the realities of vulnerable emerging markets. The net effect is that capacity fees ensure that in the event of low utilization, end-users are punished in order to insulate IPPs from market risk. This means that neither the financial sector nor IPP developers or grid operators are liable for the risk they take, as these costs are passed on to end-users who are ill- equipped to manage such risk.

To protect end-users from high prices in periods of volatile and low demand, a curtailment clause should be implemented to encourage proactive management of financial obligations to generators during exceptional circumstances. For example, Meralco has taken steps to improve procurement practices by requesting a fixed price which removes automatic fuel pass-through, and by also including a curtailment clause (known locally as a carve-out provision) to protect end-users from paying for unused power.

The ERC should take the lead in shaping new market rules to enable more transparency and competition as well as protecting end-users. It would be prudent for the ERC to implement mandatory fixed prices for PPAs by removing the automatic pass-through while including a mandatory carve-out provision for uncompetitive power.

Improve tariff setting

ERC's tariff-setting methodology should be redesigned to provide cost-efficient market-based incentives for least-cost power options. The ERC's reliance on outdated regulatory incentives has meant that power tariffs are still based on a fixed set of financial assumptions that are no longer relevant to more dynamic competitive power market norms. As they stand, fixed PPA tariffs do not take into account fuel fluctuations nor the entry of new or cheaper technology.

ERC's current rate structure includes capacity charges (capital recovery, and fixed operating and maintenance charges, subject to exchange rate and inflation risks) and

[66] https://www.reuters.com/article/column-russell-coal-asia/column-seaborne-thermal-coal-prices-slide-as-india-takes-coronavirus-hit-russell-idUSL3N2CG1DL

variable operating and maintenance costs (mainly fossil fuel). The capital cost is amortized at a fixed rate over the term of the contract, regardless of energy delivered. If there is a reduction in plant utilization due to lower demand from retail competition or an economic downturn, the average rate to the ratepayer increases.

Tariffs should be reformed so that ratepayers do not pay more as a result of forecasting errors by grid operators or policy planners. Currently, the utilities are not incentivized to hedge against USD inflation or exchange rate volatility. Fuel price change risk arises from international pricing, subject to market swings and price manipulation at the Organization of the Petroleum Exporting Countries (OPEC). Because the ERC only vets initial day-one fuel costs, fluctuations are unfairly passed onto ratepayers.

The ERC's thermal power PPA rules also create market distortions that discourage competition from renewable energy providers that must offer firm levelized costs. While renewable energy tariff structures are based on a fixed price adjusted for inflation, the ERC approves tariffs based on cash adequacy for operating and maintenance costs, with an arbitrary cap on capital expenditures. The ERC does not vet tariffs to include additional costs resulting from fuel price changes or exchange rate changes.

Going forward, the ERC should institute fair vetting across technologies to protect end-users from volatility. Moreover, part of ERC's process should also include running modernized software that take into consideration renewable energy and storage to improve power supply planning and power system design optimization.

Implement a moratorium on new inflexible power

At a meeting of the Committee on Energy in the Philippine House of Representatives on 13 May 2020, the DOE announced it was reviewing options for a moratorium on inflexible plants. While the DOE no longer provides a supply mix, it previously targeted an energy mix of 70% "baseload" capacity, 20% "mid-merit" capacity, and 10% "peaking" capacity.[67] According to the DOE, 80% of the country's baseload capacity is inflexible as the regulatory design incentivizes baseload.[68] A parallel point is mentioned in a 2019 World Bank report[69] which notes a lack of investment in mid-merit and peaking power plants.

The lack of balance in the generation mix is coming at a high cost. Depressed demand requires more use of mid-merit plants. During the pandemic lockdown, there was more use of flexible power and a drop in inflexible coal utilization from 70.3% to 52%.[70] In current demand conditions, coal plants have mid-merit plant load factors which are lower than baseload plant load factors leading to an increased cost per kilowatt hour (kWh) for end-users, as stipulated in the PPAs.

The PPAs for inflexible power compound an error in market design that favors baseload over flexible generation. As such, DOE is on the right track in studying a medium-term moratorium on new inflexible power with the long-term mandatory closure of inflexible

[67]https://ieefa.org/wp-content/uploads/2020/06/Philippines-Power-Sector-Can-Reach-Resilience-by-2021_June-2020.pdf
[68] *https://mb.com.ph/2019/12/10/doe-wants-entry-of-non-flexible-baseload-plants-moved-to-2029/*
[69] *https://www.esmap.org/power_market_experience_philippines*
[70] *Independent Electricity Market Operator of the Philippines (IEMOP), Market Operations Presentation, Joint Congressional Energy Commission, May 22, 2020.*

plants over 25 years old and which have already recovered capital costs. While not affecting credit profiles, it would create an opportunity for inflexible plants to invest in new technology to enhance flexibility, assuming they remain cost-competitive against deflationary renewable energy and storage. Part of future assessment could include a technical and economic audit to determine whether the inflexible plant should be retrofitted if cost-effective or closed if economically stranded.

In October 2020, the DOE called for a moratorium on greenfield coal power plants. The DOE decision marks a clear break with past policies and comes as the Philippines prioritizes the need for more flexible and lower cost alternatives to thermal power baseload.[71] By modernizing the power system and pivoting away from over-reliance on baseload coal, there will be a meaningful market opportunity for those companies that can master new technology options and deliver lower costs for consumers and industry, as well as domestic energy security through renewable energy. The coal moratorium reflects the importance that the DOE places on efforts to take stranded asset risk out of the system and save investors from unprofitable coal projects.

Increase clarity on who pays for stranded asset risk

Fossil fuel lock-in can translate to higher prices due to progressive uncompetitive fossil fuel asset risk, also known as stranded asset risk. This can happen for several reasons, including:

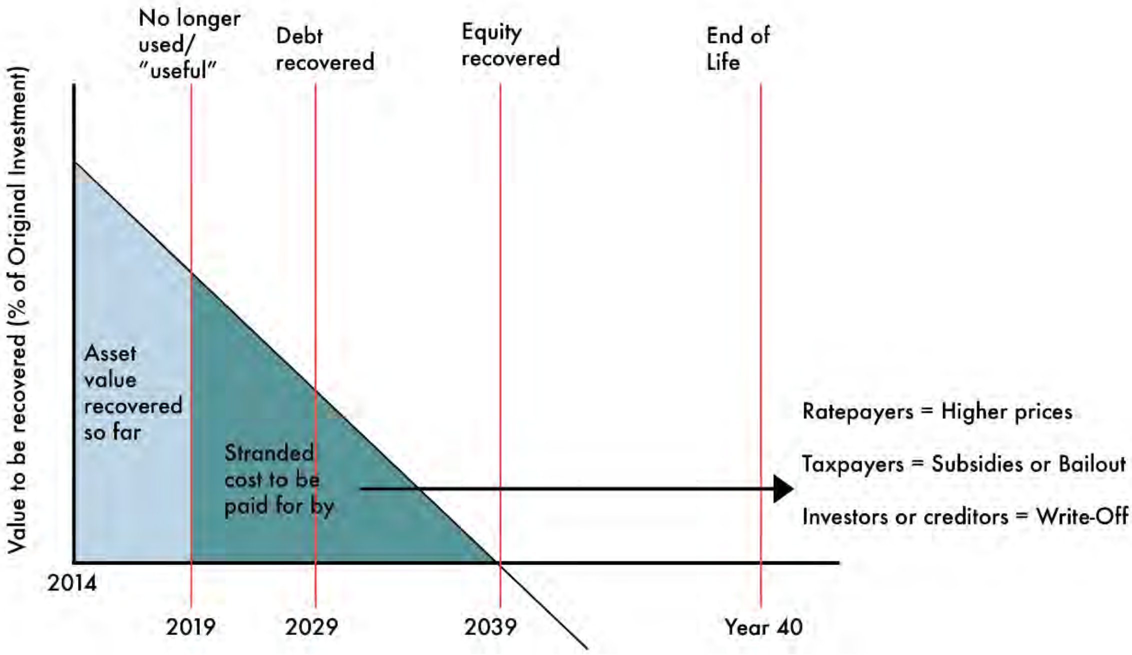
- fuel and/or technology becomes uneconomical or obsolete due to competition from cheaper alternatives;
- a power plant is badly located and the grid operator is no longer able to dispatch the facility economically;
- excess capacity due to inaccurate demand forecasts or a surplus of reserve power;
- higher than anticipated construction costs;
- operational inefficiencies in the power plant; and
- long-term contracted fuel supply exceeding demand.

Legacy plant operators and investors often claim that energy transition is triggering higher costs. Instead, as older facilities lose competitiveness, non-performing stranded assets are paid for by either end-users, investors or creditors. With the deflationary nature of renewable energy and storage costs, as well as the clamor for cheaper power, future non-performance and the stranding of assets will be a reality, resulting in a stranded asset cost burden for the same stakeholders (refer to Figure 2).

In any stranded asset scenario, the ERC must ensure such risks are not passed through to consumers and industry but are instead paid for by investors and creditors who are better equipped to manage technology risk. Section 33 of ERC's Electric Power Industry Reform Act of 2001 (EPIRA) provides a loose definition of stranded costs; however it needs to be refined so that captive end-users have recourse when such costs arise. For example, the ERC could stipulate that stranding arising from the reasons mentioned above cannot be passed onto consumers.

[71] https://ieefa.org/wp-content/uploads/2020/10/Philippines-Greenfield-Coal-Project-Moratorium-Will-Attract-Billions-in-RE-Investment_November-2020.pdf

FIGURE 10. PROSPECTIVE FOSSIL FUEL PLANT



Source: *Stanley Center for Peace and Security (2020)*

9 Bond disclosure

In light of the diverse financial impacts of energy transition, financial regulators can help minimise stranded asset risk by improving bond disclosure.

Commercial and investment banks globally have been accelerating their move away from exposure to fossil fuel power. This is common sense given the deteriorating economics of fossil fuel power and the fact that responsible managers have a fiduciary duty to factor-in known financial risks. The Philippines' financial regulators have already provided leadership in this sphere. The Securities and Exchange Commission has imposed mandatory Environmental, Social, and Corporate Governance (ESG) reporting for publicly-listed companies while Bangko Sentral Ng Pilipinas' has approved the Sustainable Finance Framework to safeguard the financial system from the evolving material hazards of transition risk, including non-performing stranded asset risk.

Banks and other financial institutions now have the impetus to start pricing in not only transition risk, but also the price stability and financials of low-carbon ventures. The next step is to protect retail investors via appropriate bond disclosures that take into consideration the changed risk-profile of fossil fuel investments. To put the question of how Philippine bond issuers are framing transition risk, we have reviewed a recent domestic bond prospectus with a focus on pandemic risk, regulatory risk and project risk. We found that, by and large, the risk disclosures are neither up to date nor adequate for retail investors.

9.1 Pandemic risk

Box 2 highlights a company's disclosure on pandemic risk. While the pandemic is a relevant and important market condition, this disclosure language fails to provide specifics or even a view on the financial impact of COVID-19 on a company beyond the quarantine (due to the prolonged economic disruption).

Further, while the company has outlined a non-specific "challenge" to cash flows and a directive that has "eased" impacts, it does not clarify the situation on take-or-pay or payables. The company also does not provide evidence of how it will support the "organization".

Considering these disclosure deficits, it may be difficult for institutional investors, let alone retail investors, to understand how to model pandemic risk, using the example provided.

BOX 2. PANDEMIC RISK

The curtailed economic activity brought about by the quarantine measures has resulted in significant drops in electricity demand and consumption which, in turn, have affected the revenue targets of Distribution Companies, Generation Companies, and RES Business Units. Nevertheless, the Company has been in constant discussions, and has been working together with its customers and other key stakeholders to minimize the impact of the pandemic to the respective parties' power supply agreements.

The Company has also been compliant with the DOE circulars on distribution utilities granting extensions on the payments of electricity consumers for bills falling due during the community quarantine period with the cumulative amount of such electricity bills being amortized in four (4) equal instalments payable in the four (4) succeeding billing months following the end of the quarantine. This increased credit and collection risk has posed a challenge to the Company's cash flows.

Such circulars also provide that all private and public corporations in the power sector shall be given a similar grace period for their respective obligations without interest, penalties, fees and charges, as well as the same four (4)- month amortized payment arrangement for all unpaid balances on obligations within the same period. This directive has eased the impact and helped manage the cash flows of Company X Subsidiaries, with respect to all payments due to NGCP, PSALM, IEMOP, independent power producers, and suppliers of oil and steam.

The Company has also been making sure that the fuel supply chain for its plants continues to remain stable, and that the supply of coal, critical spare parts, and services from outside the country continues through a number of options, including alternative local suppliers and service providers.

In order to improve pandemic risk disclosure, we recommend the company to include language around the following two items:

- Estimate the financial impact of COVID-19 on the company beyond quarantine and disclose the financial impact of a prolonged economic disruption with evidence on how the company intends to "support" the "organization".

During the COVID-19 lockdown, the Philippines' GDP contracted by 16.5% in the second quarter, and was the worst performing economy in Southeast Asia, while its manufacturing sector posted one of the largest drops relative to the rest of the region. The DOE noted electricity demand fell by 30% in Luzon, 17% in the Visayas, and 25% in Mindanao, with serious financial implications for generation companies. Meralco confirmed that should it decide to buy less power, as seen in its 30% power purchase cut during the COVID-19 lockdown, coal generators would have to sell their electricity elsewhere. Considering that the response of utility companies like Meralco has financial implications, the company must articulate how it intends to support the organization to manage the financial disruption.

- Clarify the parameters of take-or-pay agreements to determine whether force majeure clauses can protect consumers and utilities from inflexible standard clauses.

Utilities are reducing their financial exposure to falling demand decline by seeking to invoke force majeure clauses in contracts. For example, seven independent power producers (IPPs) owned by Ayala, San Miguel, and Aboitiz Power Company - the three major conglomerates in the Philippines power sector, had force majeure closes invoked during the COVID lockdown, translating into reduced collections. According to the Senate Energy Committee, without force majeure, the per kilowatt hour (kWh) rates in Luzon would have increased by 15% and 5% in the Visayas. Meralco confirms that force majeure relief saved its customers PHP1.02 billion (USD20.4 million) in total, including PHP 129 million (USD2.58 million) in fixed costs for April and PHP 877 million (USD17.54 million) in May.

We further recommend that a company include the risk of burden sharing as a new norm in the industry, while also including the size of their payables and fixed costs.

9.2 Regulatory Risk

The example of a company's disclosure on regulatory risk (detailed in Box 3) highlights changes and improvements in the regulatory environment since first filed in 2017. This data is out of date and therefore unsuitable for individual retail investors.

BOX 3. REGULATORY RISK

The electric power industry is characterized by a constantly evolving regulatory environment. Any shortcoming in regulatory compliance poses negative consequences in both the net income and reputation of each Business Unit and the Group.

To anticipate and proactively respond to changes in regulations, the Regulatory Affairs Team of Company X constantly collaborates with DOE and ERC to work towards a sound and sustainable regulatory and policy environment. Similarly, the Safety, Health, Environment and Security (SHES) Team keeps abreast with environmental laws and coordinates with DENR on matters pertaining to environmental compliance.

These teams, among others, actively participate in consultative processes and public consultations to provide feedback and positions on proposed laws and regulations. The Company's participation likewise ensures that its interpretation of such laws and regulations is aligned with the regulators. This is done in cooperation with organized industry groups such as the Philippine Independent Power Producers Association (PIPPA) and Philippine Electric Plant Owners Association (PEPOA). Regular dialogues are conducted with host communities, media, non-government organizations, and the academe, to educate and update various groups about the power industry.

Company X has likewise transitioned its Legal Team to strategically focus on compliance and to continually improve the Group's overall compliance process. The Company is institutionalizing a compliance framework across the different business and corporate support units, and is formalizing compliance reporting requirements among the Group's compliance officers. Company X has also implemented the Company X Unified Compliance Management System, a Company X-wide initiative that is based on the Governance, Risk and Compliance framework.

Since 2017, legal challenges have validated the Philippines government's intention to spur competition via transparent bidding to reduce electricity prices for consumers and industry. As a result of a challenge in 2017 by consumer group Alyansa Para Sa Bagong Pilipinas (ABP) to the Energy Regulatory Commission (ERC) which focused on transparency and competitiveness in power purchase agreement (PPA) signing processes, more retail competition is envisaged and grid operators may be barred from passing on fuel price and foreign exchange risk. On 6 May 2019, the Supreme Court of the Philippines ruled in favor of the consumer group, effectively voiding all PPAs submitted after 7 November 2015.

Below is an overview of the consumer group versus the ERC that affected the underlying asset in its bond prospectus for 2 x 668 megawatts (MW) of coal capacity.

TABLE 6. LEGAL CHALLENGES FACED BY THE COAL PLANT ASSET IN THE BOND PROSPECTUS

CASE NO	EC	YEARS	CONTRACTED CAPACITY (MW)	ABP VS ERC
2016-031	TARELCO II	20	19-38	
2016-036	PENELCO	15	25-95	
2016-037	NEECO I	20	26-43	
2016-039	AURELCO	20	0-5	
2016-046	LEYECO II	20	8	Yes
2016-047	SAMELCO II	20	15	Yes
2016-048	BILECO	20	10	Yes
2016-049	NORSAMELCO	20	16	Yes
2016-050	SAMELCO I	20	12	Yes
2016-051	DORELCO	20	12	Yes
2016-053	LEYECO III	20	3	Yes
2016-054	SOLECO	20	12	Yes
2016-055	LEYECO IV	20	16	Yes
2016-056	LEULCO	20	5	Yes
2016-057	LEYECO V	20	31	Yes
2016-058	ESAMELCO	20	15	Yes
2016-059	BATELEC II	15	20	Yes
2016-060	BOHECO II	5	12	Yes
2016-061	BOHECO I	5	12	Yes
2016-072	TEI	20	5	Yes

2017-044	QUEZELCO II	7	5	
2017-048	QUEZELCO I	7	27	
2017-065	BATELEC I	9	30-50	
2018-061	PELCO III	20	8-18	
2018-062	ZAMECO II	20	5-29	
2018-063	PRESCO	20	1-6	
2018-064	ZAMECO I	14	5-23	

The company fails to take into consideration the modernization of the wholesale spot market which removes the automatic nomination of a minimum stable load in front of the dispatch supply order. This means that coal plants are no longer guaranteed to have a buyer if they are unable to compete. The economics of coal will deteriorate because even biomass plants without feed-in-tariffs (FiTs) and incoming offshore wind will be dispatched ahead of coal. As such, when the market reorients, the company should disclose its view on how it will protect its assets from stranding.

While feedback rounds with power sector stakeholders are helpful, in the case of risk disclosure, companies shouldn't "collaborate" but rather should be compliant. Compliance is binary, which means you are compliant, or you are not. In the example provided, the company mentions that it is keeping a watch on environmental laws; this has no place in risk disclosure. The company must include the implications of the Clean Air Act and the Clean Water Act and whether the company is or will be fully compliant upon implementation. If the company is unable to verify compliance, it should disclose accordingly. Read holistically, the regulatory risk section implies the company has poor or zero internal controls, which could mean they are building generation plants and hoping it will work out.

In order to improve regulatory risk disclosure, it is recommended that the company include the implications of the following:

- Updates on the regulatory environment since 2017 including clarity on competition and transparency;
- Implications of retail competition and open access to the company's generation business revenue prospects;
- Overview of the off-taker's credit profile including the likelihood of a power purchase agreement;

- Implications of the removal of automatic pass-through in terms of how the company will manage fuel and foreign exchange fluctuations and its implications on net income[72];
- Implications of the curtailment clause in terms of whether the company can prove the generation asset can be competitive in the wholesale market or whether it can sell to others through bilateral agreements;
- Implications of a modernizing wholesale spot market in terms of the removal of guaranteed dispatch which means the company must prove the generation asset can be competitive and can be technically operational at lower utilization rates;
- Calculations and disclosures of the company cost of being compliant with the Clean Air Act and Clean Water Act and whether that will affect profitability, and how the company intends to monitor compliance; and
- Transparency in how the company intends to use internal controls to manage growing regulatory risk for fossil fuel assets.

9.3 Project Risk

The company's disclosure on project risk (detailed in Box 4) fails to include language on the energy transition, which is a material project risk as seen in the "Regulatory Risk" section. The company fails to mention the impacts of reduced utilization of energy assets and the potential curtailment on profitability.

Since project insurance coverage is mentioned, the company should clarify whether there is actual insurance for a coal project, even while it seeks to match with a transitional energy system that is increasingly pushing for cost-competitiveness.

The company shows that it anticipates delays in grid access but continues to reflect this as hypothetical. Considering this is a persistent and well-established issue, the company should not frame this risk as hypothetical. Rather, the company should include an historical analysis, including well-known recent cases, on the frequency of material delays in grid access due to inadequate transmission capacity, as well as information regarding what the company intends to do about this risk and if there is realistic access to risk mitigation tools.

[72] *In 2019, Meralco took steps to improve procurement practices by requesting a fixed price (which removed automatic fuel pass-through) and by including a curtailment clause, known locally as a carve-out provision. The removal of automatic pass-through means that generation companies (like the one in this bond prospectus) need to manage fuel and foreign exchange fluctuations. Moreover, the curtailment clause helps protect end-users from paying for unused power, also known as stranded asset risk. Meralco's curtailment clause can be triggered due to competition from cheaper options. When curtailed, generation companies can either sell in the spot market or through other bilateral contracts, assuming they can compete with more modern technology.*

BOX 4. PROJECT RISK

As Company X continues to grow its generation portfolio, the Company has identified project risks as a top risk. This risk is largely driven by delays in commercial operations, as well as late completion and delivery of the transmission lines that will enable full dispatch of the plants in the pipeline.

Project risk management plans are thoroughly defined and regularly reviewed for each project to track issues related to quality, safety, compliance, schedule, and resources. This ensures that identified risk control measures and recovery actions are implemented. Appropriate project insurance coverage, as well as periodic performance reviews of selected partners, reputable contractors and third-party suppliers, are also in place in the Company's projects.

To further mitigate project risks, delivery of transmission lines is closely coordinated with NGCP. Operational readiness reviews are performed to ensure that new generating units are ready for commercial operations prior to going on-line. Project post-mortem reviews are also conducted to determine key learnings that can be applied to ongoing and future projects in the pipeline.

To address challenges in land procurement, conversion, permitting, right-of-way, and other land-related issues, constant collaboration with partners, contractors, regulatory agencies, host communities, and other key stakeholders is undertaken in alignment with project execution timelines.

In order to improve project risk disclosure, it is recommended that the company include the following:

- Transparency on the impacts on profitability due to reduced utilization and curtailment potential;
- Analysis of grid access, risk mitigation and impacts on profitability; and
- Overview of realistic risk mitigation tools and the cost-effectiveness of such tools.

Considering the weaknesses of the company disclosures we have reviewed, it is unlikely that individual retail investors will be able to adequately understand the risks involved in fossil fuel projects.

We recommend that financial regulators request improved company disclosures to protect individual retail investors. Further, investors and bankers must consider whether directors should be held personally liable if they have breached their fiduciary duty to act in shareholders' best interests by ignoring fossil fuel risks.

Conclusion

The objective of this report is to analyse energy transition risk for power generation in the Philippines. This report is funded by the UK government and is the result of a stakeholder engagement process with investors and policymakers in the Philippines power sector. Although Southeast Asia is seen as the last growth market for fossil fuel power, deteriorating economics is likely to undermine demand for coal and gas in the region in the future.

We reviewed several LCM to better understand transition risk of power generation in the Philippines. This review coupled with CPA found that while the Filipino government has made good progress to take advantage of these deflationary cost trends, additional efforts are needed to realise a least-cost electricity system. Of note is the preponderance of long-term bilateral contracts for conventional thermal generators, which could cause a "missing money" problem for merchant generators without further interventions from policymakers.

To avoid stranded assets and ensure least-cost energy, we recommend the following policy interventions: 1) fast-track auctions to ensure new capacity decisions are cost-competitive and complementary to grid flexibility; 2) impose the mandatory removal of cost pass-throughs to end-users; 3) improve tariff setting to ensure least-cost and flexibility generation; 4) build on the current moratorium by implementing a permanent moratorium on new inflexible power; and 5) increase clarity on who pays for stranded asset risk.

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