Carbon Tracker Initiative

Economic and financial risks of coal power in Indonesia

Briefing

October, 2018

Table of Contents

1 Summary

By 2021 it will be cheaper to invest in new solar PV than new coal. This represents the first inflection point when new investments in coal capacity become economically uncompetitive relative to new investments in renewable energy. These changing cost dynamics call into question the 30 GW or $50 bn of planned coal investments and the long-term role of the existing fleet to deliver an economic return to investors.

It will be cheaper to build new solar PV than to run existing coal plants by 2028, calling into question the economic viability of the operating fleet thereafter. The second inflection point highlights the risk when new investments in renewables outcompete existing coal plants. The levelised cost of solar PV has more than halved in Indonesia since 2014, which will have a dramatic impact on the competitiveness of coal power over the next decade. Based on prevailing fuel costs of around $100/t, it could be cheaper to build new solar PV than operate existing coal plants by 2028. Under the government's $70/t price cap, we see this inflection point in 2030.

Existing market structure favours coal at the expense of consumer. Perusahaan Listrik Negara (PLN), the state-owned utility, uses capacity payments to incentivise private investment in new coal power capacity. The pass-through of fuel costs in coal power contracts exposes PLN to a higher risk of stranding from future tightening of climate and environmental regulations. If PLN remains committed to coal, this dynamic could result in consumers paying significantly more for electricity.

In a scenario where coal is phased-out consistent with the Paris Agreement, Indonesian coal power owners risk losing $34.7 bn of mostly operating capacity. We have developed a cost-optimised asset-level methodology and scenario analysis which phases out coal power in a manner consistent with the temperature goal in the Paris Agreement. In such a scenario, Indonesian coal power owners are borne with $34.7 bn of stranded value stemming from the premature retiring of coal capacity. PLN Persero, Sumitomo Corporation and Sinar Mas Group are at most risk due to increasing unviability of coal, with stranding asset values of $15 bn, $3 bn and $2.1 bn, respectively. This financial risk is material, representing 56% of Sinar Mas Group's total capital and 17% for PLN and 8% for PT Semen Indonesia. This scenario, however, does not take into consideration existing PPA agreements and any changes to future market dynamics of the Indonesian power market.

2 Background

Indonesia is the largest energy consumer among ASEAN countries, responsible for more than 35% of the region's total energy demand in 2016.[1] The country's unique geography as an archipelago state of over 17,000 islands poses severe challenges for delivering electricity to everyone.[2] The electricity distribution is uneven across regions,[3] with industrialised areas such as Java-Bali accounting for more than 70% of power demand.[4] Indonesia plans to achieve near 100% electrification by 2024 according to the 2017-2026 PLN Electricity Supply Business Plan (2017 RUPTL), up from 91.1% in 2016.[5]

Indonesia is also the world's fourth-largest producer of coal and a top coal exporter.[6] Coal accounted for 58% of entire power generation in 2017.[7] Coal generation increased by 53% from 2010 to 2017, reaching 146.7 TWh in 2017. Installed coal capacity was 49% of total generation in 2017, while wind and solar was collectively 0.2%. The government initially set an ambitious target of 24.6 GW of new coal capacity by 2026;[8] however it was revised down to 20.8GW in the 2018-2027 Electricity Power Supply Plan (2018 RUPTL) due to sluggish energy demand.[9]

State-owned Perusahan Listrik Negara (PLN) controls the majority of power generation and has a regulated monopoly on transmission and distribution (see Figure 1). In 1985, the power market structure moved away from a vertically integrated monopoly to a single-buyer model.[10] The Electricity Law No. 30 of 2009 introduced a more significant role for the private players in power generation. [11] PLN controlled 78% of generation capacity in 2008,[12] and by 2022 it is expected to deliver 41% of generation, transmission, and distribution capacity.[13] Indonesia Power and PT Pembangkitan Jawa-Bali are the most significant two subsidiaries of PLN, accounting for 22% of coal generation assets.

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[1] *IEA, (2017). Southeast Energy Outlook, p.19. Available: https://www.iea.org/publications/freepublications/publication/WEO2017SpecialReport_SoutheastAsiaEnergyOutlook.pdf*

[2] *Asian Development Bank (ADB), 2016. Achieving Universal Electricity Access in Indonesia. Available: https://www.adb.org/sites/default/files/publication/182314/achieving-electricity-access-ino.pdf*

[3] *There are more than 600 local grids and 8 large networks in Indonesia. Larger grids located in western islands such as Java-Bali and Sumatra are reliant on coal power generation, whereas smaller eastern islands are powered mainly by diesel and have lower electrification rates (47.8% in 2016). See PWC, (2017). Power in Indonesia: Investment and Taxation Guide. Available: https://www.pwc.com/id/en/energy-utilities-mining/assets/power/power-guide-2017.pdf*

[4] *IRENA, (2017). Renewable Energy Prospects: Indonesia. Available: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Mar/IRENA_REmap_Indonesia_summary_2017.pdf?la=en&hash=F530E18BAFC979C8F1A0254AFA77C9EBC9A0EC44*

[5] *PWC, (2017). Power in Indonesia: Investment and Taxation Guide. Available: https://www.pwc.com/id/en/energy-utilities-mining/assets/power/power-guide-2017.pdf*

[6] *IEA, (2018). Indonesia. Available: https://www.iea.org/countries/indonesia/*

[7] *BNEF, (2018). New Energy Outlook 2018. Unavailable without subscription.*

[8] *Policymakers target the majority of coal expansion in the western islands. Micro-grid or off-grid renewables are seen an attractive option in eastern islands with lower electrification rates. See NREL, (2015). Sustainable Energy in Remote Indonesian Grids: Accelerating Project Development. Available: https://www.nrel.gov/docs/fy15osti/64018.pdf*

[9] *PWC, (2018). Alternating Currents: Indonesian Power Industry Survey 2018. Available:https://www.pwc.com/id/en/publications/assets/eumpublications/utilities/power-survey-2018.pdf*

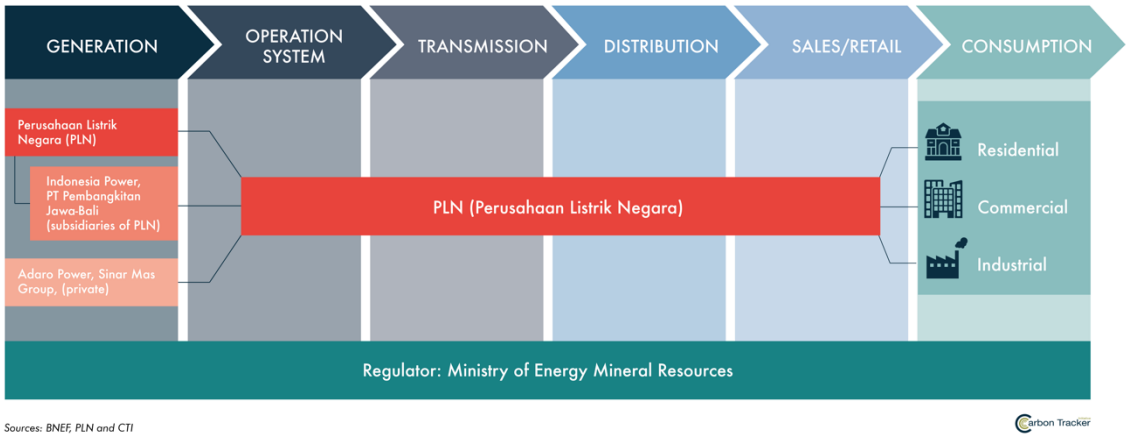
[10] *Setyawan, (2014). Assessing the Current Indonesia's Electricity Market Arrangements and The Opportunities to Reform. Available: https://ejournal.undip.ac.id/index.php/ijred/article/view/6145/pdf*

[11] *IEA, (2009). Electricity Law (No.30/2009). Available: https://www.iea.org/policiesandmeasures/pams/indonesia/name-140166-en.php*

[12] *World Bank, (2013). Power Market Structure. Available: http://documents.worldbank.org/curated/en/795791468314701057/pdf/761790PUB0EPI00LIC00pubdate03014013.pdf*

[13] *IEA, (2015). Indonesia 2015. Available: https://www.iea.org/publications/freepublications/publication/Indonesia_IDR.pdf*

FIGURE 1 – INDONESIA POWER MARKET DESIGN



Indonesia's electricity demand is predicted to increase by 80% by 2030 in a business-as-usual case.[14] The government set a target of achieving 23% of energy supply from renewables by 2025 and 31% by 2050 in the 2014 National Energy Policy.[15] This target entails increasing the share of renewable energy to 17% of total energy consumption by 2030 under the IRENA's Reference Case[16], up from 9% in 2017.[17]

In 2013, the Indonesian government initiated a solar auction program at a ceiling price of $0.25/kWh, which the Supreme Court ruled was unconstitutional.[18] Instead, the Feed-in Tariff (FIT) for solar ($0.145-0.25/kWh) was introduced in 2016, with a target capacity of 250 MW of utility solar.[19] However, the FIT legislation for renewables was insufficient to recover PLN's additional costs.[20] In 2017, the Ministry of Energy and Mineral Resources (MEMR) released new rules to address this issue, capping the renewable power purchase price at 85% of the region's generation cost if the tariff is higher than the national average.[21]

[14] *IRENA, (2017). Renewable Energy Prospects: Indonesia. Available: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Mar/IRENA_REmap_Indonesia_summary_2017.pdf?la=en&hash=F530E18BAFC979C8F1A0254AFA77C9EBC9A0EC44*

[15] *Ministry of Energy and Mineral Resources (MEMR), (2014). The General Plan for National Electricity 2015-2034. Available: http://www.djk.esdm.go.id/pdf/Draft%20RUKN/Draft%20RUKN%202015%20-%202034.pdf*

[16] *IRENA, (2017). Renewable Energy Prospects: Indonesia. Available: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Mar/IRENA_REmap_Indonesia_report_2017.pdf*

[17] *BNEF, (2018). Indonesia Capacity. Unavailable without subscription.*

[18] *Climatescope, (2017). Indonesia Solar Auction Programme. Available: http://global-climatescope.org/en/policies/#/policy/3668*

[19] *IEA, (2016). Solar Feed-In Tariff of Indonesia. Available: https://www.iea.org/policiesandmeasures/pams/indonesia/name-162230-en.php*

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[21] *MEMR, (2017). Regulation No 12 and No 50. Available: http://jdih.esdm.go.id/peraturan/Permen%20ESDM%20Nomor%2012%20Tahun%202017.pdf http://jdih.esdm.go.id/peraturan/PerMen%20ESDM%20NO.%2050%20TAHUN%202017.pdf*

3 Current situation

PLN uses capacity payments to incentivise private investment in new coal power capacity. According to the 2018-2027 RUPTL, a total of 26.8 GW of coal generation capacity will be granted to IPPs by 2027, and 37% of total capacity will be from coal-fired plants.[22] PLN has reduced the amount of planned coal capacity by 18% from 2017 to 2018, due to lower than expected energy demand.[23] Their overestimation for future electricity demand could lead to investment in underutilised coal capacity. A study by IEEFA shows the RUPTL 2017 plan could oblige PLN to pay $16.2 billion for idle capacity (5.1 GW).[24]

We modelled the operating cost[25] and gross profitability of each coal unit in Indonesia and found that all existing coal capacity is currently cash flow positive. The pass-through of fuel costs in thermal power contracts exposes PLN to a higher risk of stranding.[26] While the cost of coal is on the rise, the levelised cost of electricity from renewable energy is going down significantly. The cost of solar PV and onshore wind fell by 102% and 26% since mid-2014, respectively, while the operating cost of coal-fired plants increased by 27% due to an increase in fuel prices.[27] The cost of coal already increased in 16 out of 21 provinces from 2015 to 2016, IEEFA finds.[28]

[22] *MEMR, (2018). Executive Summary: RUPTL PT PLN (PERSERO) 2018-2027. Available: http://www.djk.esdm.go.id/pdf/RUPTL/180322--Executive%20Summary%20RUPTL%20PLN%202018-2027-1.pdf*

[23] *PWC, (2018). Alternating Currents: Indonesian Power Industry Survey 2018. Available: https://www.pwc.com/id/en/publications/assets/eumpublications/utilities/power-survey-2018.pdf*

[24] *IEEFA, (2017). Overpaid and Underutilized: How Capacity Payments to Coal-Fired Power Plants Could Lock Indonesia into a High-Cost Electricity Future. Available: http://ieefa.org/wp-content/uploads/2017/08/Overpaid-and-Underutilized_How-Capacity-Payments-to-Coal-Fired-Power-Plants-Could-Lock-Indonesia-into-a-High-Cost-Electricity-Future-_August2017.pdf*

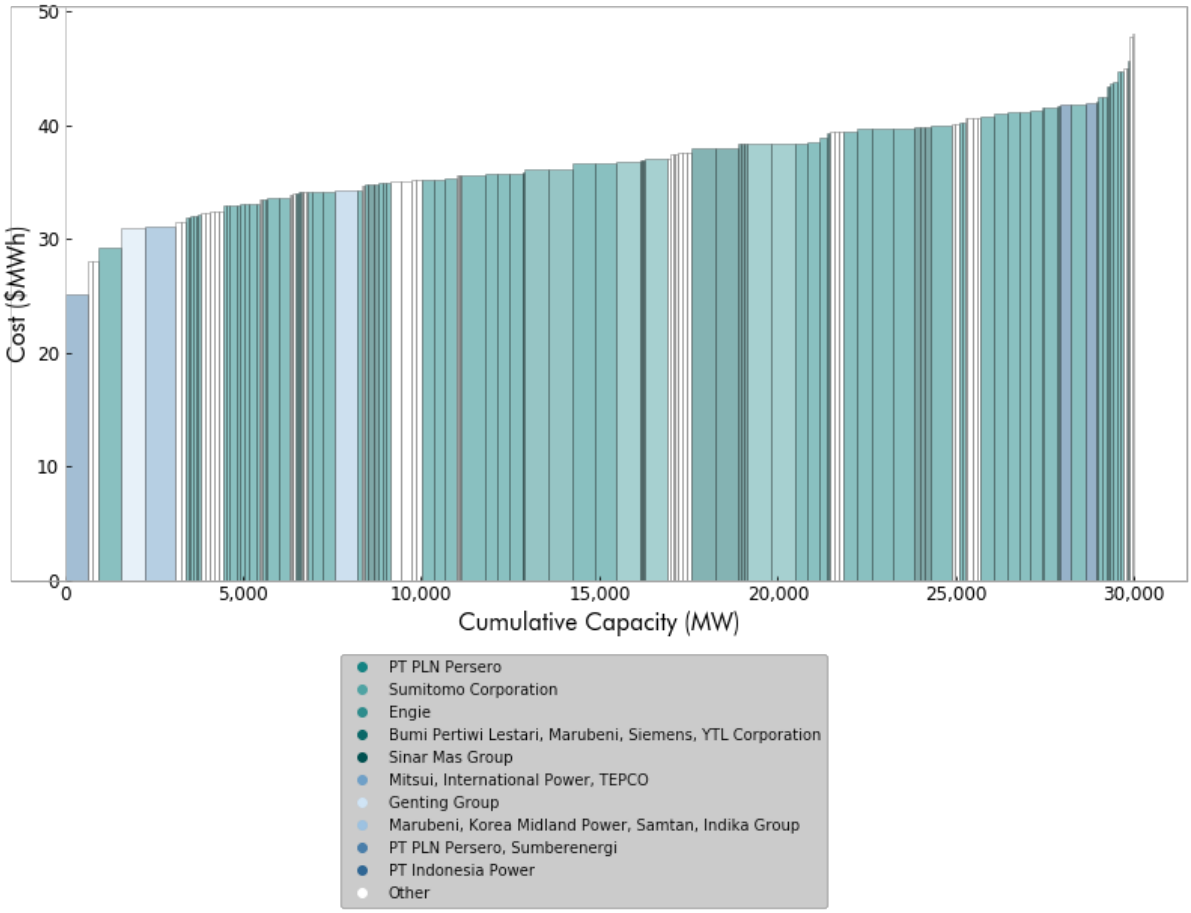
[25] *Unless otherwise stated, we define cost as long-run operating cost which includes fuel, variable O&M, fixed O&M, and capital additions from meeting regulation and maintaining unit performance.*

[26] *The coal tariffs paid to IPPs covers both fuel and variable O&M cost charges. This locks PLN to capacity payments for underutilised thermal power in the future. See IEEFA, (2017) cited above.*

[27] *BNEF, (2018). Levelised Cost of Electricity, Historic Range. Unavailable without subscription.*

[28] IEEFA, (2017).

FIGURE 2 - SHORT-RUN MARGINAL COST OF INDONESIA'S COAL FLEET IN 2018



Source: CTI analysis.

Notes: *The short-run marginal cost (SRMC), or cash cost, includes fuel and variable operating and maintenance costs.*

4 Future situation

There are two main inflection points that will make coal power economically uncompetitive: when new investments in renewables outcompete new investments in coal; and when new investments in renewables outcompete the operating costs of existing coal.

Indonesia has over 30 GW of coal capacity announced or planned to come online over the coming decade[29], which assumes the continuing cost-competitiveness of coal power. However, the deflationary nature of renewable energy costs will undermine the economics of new coal power in the near term. As shown in Figure 3, it could be cheaper to build new solar PV than to build new coal by 2021 in Indonesia. By 2028, we estimate that the second inflection point will be reached when new solar PV will be cheaper than operating existing coal-fired power.[30] This inflection point could be brought forward should pollutant emission limits for coal plants tighten in Indonesia[31], which will also require plants to incur additional costs from the installation of post-combustion control technologies.

At the time of writing, the prevailing Indonesian coal price was around $100/t (HBA thermal coal price index).[32] Earlier this year government officials capped the price of domestic coal for power stations at $70/t.[33] Bloomberg New Energy Finance (BNEF) predicts that utility-scale solar PV and onshore wind capacity will increase to 13.6 GW and 19.5 GW in 2040, respectively.[34] These changing cost dynamics call into question the $50bn of planned coal investments and the long-term role of the existing fleet.[35] See the Appendix for more information on our asset-level economic analysis.

[29] *CoalSwarm (2018), Global Coal Plant Tracker. Unavailable without subscription.*

[30] *Based on LCOE 1H 2018 estimates and capacity addition forecasts from BNEF, with learning rates of 21% for solar PV and 18% for wind.*

[31] *In our modelling we do not assume more stringent air pollution regulation in Indonesia for coal plants. For pollutant emission limits for existing and new plants see IEA, (2016). Energy and Air Pollution, p.47. Available: https://www.iea.org/publications/freepublications/publication/WorldEnergyOutlookSpecialReport2016EnergyandAirPollution.pdf*

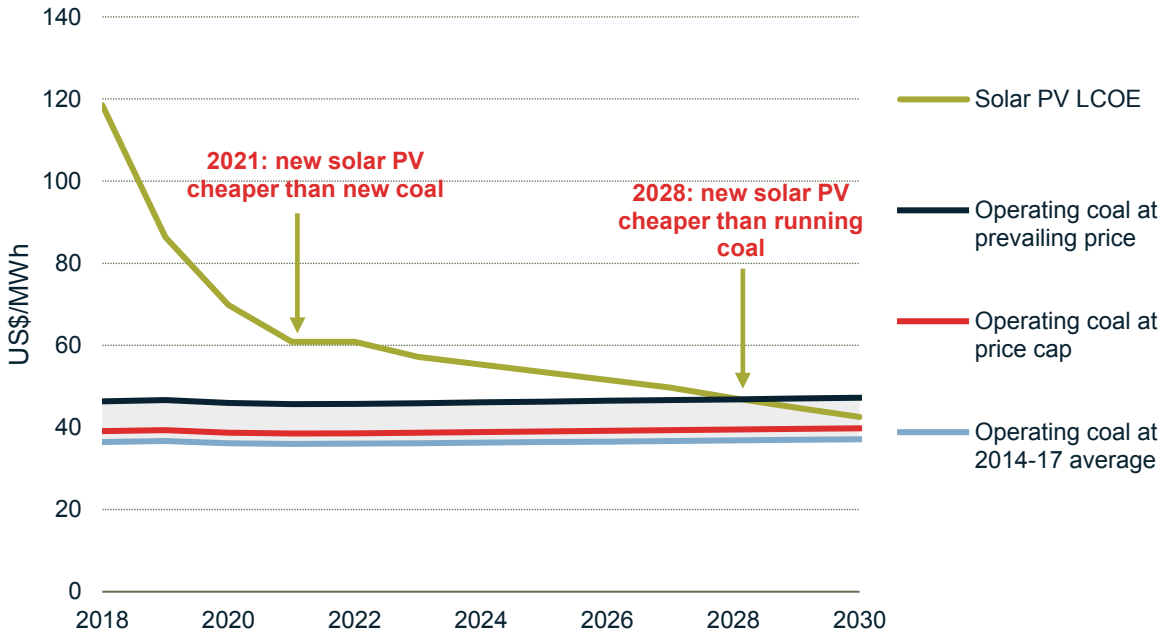
[32] *The HBA price for thermal coal is the basis for determining the prices of 77 Indonesian coal products and calculating the royalty producers have to pay for each metric ton of coal sold. It is based on 6,322 kcal/kg GAR coal with 8% total moisture content, 15% ash as received, and 0.8% sulphur as received. The HBA is a monthly average price based 25% each on Platts Kalimantan 5,900 kcal/kg GAR assessment, Argus-Indonesia Coal Index 1 (6,500 kcal/kg GAR); Newcastle Export Index (6,322 kcal/kg GAR) and global COAL Newcastle (6,000 kcal/kg NAR). Bloomberg LP, (2018). Terminal. Unavailable without subscription.*

[33] *Reuters, (2018). Indonesia caps domestic coal price for power stations, could hit miners. Available: https://www.reuters.com/article/us-indonesia-coal/indonesia-caps-domestic-coal-price-for-power-stations-could-hit-miners-idUSKCN1GL0F7*

[34] *BNEF, (2018). New Energy Outlook 2018. Unavailable without subscription.*

[35] *Based on planned and under-construction capacity. Assumed capital costs of $1,000/kW, $1,200/kW, $1,400/kW, $1,600/kW and $1,600/kW for subcritical, supercritical, ultra-super critical, IGCC and CFB, respectively.*

FIGURE 3 - THE COST OF NEW RENEWABLES VERSUS THE CAPACITY-WEIGHTED OPERATING COST OF COAL UNDER DIFFERENT FUEL PRICES



Source: BNEF, CTI analysis[36]

Notes: *Operating coal cost is capacity-weighted and based on long-run marginal cost, which includes fuel, variable O&M and fixed O&M. Coal is sourced domestically from the Kalimantan and Sumatra regions. The low range assumes $24/t for lignite, $38/t for sub-bituminous and $52/t for bituminous coal. The high range assumes $35/t for lignite, $55/t for sub-bituminous and $75/t for bituminous coal. Calorific values assumed at 3,713 kcal/kg, 4,897 kcal/kg and 5,316 kcal/kg respectively. New coal is based on LCOE estimates for Indonesia from BNEF, which assumes an average of coal-fired power over 2017-18 at $61/MWh*[37].

[36] *In some parts of Indonesia, rooftop solar is already grid competitive. The solar PV (utility, rooftop and off-grid) could make inroads sooner in off-grid cities and remote islands. See Centre for Science and Environment Assessment (2017), A Case for Solar Rooftop in Indonesia. Available: https://cdn.cseindia.org/userfiles/case-for-solar-rooftop-in-indonesia.pdf*

[37] *BNEF, (2018). Levelised Cost of Electricity (LCOE) by Country. Unavailable without subscription.*

5 Company ranking

Carbon Tracker has developed a Paris-compliance scenario analysis. This involved three steps: (i) identify the amount of capacity required to fill the generation requirement in the IEA's Beyond 2◦C Scenario (B2DS)33; (ii) rank the units based on long-run operating cost to develop a cost-optimised retirement schedule; and (iii) calculate the cash flow of every operating and under-construction unit in both the B2DS and business as usual (BAU) outcomes to understand stranded risk. More information on this methodology is provided in the Appendix. This does not consider the existing PPA arrangements in place.

In a scenario where Indonesia phases-out coal power in accordance with the Paris Agreement, coal power owners risk losing $34.7 bn. This asset stranding is due to the premature retirement of coal capacity. Our cost-optimised retirement schedules show an average plant lifetime of 16 years, which is 24 years less than the typical lifetime of a coal plant. PLN Persero, Sumitomo Corporation, and Sinar Mas Group are at most risk from a scenario that sees Indonesian coal power phased-out in a manner consistent with the temperature goal in the Paris Agreement, with stranding asset risk of $15 bn, $3 bn and $2.1 bn, respectively. Regardless of whether Indonesia phases-out its coal fleet in accordance with Paris, coal capacity overbuild, and the deflationary trajectory of renewables could result in asset stranding. This financial risk is material, representing 56% of Sinar Mas Group's total capital and 17% for PLN and 8% for PT Semen Indonesia.

TABLE 1 - ASSET-LEVEL ECONOMIC MODELLING AND CLIMATE SCENARIO ANALYSIS OF INDONESIA'S TOP TEN COAL OWNERS

COMPANY	CAPACITY (MW)	CAPACITY-WEIGHTED AVERAGE COST 2018 ($/MWH)	CAPACITY-WEIGHTED AVERAGE PROFITABILITY 2018 ($/MWH)	AVERAGE PLANT AGE AT RETIREMENT	STRANDED RISK ($/MN)	STRANDED RISK AS % OF TOTAL CAPITAL
PT PLN Persero	15,071	39.98	28.88	17	15,021	17%
Sumitomo Corporation	2,640	39.28	28.01	19	3,068	5%
Sinar Mas Group	1,216	40.79	35.10	16	2,127	56%
Engie	1,340	38.23	29.26	28	1,250	1%
Genting Group	670	33.67	33.52	13	536	3%
PT Indonesia Power	632	44.39	22.80	11	722	N/A
China Huadian	381	41.73	26.60	7	511	0.5%
Bosawa Corporation	250	37.40	30.92	16	354	N/A
PT Puncakjaya Power	195	40.24	36.03	27	297	N/A
PT Semen Indonesia	140	36.86	31.46	9	231	8%
Other	7,449	36.93	31.76	14	10,620	N/A
Total	**29,984**	**39.10**	**29.77**	**16**	**34,736**	**N/A**

Source: CTI analysis

Notes: *Those coal-fired power plants with multi-ownership structures are included under 'Other'. Total capital represents total investment that shareholders and debtholders have made in a company. Short-term borrowings plus long-term borrowings plus preferred equity plus minority interest plus total common equity.*

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7 Appendix – scenario methodology and key assumptions

Plant-level generation model outputs allow us to apply 'investment grade' climate scenario analysis for coal power. Our modelling approach involves three steps.

Firstly, identify the amount of capacity required to fill the generation requirement in the IEA's B2DS. Under the B2DS, coal-fired power in Indonesia is phased-out by 2040. To keep coal generation consistent with a below 2˚C pathway, units are retired when generation exceeds the B2DS generation. For example, the model keeps retiring units on a yearly basis until generation reaches or goes below B2DS generation.

Secondly, rank the units to develop retirement schedule. We rank units based on operating cost per power grid, due to the regulated nature of the Indonesian power market and our expectation that economics will become the primary driver to phase-out coal. This scenario aims to replicate a phaseout from the perspective of a utility interested in providing cost-optimised generation. We define cost as long-run operating cost which includes fuel, variable O&M, fixed O&M and capital additions from meeting regulation and maintaining unit performance.

Thirdly, calculate the cash flow of every operating and under-construction unit in both the B2DS and BAU outcomes to understand stranded risk. Stranded risk under the B2DS is defined as the difference between the net present value (NPV) of cashflow in the B2DS (which phases-out all coal power by 2040) and the NPV of cashflow in the BAU scenario (which is based on retirements announced in company reports).

Our modelling uses the following inputs: asset inventory data, technical, marketing and regulatory assumptions and asset performance data. These inputs produce the following outputs: (i) Paris Agreement compliance analysis; (ii) asset modelling economics; and (iii) market scenario analysis. These inputs and outputs are illustrated in Figure 4 below.

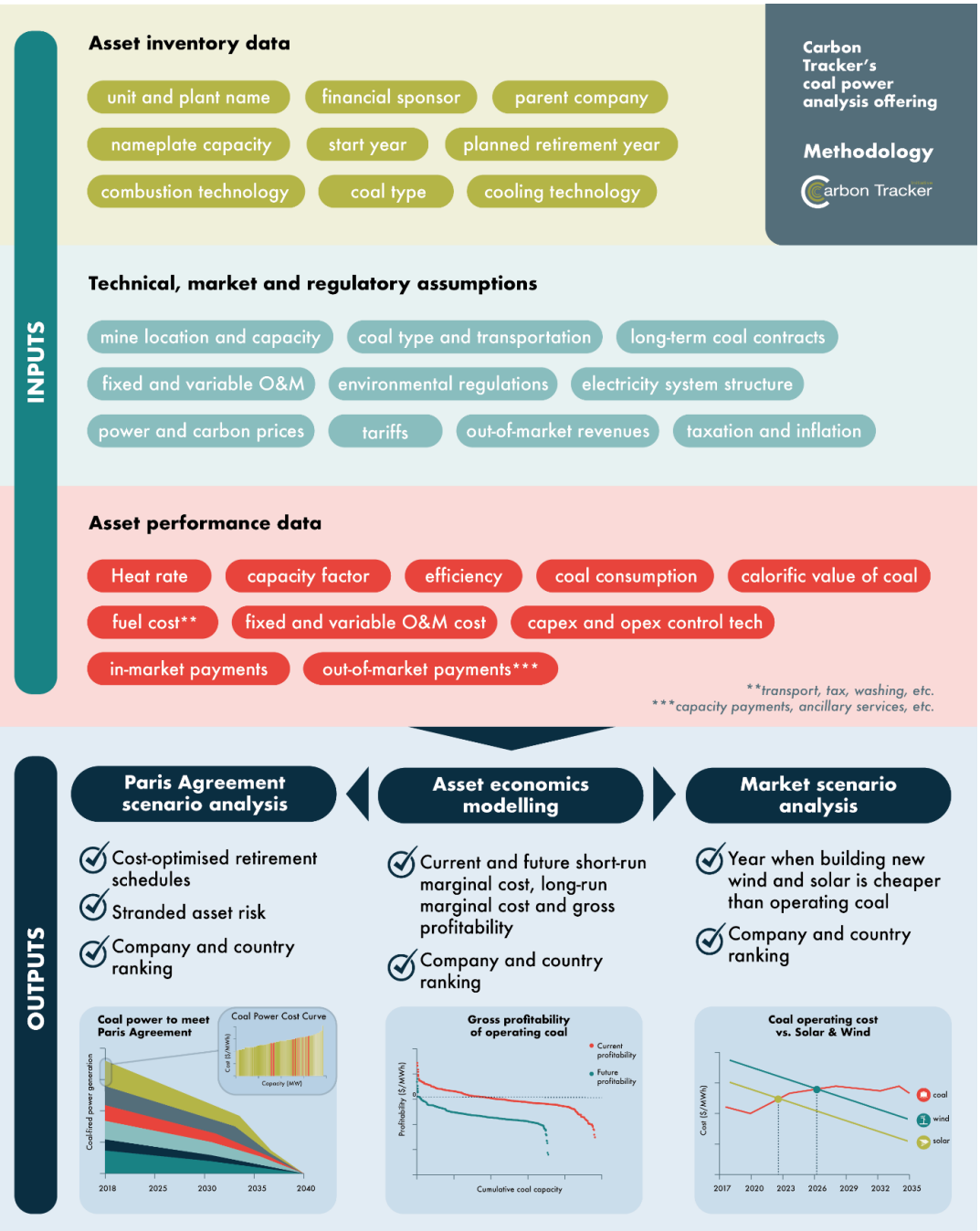
The asset modelling in this report is based on a series of reasonable assumptions about commodity prices (fuel, power and carbon), asset operating costs (variable and fixed) and policy outcomes (out of market revenues and control technologies costs).

Fuel costs include the expenses incurred in buying, transporting and preparing the coal. For the cost of coal for producers we use benchmarks from Wood Mackenzie and Bloomberg LP. For the transport of coal, a cost-optimised supply route algorithm has been developed, which calculates the distance between a unit's demand and the nearest suitable coal mine, considering coal type, mode of transport and related costs and other charges, and available port, mine and import capacities. Producing areas of Kalimantan and Sumatra use local coal transported by road. Plants located on the islands of Papua, Java-Bali, Sulawesi and Nusa Tengara source their coal from Kalimantan via seaborne and land routes. Provincial tariffs are used as per the *MoEMR Regulation No. 19/2017 provisions on tariffs*, with limited visibility on PPAs. We assume no carbon pricing throughout the modelling horizon.

The variable costs we used depend on the size of the unit: 0-100 MW ($4.49/MWh), 100-300 MW ($3.59/MWh) and 300 MW or more ($3.37/MWh). Fixed costs include the costs

incurred at a power plant that do not vary significantly with generation and include: staffing, equipment, administrative expenses, maintenance and operating fees. The fixed cost assumptions included in this report depend on the combustion technology of the unit: $7.79/kW for subcritical; $10.39/kW for supercritical; $11.87/kW for ultra-supercritical; $18.37/kW for integrated gasification combined cycle (IGCC); and $10.39/kW for circulating fluidized bed (CFB). We adopt a conservative view on future air pollution regulation and assume no additional capital costs for the installation of environmental control technologies across the fleet.

FIGURE 4 - DIAGRAM OF THE RESEARCH METHODOLOGY FOR COAL POWER ANALYSIS



Carbon Tracker Initiative

Economic and financial risks of coal power in Vietnam

Briefing

October, 2018

Table of Contents

1 Summary

By 2020 it will be cheaper to invest in new solar PV than new coal and 2022 for onshore wind. This represents the first inflection point when new investments in coal capacity become economically uncompetitive relative to new investments in renewable energy. These changing cost dynamics call into question over 30 GW or $40 bn of planned coal investments in Vietnam and the long-term role of the existing fleet to deliver an economic return to investors.

It will be cheaper to build new solar PV than operate existing coal plants by 2027 and onshore wind by 2028, calling into question the economic viability of the operating fleet in Vietnam thereafter. The second inflection point highlights the risk when new investments in renewables outcompete existing coal plants. Both solar PV and onshore wind have experienced impressive cost reductions over the past four years, declining around 50% and 30%, respectively. We expect this deflationary trend to continue such that in the future new investments in renewable energy will likely cost less than operating coal. Based on prevailing fuel costs, building new solar PV will be cheaper than operating coal by 2027 and onshore wind by 2028. Coal plants' relative cost competitiveness could be further exacerbated with the introduction of tighter air pollution regulations, which would require expensive plant retrofits.

Existing market structure is dominated by state-owned energy companies that are financially burdened by higher coal prices. Vietnam Electricity (EVN), the state-owned utility, uses low-subsidised tariffs to incentivise private investment in power generation. However, EVN has incurred critical financial losses, due to lower tariff rates that do not cover the full cost of power production. Higher coal prices have increased the cost of power generation and could further compromise EVN's financials, if it remains committed to coal. Indeed, plans to create fully competitive retail market by 2023 will allow consumers to purchase power from those utilities less exposed to coal.

In a scenario where coal is phased-out consistent with the Paris Agreement, Vietnamese coal power owners risk losing $11.7 bn of mostly operating capacity. We have developed a cost-optimised asset-level methodology and scenario analysis which phases out coal power in a manner consistent with the temperature goal in the Paris Agreement. In such a scenario, Vietnamese coal power owners are borne with $11.7 bn of stranded value stemming from the premature retiring of coal capacity. EVN, PetroVietnam, and Vinacomin are at most risk due to increasing unviability of coal, with stranding asset risk of $6.1 bn, $1.5 bn and $0.8 bn, respectively. This financial risk is material, representing 79% of Vinacomin's total capital and 66% for PetroVietnam. This scenario, however, does not take into consideration existing PPA agreements and any changes to future market dynamics of the Vietnamese power market.

2 Background

Coal is the second largest source of power generation in Vietnam, responsible for 34% of electricity generated in 2017.[1] The electricity production from coal-fired plants surged by 72% between 2010 and 2017, going up to 67.5 TWh in 2017. Coal capacity increased by 84% from 2.7 GW in 2010 to 17 GW in 2017. Coal's share of capacity was 37% in 2017, whereas onshore wind and solar PV was 0.4%. According to the revised Power Development Plan VII (PDP 7), the share of coal capacity is expected to be 42.6% by 2030, equivalent to 43 GW of new coal plants. [2]

Vietnam has reformed its power sector towards a more competitive system.[3] Before 2012, the Vietnam Electricity (EVN) had a monopoly over the generation, transmission, and distribution. The Electricity Law of 2004 initiated the restructuring of the EVN to encourage private players' participation.[4] With the establishment of the Vietnam Competitive Generation Market (VCGM) in 2012, EVN's affiliate power generation companies (Gencos) and IPPs began selling power to a single-buyer, the Electricity Power Trading Company (EPTC).[5]

In 2016, Vietnam began a pilot scheme of Wholesale Electricity Market (VWEM).[6] VWEM will be fully operational in 2019, allowing generators to sell electricity to industrial consumers at the spot market. The EVN owns 60% of power generation assets, and the remaining is held by PetroVietnam (13%), Vinacomin (4%) and IPPs.[7] A fully competitive retail market will be in working order by 2023, giving the consumers the option to choose the supplier.[8]

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[1] *BNEF, (2018). Power Generation. Data obtained from BNEF analyst.*

[2] *GIZ, (2017). Vietnam Development Plan 2011-2020: Highlights of the PDP 7 revised. Available: http://gizenergy.org.vn/media/app/media/legal%20documents/GIZ_PDP%207%20rev_Mar%202016_Highlights_IS.pdf*

[3] *World Bank, (2016), Fourth Power Sector Reform Development Policy Operation. Available: http://documents.worldbank.org/curated/en/539451470822913319/pdf/107674-PGID-P157722-Initial-Concept-Box396301B-PUBLIC-Disclosed-8-9-2016.pdf*

[4] *The Electricity Law, (2004). Available: http://www.tracuuphapluat.info/2010/06/toan-van-luat-ien-luc-nam-2004.html E*

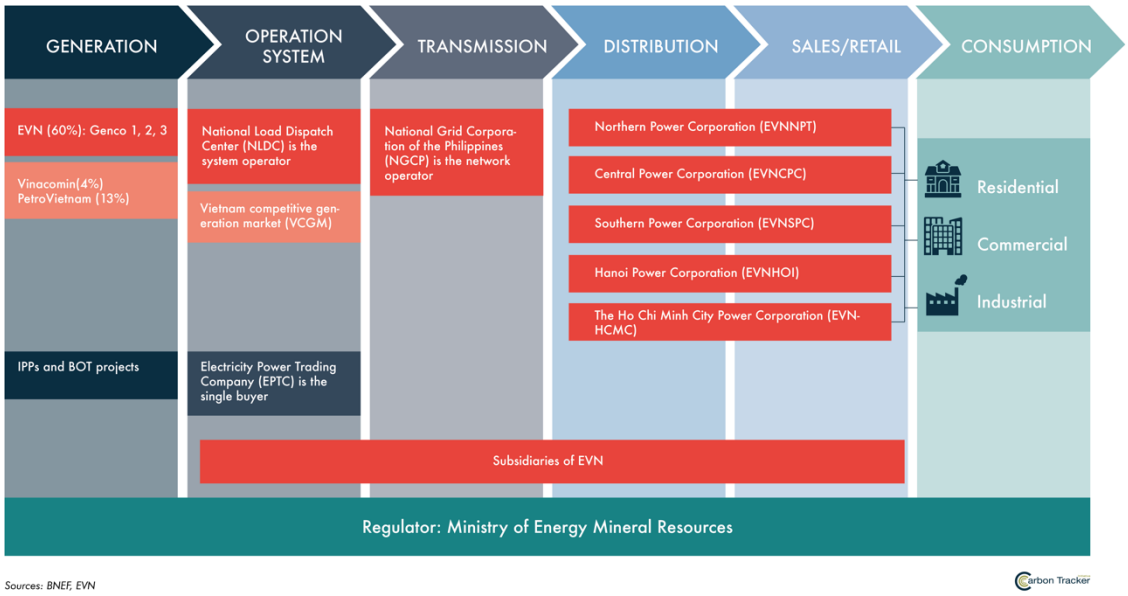
[5] *EPTC is a subsidiary of EVN and responsible for regulating the price of electricity in the competitive power pool.*

[6] *Asian Development Bank, (2014). Socialist Republic of Viet Nam: Establishing the Wholesale Electricity Market. Available: https://www.adb.org/sites/default/files/project-document/153379/48328-001-tar.pdf*

[7] *BNEF, (2017). Vietnam Power Market: Opportunities and Risks. Unavailable without subscription.*

[8] *Asian Development Bank, (2015). Assessment of Power Sector Reforms in Vietnam. Available: https://www.adb.org/sites/default/files/institutional-document/173769/vie-power-sector-reforms.pdf*

FIGURE 1 – VIETNAM POWER MARKET DESIGN



Vietnam committed to cut its greenhouse gas emissions up to 25% compared to business-as-usual levels by 2030.[9] To reach this goal, the government targets the deployment of 18 GW of onshore wind and solar PV by 2030.[10] The revised PDP 7 plans to increase renewable capacity by 10% by 2020 and 21% by 2030.[11] The majority of new renewable capacity additions will be from solar PV, rising from 8 MW in 2017 to 12 GW in 2030.[12] Wind capacity is also expected to grow from 183 MW in 2017 to 6 GW by 2030.

Vietnam supports renewables through a feed-in-tariff (FiT) of $0.08/kWh for wind[13] and $0.09/kWh for solar PV[14]. The Ministry of Industry and Trade (MoIT) is also partnering with the USAID to develop a direct power purchase agreement policy that will enable direct power purchases from independent renewable energy producers.[15]

[9] *Intended Nationally Determined Contribution of Viet Nam, 2016. Available: http://www4.unfccc.int/ndcregistry/PublishedDocuments/Viet%20Nam%20First/VIETNAM'S%20INDC.pdf*

[10] *World Resources Institute, (2018). Vietnam: An Up-and-Coming Clean Energy Leader? Available: https://www.wri.org/blog/2018/02/vietnam-and-coming-clean-energy-leader*

[11] *Green ID, (2017). Prospects and Challenges of Energy Transition in Vietnam. Available: https://mm.boell.org/sites/default/files/uploads/2017/07/12jul17-greenid_presentation_on_vietnam_energy_transition_dmt.pdf*

[12] *Ministry of Industry and Trade (MoIT), (2016). Vietnam Renewable Energy Development Project to 2030 with outlook to 2050. Available: http://www.vn.undp.org/content/dam/vietnam/docs/Publications/Mr%20Thuc.pdf*

[13] *VN Express, (2018). New Tariffs Could Recharge Vietnam's Wind Projects. Available: https://e.vnexpress.net/news/business/industries/new-tariffs-could-recharge-vietnam-s-wind-power-projects-3808113.html*

[14] *Vietnam Investment Review, (2018). FiT Rates Heat Up Solar Power Interest. Available: https://www.vir.com.vn/fit-rates-heat-up-solar-power-interest-60048.html*

[15] *WRI, (2018). Vietnam: An Up-and-Coming Clean Energy Leader? Available: https://www.wri.org/blog/2018/02/vietnam-and-coming-clean-energy-leader*

3 Current situation

Vietnam's power market liberalisation has not changed EVN's monopolistic position as a single buyer.[16] In 2017, PPA contracts supplied 80% of the power output sold, and the rest is sold at the spot market.[17] Fluctuations in electricity prices at the VCGM, imported fuel prices and foreign exchange rate affects the profitability of coal plants.[18] EVN endured significant financial losses due to tariff rates below the cost of power generation.[19]Vietnam is heavily dependent on coal imports from Australia, Indonesia, and Russia. In 2017, the imported coal volume was 11.7 million tons, and by 2030 it is expected to reach 102 million tons.[20] The steady increase in coal prices slumped the imported fuel costs since 2016, and by 2021 an additional $1.27 billion will be spent on importing coal per year, according to IEEFA estimates.[21]

We modelled the operating cost[22] and gross profitability of each coal unit in Vietnam in 2018 and found the coal fleet is currently cash flow positive and operates at a lower cost than building new solar PV and onshore wind. However, the levelised cost of renewable energy has declined significantly over the last four years, with the levelised cost of solar PV and onshore wind falling around 50% and 30%, respectively. These deflationary trends contrast with the cost of coal power, which has increased 30% over the same period.[23]

[16] *GIZ, (2017). Vietnam Development Plan 2011-2020: Highlights of the PDP 7 revised. Available: http://gizenergy.org.vn/media/app/media/legal%20documents/GIZ_PDP%207%20rev_Mar%202016_Highlights_IS.pdf*

[17] *Danish Energy Agency (DEA), (2017). Vietnam Energy Outlook Report. Available: https://ens.dk/sites/ens.dk/files/Globalcooperation/Official_docs/Vietnam/vietnam-energy-outlook-report-2017-eng.pdf*

[18] *Vietcombank Securities, (2016). Vietnam Power Industry 2016. Available: https://vcbs.com.vn/vn/Communication/GetReport?reportId=4793*

[19] *World Bank, (2016), Fourth Power Sector Reform Development Policy Operation. Available: http://documents.worldbank.org/curated/en/539451470822913319/pdf/107674-PGID-P157722-Initial-Concept-Box396301B-PUBLIC-Disclosed-8-9-2016.pdf*

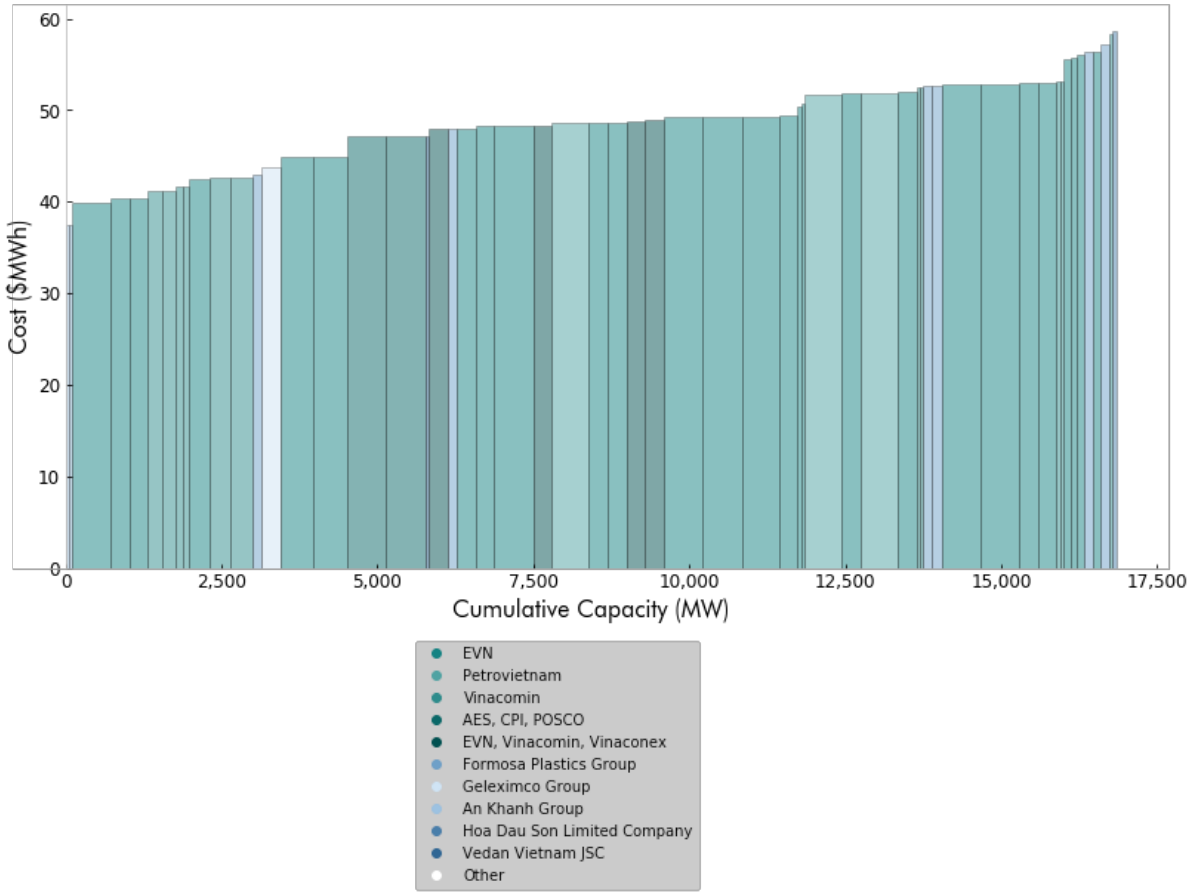
[20] *Vietnam News, (2017). MoF Refuses to Cut Tax Rates for Coal Industry. Available: https://vietnamnews.vn/economy/380808/mof-refuses-to-cut-tax-rates-for-coal-industry.html#8ae8aZu9usw7bpCy.97*

[21] *IEEFA, (2017). Price Increase Highlights Growing Risk to Coal-Import Economies. Available: http://ieefa.org/ieefa-asia-price-increase-highlights-growing-risk-coal-import-economies/*

[22] *Unless otherwise stated, we define cost as long-run operating cost which includes fuel, variable O&M, fixed O&M, and capital additions from meeting regulation and maintaining unit performance.*

[23] *BNEF, (2018). Levelised Cost of Electricity, Historic Range. Unavailable without subscription.*

Figure 2 – Short-Run Marginal Cost of Vietnam's coal fleet in 2018



Source: CTI analysis.

Note: The short-run marginal cost (SRMC), or cash cost, includes fuel and variable operating and maintenance costs.

4 Future situation

There are two main inflection points that will make coal power economically uncompetitive: when new investments in renewables outcompete new investments in coal; and when new investments in renewables outcompete the operating costs of existing coal.

Deflationary renewable energy costs will undermine the competitiveness of new coal power in Vietnam. As depicted in Figure 3, the first inflection point will be reached in the near term, where new solar PV will be cheaper than new coal by 2020 and for onshore wind by 2022. We estimate that the second inflection point will be reached by 2027, when operating coal will be more costly than building new solar PV and by 2028 for onshore wind, where fuel costs are $100/t, and by 2032 where fuel costs are $60/t. This inflection point could be brought forward should pollutant emission limits for coal plants tighten in Vietnam[24], which will also require plants to incur additional costs from the installation of post-combustion control technologies. Coal overcapacity has already resulted in underutilisation of coal power plants, with average capacity factors declining from 73% in 2010 to 57% in 2017.[25] These changing cost dynamics call into question the $40 bn of planned coal investments and the long-term role of the existing fleet.[26]

Since coal power is expected to peak by 2020, $60 billion will be saved by not building new coal plants according to a study by GreenID.[27] It shows cancelling 30 GW of new coal power from the revised PDP 7 would save $7 bn per year on imported coal costs.[28] If coal use grows as planned, the health burden of coal pollution will increase from 4300 premature deaths per year to 21,100 cases by 2030.[29]

[24] *In our modelling we do not assume more stringent air pollution regulation in Vietnam for coal plants. For pollutant emission limits for existing and new plants see IEA, (2016). Energy and Air Pollution, p.47. Available: https://www.iea.org/publications/freepublications/publication/WorldEnergyOutlookSpecialReport2016EnergyandAirPollution.pdf*

[25] *Global Witness, (2018). The Coal Power Financing Problem at HSBC and Standard Chartered. Available: https://www.globalwitness.org/documents/19388/Times_Global_Witness_HSBC_Stand_Chart_coal_briefing_18_July_2018.pdf*

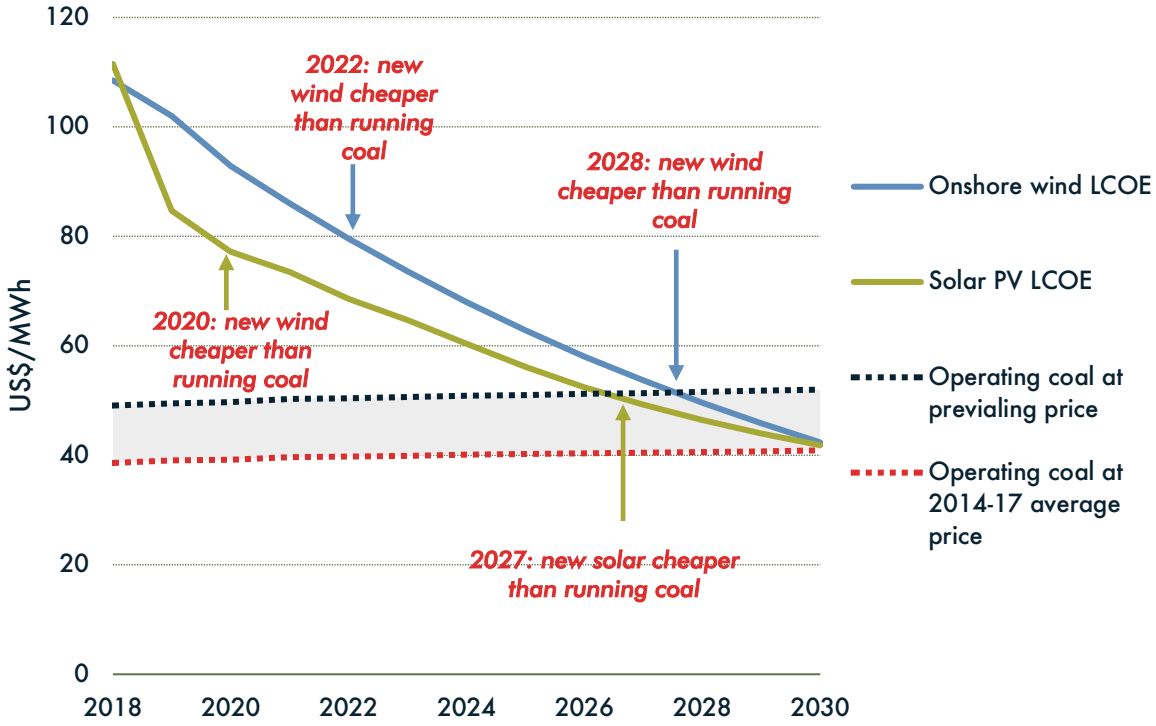
[26] *Based on planned and under-construction capacity. Assumed capital costs of $1,000/kW, $1,200/kW, $1,400/kW, $1,600/kW and $1,600/kW for subcritical, supercritical, ultra-super critical, IGCC and CFB, respectively.*

[27] *GreenID, (2017). Analysis of Future Generation Capacity Scenarios for Vietnam. Available: http://en.greenidvietnam.org.vn/app/webroot/upload/admin/files/060618_GreenID_Study%20on%20future%20power%20sources.pdf*

[28] *GreenID, (2017).*

[29] *Vietnam Sustainable Energy Alliance, (2016). Synthesis Report on Socio-Economic Impacts of Coal and Coal-fired Power Plants in Vietnam. Available: https://hal-enpc.archives-ouvertes.fr/hal-01441680/document*

FIGURE 3 - THE COST OF NEW RENEWABLES VERSUS THE CAPACITY-WEIGHTED OPERATING COST OF COAL UNDER DIFFERENT FUEL PRICES



Source: BNEF, CTI analysis

Notes: *Operating coal cost is capacity-weighted and based on long-run marginal cost, which includes fuel, variable O&M and fixed O&M (SRMC plus fixed operating and maintenance costs). Imported bituminous coal is assumed from Australia, Russia and Indonesia. The low range assumes $55/t for imported bituminous coal and $55/t for domestic anthracite. The high range assumes $80/t for imported bituminous coal and $80/t for domestic anthracite. Calorific values assumed at 3,713 kcal/kg, 4,897 kcal/kg and 5,316 kcal/kg respectively. New coal is based on LCOE estimates for Vietnam from BNEF, which assumes an average of coal-fired power over 2017-18 at $81/MWh*[30].

[30] *BNEF, (2018). Levelised Cost of Electricity (LCOE) by Country. Unavailable without subscription.*

5 Company ranking

Carbon Tracker has developed a Paris-compliance scenario analysis. This involved three steps: (i) identify the amount of capacity required to fill the generation requirement in the IEA's Beyond 2°C Scenario (B2DS)33; (ii) rank the units based on long-run operating cost to develop a cost-optimised retirement schedule; and (iii) calculate the cash flow of every operating and under-construction unit in both the B2DS and business as usual (BAU) outcomes to understand stranded risk. More information on this methodology is provided in the Appendix. This does not consider the existing PPA arrangements in place.

In a scenario where Vietnam phases-out coal power in accordance with the Paris Agreement, coal power owners risk losing $11.7 bn. This asset stranding is due to the premature retirement of coal capacity. Our cost-optimised retirement schedules show an average plant lifetime of 13 years, which is 27 years less than the typical lifetime of a coal plant. EVN, PetroVietnam, and Vinacomin are most at risk from a scenario that sees Vietnamese coal power phased-out in a manner consistent with the temperature goal in the Paris Agreement with asset stranding risk of $6.1 bn, $1.5 bn and $0.7 bn, respectively. Regardless of whether Vietnam phases-out its coal fleet in accordance with Paris, coal capacity overbuild, and the deflationary trajectory of renewables could result in asset stranding. This financial risk is material, representing 79% of Vinacomin's total capital and 66% for PetroVietnam.

TABLE 1 - ASSET-LEVEL ECONOMIC MODELLING AND CLIMATE SCENARIO ANALYSIS OF VIETNAM'S TOP COAL OWNERS

COMPANY	CAPACITY (MW)	CAPACITY-WEIGHTED AVERAGE COST 2018 ($/MWH)	CAPACITY-WEIGHTED AVERAGE PROFITABILITY 2018 ($/MWH)	AVERAGE PLANT AGE AT RETIREMENT	STRANDED RISK ($/MN)	STRANDED RISK AS % OF TOTLA CAPITAL
EVN	9,587	51.09	3.69	16	6,129	N/A
Petrovietnam	1,800	53.68	1.10	11	1,534	66%
Vinacomin	1,584	47.92	6.86	14	760	79%
Formosa Plastics Group	900	55.07	-0.29	15	189	1%
Geleximco Group	300	47.34	7.44	18	91	N/A
An Khanh Group	100	43.05	11.73	14	45	N/A
Hoa Dau Son Limited Company	75	62.22	-7.44	10	-5	N/A
Vedan Vietnam JSC	60	50.95	3.83	12	17	N/A
Other	2,440	50.61	4.17	7	2,922	N/A
Total	**16,846**	**51.1**	**3.6**	**13**	**11,683**	**N/A**

Source: CTI analysis

Notes: *Those coal-fired power plants with multi-ownership structures are included under 'Other'. Total capital represents total investment that shareholders and debtholders have made in a company. Short-term borrowings plus long-term borrowings plus preferred equity plus minority interest plus total common equity.*

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Vietnam News, (2017). Average Electricity Price Rises to $0.076 per kWh. Available: https://vietnamnews.vn/economy/418630/average-electricity-price-rises-to-0076-per-kwk.html#dmLpObCCf0DJCbfK.97

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7 Appendix – scenario methodology and key assumptions

Plant-level generation model outputs allow us to apply 'investment grade' climate scenario analysis for coal power. Our modelling approach involves three steps.

Firstly, identify the amount of capacity required to fill the generation requirement in the IEA's B2DS. Under the B2DS, coal-fired power in Vietnam is phased-out by 2040. To keep coal generation consistent with a below 2°C pathway, units are retired when generation exceeds the B2DS generation. For example, the model keeps retiring units on a yearly basis until generation reaches or goes below B2DS generation.

Secondly, rank the units to develop retirement schedule. We rank units based on operating cost per power grid, due to the regulated nature of the Vietnamese power market and our expectation that economics will become the primary driver to phase-out coal. This scenario aims to replicate a phaseout from the perspective of a utility interested in providing cost-optimised generation. We define cost as long-run operating cost which includes fuel, variable O&M, fixed O&M and capital additions from meeting regulation and maintaining unit performance.

Thirdly, calculate the cash flow of every operating and under-construction unit in both the B2DS and BAU outcomes to understand stranded risk. Stranded risk under the B2DS is defined as the difference between the net present value (NPV) of cashflow in the B2DS (which phases-out all coal power by 2040) and the NPV of cashflow in the BAU scenario (which is based on retirements announced in company reports).

Our modelling uses the following inputs: asset inventory data, technical, marketing and regulatory assumptions and asset performance data. These inputs produce the following outputs: (i) Paris Agreement compliance analysis; (ii) asset modelling economics; and (iii) market scenario analysis. These inputs and outputs are illustrated in Figure 4 below.

The asset modelling in this report is based on a series of reasonable assumptions about commodity prices (fuel, power and carbon), asset operating costs (variable and fixed) and policy outcomes (out of market revenues and control technologies costs).

Fuel costs include the expenses incurred in buying, transporting and preparing the coal. For the cost of coal for producers we use coal price benchmarks from Wood Mackenzie and Bloomberg. For the transport of coal, a cost-optimised supply route algorithm has been developed, which calculates the distance between a unit's demand and the nearest suitable coal mine, considering coal type, mode of transport and related costs and other charges, and available port, mine and import capacities. Bituminous coal is imported from Australia, Russia and Indonesia via seaborne and then land routes to mine. Anthracite is sourced domestically. Prices from the newly introduced competitive wholesale market are used with limited visibility on PPAs and we assume no carbon pricing throughout the modelling horizon.

The variable costs we used depend on the size of the unit: 0-100 MW ($4.49/MWh), 100-300 MW ($3.59/MWh) and 300 MW or more ($3.37/MWh). Fixed costs include the costs incurred at a power plant that do not vary significantly with generation and include: staffing, equipment, administrative expenses, maintenance and operating fees. The fixed cost assumptions included in this report depend on the combustion technology of the unit:

$7.79/kW for subcritical; $10.39/kW for supercritical; $11.87/kW for ultra-supercritical; $18.37/kW for integrated gasification combined cycle (IGCC); and $10.39/kW for circulating fluidized bed (CFB). We adopt a conservative view on future air pollution regulation and assume no additional capital costs for the installation of environmental control technologies across the fleet.

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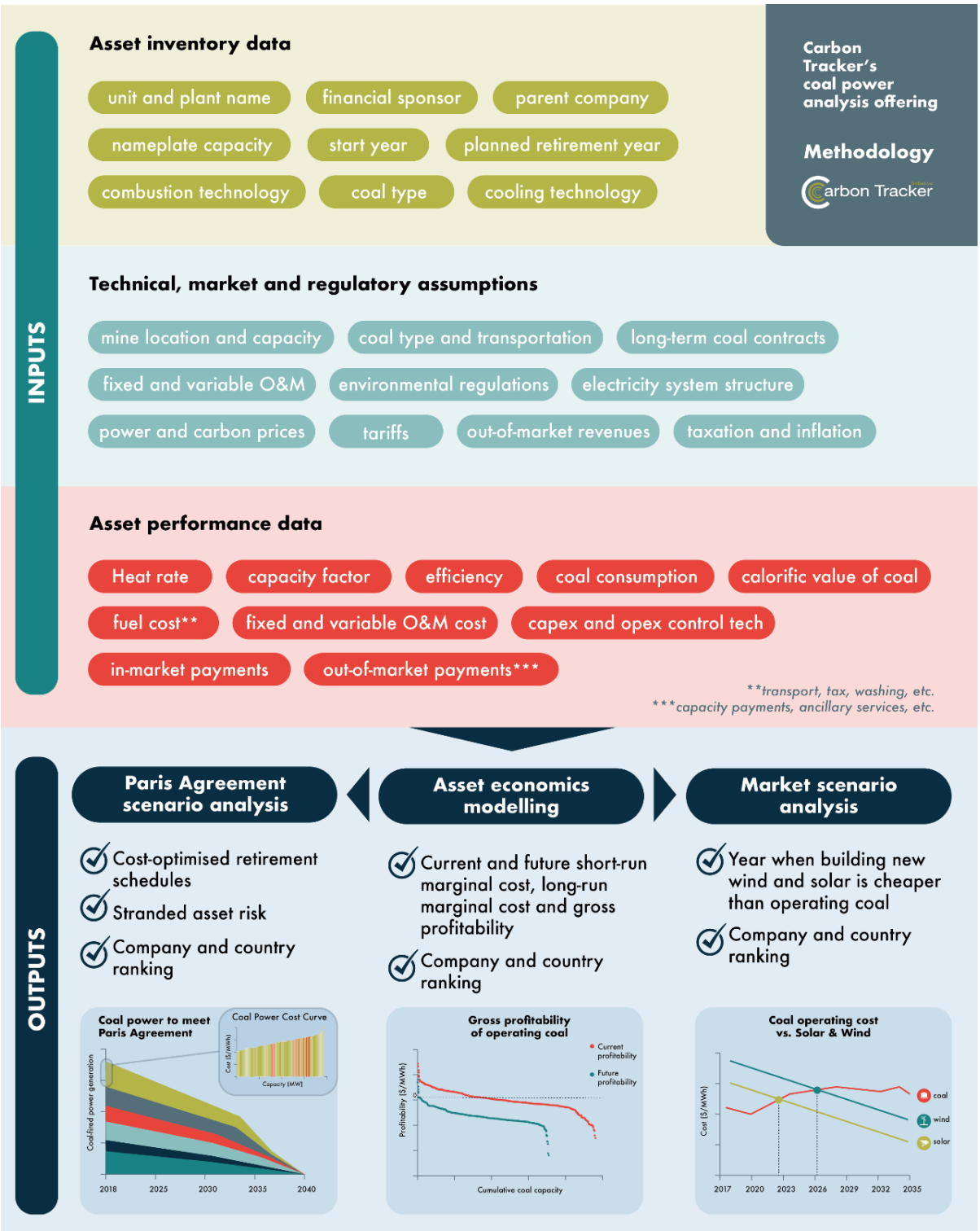

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1 Summary

By 2021 it will be cheaper to invest in new solar PV than new coal. This represents the first inflection point when new investments in coal capacity become economically uncompetitive relative to new investments in renewable energy. These changing cost dynamics call into question the 10 GW or $30 bn of planned coal investments and the long-term role of the existing fleet to deliver an economic return to investors.

It will be cheaper to build new solar PV than to run existing coal plants by 2029, calling into question the economic viability of the operating fleet thereafter. The second inflection point highlights the risk when new investments in renewables outcompete existing coal plants. Costs in solar PV have already declined around 60% since mid-2014 in the Philippines and is projected to continue as deployment increases, which will have a dramatic impact on the competitiveness of coal power over the next decade.

Current market structure exposes ratepayer to high-cost coal power. The Philippines has accelerated the liberalisation process of its power markets since 2001. The current power market structure guarantees a return by passing fuel costs on to the ratepayer. These costs will be harder to justify with the advent of low-cost renewable energy.

According to IEEFA and ICSC, the Philippines has $21 bn of stranded risk associated with the new-build of coal. IEEFA and ICSC highlighted that the continued expansion of the coal fleet could lead to $21 bn of stranded asset risk due to renewable cost deflation, the reduction in utilisation rates, presence of retail competition, and competition from bilateral agreements and merchant plants from renewable sources.

In a scenario where coal is phased-out consistent with the Paris Agreement, Filipino coal power owners risk losing $13.1 bn of mostly operating capacity. We have developed a cost-optimised asset-level methodology and scenario analysis which phases out coal power in a manner consistent with the temperature goal in the Paris Agreement. In such a scenario, Filipino coal power owners are borne with $13.1 bn of stranded value stemming from the premature retiring of coal capacity. San Miguel Corporation, DMCI Holding and EGCO Group are at most risk in this scenario, with stranding asset values of $3.3 bn, $1.7 bn and $1.2 bn, respectively. This financial risk is material, representing 86% of A Brown Company's total capital and 65% for DMCI Holdings and 21% for EGCO Group. This scenario, however, does not take into consideration existing PPA agreements and any changes to future market dynamics of the Filipino power market.

2 Background

The Philippines' power sector is heavily dependent on coal. Coal was responsible for almost half of power generation in 2017.[1] Power generation from coal-fired plants more than doubled from 2010 to 2017, increasing to 46.8 TWh in 2017. The share of coal in installed capacity was 35% in 2017, whereas wind and solar was only 6%.

The Philippines was the first ASEAN county to adopt power market reforms. The Electricity Power Industry Reform Act (EPIRA) of 2001[2] accelerated the market liberalisation and unbundled the generation, wholesale and distribution markets.[3] A wholesale electricity spot market (WESM) was established. The EPIRA initiated the privatisation of the National Power Corporation (NPC) and allowed the participation of private utilities and electric cooperatives in distribution and retail.[4]

The majority of existing coal plants are owned by independent power producers (IPPs) and privatised NPC companies.[5] NPC had a monopoly over power generation until 2001, and by 2016 74% of its generation assets were privatised.[6] Aboitiz, Alcantara, Ayala, San Miguel, and Filinvest are major conglomerates involved in coal plant construction in the Philippines.[7] Power produces sell power at the spot market in the event that they do not have bilateral contracts in place.[8]

[1] *Department of Energy (DOE), (2018). Power Statistics. Available: https://www.doe.gov.ph/sites/default/files/pdf/energy_statistics/01_2017_power_statistics_as_of_30_april_2018_summary_05092018.pdf*

[2] *The Electricity Power Industry Reform Act (2001). Available: https://www.doe.gov.ph/sites/default/files/pdf/issuances/20010608-ra-09136-gma.pdf*

[3] *IEA, (2015). Development Prospects of the ASEAN Power Sector: Towards an Integrated Electricity Market. Available:https://www.iea.org/publications/freepublications/publication/Partnercountry_DevelopmentProspectsoftheASEANPowerSector.pdf*

[4] *DOE, (2016). Energy Regulatory Commission's Regulatory Framework. Available: https://www.doe.gov.ph/sites/default/files/pdf/e_ipo/2016_leif_03_erc_regulatory_framework.pdf*

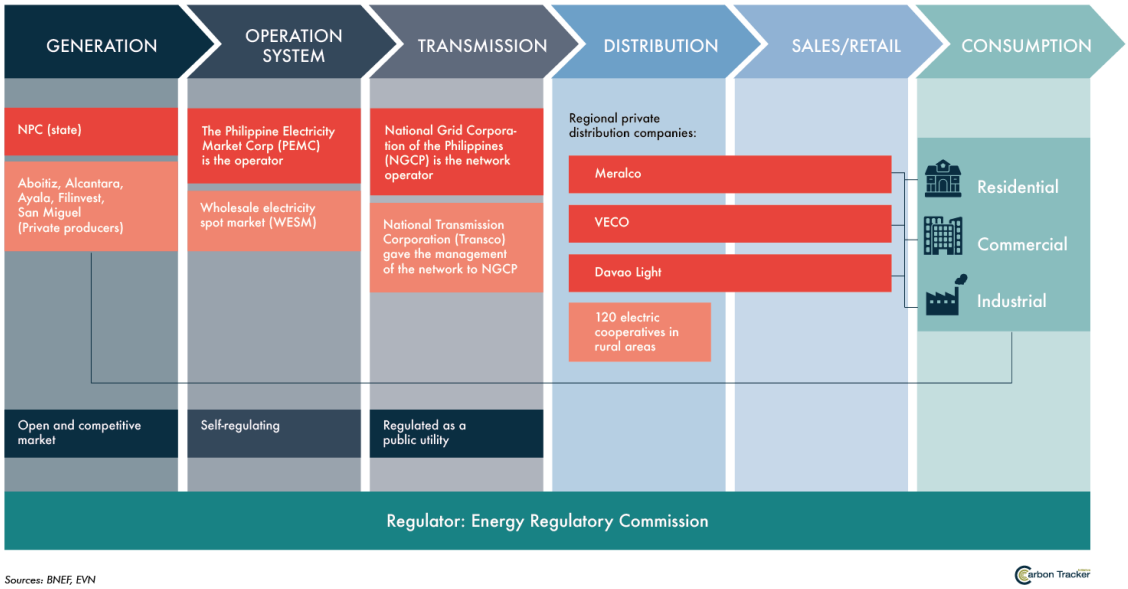
[5] *DOE, (2017). Gross Power Generation by Ownership. Available: https://www.doe.gov.ph/sites/default/files/pdf/energy_statistics/06_2017_power_statistics_as_of_30_april_2018_6.gen_per_ownership.pdf*

[6] *BNEF, (2016). Philippines Power Market Primer. Unavailable without subscription.*

[7] *IEEFA and ICSC. (2017). Carving out Coal in the Philippines: Stranded Coal Assets and the Energy Transition. Available: http://ieefa.org/wp-content/uploads/2017/10/Carving-out-Coal-in-the-Philippines_IEEFAICSC_ONLINE_12Oct2017.pdf*

[8] *Pacudan, (2014). Electricity Price Impacts of Feed-in Tariff Policies: The Cases of Malaysia, the Philippines, and Thailand. Available: http://www.eria.org/RPR_FY2013_No.29_Chapter_11.pdf*

FIGURE 1 – PHILIPPINES POWER MARKET DESIGN



The Philippine Energy Plan 2012-2030 set a long-term target of 9.9 GW of new renewable capacity by 2030.[9] The installed renewable capacity increased from 5.5 GW in 2013 to 7 GW in 2017, of which solar accounted for 57%.[10] The cumulative capacity for utility solar PV will reach 19 GW in 2030, according to BNEF.[11]

The Renewable Energy Act of 2008 laid out a policy framework to increase renewable capacity. The Feed-in-Tariff (FIT) scheme[12] was critical for the uptake of renewables in the Philippines, with 700 MW of solar and 439 MW of wind projects built by the end of 2016.[13] The Renewable Portfolio Standards (RPS) will drive further growth by mandating utilities to supply a minimum share of electricity from renewables, in line with the country target of 35% renewable capacity by 2030.[14]

[9] *DOE, (2012) Philippine Energy Plan 2012-2030. Available: https://www.doe.gov.ph/sites/default/files/pdf/pep/2012-2030_pep.pdf*

[10] *DOE, (2018). Power Statistics. Available: https://www.doe.gov.ph/sites/default/files/pdf/energy_statistics/01_2017_power_statistics_as_of_30_april_2018_summary_05092018.pdf*

[11] *BNEF, (2018). New Energy Outlook. Unavailable without subscription.*

[12] *In April 2015, the FIT rates for solar was decreased from PhP 9.68/kWh to 8.69/kWh, and the rates for wind was revised from PhP 8.53/kWh to 7.40/kWh. The FIT installation targets were also revised for solar (from 50MW to 500MW) and wind (from 200 MW to 400MW). See: DOE, (2018). Renewable Energy Development and Climate Change Mitigation. Available: http://climate.gov.ph/images/NPTE/5th_NPTE_Forum/MR-JHUN-ESCOBAR.pdf*

[13] *DOE, (2016). Renewable Energy in the Philippines. Available: http://www.irena.org/eventdocs/Philippines%20presentation.pdf*

[14] *DOE, (2018). Renewable Portfolio Standards. Available: https://www.doe.gov.ph/sites/default/files/pdf/consumer_connect/2017_renewable_portfolio_standards_flyer.pdf*

3 Current situation

The Philippines has the highest electrification rates in Southeast Asia.[15] Private utilities view coal-fired plants as secure investments with guaranteed returns, as the automatic pass-through of fuel costs to consumers shields investors from price fluctuations.[16] The Philippines is heavily reliant on imported coal. In 2016, 93% of its imported coal came from Indonesia.[17] The electricity system is therefore highly exposed to coal price and exchange rate volatility.[18]

Power purchase agreements are offered to investors that secure a return on capital for a period of 20 years. These agreements have the potential to create asset stranding risk if policymakers and investors overestimate power demand and underestimate the competitiveness of renewable energy. Lower capacity factors would increase the operating costs as fixed operating costs are spread across fewer operating hours. These higher operating costs would be passed on to consumers. The coal fleet presently has a lower operating cost than wind and solar.[19] The FIT and net metering schemes drove the solar boom since mid-2014. [20] The levelised cost of solar PV plummeted 138% over the last four years.[21]

We modelled the operating cost[22] and gross profitability of each coal unit in the Philippines, which can be seen in Figure 2.

[15] *DOE, (2017). Philippine Electricity Rates Still Highest in Southeast Asia. Available: https://www.doe.gov.ph/energists/index.php/83-categorised/electric-power-industry/12561-philippine-electricity-rates-still-highest-in-southeast-asia*

[16] *IEEFA and ICSC, (2017).*

[17] *DOE, (2016). Coal Statistics. Available: https://www.doe.gov.ph/energy-resources/2016-coal-statistics*

[18] *IEEFA and ICSC, (2017).*

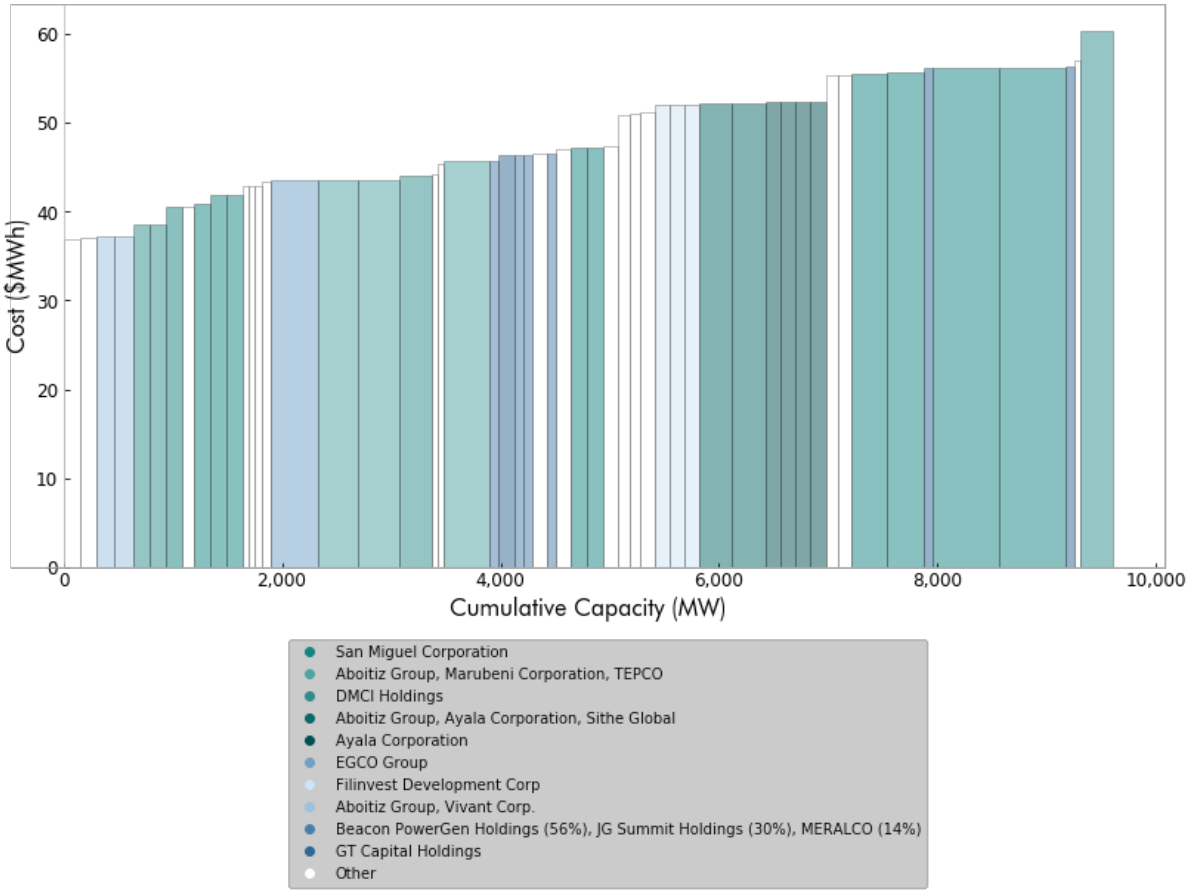
[19] *LCOE estimates for solar PV and onshore wind are based on BNEF's 1H 2018 data. See BNEF, (2018). Levelised Cost of Electricity (LCOE) by country. Available: https://www.bnef.com/core/data-hubs/5/27?tab=Current%20LCOE%20by%20Country*

[20] *IEEFA, (2018). Unlocking Rooftop Solar in the Philippines: Energy-Supply Security and Lower Electricity Costs. Available: http://ieefa.org/wp-content/uploads/2018/08/IEEFA_Unlocking-Rooftop-Solar-in-the-Philippines_August-2018.pdf*

[21] *BNEF, (2018). LCOE Historical Benchmark 1H 2018. Unavailable without subscription.*

[22] *Unless otherwise stated, we define cost as long-run operating cost which includes fuel, variable O&M, fixed O&M, and capital additions from meeting regulation and maintaining unit performance.*

FIGURE 2 - SHORT-RUN MARGINAL COST OF THE PHILIPPINES' COAL FLEET IN 2018



Source: CTI analysis.

Notes: *The short-run marginal cost (SRMC), or cash cost, includes fuel and variable operating and maintenance costs.*

4 Future situation

There are two main inflection points that will make coal power economically uncompetitive: when new investments in renewables outcompete new investments in coal; and when new investments in renewables outcompete the operating costs of existing coal.

The Philippines has approximately 10 GW of coal-fired power in the pipeline planned to come online over the coming decade[23], which assumes the continuing cost-competitiveness of coal-fired power over the long-term. Regarding the first inflection point, IEEFA and ICSC highlighted that the continued expansion of the coal fleet could lead to $21 bn of stranded asset risk due to renewable cost deflation, the reduction in utilisation rates, presence of retail competition and competition from bilateral agreements, and merchant plants from renewable sources[24]. Indeed, the economic case for continuing to build coal-fired power in the Philippines is deteriorating. By 2021, we expect new investments in solar PV will be cheaper to build than new investments in coal (see Figure 3).

The Philippines recently approved a 500% increase in coal tax which will undermine the competitiveness of coal power relative to renewable energy.[25] Falling renewable energy costs and the increased coal tax will further weaken the future economics of coal power.[26] As detailed in Figure 3, based on prevailing fuel costs, new solar PV will be cheaper than operating coal by 2029.[27] This second inflection point could be brought forward should pollutant emission limits for coal plants tighten in the Philippines[28], which will also require plants to incur additional costs from the installation of post-combustion control technologies.

According to BNEF, the installed capacity for utility-scale solar PV and onshore wind could reach 35 GW and 5 GW, respectively, by 2040.[29] In liberalised power markets, renewable energy drives down wholesale power prices, as renewables typically have grid priority on a merit order basis, further deteriorating the utilisation of coal plants.[30] These changing cost dynamics call into question the $30 bn of planned coal investments and the long-term role of the existing fleet in the Philippines.[31]

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[23] *This represents those plants in Pre-permit, permit and construction stage as listed by Global Coal Plant Tracker (2018)*

[24] *IEEFA and ICSC (2017)*

[25] *IEEFA, (2018). Investor Signal: Philippine Coal Tax. Available: http://ieefa.org/investor-signal-philippine-coal-tax/*

[26] *Reuters, (2018). Coal-reliant Philippines Struggles to Power Clean Energy. Available: https://www.reuters.com/article/us-philippines-coal-renewables/coal-reliant-philippines-struggles-to-power-up-clean-energy-idUSKCN1IJ1DL*

[27] *Based on LCOE 1H 2018 estimates and capacity addition forecasts from BNEF, with learning rates of 21% for solar PV.*

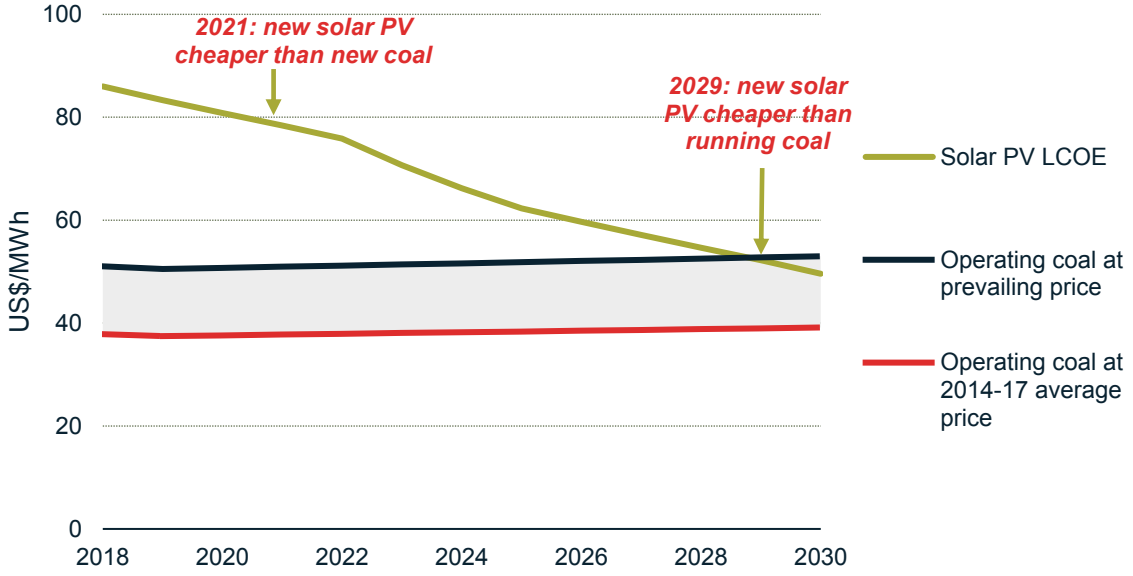
[28] *In our modelling we do not assume more stringent air pollution regulation in the Philippines for coal plants. For pollutant emission limits for existing and new plants see IEA, (2016). Energy and Air Pollution, p.47. Available: https://www.iea.org/publications/freepublications/publication/WorldEnergyOutlookSpecialReport2016EnergyandAirPollution.pdf*

[29] *BNEF, (2018). New Energy Outlook 2018. Unavailable without subscription.*

[30] *IEEFA and ICSC, (2017).*

[31] *Based on planned and under-construction capacity. Assumed capital costs of $1,000/kW, $1,200/kW, $1,400/kW, $1,600/kW and $1,600/kW for subcritical, supercritical, ultra-super critical, IGCC and CFB, respectively.*

FIGURE 3 – THE COST OF NEW SOLAR PV VERSUS THE CAPACITY-WEIGHTED OPERATING COST OF COAL UNDER DIFFERENT FUEL PRICES



Source: BNEF, CTI analysis

Notes: *Operating coal cost is capacity-weighted and based on long-run marginal cost, which includes fuel, variable O&M and fixed O&M. Operating coal cost is capacity-weighted and based on long-run marginal cost, which includes fuel, variable O&M and fixed O&M. Coal is mostly sourced from Indonesia. The low range assumes $25/t for lignite, $40/t for sub-bituminous and $55/t for bituminous coal. The high range assumes $45/t for lignite, $60/t for sub-bituminous and $90/t for bituminous coal. Calorific values assumed at 3,713 kcal/kg, 4,897 kcal/kg and 5,316 kcal/kg, respectively. New coal is based on LCOE estimates from BNEF, which assumes an average of coal-fired power over 2017-18 at $79.50/MWh*[32].

[32] *BNEF, (2018). Levelised Cost of Electricity (LCOE) by Country. Unavailable without subscription.*

5 Company ranking

Carbon Tracker has developed a Paris-compliance scenario analysis. This involved three steps: (i) identify the amount of capacity required to fill the generation requirement in the IEA's Beyond 2°C Scenario (B2DS)[33]; (ii) rank the units based on long-run operating cost to develop a cost-optimised retirement schedule; and (iii) calculate the cash flow of every operating and under-construction unit in both the B2DS and business as usual (BAU) outcomes to understand stranded risk. More information on this methodology is provided in the Appendix. This does not consider the existing PPA arrangements in place.

The total amount of stranded asset risk for the entire coal fleet is $13.1 bn. The risk of stranding stems from the premature retiring of coal capacity. Our cost-optimised retirement schedules show that an average plant lifetime is 14 years, which is 26 years less than the typical lifetime of a coal plant. San Miguel Corporation, DMCI Holding and EGCO Group are at most risk from a scenario that sees coal power phased-out in the Philippines in a manner consistent with the temperature goal in the Paris Agreement, with stranding asset values of $3.3 bn, $1.7 bn and $1.2 bn, respectively. Regardless of whether the Philippines phases-out its coal fleet in accordance with Paris, coal capacity overbuild, the deflationary trajectory of renewables and increasing retail competition could result in asset stranding.[34] This financial risk is material, representing 86% of A Brown Company's total capital and 65% for DMCI Holdings and 21% for EGCO Group.

[33] *IEA, (2017). Energy Technology Perspectives 2017*

[34] *IEEFA and ICSC, (2017).*

TABLE 1 - ASSET-LEVEL ECONOMIC MODELLING AND CLIMATE SCENARIO ANALYSIS OF PHILIPPINES' TOP TEN COAL OWNERS

COMPANY	CAPACITY (MW)	CAPACITY-WEIGHTED AVERAGE COST 2018 ($/MWH)	CAPACITY-WEIGHTED AVERAGE PROFITABILITY 2018 ($/MWH)	AVERAGE PLANT AGE AT RETIREMENT	STRANDED RISK ($/MN)	STRANDED RISK AS % OF TOTAL CAPITAL
San Miguel Corporation	2,778	54.02	13.69	17	3,351	14%
DMCI Holdings	900	49.62	18.74	21	1,733	65%
EGCO Group	440	45.37	23.00	19	1,214	21%
Filinvest Developme nt	405	54.58	7.71	6	401	8%
GT Capital Holdings	314	54.20	-1.73	9	101	2%
Aboitiz Group	300	40.26	22.03	15	206	3%
A Brown Company	270	50.20	2.27	13	79	86%
STEAG	232	57.96	4.33	12	244	N/A
Alcantara Group	105	43.09	19.20	8	247	N/A
Anda Power Corporation	84	46.49	21.87	14	82	N/A
Other	3,772	49.46	13.62	14	5,451	N/A
Total	**9,600**	**50.82**	**13.65**	**14**	**13,111**	**N/A**

Source: CTI analysis

Notes: *Those coal-fired power plants with multi-ownership structures are included under 'Other'. Total capital represents total investment that shareholders and debtholders have made in a company. Short-term borrowings plus long-term borrowings plus preferred equity plus minority interest plus total common equity.*

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7 Appendix – scenario methodology and key assumptions

Plant-level generation model outputs allow us to apply 'investment grade' climate scenario analysis for coal power. Our modelling approach involves three steps.

Firstly, identify the amount of capacity required to fill the generation requirement in the IEA's B2DS. Under the B2DS, coal-fired power in Indonesia is phased-out by 2040. To keep coal generation consistent with a below 2˚C pathway, units are retired when generation exceeds the B2DS generation. For example, the model keeps retiring units on a yearly basis until generation reaches or goes below B2DS generation.

Secondly, rank the units to develop retirement schedule. We rank units based on operating cost per power grid, due to the regulated nature of power market in the Philippines and our expectation that economics will become the primary driver to phase-out coal. This scenario aims to replicate a phaseout from the perspective of a utility interested in providing cost-optimised generation. We define cost as long-run operating cost which includes fuel, variable O&M, fixed O&M and capital additions from meeting regulation and maintaining unit performance.

Thirdly, calculate the cash flow of every operating and under-construction unit in both the B2DS and BAU outcomes to understand stranded risk. Stranded risk under the B2DS is defined as the difference between the net present value (NPV) of cashflow in the B2DS (which phases-out all coal power by 2040) and the NPV of cashflow in the BAU scenario (which is based on retirements announced in company reports).

Our modelling uses the following inputs: asset inventory data, technical, marketing and regulatory assumptions and asset performance data. These inputs produce the following outputs: (i) Paris Agreement compliance analysis; (ii) asset modelling economics; and (iii) market scenario analysis. These inputs and outputs are illustrated in Figure 4 below.

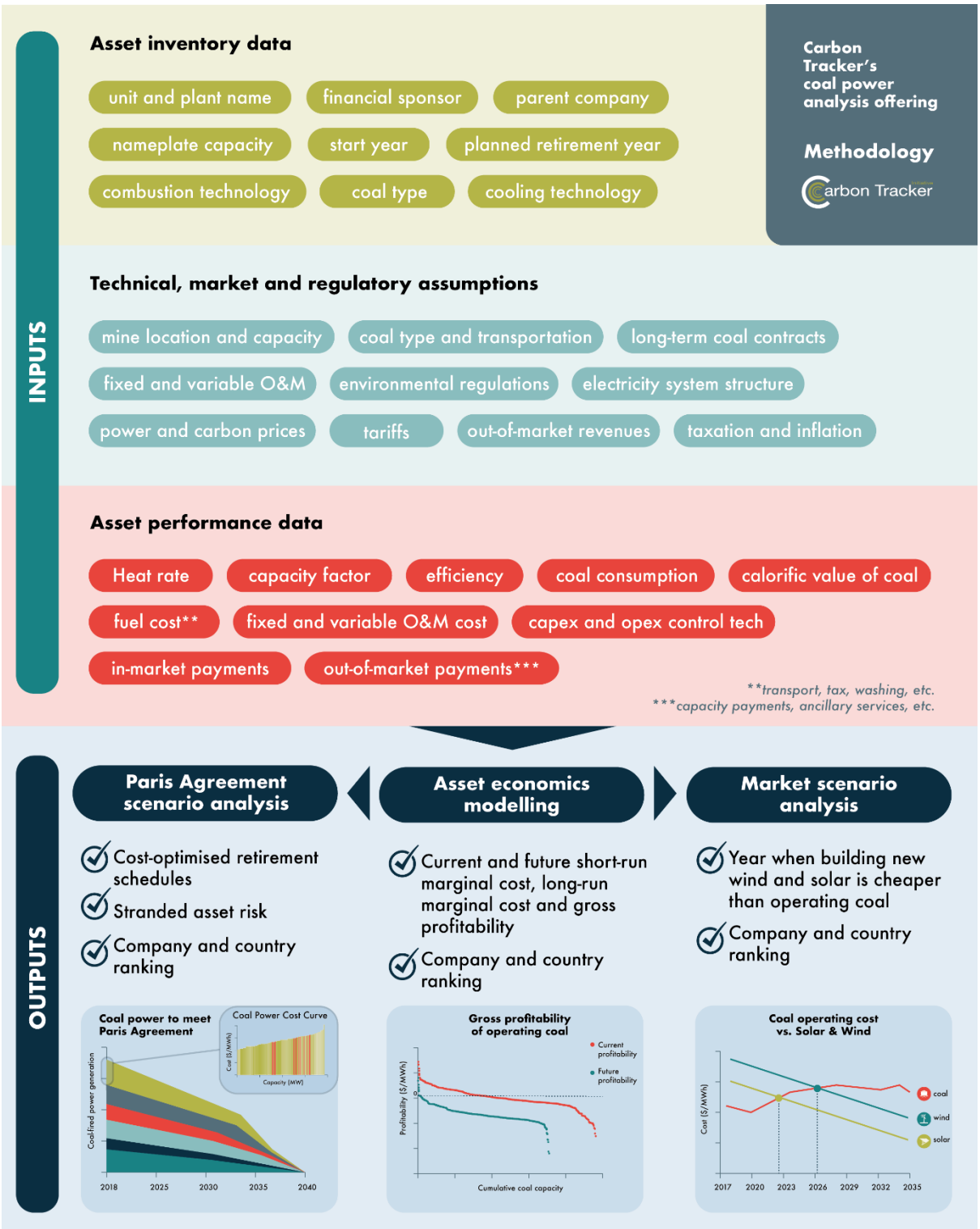
The asset modelling in this report is based on a series of reasonable assumptions about commodity prices (fuel, power and carbon), asset operating costs (variable and fixed) and policy outcomes (out of market revenues and control technologies costs).

Fuel costs include the expenses incurred in buying, transporting and preparing the coal. For the cost of coal for producers we use benchmarks from Wood Mackenzie and Bloomberg LP, assuming nearly all coal is imported from Indonesia. For the transport of coal, a cost-optimised supply route algorithm has been developed, which calculates the distance between a unit's demand and the nearest suitable coal mine, considering coal type, mode of transport and related costs and other charges, and available port, mine and import capacities. In-market revenues are based on the Wholesale Electricity Spot Market per region, in the absence of data from PPAs. We assume no carbon pricing throughout the modelling horizon.

The variable costs we used depend on the size of the unit: 0-100 MW ($4.49/MWh), 100-300 MW ($3.59/MWh) and 300 MW or more ($3.37/MWh). Fixed costs include the costs incurred at a power plant that do not vary significantly with generation and include: staffing, equipment, administrative expenses, maintenance and operating fees. The

fixed cost assumptions included in this report depend on the combustion technology of the unit: $7.79/kW for subcritical; $10.39/kW for supercritical; $11.87/kW for ultra-supercritical; $18.37/kW for integrated gasification combined cycle (IGCC); and $10.39/kW for circulating fluidized bed (CFB). We adopt a conservative view on future air pollution regulation and assume no additional capital costs for the installation of environmental control technologies across the fleet.

FIGURE 4 - DIAGRAM OF THE RESEARCH METHODOLOGY FOR COAL POWER ANALYSIS



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Acknowledgments

The authors would like to formally thank Sara Jane Ahmed (IEEFA), Lauri Myllyvirta (Greenpeace) and Aviva Imhof (ECF) for their valuable comments and guidance. The report was also reviewed by colleagues: Andrew Grant, Tom Drew, Joel Benjamin and Aurore le Galiot. Report design and typeset: Margherita Gagliardi.

The report was updated on October 31, 2018.

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