S&P Global
Ratings

Industry Top Trends 2022

Asia Pacific Utilities

Energy Transition Will Be The Key Credit Driver

This report does not constitute a ratings action

January 26, 2022

Authors

Abhishek Dangra
Singapore
+65 6216 1121
abhishek.dangra
@spglobal.com

Apple Li
Hong Kong
+852 2533 3512
apple.li
@spglobal.com

Parvathy Iyer
Melbourne
+61 3 9631 2034
parvathy.iyer
@spglobal.com

What's changed?

Demand is normalizing. A normalization of economic activity has revived industrial and commercial activities, supporting power demand across markets.

Energy transition is here. We see momentum gaining over the next one to three years to transition away from coal. Environmental, social and governance (ESG) factors will drive investments, altering the credit impact.

All hands on deck. Solar and wind projects will lead investments. Large-scale nuclear plants in China, and liquified natural gas (LNG) terminals with gas projects will also act as a bridge in the drive for energy transition.

What are the key assumptions for 2022?

Moderate demand growth. We expect power unit demand to grow at 2%-5%, broadly in line with revivals in economic activities and GDP growth for most Asian economies. Mature Pacific markets will register flat demand.

Elevated capex spending. Investments for energy transition will drive capital expenditure (capex) across markets. Growth capex in India and Indonesia, acquisitions in Pacific, and transition capex in China will keep expenditures high.

Cost pressures to subside; margins to stabilize. Established regulatory parameters in Pacific, regulatory continuity in most South and Southeast Asia markets, and expected moderation in coal prices in China should protect earnings.

What are the key risks around the baseline?

Evolving policies around energy transition. Deregulation of the power sector in China, carbon taxes in Indonesia, and emerging regulatory policies to meet emission targets can disrupt business plans and cash flows.

Investment needed to buy green growth. Renewable investments with elevated valuations can put further pressure on financial metrics of leveraged utilities.

Divergence in financial discipline. Growth and energy transition in a rising interest rate environment can lead to diverging credit fundamentals if some reassess while others take on debt to expand.

Ratings trends and outlook

Asia Pacific Utilities

Chart 1

Ratings Distribution

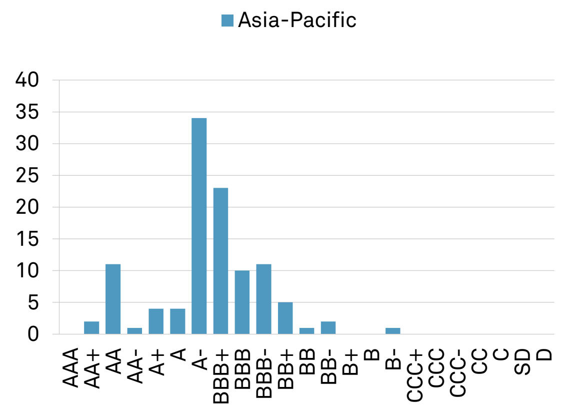


Chart 2

Ratings Distribution By Country/Region

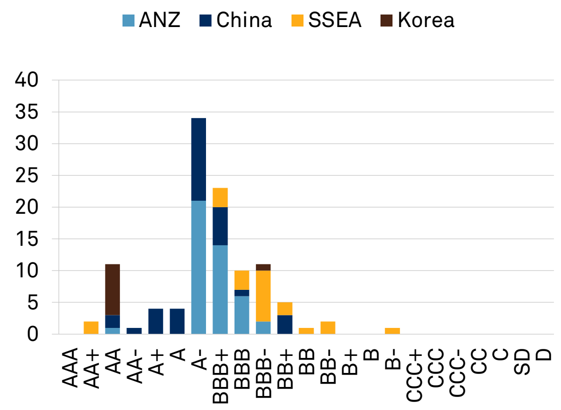


Chart 3

Ratings Outlooks

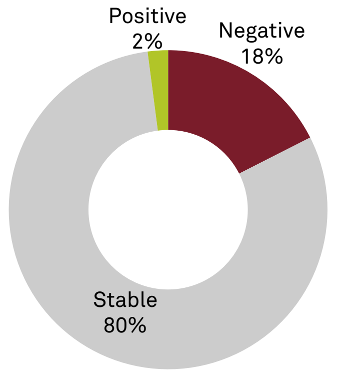


Chart 4

Ratings Outlooks By Country/Region

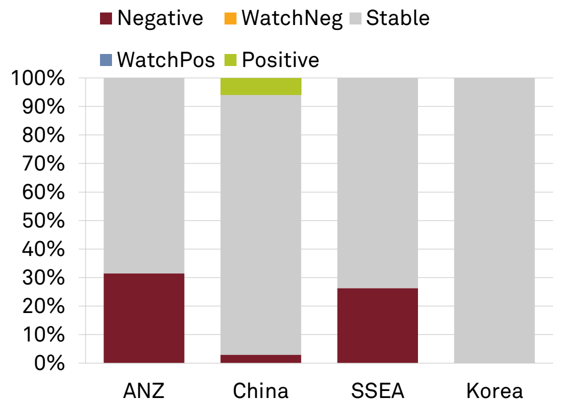


Chart 5

Ratings Outlook Net Bias

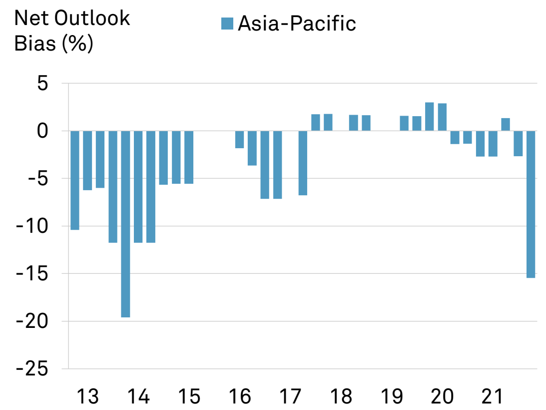
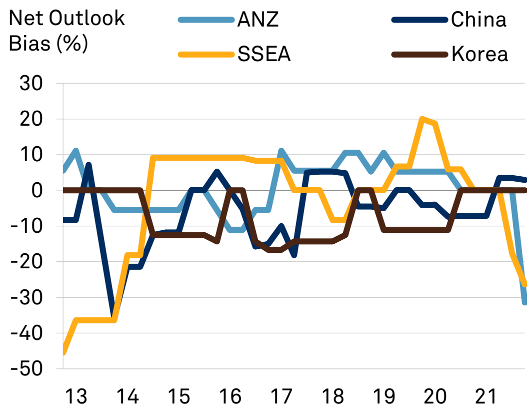


Chart 6

Ratings Net Outlook Bias By Country/Region



Source: S&P Global Ratings. Ratings data measured at quarter end.

Industry credit metrics

Asia Pacific Utilities

Chart 7

Debt / EBITDA (Median, Adjusted)

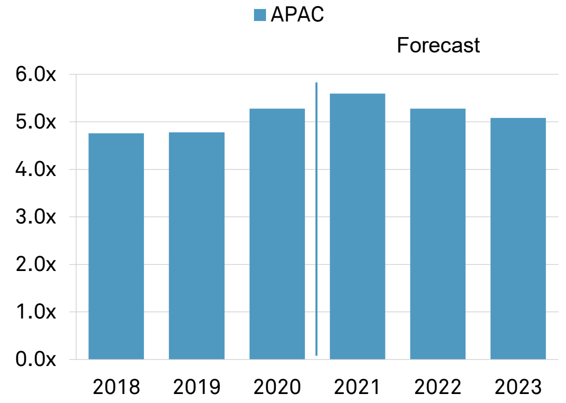


Chart 8

FFO / Debt (Median, Adjusted)

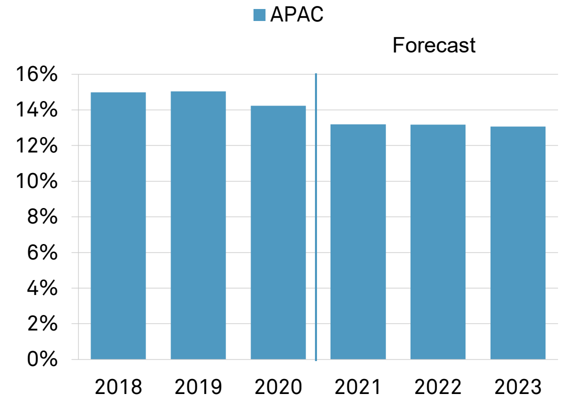


Chart 9

Cash flow And Primary Uses

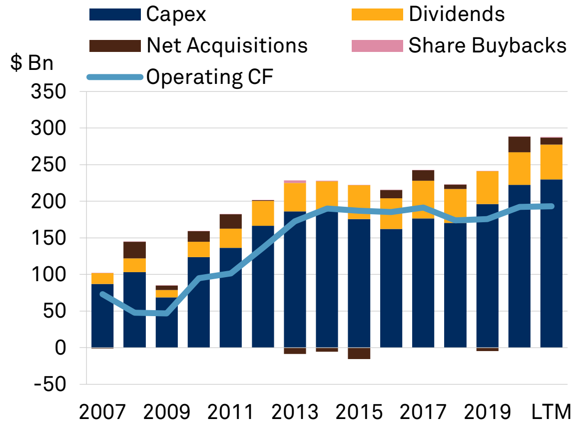
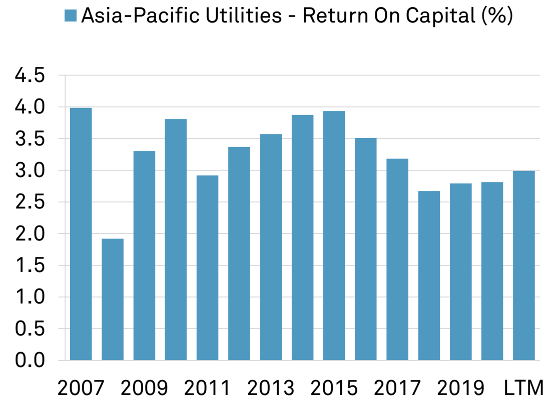


Chart 10

Return On Capital Employed



Source: S&P Global Ratings, S&P Global Market Intelligence. All figures are converted into U.S. Dollars using historic exchange rates. Forecasts are converted at the last financial year-end spot rate. FFO--Funds from operations. Most recent (2021) figures are using last twelve months (LTM) data.

Australia and New Zealand

Ratings trends and outlook

Large growth projects and mergers and acquisitions (M&A) will be focus areas for Australian and New Zealand utilities over 2022-2024. Regulated utilities are likely to retain stable outlooks, although entities pursuing growth into mid-stream or alternative energy space will have to balance risk versus ratings. Australian unregulated utilities face credit risk from volatile pricing and earnings amid growth in renewables. New Zealand unregulated utilities have balance-sheet capacity to complete their growth projects currently underway.

Main assumptions about 2022 and beyond

1. Benign energy demand and margin pressure

In line with past few years, energy demand is likely to remain flat in the mature Pacific markets. Lower returns for regulated utilities will somewhat weaken margins, while volatile energy prices or hydrology patterns will pressure margins for unregulated power entities.

2. High capex to support renewables and potential growth via M&A

Capex in line with regulated resets or projects currently underway will be the main driver in 2022). Global supply-chain constraints may add some risks. While we factor in some M&A-related spending, this will fluctuate. Continuing growth in renewables will demand large network investments beyond 2022. We expect M&A in this sector over the next two to three years to achieve growth or consolidation.

3. Shareholder philosophy on growth and future direction

We expect the continuing energy transition, particularly the faster decline of coal-fired power plants, will influence shareholder philosophy on the future direction of growth. We see this gaining momentum over the next one to three years as ESG-related factors evolve and place disclosure and financial demands on the entities. As such, financial policies or risk tolerance will become increasingly important.

Australia: Unlike elsewhere in the region, electricity and gas demand will remain flat. Recently established regulatory parameters and efficient operations of the regulated utilities should result in ratings stability. Regulated entities with midstream activities are protected from commodity risk but will increasingly face challenges in contract renewals and pricing and tenor of new contracts . To this end we expect caution in pursuit of growth in the midstream segment, with M&A activities likely to emerge in the renewable or alternate energy space. Large transmission-network projects needed to connect growing solar/ wind projects will require an appropriate funding approach or could result in some rating erosion. Unregulated energy companies are unlikely to see any respite from lower market pricing (reflected in lower regulated retain tariffs). This will not only affect their core earnings but also constrain their capacity to invest in new projects or support projects underway on their balance sheet. External support, if any, will be evaluated as it is confirmed.

New Zealand: This market is a strong contrast to Australia. Market risk is now relatively lower because the closure of the Tiwai Aluminum smelter will now occur not before end 2024 and will reduce excess power in the market. . The key risks for the rated integrated utilities could come from the pandemic-related global supply-chain constraints, potential contractual delays, and access to adequate contractors. This is because three of the four integrated players are in the midst of new wind/ geothermal projects that will complete over the next two years. All the entities have adequate balance sheet strength to manage these risks; and if required we expect it will be supplemented with prudent shareholder distribution policies. These projects will lift the proportion of renewable energy to above 90% assuming flat demand. Hydrological conditions are the main risk that can materially affect the earnings in this sector in one year but reverse in the next. Balance sheets are carefully managed to accommodate the hydro risk and fund the new project underway. The staged exit of the Tiwai smelter (accounting for 13% of the market load) over the next three years provide time to unlock future optionality for new electricity load. Transmission upgrades are underway to support the new projects and position the market for future growth. The regulated utilities space is benign but lower returns continue to squeeze the financial headroom for two of the three entities and will need careful management over the next three years.

Credit metrics and financial policy

The outlook is stable for rated entities in Australia and New Zealand. Most of the rated entities have a strong focus on maintaining investment-grade credit profiles and financial buffers. Financial policies are articulated mainly through targets on ratios of funds from operations (FFO) to debt or debt to EBITDA. We do not anticipate this will change over the next 12 months. Further, we expect supportive shareholder behavior or management approaches to preserve credit quality and liquidity.

We expect ratios of FFO to debt (the reference ratio for regulated utilities) to remain largely stable. A short dip in 2022 will come on the back of recent resets with lower returns, partly offset by some savings on interest costs in the outer years. Increases in debt-to-EBITDA ratios (the reference for unregulated utilities) mainly reflects debt funding for new investments underway. As these new projects yield cashflows we expect the ratio to settle to around 6x.

Key risks or opportunities around the baseline

1. Evolving business mix and associate financial impact

Energy transition and longer-term risk in the midstream segment can cause companies to reassess their growth strategy. Opportunities for offshore growth, renewable investments, large domestic network projects, and hydrogen projects are growth options. These factors can alter the business risk; and even if not willingness to accommodate higher debt to expand can affect the baseline.

2. Shareholder expectations and objectives

Shareholder returns have been benign over the past few years due to various factors. We don’t expect this to change; however, changes to shareholder objectives alongside the growth direction can affect credit profiles.

3. Various stakeholder responses to rapid market changes and ESG concerns

Continuing rapid growth in renewable power in Australia even as network investments lag—this is a key concern. The gas sector is facing the longevity question, while hydrogen cost economics remain uncertain. Lack of a considered and progressive action plan by the government and regulators can hurt the sector.

Industry credit metrics

Australia and New Zealand Utilities

Chart 11

Debt / EBITDA (Median, Adjusted)

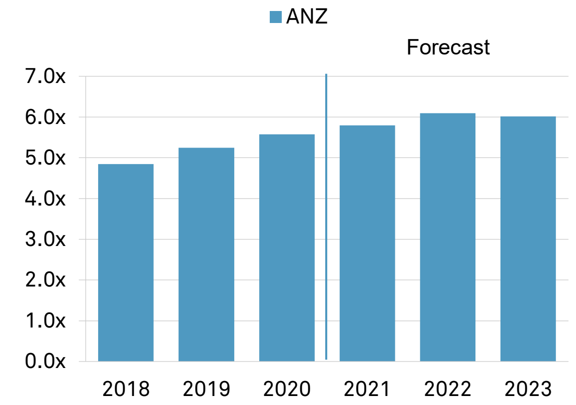


Chart 12

FFO / Debt (Median, Adjusted)

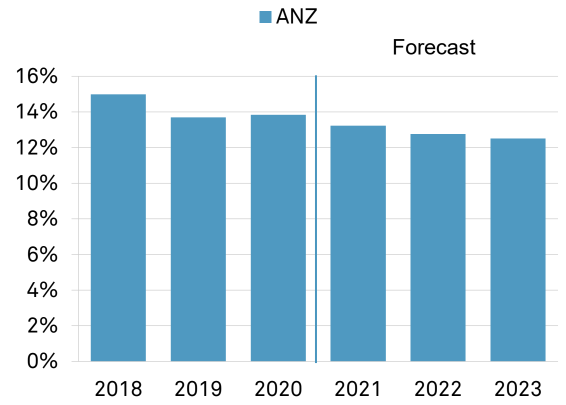


Chart 13

Cash Flow And Primary Uses

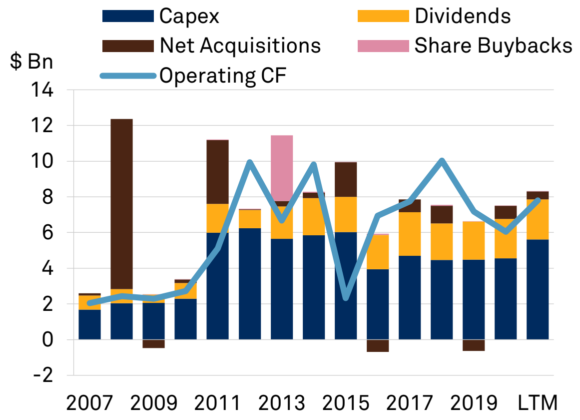
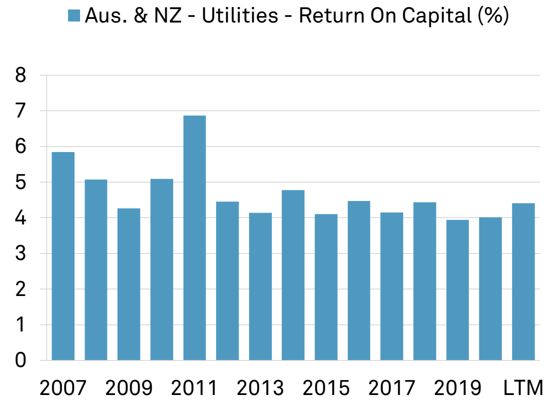


Chart 14

Return On Capital Employed



Source: S&P Global Ratings, S&P Global Market Intelligence. All figures are converted into U.S. Dollars using historic exchange rates. Forecasts are converted at the last financial year-end spot rate. FFO--Funds from operations. Most recent (2021) figures are using last twelve months (LTM) data.

China and Hong Kong

Ratings trends and outlook

Rating trends and outlooks across utilities in Greater China remain mostly stable. This trend is supported by moderating fuel costs, recovery of demand growth, and relatively low interest rates that facilitate growing debt-funded capex in renewables. Anticipated regulatory developments and planned capex can be generally accommodated within the rating headroom for Hong Kong utilities.

Main assumptions about 2022 and beyond

1. Profitability of IPPs to restore on moderating fuel cost

Losses at China's independent power producers (IPPs) should ease. This follows government moves to curb coal prices by setting a benchmark price and boosting supply, as well as increased flexibility in on-grid tariff hikes. Growing market-based trading volume for coal-fired power units will also help enhance cost pass-through. Dollar margins for natural gas distributors will likely restore in 2022 from a slight decline in 2021 due to higher gas cost and disrupted demand by power crunch.

2. Net-zero policies as a driving force for energy transition

The Chinese government remains strongly committed to decarbonization goals. This is underlined in the current five-year plan, which prioritized climate-related targets, in some cases even over economic benefits. Major state-owned IPPs will accelerate transitions into clean energy-dominated capacity so as to fulfill net-zero targets ahead of time. Renewable energy and power-storage facilities are poised to grow while coal-power will undertake more of a peak-shaving role over the longer term).

3. Capex remains elevated on clean-power additions

Chinese gencos will accelerate spending to meet power-mix targets, while grids will keep up infrastructure construction to facilitate structural change of power supply. Natural gas distributors may add investments in upstream facilities, such as LNG terminals, to achieve cost advantage. Hong Kong's spending on power infrastructure will be compensated by higher tariffs.

Profitability of IPPs to restore on moderating fuel cost

China's coal-fired power operators suffered losses in 2021 mainly due to surging coal prices amid coal shortages. Tight supply led to average unit fuel cost increasing by more than 50% in the first half. The Qinghuangdao 5500kcal index peaked at Chinese renminbi (RMB) 2,593/ton in October—a 318% year-on-year rise—before dropping 69% from the peak to about RMB800/ton by end-2021 upon implementation of new government requirements and policies. We expect coal prices to moderate further in the first half of 2022 on boosted coal domestic supply and higher imports. Monthly production capacity from qualified domestic coal mines expanded 22% to 318 million tons by November 2021 compared with July 2021. At end-October 2021, the central government set a benchmark pit price for coal mines, capped at a 20% upper limit, resulting in a level higher than the average price in 2020, yet preventing irrationally high pricing in the near term.

Losses at coal-fired units began to narrow toward the end of 2021. Following a notice by the key planning body NDRC in December 2021, IPPs are required to sign long-term contracts with coal suppliers to cover 100% of their coal usage in 2022, so as to minimize supply disruptions. The contractual prices, however, may still frequently adjust to reflect the market price, though with some time lag. In our base-case for most Chinese IPPs, we expect a year-on-year decline of 4%-8% in average fuel cost for their coal-fired segments in 2022-2023. Every 1% decline in coal costs could translate into 1%-2% increase in EBITDA for the IPPs that we rate.

The power crunch also reflects ineffective cost pass-through for power operators. In October, the State Council announced a new tariff policy where electricity supply for non-residential/agricultural users can henceforth trade at a wider range in the open market of -20% to +20% over the benchmark (previous -15% to +10% in 2019). After the change, a few provinces announced coal-power tariff hikes by the maximum 20% over the benchmark price. We believe the increased flexibility on tariffs and a wider scale of market-based trading volume (all coal-fired generation will be sold at market-based trading) will help IPPs to pass through cost fluctuations more frequently in the future, fostering a better financial condition for operations and further investments in renewable capacity. We estimate a 1% hike for coal-power on-grid tariffs could translate into 1.5%-2% increase in EBITDA for the IPPs.

On the retail side, the preset retail tariff catalogues for all commercial and industrial users will be scraped and replaced by market price from the power suppliers or via agents over the grids. Industries with high energy-intensity may pay an even higher tariff with no bound to the 20% upper limit (see above) , which is in line with government's commitment to its climate policies.

For China's natural gas distributors, higher global gas prices and the domestic power crunch squeezed dollar margins on both the supply and demand side in 2021. Many cities have already raised retail gas tariffs (residential and non-residential), mostly effective from Sept. 1, 2021. Sales for the distributors we rate are mainly to commercial and industrial (C&I) customers, which are better able to bear the brunt of tariff increases than residential customers.

In Hong Kong, we expect power operators to withstand cost fluctuations under the protection of the long-term Scheme of Control regulatory framework. Electricity tariffs can be adjusted to match the fuel cost at a more frequent manner under the recent reset since 2019.

Net-zero policies as a driving force for energy transition

China's 14th five-year plan (14FYP) has set a course toward decarbonization and fulfilment of its Paris Agreement commitments. In late 2020, China announced commitment to achieve carbon peaking by 2030 and carbon neutrality by 2060. It also raised the 2030 target of non-fossil fuel in primary energy mix to 25% from 20%, and the ratio will further increase to 80% by 2060. Accordingly, share of coal as generation mix will likely to decline to 45% by 2030, from over 70% in 2005. Hydropower, as the key components will see addition of a total 80GW by 2030, including some 26.2GW from the newly commissioned Wudongde and Baihetan projects by 2022.

The government's flexible economic growth target of "above 6%" for 2021 and omission of an explicit growth target in the 14FYP could provide some breathing room to achieve climate change priorities. The temporary power supply disruptions to the high energy-intensity industries in 2021 was a demonstration of the government's commitment to its climate targets. Industrial companies in provinces that were lagging behind the "dual-control" targets (energy consumption and energy intensity) experienced power halts in the third quarter and then material hikes in electricity tariffs. To fulfill the "dual-control" goals in the future, more intake of renewables is essential given wind and solar power is not counted in the total energy consumption targets.

We expect the economic recovery from COVID-19 will support power demand growth over the next one to two years. As a result, renewable operators could benefit from enhanced utilization hours by replacing fossil fuels. In 2021, national power demand saw a robust growth of 10.3% year-on-year, or up by 5.8% compared with the growth rate in 2019. The continuous transition of power consumption is also an indicator of China’s path to decarbonize.

While China aims to have at least 1,200GW of wind and solar capacity by the end of 2030, implying approximate 67GW of new installation annually over this decade, the target could easily be surpassed. Operators rushed more than of 120GW wind and solar projects out in 2020, in part to catch the last window for central-government subsidies. The National Energy Administration (NEA) pushed for some 90GW of installation of renewables in 2021, despite the lack of subsidy and potentially higher construction cost due to higher commodity prices.

China's demand for natural gas remains strong to reduce air pollution and carbon emissions. We expect gas demand growth to outpace GDP growth over the coming years thanks to new demand from ongoing urbanization and industrialization and replacement demand of conversion from coal and oil.

Capex remains elevated on clean-power additions

The "Big-Five" state-owned IPPs, who contribute about 45% of power supply in China, will accelerate their expansion of renewable capacity to align with the national goals – they are aiming to have a 50% mix of renewable capacity by 2025. We anticipate capex in the generation segment will increase by 15%-20% to RMB600 billion-RMB620 billion in 2022, mainly in renewable projects. Unit construction cost will trend down gradually on technology advances, though offset moderately by up-pick of commodity prices.

In China’s oligopolistic transmission and distribution (T&D) sector, investment by State Grid Corp. of China (A+/Stable/--) may peak at RMB530 billion-RMB550 billion annually in 2022 for constructing several ultra-high voltage transmission lines and installation of power storage facilities to accommodate rising mix of renewables in the system. China Southern Power Group (A+/Negative/--) will also support key infrastructure projects, such as in Guangdong province within the Greater Bay Area. We expect companies to prioritize domestic market investment given stagnated overseas expansion due to travel bans.

We expect stable capex for pipeline construction as large gas utilities purse organic growth. They will also deploy capital to integrated energy businesses as a new growth driver.

Hong Kong-based power utilities plan their capex in accordance with the government's five-year development goals. In addition to maintenance, they are also spending on building up new gas-fired facilities to meet Hong Kong's 2030 fuel mix target. CLP Power Hong Kong Ltd. (A+/Stable/A-1) and Hongkong Electric Co. Ltd. (A-/Stable/--) are jointly investing in the Hong Kong offshore LNG terminal project, which involves the use of floating storage and regasification unit technology for the first time in Hong Kong. This is approved capex and as such is entitled to permitted returns and compensation via base tariff hikes if necessary.

Credit metrics and financial policy

We anticipate Chinese utilities will maintain rating headroom despite declining trend on credit metrics. This is partly attributable to the strong government support and most SOEs’ strong refinancing ability amid a declining interest-rate environment.

The financial policy of Chinese utilities, especially the state-owned gencos, is generally less supportive to ratings due to their debt-driven growth strategy. The Big Five have significantly grown their capacities in the past decade to address growing energy demand, and their stubbornly high capex led to high leverage. Their ratios of total liabilities to total assets (gearing ratio) all hover 70%-80%. On the other hand, profitability and cash flows are volatile and vulnerable to fuel cost swings although tempered moderately by more flexibility in tariff adjustments.

As demanded by the State Assets Supervision and Administration Commission (SASAC), the Big Five will continue employ various measures to deleverage, such as introducing strategic investors, public listing of operating assets, debt for equity swaps, and issuing perpetual bonds (perps). S&P Global Ratings treats those perps as debt because they are either senior in the capital structure, or provide high step-up coupons and short call periods--conditions that do not meet our criteria for equity treatment.

In our view, high capex will continue to weigh on the Big Five’s leverage and credit strength, and their deleveraging efforts will pay off only if the companies keep improving profitability and recapitalize their balance sheet with real equity finance.

Key risks or opportunities around the baseline

1. Accelerated power reform facilitates cost pass through

Coal power is now 100% traded on a market basis and as such, the segment's tariffs should better reflect supply demand dynamics. Gridcos will benefit from a more transparent and stable regulatory regime despite reduced T&D tariffs in the regulatory period that began in 2021. Natural gas distributors will also see more effective cost pass-through under China's reform process.

2. Nuclear is on the rise

While renewables will drive the mid-term energy transition, nuclear power is also an indispensable part of the country's long-term decarbonization goals, given its low emissions, stable output, and competitive operation costs. China targets to add 150GW of nuclear projects under operation or construction by end of 2035.

3. Carbon trading and ESG will have critical impacts

China's first year of carbon trading in 2021 lacked excitement, likely due to limited incentives for the power genco participants. Once more industries enter the market, transactions and price dynamics should become more meaningful. ESG will increasingly have a profound impact on investor decision-making, which will also serve as critical factor for Chinese utilities companies to transit away from coal power.

Accelerated sector reform facilitates cost pass-through

China’s ongoing power sector reform aims to deregulate the upstream generation and the downstream retail market, while tightening the regulation on the midstream power transmission and distribution. It aims to liberalize the electricity price for C&I use which accounts for 60%-70% of total power consumption in China. Electricity prices for public welfare, such as households and agriculture, will continue to be regulated.

Reforms accelerated after last year's power shortages, especially for coal power. 100% of coal power is now traded on a market basis, mostly via direct power sales (DPS) to large industrial users on the arm-length basis as well as through market trading centers in Beijing and Guangzhou. Power tariffs will better reflect supply demand dynamics.

In late 2021, the NDRC and the NEA also encouraged renewable energy to participate in market-based trading. New renewable projects will be more cost competitive) when competing with coal-power. The higher system cost for intaking more renewables can be passed to the user side in a more efficient way.

In late 2020, the NDRC announced the provincial level T&D tariff over 2021-2022. The average T&D tariffs after this second round of reset was generally lower than that in the first regulatory period (2017-2019). This is partly due to more stringent criteria and auditing for the regulatory asset base and permitted cost, despite permitted returns remaining largely stable. In addition, the actual earnings of gridcos were higher than expected in the past regulatory period due to better-than-expected power demand, leaving room for adjusting down tariffs in the next period from the cumulated surplus account. We expect the regulatory regime for grid operators to head toward a more transparent and stable trend. Government intervention--such as letting gridcos charge reduced retail tariffs to C&I users in the past three years-- is unlikely to replicate in the future, in our view.

China's latest 2020 central pricing catalogue specifies city-gate tariffs will be determined by market forces in provinces with sufficient competitive conditions. This is an important reform step because gas distributors in those provinces typically have denser networks and multiple gas sources, and therefore face gas costs that are more reflective of market conditions. The reform would indirectly push consolidation because companies of a smaller scale wouldn't typically obtain better upstream input costs.

Nuclear is on the rise

Around COP26 held in November 2021, the Chinese government reiterated its goal of adding 150GW of nuclear power projects over the next 15 years. During the 14FYP that runs to 2025, about 15 units of nuclear power projects will be constructed, amounting to about 16GW, comparing 53.2GW total installed by end of 2021. The ambitious long-term target implies nearly 130GW will have to be added between 2026-2035. Risks lay with new technology applications and approval for inland nuclear power projects which may arouse public resistance given safety concerns. Given geopolitical tensions, we anticipate new projects may prioritize China's self-designed G-III reactor, HPR1000 and CAP1400, to avoid unexpected technology boycott from other nations.

China has the world's fastest-growing nuclear generation fleet and ranks the second in the global nuclear league table. The country has established a complete supply chain and accumulated rich experience and a skilled work force in the design, construction, project management, and operation of nuclear plants. That said, nuclear power accounted for about 5% of electricity generation in 2021, well below the global average of about 10%.

Nuclear power will be cost-competitive in China on operating basis compared with thermal power in China. Its per unit generation cost including fuel is less volatile and more competitive compared with thermal power. Construction costs of HPR1000 reactors will likely come down with engineering improvement and more reactors adopt the technology. Nuclear power also seems an indispensable part of China's decarbonization goals. This is because of resource constraints and the intermittent nature of renewables, at least given the current technology developments.

The credit quality of nuclear companies such as China General Nuclear Power Corp. (A-/Stable/--) is boosted by our expectations of state support, given leveraged investments in nuclear and non-nuclear projects. In addition, State Power Investment Corp. Ltd. (SPIC; A-/Stable/--), one of China's Big Five power generators, commissioned its first majority-owned nuclear power project in October 2018.

Impacts of carbon trading and ESG can be profound

China launched its carbon trading scheme (CTS) in July 2021. The past six months saw limited trading volume and liquidity in the market. The initial scheme only covered about 2,162 power generation companies. Given most power gencos have mixed-asset portfolios and carbon quotas are not yet very demanding , they generally have limited incentive to trade carbon credits in the market at the stage. Nevertheless, we expect to see a more activated and meaningful carbon price in the near future upon participation of other industrial sectors, such as cement clinkers and electrolytic aluminum in 2022. Moreover, in time the government will post more stringent carbon quotas. Carbon credits will serve as an important market tool for these industrial companies to decarbonize. Eventually, the carbon credit may supplement income to suppliers, mainly renewable gencos, to compensate loss of tariff subsidies for their new projects. We also expect the CTS to function with other initiatives, including mandatory green certificates and the renewables quota system, to accelerate China's transition to a low-carbon economy.

ESG is evolving rapidly. Utilities have always been at the forefront of ESG, given the sector is responsible for 60% of global primary energy consumption and 40% of carbon emissions (mainland China: 45%). Renewable operators are ahead of the curve in the appreciation of ESG factors, given more investors now consider ESG factors in their investment decision making process. Not only demand from asset owners, but also ESG factors play an important role in terms of the risk-reward profile in the investment process. ESG issues may present the risks of damaged assets, reputation, changing regulations and—with increasing frequency--catastrophic events. As a result, ESG trends are providing more information to investors and increasingly weighing on their position in sectors or issuers.

Industry credit metrics

China and Hong Kong Utilities

Chart 15

Debt / EBITDA (Median, Adjusted)

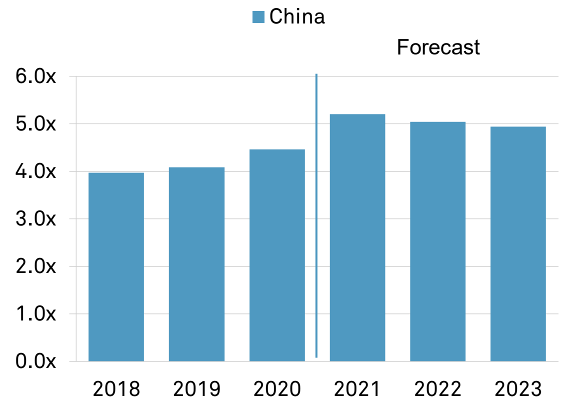


Chart 16

FFO / Debt (Median, Adjusted)

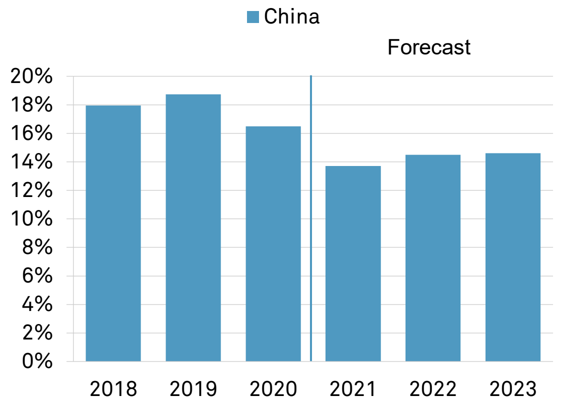


Chart 17

Cash flow And Primary Uses

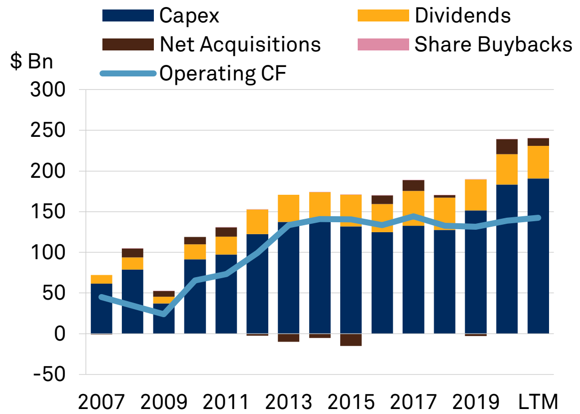
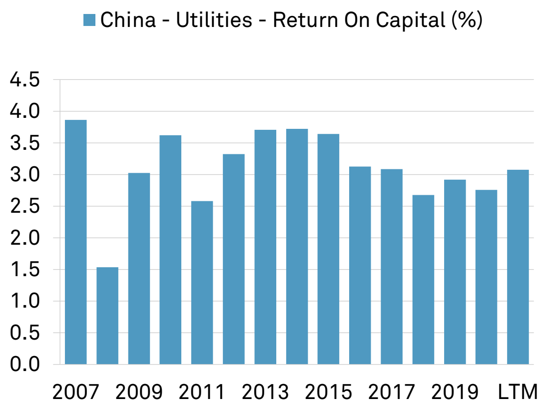


Chart 18

Return On Capital Employed



Source: S&P Global Ratings, S&P Global Market Intelligence. All figures are converted into U.S. Dollars using historic exchange rates. Forecasts are converted at the last financial year-end spot rate. FFO--Funds from operations. Most recent (2021) figures are using last twelve months (LTM) data.

South and Southeast Asia

Ratings trends and outlook

Regulatory continuity and resilient demand with economic recovery will continue to support the stable rating outlook for South and Southeast Asia Utilities. Opportunistic or strategic acquisitions to improve energy mix will be the key rating drivers.

Main assumptions about 2022 and beyond

1. Power demand to grow in line with the economy

We expect power unit demand growth of 3%-5% for most South and Southeast Asian (SSEA) economies. This will be driven by revivals in economic and industrial activities and will be broadly in line GDP growth, which we estimate at 2.5%-7.8% for most of the SSEA countries. Tariff increases will be driven by regulatory frameworks which vary significantly across the region.

2. Capex and leverage to remain elevated

We estimate ratios of debt to EBITDA for most power utilities in the region will continue to trend between 4x-6x. Indian and Indonesian utilities will likely maintain higher leverage of around 6x or above due to continuing capex. We forecast utilities in Singapore, Malaysia and Philippines will maintain relatively lower leverage of between 3x-4x due to moderate capex.

3. Share of renewables will continue to grow in the region, but fossil fuels will remain the mainstay

The share of renewable energy will continue to increase in the generation mix of most markets in the region, albeit from a relatively lower base (over 70% fossil fuel for most). However, coal and natural gas will remain the dominant fuel in these markets to meet the base load demand and increasing energy needs of the economies.

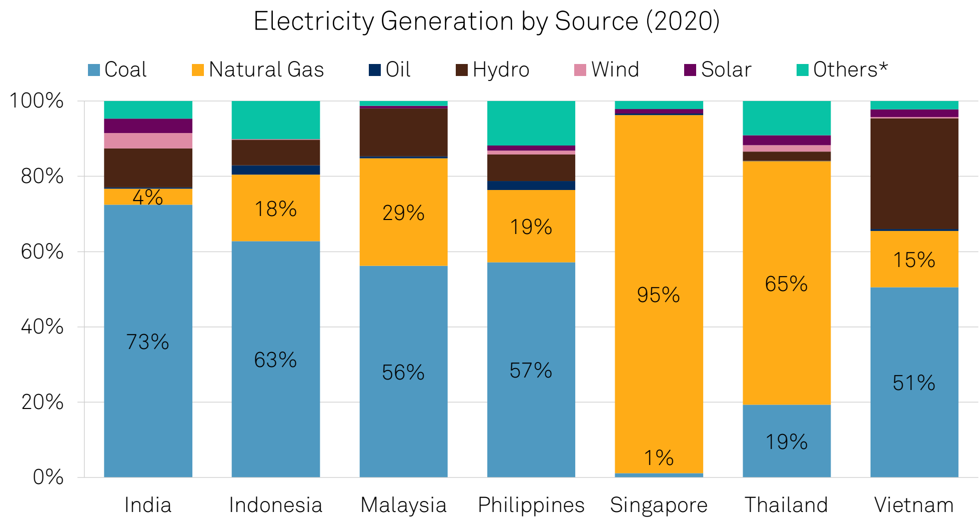
Moderate power demand: Economic growth for key SSEA markets is estimated to range between 2.5% to 7.8% for 2022 While the pace of vaccination and new infections vary significantly, most governments in the region favor targeted mobility lockdowns rather than the nationwide restrictions seen at the beginning of the pandemic. Power demand will largely be in line with economic growth, driven by improving economic activity; particularly in the industrial and commercial sector. Since these sectors tend to cross-subsidize the lower tariffs for some residential and agricultural customers, their recoveries should positively support earnings. Tariffs in India for centrally regulated power plants will reflect changes in costs and automatically adjust; while in Indonesia, we don't expect any tariff changes since the government put tariff caps as a precursor to elections in 2019 and as evidenced by new 10-year plan assuming no tariff increases over the period. India and Indonesia managed to maintain unit demand in 2021 despite COVID due to stronger residential and agriculture demand offsetting falls in industrial demand. However, demand fell by 3%-5% in other industrial economies like Malaysia, Thailand, and Philippines due to disruptions in industrial activities--which we now expect to revive.

Elevated capex and leverage: Utilities in India and Indonesia continue to add significant capacity to meet power demand and energy transition needs. Operating cash flows will be insufficient to cover investment needs so additional debt will be required. We believe regulated utilities in India will continue to adopt an 80:20 debt to equity mix for new projects. Continuing capex and existing high leverage will keep ratios of debt to EBITDA at about 6x for large national utilities across the value chain (generation/transmission). Private renewable players continue to burn through cash flows to chase size and growth resulting in even weaker financial metrics than traditional utilities—i.e., ratios of debt to EBITDA of 6x-8x and EBITDA interest coverage of below 1.5x. Strong financial sponsors and investors looking for green investment opportunities continue to provide capital at attractive rates. Utilities in Singapore, Malaysia, Thailand, and Philippines have relatively modest growth opportunities and capex mostly conservative financial profiles, with ratio of debt of EBITDA of 3x-4x. That said, more aggressive debt-funded capex for energy transition could weaken such profiles

Growing renewables but dominant coal: We expect the share of renewables to continue to grow in most countries in the region. Fossil fuels still generate 60% or more of the power needs for most countries in the region (see chart 19). In India, renewables growth is driven by their relatively lower costs while in most other countries in the region it will be driven by efforts (policy driven or otherwise) for energy transition. The COVID shock has allowed power deficit-countries like India and Indonesia to temporarily bridge the supply gap, while reserve margins in many other countries have increased above their desired level of 20%. This has also allowed for policy options to encourage faster adoption of renewables. However, we don't expect the pace of energy transition before 2025 to be transformational. The energy policy plans--even for countries like Indonesia, which has announced no more new coal plants post 2025--are highly dependent on emergence of cheaper storage solutions for renewables by that time. In the event that such technologies fail to emerge, these plans will be back on the drawing board.

Chart 19

Fossil Fuels Will Remain Dominant In SSEA



*Includes geothermal, biofuels, biomass, nuclear and waste. Sources: IEA, EIA, BP Statistical Review of World Energy 2021, Philippines Department of Energy.

Credit metrics and financial policy

The credit quality of power majors in the region is partly dependent on continuing government support, which we believe remains intact across all markets. Indian utilities expanding into the renewable business don't benefit from an assured returns and cost pass-through mechanism. However, 25-year fixed-price contracts provide strong cash flow visibility. Varying generation capability due to resource risk also remains a key watchpoint for Indian renewables' credit quality. Southeast Asia power majors are using balance sheet flexibility to diversify into different markets (Thailand utilities) or increasing renewables investments, which can impact their credit profile.

Key risks or opportunities around the baseline

1. Energy transition may not be smooth due to evolving policies

Many countries in the region depend on coal and have made commitments to reduce its high share in the energy mix. New policy directives could change the industry landscape. For instance, Indonesia has announced no more new coal plants after 2025. Coal shortages and demand pressures in 2021 have already led some governments to work on solutions to ensure continuing thermal power generation while the plans for renewable energy remains unclear for providing 24/7 power supply.

2. Operating cash flows could diverge from operational performance

Indonesian power companies are significantly dependent on subsidies and government compensation for meeting their interest and debt servicing needs. Any delays in payments from the government can constrain cash flows. Similarly, Indian utilities continue to face burdens from delayed payments of receivables from weak state distribution utilities. This can significantly burden working capital on already leveraged balance sheets.

3. Challenges to contractual sanctity

In markets with cheaper costs for renewable power, we see increased risk of contractual challenges or renegotiation for coal-power producers or renewable players providing power at significantly higher rate than current levels. While we expect contractual sanctity to be ultimately upheld in the case of dispute with State of Andhra Pradesh with Indian renewable players, continuing delays in payments of full tariff is swelling overdue receivables. Indonesia's power major has also engaged in contractual renegotiation with some IPPs. The state-owned power major says this is on a mutually agreeable basis but, in our view, this process can significantly impact the timing of the cash flows for the IPPs where it's renegotiated downwards.

Energy transition can be bumpy: Most SSEA countries have significant reliance on fossil fuels (~80%) and high economic growth rates, complicating their plans for energy transition. Few if any countries have clear plans for active phase-outs and most are primarily adding renewables capacity to slowly improve the generation mix. The pace of the energy transition will depend on two key factors: the policy direction and commercial incentives. Some countries which have come out with blanket policies, e.g., Indonesia will prohibit new coal plants post 2025. Such policies will require significant shifts in their ability to scale up renewable capacity. Otherwise they will risk missing energy targets like in the past, or transition targets in the future. Also, the plans are highly dependent on the evolution of cheaper industrial-scale storage solutions. If such solutions fail to emerge by 2025, the ability of most countries to transition would be significantly impaired. India has been increasingly bidding out round-the-clock power solutions to bridge this gap but won't see the first such projects completed until 2023. The profitability and returns of such projects will be key to their growth potential.

Cash flow divergence poses risk: The regulated nature of power utilities and the resilience of demand means that most utilities in the region remained relatively unscathed even during peak of COVID. We believe earnings for regulated utilities will remain largely protected, including from the sharp increase in coal prices (with potential time laps depending on the effectiveness of the regulatory system). However, the key risk lies in divergence between reported profits and cash flows. The Indian power sector's cash flows can be hard hit by overdue receivables: these ballooned to ~US$17.5 billion (as of December 2021) despite a relief package to state distributors. Further burdens on working capital or delays in collections would make it even harder to deleveraging from already high levels of 6x-8x ratios of debt/EBITDA. Perusahaan Perseroan (Persero) PT Perusahaan Listrik Negara (PLN) is dependent on timely subsidy payments of about Indonesian rupiah (IDR) 60 trillion a year just to meet even its interest obligations. Any inordinate delay in monthly subsidy payments breaking past the decade's record can put the power major under financial distress. Deferred compensation payments (about IDR30 trillion a year) are paid in lump sums and with a lag. Significant delays would hit cash flows hard, given continuing capex and insufficient cash flows from flat tariffs.

Industry credit metrics

South and Southeast Asia Utilities

Chart 20

Debt / EBITDA (Median, Adjusted)

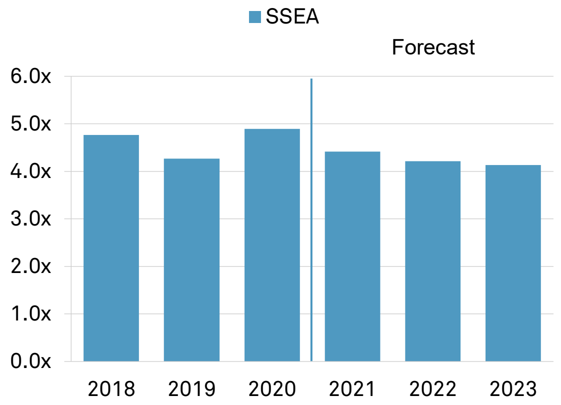


Chart 21

FFO / Debt (Median, Adjusted)

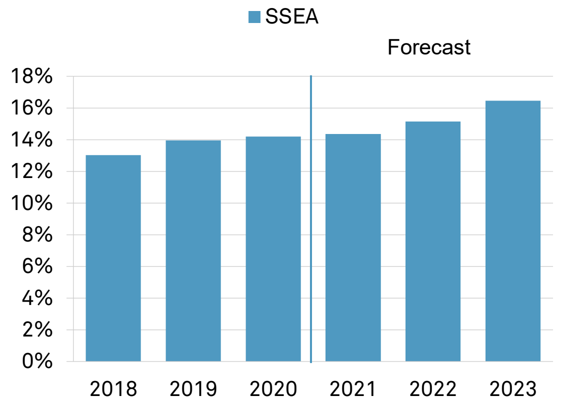


Chart 22

Cash Flow And Primary Uses

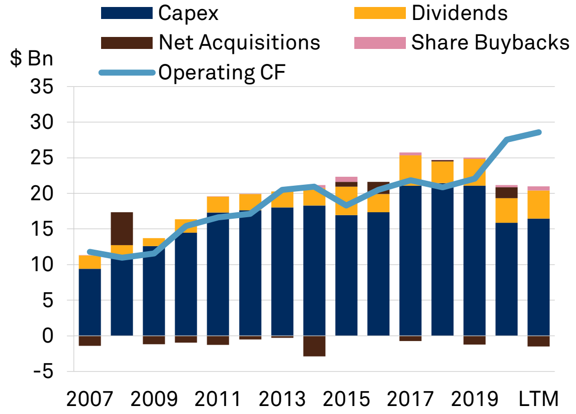
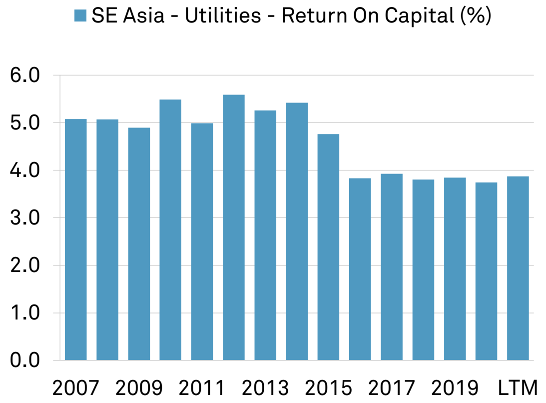


Chart 23

Return On Capital Employed



Source: S&P Global Ratings, S&P Global Market Intelligence. All figures are converted into U.S. Dollars using historic exchange rates. Forecasts are converted at the last financial year-end spot rate. FFO--Funds from operations. Most recent (2021) figures are using last twelve months (LTM) data.

Related Research

- Credit FAQ: China's Power Outages--Get Used To It, Oct. 18, 2021
- Sector Review: China's Gas Distributors Won't Get Burned By Higher Costs, Oct. 7, 2021
- Energy Transition in Asia-Pacific: A Marathon, Not a Sprint, April 19, 2021

spglobal.com/ratings