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The Clean Technology Fund and Concessional Finance

Lessons Learned and Strategies Moving Forward

BloombergNEF

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The Clean Technology Fund and Concessional Finance: Lessons Learned and Strategies Moving Forward

This report was commissioned by the Climate Investment Funds, a multilateral climate fund housed within the World Bank and produced by BloombergNEF. It aims to improve understanding of how CTF funds have been deployed in support of renewables to date. It assesses how this capital has impacted low-carbon markets in target countries and considers how concessional financing could be optimally utilized in fast-growing, high-emitting developing countries, with a focus on middle-income countries. The report seeks to emphasize how to crowd-in private finance for utility-scale renewable energy projects.

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About

The $8 billion Climate Investment Funds (CIF) accelerates climate action by empowering transformations in clean technology, energy access, climate resilience, and sustainable forests in 72 developing and middle-income countries. The CIF's large-scale, low-cost, long-term financing lowers the risk and cost of climate financing. It tests new business models, builds track records in unproven markets, and boosts investor confidence to unlock additional sources of finance. The CIF business model, which is based on the programmatic approach as its primary model of delivery, leverages the expertise, standards, and global reach of the MDBs to drive climate action at scale through both advisory and investments at both the strategic planning and project implementation phases. The Climate Investment Funds encompasses four different programs: the Clean Technology Fund (CTF), the Scaling-Up for Renewable Energy Program in Low-Income Countries (SREP), the Pilot Program for Climate Resilience (PPCR) and the Forest Investment Program (FIP).

The Clean Technology Fund

The Clean Technology Fund (CTF) was established under the Climate Investment Funds to provide scaled-up financing to developing countries for the demonstration, deployment, and transfer of low-carbon technologies with a significant potential for long-term greenhouse-gas emissions savings. The objectives of the CTF are to finance transformation through large-scale financing of low-carbon technologies and innovative business models in energy efficiency, renewable energy, and sustainable transport while providing experience and lessons in responding to the challenge of climate change through learning-by-doing.

During the past 10 years of operation, the $5.5 billion CTF has financed the development and implementation of low-carbon investment plans in 15 middle-income countries, a regional program on concentrated solar power (CSP) in the Middle East and North Africa, and three phases of Dedicated Private Sector Programs. The CTF portfolio encompasses large-scale investments in energy efficiency in industrial, commercial, and residential sectors; renewable energy technologies ranging from solar to geothermal, wind, and biomass; and sustainable urban transport for public transit, hybrid buses, and green logistics.

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Section 1. Executive Summary

The economics of clean energy have been transformed radically and positively since the founding of the Clean Technology Fund (CTF) a decade ago. Costs of key technologies have plummeted so substantially that wind- and solar-generated power today are regularly cost-competitive in many parts of the world without the benefit of subsidies. Moreover, zero-carbon energy is no longer a privilege exclusively for wealthy nations; it is affordable and accessible to billions in less developed countries as well.

These changed circumstances offer a useful juncture for reconsidering the role concessional finance and development finance can play in fostering further clean power production, delivery, and consumption[1]. While major progress has been achieved, considerable work remains to ensure non-OECD nations can grow their economies without expanding their energy-sector carbon footprints.

Using the lens of the CTF experience, this report contemplates the best new opportunities for deploying concessional capital. It starts by reviewing CTF efforts in five select countries: Chile, Kazakhstan, Mexico, Morocco, and Thailand[2]. It then delves into how the economics of clean energy have shifted in recent years and stand to progress further in the short and longer term.

The report presents an analysis of how the cost of capital affects the competitiveness of wind and photovoltaics (PV) vs. fossil generation in developing countries. It then offers a simple framework that could be used by development finance institutions when considering investment opportunities. Finally, it examines four technologies and their applications – power storage, distributed PV, offshore wind, and digitalization – that could be intriguing areas for CTF capital deployment.

As the report covers such a wide spectrum, its key findings are best sub-divided by the topics they address below.

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[1] Development finance can be broadly defined as the use of public sector resources to facilitate investment in low- and middle-income countries where the commercial or political risks are too high to attract purely private capital, and where the investment is expected to have a positive developmental impact on the host country. Concessional finance is a subset of development finance; concessional finance instruments including loans, grants, and guarantees are offered at below market-rate terms, such as through longer repayment times, low interest rates, or both. Development finance institutions often use concessional finance to de-risk or encourage certain investments.

[2] The CTF works mainly in fast- growing middle income countries. Therefore both the retrospective and forward looking analyses in this report generally focuses those countries.

Key findings on CTF activity in five key countries:

- **In the nations examined** – Chile, Kazakhstan, Mexico, Morocco and Thailand – **CTF has invested $749 million in 2.3GW of utility-scale clean energy projects** (as of year-end 2017). This, along with $1.3 billion in co-financing from multilateral development banks (MDBs) helped achieve total leveraged investment worth $6.2 billion, with project developers, commercial banks and other development banks providing the rest of the capital.
- While much less **CTF capital** has been deployed to date in Chile than first envisioned, it **helped kick-start Chile's clean energy sector** in 2013. Chile has also moved rapidly to encourage clean energy development through a series of policies, including reverse auctions for clean power-delivery contracts, the availability of net billing for retail customers to encourage distributed solar, and a carbon tax to make fossil less generation less competitive overall.
- Chile today attracts large, multinational developers who can finance utility-scale projects directly from their balance sheets. Most recently, the market **has experienced issues related to an over-build of PV** as the country's overall electricity demand has not grown as quickly as anticipated. The presence of so much zero marginal cost, utility-scale PV on the grid has depressed power prices.
- In advance of providing funds to wind and PV plants, **CTF supported Kazakhstan's** clean energy policy development. In 2013, the country established **feed-in tariffs (FiT)** supporting wind, PV, hydro and biofuel power generation projects. The policy succeeded in jump-starting Kazakhstan's renewable energy market **helping to attract over $1 billion in clean energy investment**.
- A series of factors has historically limited capital deployment in Kazakhstan, including limited tenors for loans, high inflation, substantial currency fluctuation, and high interest rates. **CTF** sought to address these and its **in-country investment has totaled $55.5 million**, **which helped leverage $200 million of MDB co-financing, plus another $412 million in follow-up financing**. No less than 85% of Kazakhstan's existing installed PV capacity and 40% of its wind capacity have received CTF financial support.
- Total build has been limited to date, however and the market is now at an important juncture after the government held its first-ever tender for clean energy power-delivery contracts. Along with MDBs, **CTF could play a critical role in ensuring projects that won contracts under Kazakhstan's tender actually get built** on time and on budget.
- The policy landscape in **Mexico** has changed dramatically since CTF first engaged there a decade ago. The Peña Nieto administration (2012-2018) **undertook a major liberalization of Mexico's power sector which** also included a series of auctions for clean power-delivery contracts. This **helped spur a record $6.2 billion in new clean energy investment in the country in 2017** – more than was deployed in the prior three years combined.
- Well before the most recent reforms, CTF support in Mexico, along with incentives for large-scale self-generation from renewable energy plants, helped establish a local wind market. At the time of CTF's first engagements, access to long-term capital for projects was limited. Partly in response, CTF helped refinance two of the country's earliest wind farms, allowing developers to move on to other projects. **CTF funds were also deployed at the height of the financial crisis in Mexico to keep projects moving toward completion**.
- Today, wind and PV can undercut fossil sources of generation on cost in Mexico and attract private capital. Still, there may well still be a role for concessional finance in the country. To enter Mexico's PV and wind markets, large utilities are finding new ways to be competitive. But as the capacity of intermittent sources grows, concessional finance/development

institutions could have a role to play with newer, less mature technologies to accommodate deeper penetration of wind and PV.

- **Morocco has received more CTF funding than any other country, except India**. Utility-scale renewable energy projects received around $600 million from CTF plus almost $950 million in co-finance from partner multilateral development banks. This, in turn, helped attract an additional $4.4 billion in investment.
- **CTF financing was instrumental in kick-starting the solar thermal and PV sectors in Morocco.** Concessional financing lent credibility to these new technologies in a new market, mobilized capital and delivered competitively-priced generation available when the system needs it the most. Solar thermal, in particular, has been the technology that received the most support in Morocco with $435 million invested in the Noor I, II and III projects. More recently, another $25 million was announced for the Noor-Midelt solar project, which combines solar thermal and PV.
- **CTF has to date supported 134MW of utility-scale PV and 87.5MW of wind projects in Thailand** representing 5% and 10% of each technology's overall capacity there, respectively. Commercial banks in Thailand are generally well-capitalized, have financed fossil-fired plants, and are well positioned to support a clean energy build-out once they become more comfortable with PV technology risks.
- The varied experiences of these five nations highlight the multiple ways CTF capital and concessional capital writ large can be usefully deployed. Such funds can be channeled through partner MBDs, leveraging local expertise in the process. Or they can be used to partner with national institutions to develop effective policies.
- **Flexibility and agility are key**. Equipment costs can change quickly, along with local circumstances. The ability to adjust strategies on the fly is critical to avoid being caught flat-footed by new trends. **This inevitably requires** a willingness to take chances on new financing models, new business models, and new technologies. It also, inevitably, requires an understanding that new ideas often do not succeed – and **a high degree of comfort with failure**.

Key findings on future opportunities for deploying concessional finance in support of conventional renewable energy technologies:

- Auctions have been critical to the growth of the renewables pipeline globally. BloombergNEF tracked 57.7GW of new capacity contracted in 32 countries in 2017 alone, with two thirds in non-OECD nations. As of 1H 2018, BNEF was aware of 29GW of renewables projects seeking financing after winning contracts in auctions. **The bulging pipeline of tender-contracted projects** accompanied by promises to deliver power at record low prices, **has created substantial demand for affordable financing**. This may be an area where concessional finance is required. However, organizations need to be careful when providing concessional finance to auction-winning projects to avoid distorting markets or crowding out private finance.
- The cost-competitiveness of renewables in developing countries has historically been hampered by higher-priced domestic capital. As renewable power projects are capital-intensive, the cost of finance available to project developers has historically resulted in a segregation between wealthy and less developed nations. In OECD countries, the benchmark weighted average cost of capital (WACC) BNEF tracked for wind and PV projects in 2017-18 ranged from 2.5-6.5%. In emerging economies, the benchmark ranged from 5-11%.

- Differences in financing terms translate directly into discrepancies in total levelized costs of energy (LCOE). As a result, developing economies have tended to be home to the highest LCOEs.
- The good news: rapidly falling equipment prices and lower resulting capex's are reducing the influence financing costs have on final LCOEs. For instance, in 2017, for each percentage point increase in the overall cost of financing for a utility-scale PV, the LCOE rose $5.8/MWh. Thanks to lower costs for PV equipment in 2018, however, this had dropped to $3.3/MWh. Nonetheless, **affordability-priced capital remains integral to the economics of clean energy** projects and will remain so for the foreseeable future.
- When it comes to the long-term competition between clean and fossil-fired power generation, **BNEF has identified two key "tipping points."** The first comes when building and operating a new clean power plant is more cost-efficient than doing the same for a fossil plant. The second tipping point comes when a newly built clean energy plant can undercut the economics of an *existing* fossil plant an LCOE basis. In other words, the point when building and operating a new renewable energy plant should, in theory, trigger the retirement of an existing fossil-fueled plant.
- In developing nations where neither tipping point has yet arrived, **concessional capital can** be deployed to lower LCOEs for clean energy, **pull forward the arrival of tipping point one, and ensure only zero-carbon power-generation gets added to the grid**. In countries where the first tipping point has already arrived, **concessional capital can also be deployed to widen the advantage clean energy enjoys over other technologies**. In these nations, such capital also has the potential to accelerate the arrival of tipping point two **and bring forward retirement dates for coal-fired power plants**.
- In almost all markets, concessional capital can help move forward the date when tipping point two arrives. And for many countries, BNEF projects tipping point two is not too far in the future.
- **In Thailand**, for instance, new utility-scale PV financed on commercial terms **stands to undercut new combined-cycle gas turbine plants (CCGT) by 2019 and coal-fired power plants by 2020** to reach the first tipping point, BNEF estimates. Concessional capital has the potential to reduce the levelized cost of PV by 5.3%-7% putting those PV plants on par with new CCGT approximately one year earlier.
- **In India, concessional financing has the potential to shift the crossover point for new onshore wind with existing coal by at least two years** (*high LCOE scenario*) or four years considering the highest share of concessional finance (*low LCOE scenario)* This shift is fundamental considering India installed 94.3GW of coal over 2012-2017.
- **In Brazil** today, new PV and wind already outcompete new fossil fuel power plants on cost. Therefore, in Brazil, **concessional finance is likely to have a higher impact if directed to newer and less mature technologies** than conventional wind and PV. **The story is similar for Mexico.**
- An additional potentially useful analytical framework providers of concessional capital can use to identify opportunities takes into account the following characteristics for any given country:
  - **Its current enabling environment including policies on the books, the structure of its power market, and other attributes**
  - **The opportunities it offers, including current and future electricity demand**
  - **Its experience in clean energy development, including the volume of clean energy installed to date**

- Countries with **middling enabling environments** for PV and onshore wind **and low experience** in deploying those technologies **present the best potential opportunities for deploying concessional** finance in support of these technologies. Meanwhile, countries with strong enabling environments and high levels of experience suggest that concessional investment may no longer be needed for these technologies.
- Concessional finance provided to countries with weak enabling environments is likely to result in low impact in crowding-in commercial finance as these markets present more barriers to private investors. In these countries, **development institutions can play a crucial role in providing technical assistance to create new clean energy policies and support a power sector reform**.

Key findings on the potential for deploying newer clean energy technologies in developing nations:

- As generation from intermittent sources such as wind and solar grows so does the need for grid flexibility, including notably energy storage. Even in established markets, revenue uncertainty associated with storage projects has to date deterred investors. Lower costs of capital for energy storage projects would result in significant lower energy storage levelized costs of electricity. At the extremes, a project with a 2% weighted average cost of capital would have an LCOE $125/MWh lower than one financed at a 13% cost of capital. The **availability of finance**, especially concessional finance, **could prove crucial in incentivizing new-build storage globally**.
- **Concessional capital can have greater impact on the cost-competitiveness of lithium-ion battery projects than on conventional PV and onshore wind projects.** Specifically, in BNEF's benchmark scenario, for each percentage point rise in the overall cost of capital for a lithium-ion battery project, its LCOE rises by $10/MWh. This is three times the level of impact on storage as on onshore wind and PV LCOEs.
- Unlike the deployment of utility-scale power stations, the uptake of small-scale PV is a decision predominantly taken by households and businesses looking to offset retail power tariffs, to reduce their bills or, particularly in emerging markets, to improve the reliability of their electricity supply. BNEF estimates that **commercial-scale PV already makes economic sense without government support in many developing nations**. By 2035, the economics will work in virtually every developing country.
- Limited resources exist for funding distributed energy resources in developing nations today. Development finance institutions could up their use of concessional capital to support lending programs for small-scale PV projects, potentially in collaboration with domestic banks who may have better information on the credit-worthiness of would-be borrowers.
- BNEF projects the annual offshore wind installation rate to nearly double in the 2020s to 9.5GW. This would bring total global capacity to 129GW by 2030 from approximately 20GW today. Still, despite extraordinary progress seen to date in reducing offshore wind costs, **China, Taiwan and India are the only non-OECD markets where BNEF anticipates substantial offshore wind build** over the next decade given infrastructure and capital requirements.
- **India has set a bold goal of building 5GW offshore** by 2022 but what site assessments that have been completed there suggest the winds could be weaker than in areas where European projects have been built. BNEF anticipates capex for any first-of-its kind offshore project in India would be $2.03-2.83 million/MW depending on under-sea transmission costs and choice of turbines. BNEF does not expect India to hit its current offshore wind goals but

there may be a role for concessional finance to play supporting the country's first projects.

- **Digital systems** are currently used primarily in OECD nations to monitor and **optimize generation assets**, reduce operations and maintenance costs through predictive maintenance, and aggregate and control distributed assets to provide power and services to the grid. These technologies **can offer the same benefits to emerging nations' energy systems**, while also helping to address challenges specific to new markets. Emerging markets have a unique opportunity to leapfrog more developed countries in terms digital technology adoption on their grids. However, financing remains a challenge.
- **BNEF assessed the readiness of 128 nations to quickly digitize** their energy sectors. The higher the score, the higher the potential for progress in this area. **Chile, Colombia, Egypt, Indonesia, Mexico, Morocco, Nigeria, and Vietnam each offer intriguing opportunities and challenges** for the deployment of digital technologies.

This study's findings about potential opportunities for deploying concessional capital are by no means exhaustive. There are no doubt other countries and technologies where such funds might potentially be put to use.

That said, the report does offer frameworks and guidelines for considering new investment opportunities in a variety contexts. The economics of clean energy have changed dramatically and positively since CTF's founding. In light of that, new thinking about where and how to deploy capital is merited. This report is intended to contribute in some small part to that re-consideration.

Section 2. Retrospective analysis

Concessional finance has played a critical role in opening new markets for clean energy investment in developing countries. As recently as five years ago, developers of wind, solar, and other renewable struggled to raise capital from private financial firms to build projects in these nations. Typically, such financiers would cite both the technological and sovereign risks associated with renewables as being too high to deploy capital -- or at least too high to deploy capital at reasonable interest rates or expected rates of return.

Today, concerns over that first set of risks (technological) have to a large degree been allayed. In 2017, total wind, solar, geothermal, biomass, and small hydro capacity topped 1,000GW worldwide. The sheer scale clean energy has achieved to date is testament to the faith that the finance community now has in the reliability of these technologies. If anything, the fact that wind, solar, and other renewables projects do not rely on fuel inputs (and their associated fluctuating prices) can make them *more* appealing than fossil-fueled plants to financial backers.

The community of multilateral development banks, development aid agencies, export-credit agencies, and similar organizations have combined to allow clean energy to achieve scale in a growing number of nations. This group has also allowed clean energy to "prove out" its technologies in many parts of the world[3].

More immutable are the risks associated with individual developing nations. These can include questions over the stability of political systems, fluctuations in local currency, or the financial health of state-run utilities, among other factors.

Within the universe of financiers, the CTF has played the specific role of making almost $5 billion available to middle-income nations to scale up the demonstration, deployment, and transfer of low-carbon technologies in renewable energy, energy efficiency, and sustainable transport. This first section of the report seeks to parse out the role that CTF has played to date specifically in Chile, Kazakhstan, Mexico, Morocco and Thailand in allowing clean energy to achieve scale[4].

Each of the country studies below provides an overview on the nation's power sector and clean energy policies, details investment provided to new-build projects, analyzes the impact of CTF in the country's renewable energy sector and briefly discusses future potential roles for concessional finance.

Investment data crosses BNEF proprietary investment numbers with CTF's portfolio of investment. To deeper understand the impact that CTF and development banks had to date in each of the markets, the retrospective analysis look at type of investors providing funds to each key technology as well as lead providers in these nations.

Some country studies also include BNEF's proprietary historical levelized cost of electricity (LCOE) to assess progress of each technology's cost and competitiveness with fossil fuel-fired sources. BNEF defines LCOE as the long-term offtake price required to achieve a certain equity hurdle rate for a developer, considering its total capital, operating and finance costs over the

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[3] For example, see the World Bank report Strategic Use of Climate Finance to Maximize Climate Action for proposed framework for deciding how to use international public finance with a concessional component to maximize the impact of climate action.

[4] The CTF works mainly in fast- growing middle income countries. Therefore both the retrospective and forward looking analyses in this report generally focuses those countries.

lifetime of the project. The LCOE estimates exclude costs of grid connection and transmission. They also do not take into account subsidies or incentives as they are intended to assess the true economic viability of technologies outside the bounds of policy support. BNEF's LCOEs are derived from our monthly and semi-annual surveys of equipment buyers/sellers, combined with estimates about natural resource availabilities in countries.

To assess the more qualitative ways in which CTF investment may have impacted the markets where they were deployed BNEF conducted interviews with key stakeholders and other experts in the five markets analyzed. Interviews were split in three parts:

1. Project-level questions focusing on how CTF investment was deployed, its barriers, challenges and success and why concessionality was envisioned for those targeted sectors.
2. Market-level impact questions looking at the how conditions have changed over time and the role that CTF funds and concessional finance in general have played to driving down technology costs, supporting first-movers, bridging financing gaps, creating and de-risking markets, and innovating private sector finance, among other things.
3. Country-specific questions assessing the challenges and success stories unique to each market.

At the end of this section we analyse the Key findings and lessons learned in the five nations and summarize the impact of the CTF work in the select countries. This sub-section also highlights some future potential roles for concessional finance in these markets, which is further explored in the Forward looking analysis section of the report.

2.1. Chile

2.1.1. Country context

Overview

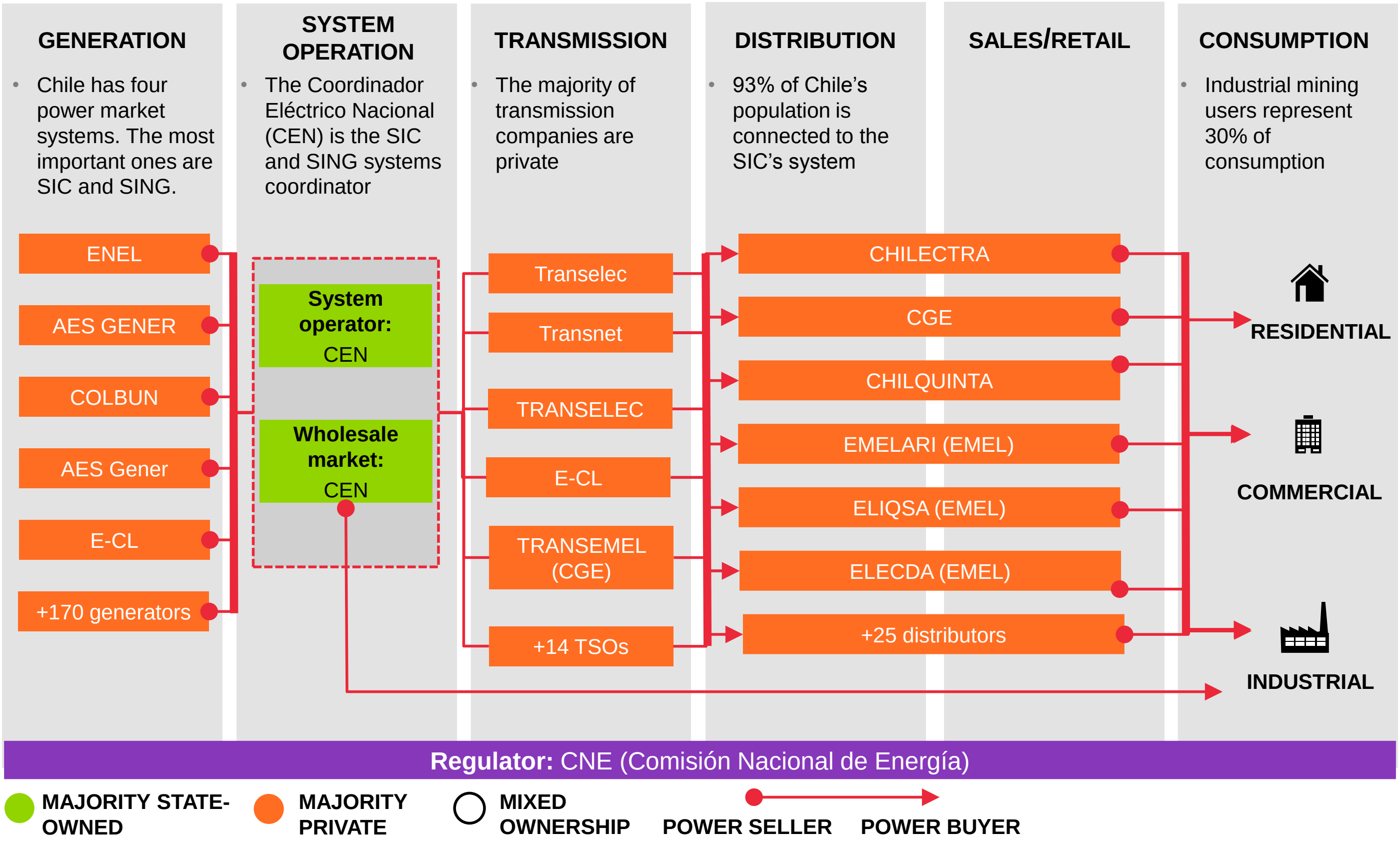
Chile is South America's fifth largest country by total GDP but its wealthiest on a per-capita GDP basis. The nation’s economy has benefited in recent decades from growing exports of copper, wood pulp, fish, and wine. A generally stable political climate and currency have also fostered confidence in Chile’s growth and helped to attract foreign capital.

Beyond its exportable commodities, Chile has over the last decade begun to capitalize on other domestic resources, namely gusty coastal winds, strong desert sun, and plate tectonic conditions that have made geothermal power-generation viable in some areas. A rapid shift away from fossil sources of power generation toward cleaner energy has been aided by the presence of a liberalized power market and strong policy support for non-large hydro renewables. Recent additions of new renewables in Chile have, in fact, been so substantial that they have created new challenges. The build-out’s unintended impacts: deeply depressed power prices and power curtailment in some regions.

Power sector structure

Chile's power sector has been de-regulated since the 1980s and invites private investment at multiple segments of its value chain, including generation, transmission, and distribution (Figure 1).

Figure 1: Chile power-sector structure



Source: BloombergNEF. Note: The SIC and SING systems were interconnected in November 2017.

Participants have included international power generators such as U.S.-based AES, Italy's Enel, and others, either directly or via various partnerships and joint ventures. Well over 100 corporate entities have been involved with owning power-generating assets. Transmission, distribution, and sales and retail services are similarly controlled by private players.

Chile has long had two major power grids (and two very minor ones) due mainly to the vertical nature of the country, which runs 4,300km (2,700 miles) from north to south (Figure 2). Over 90% of the population was traditionally served by the *Sistema Interconectado Central* (SIC) while the *Sistema Interconectado del Norte Grande* (SING) was critical in servicing the country's mining operations in northern part of the country.

Figure 2: Chile's power grids

Source: CNE

Figure 3: Chile installed capacity, 2017

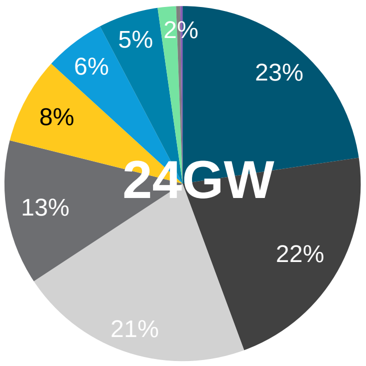
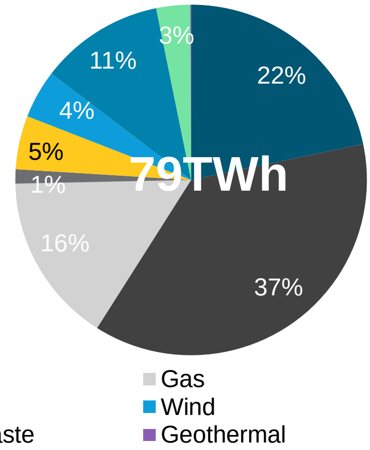


Figure 4: Chile power generation, 2017



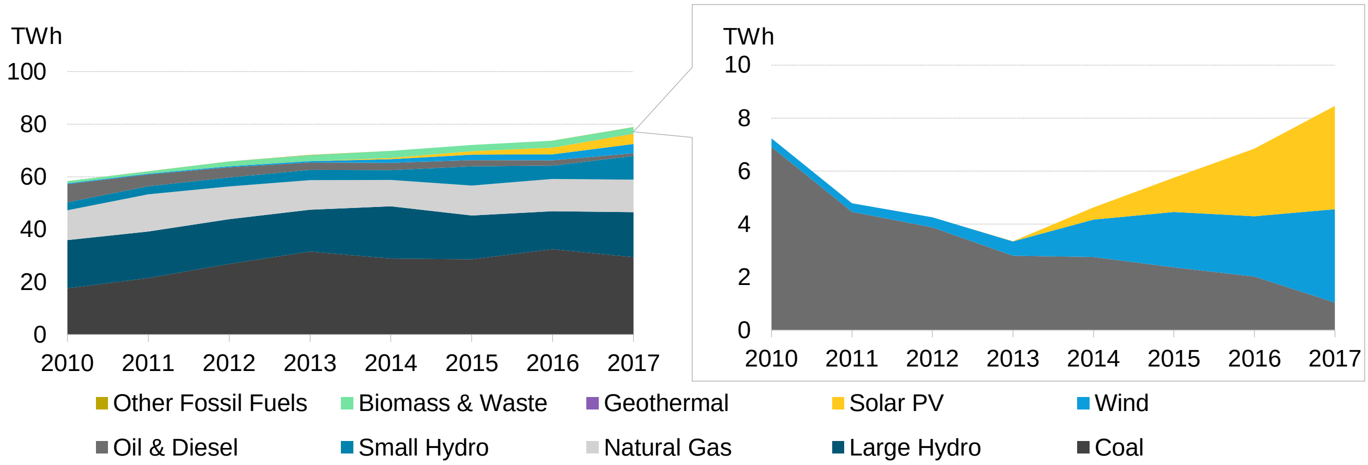
Source: CNE, BloombergNEF, Climatescope

The Atacama Desert in the north receives some of the strongest, most consistent sunshine on Earth and has seen substantial solar project development. The SING is home to a quarter of the country's total generating capacity, which largely serves mining operations in the region. For decades, the SIC and SING operated independent of one another. That changed in November 2017 when a new, $700-million interconnection was completed. Among its goals: to ease delivery of low-cost clean energy from the remote desert to population centers further south.

In addition to sun, Chile has exceptional wind and underground resources to support wind and geothermal projects. Today, solar, wind, geothermal, biomass, and small hydro account for 22% of the country's capacity and 24% of generation (Figure 3 and Figure 4). Given that capacity factors for wind and solar projects are typically below 50%, it is unusual for clean power generation in a country to exceed its capacity on a percentage basis. However, in 2017 capacity factors for Chile's gas, coal and oil plants slipped.

Figure 5: Chile generation by technology

Figure 6: Chile generation from select technologies



Source: CNE, BloombergNEF, Climatescope

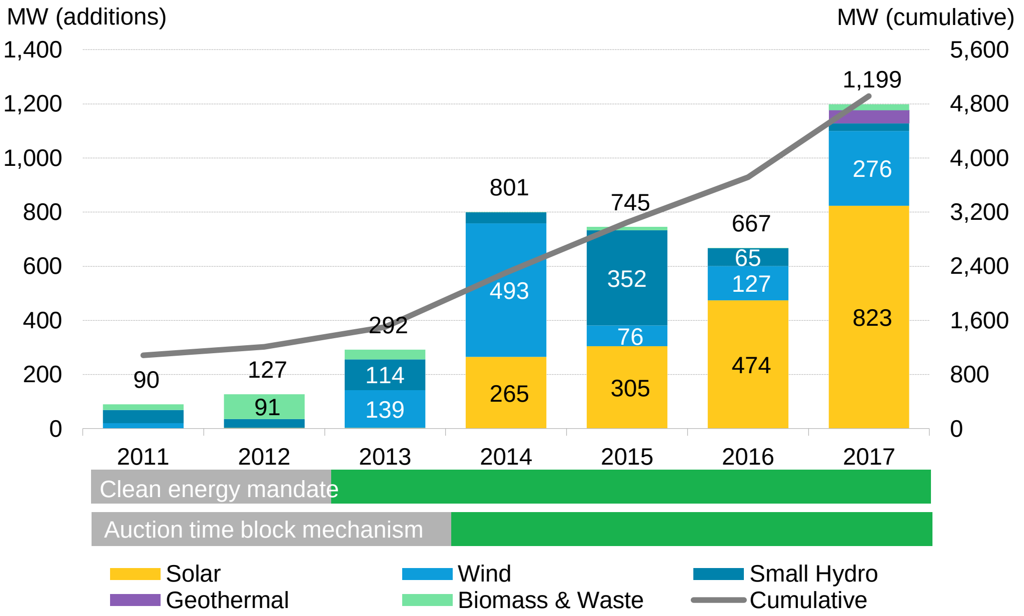
Policies

Chile has added virtually all of its non-hydro renewable capacity in the five years. That build-out has been spurred by concerted policy support from the national government starting in 2013 with the amendment of Law No. 20.527 and the requirement that utilities with up to 200MW of operational capacity meet 20% of their contractual obligations with renewable sources by 2025. The amendment marked a substantial increase from the 10% by 2024 goal Chile first set for itself in 2008.

The raising of the quota was well timed as clean energy equipment prices were just beginning a precipitous decline that has continued to today. Beyond merely setting a goal, the government followed through with specific policies to promote clean energy's growth. Most notable among these were:

- **Tenders to secure clean power-delivery contracts**. Chile has organized reverse auctions to procure power from various sources since 2006. But only in 2014 did the government create a tender mechanism tailored to wind and solar developers' needs. Under the new scheme, generators compete in auctions to supply power during specific periods of the day or "time blocks". This change served to improve the competitiveness of intermittent sources such as wind and solar by allowing them to bid most aggressively during the blocks when they could best serve the market. Such tenders have been technology-blind, meaning renewables have competed directly with fossil sources of generation. As wind and, in particular, solar costs fell, those technologies became increasingly competitive.
- **Net billing to promote distributed generation**. In October 2014, Chile began allowing those with localized, distributed power-generating capacity such as rooftop PV systems to "sell" their excess generation back to their utility at the retail rate by receiving compensating discounts on their bills. In cases where generation in a given month from a distributed system exceeds the amount a customer receives from the grid, credits can be rolled into the following month's bill. The program is similar to "net metering" schemes on the books in some U.S. states and elsewhere around the world.
- **A carbon tax to make fossil generation less competitive.** Law 20.780, passed in 2014, established for the first time a levy on CO_2 emissions. The regulation, which went into effect in 2017, requires power plants 50MW or larger to pay $5 per ton of CO_2 emissions.

Figure 7: Chile renewable energy capacity additions



Source: CNE, BloombergNEF

Nearly all Chile's current wind and PV capacity has been built since these policies were put in motion with the law supporting tenders playing a particularly critical role in supporting utility-scale demand. From 2014 through 2017, Chile brought on line 973MW of wind and 1.9GW of PV to become Latin America's third largest clean energy market (Figure 7).

In the first tender, held in 2014, renewables projects won contracts to deliver just 7% of the generation up for contract. The contribution of renewables' rose in the ensuing two auctions as the average price of the contracts slipped. In two of the last three tenders held, renewables have accounted for 100% of all generation up for contract.

The goal of the tenders was to tap market forces to solicit the lowest possible bids for clean energy and appear to have had their intended effect. A tender held in 2015 produced an average weighted bid price of $45/MWh for wind and $29/MWh for solar. Another reverse auction held in 2017 saw the average winning wind bid sink to $36 and solar bid fall to just $25. The auction also included a contract-winning PV project which promised to deliver power at an incredible $21.5/MWh for a project in the Atacama under development by Enel.

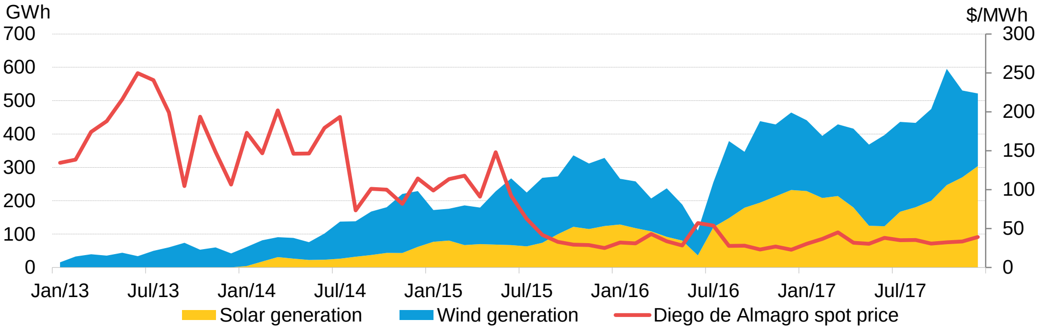
Rising renewable energy penetration, falling power prices

Despite better insolation and wind resources in the SING, where the Atacama Desert is located, SIC hosts 93% of wind and 70% of solar commissioned projects in Chile. Developers have often opted to build in the SIC because it is home to most retail power demand but still offers exceptional solar resources at the northern end of its grid. Only in November 2017 were the SIC and SING physically connected for the first time, via a 600-km line.

Because they have no associated fuel costs, solar and wind projects essentially operate as zero marginal-cost generators in Chile's liberalized power market. Provided demand exists, these projects generally generate and sell their power onto the system regardless of the power price. By producing for least cost and "at the bottom of the stack" of generators, they pull down the overall market-clearing price for all generators.

Chile has numerous nodes where power gets bought and sold and strictly speaking no single benchmark hub price. However, the Diego de Almagro node located near the northern end of the SIC is useful in illustrating the impact renewables have had on pricing in Chile. During one particularly active period from September 2014 through 2016, Diego de Almagro spot prices fell 72% while solar and wind output grew 379% and 29%, respectively, in the same period in the SIC (Figure 8).

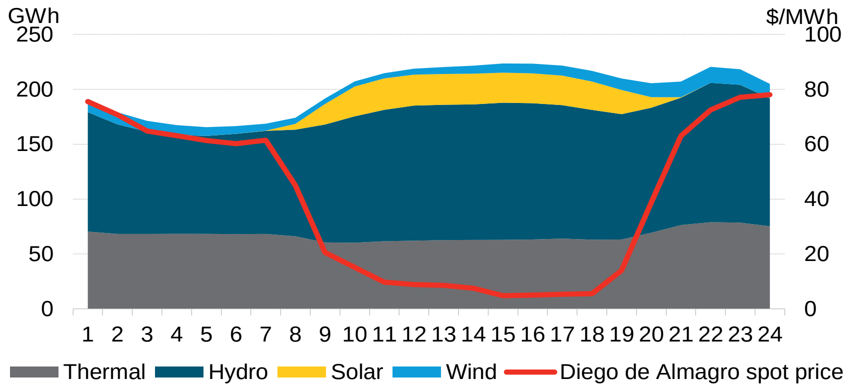
Figure 8: SIC system wind and solar generation (GWh) vs. Diego de Almagro node spot prices ($/MWh)



Source: CDEC SIC

There are few signs that power prices are poised for a quick rebound. In December 2017, for instance, the Diego de Almagro spot price averaged approximately $7 between 11am and 6pm. While prices climbed during the nighttime hours, that offers little comfort to owners of PV projects who generate during daytime hours alone (Figure 9).

Figure 9: SIC hourly generation vs. Diego de Almagro spot price, December 2017



Source: SIC

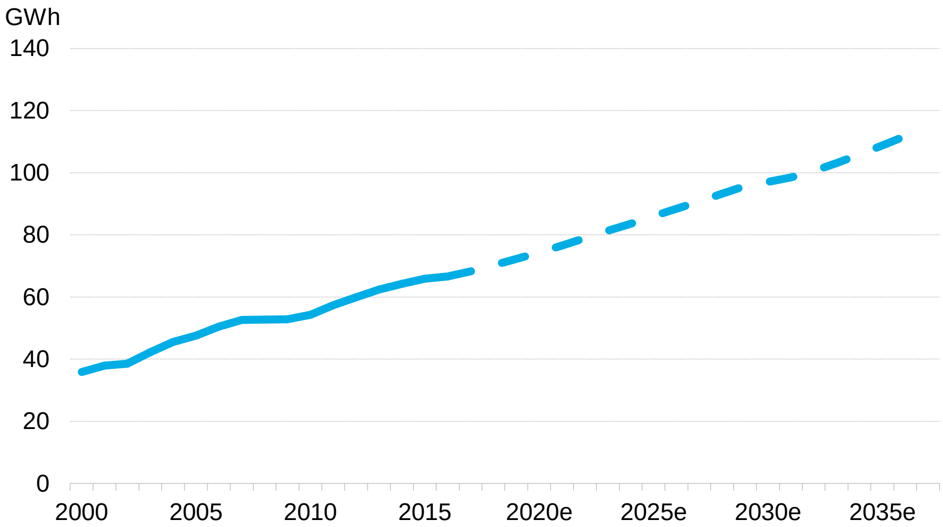
Both "merchant" projects that seek to sell all their power at spot prices and those with signed long-term power-purchase agreements (PPA) are exposed to wholesale price volatility risk in Chile. For the latter, this is because all power that a project generates must first be sold at the node where it connects to the grid, then be bought back by that same generator at the node nearest to where the offtaker has contracted to receive it. The original producer then sells the power to the offtaker at the pre-agreed PPA price.

Disappointing economic growth and the role of copper

Chile's GDP grew in real terms by 6% per year during each of the first few years of this decade and policy-makers had expected continued strong economic growth would require substantial new power-generating capacity. However, the economy has fallen short of expectations in recent years, growing at approximately 2% annually in real terms each year since 2014. Growth totaled just 1.5% in 2017 and is forecast to hit 2.7% in 2018.

For its part, the energy regulator's predictions for load (electricity demand) growth have proven overly optimistic. At the start of each year since 2014, the Comisión Nacional de la Energía (CNE) has forecast future Chile power demand. In 2015, CNE forecast an average of 3.9% per year in electricity demand growth through 2030. In 2016, the agency lowered that to 3.5%. In 2017, it reduced it again, to 2.7% (Figure 10).

Figure 10: Chile National Electricity System (SEN) demand forecast



Source: CNE's 2017-2037 National Electricity System (SEN) demand forecast published in December 2017, BloombergNEF

Chile's export-reliant economy has felt the pinch as global demand for its copper has cooled somewhat. In 2014, copper sales accounted for 11% of total GDP and 55% of all exports. Annual copper production then peaked in Chile at 5.8m tons in 2015 and has been slightly down ever since. While copper prices rose by about third in 2017, in 2018 they have given back nearly all those gains (as of mid-August). There is little to suggest the industry will return to strong growth this year. Given that mining, led by copper, accounts for approximately 30% of all power consumed in Chile in a given year, slow demand for the metal is likely to cap overall load growth in Chile.

Curtailment and the push for new transmission

Slower than anticipated demand growth coupled with the addition of approximately 50% new power-generating capacity in the past decade has not just depressed power prices in Chile, it has also caused curtailment of generation from certain clean energy projects.

Curtailment first appeared in Chile in August 2015 and has since grown. In 2016, 140GWh, or 4%, of total wind and solar generation went unconsumed in the SIC. In 2017, that rose to

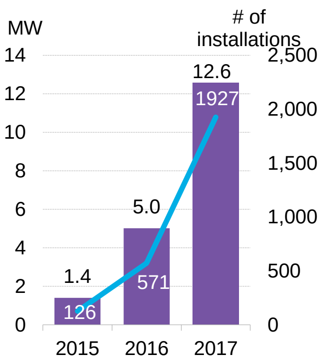
394GWh (7%). Not all that curtailment was entirely economically driven as some fossil fuel-burning plants received higher dispatch priority in the system to ensure baseload needs were met. Since 2017, the government has been auditing certain thermal plants in an effort to reduce their dispatch requirements.

Lack of adequate transmission remains an ongoing challenge in Chile. In response, in August 2017, the government launched the 2017-2018 transmission expansion tenders. They aim to award projects for the construction of 10 projects on the national transmission system, valued at over $1.5 billion, and 38 smaller projects for the zonal transmission system for a total of $213 million. All lines are scheduled to be tendered in 2H 2018 and be commissioned between 2019 and 2023.

In addition to the plan, the under-construction Polpaico-Cardones 753-kilometer line in the north is expected to significantly alleviate grid congestion. It is now expected to be operational in March 2019.

The role of distributed energy

Figure 11: Small-scale PV installations



Source: CNE

Chile has had supportive net-metering rules on its books since 2014 to encourage small-scale distributed energy power generation from small systems. Over the past three years, the country has seen a total of 1,927 small PV systems come on line, totalling 12.6MW of installed capacity (Figure 11). The installation rate nearly tripled from 2015 to 2016 then more than doubled from 2016 to 2017. The country's exceptionally strong sun combined with high residential power prices make small-scale PV quite appealing to many consumers – provided they have the financial resources to install such systems.

Chile also offers its Pequeños Medios de Generación Distribuida (PMGD) mechanism to support the development of somewhat larger distributed-energy projects. PMGD allows projects with capacity below 9MW to sell into the spot market using a stabilized price fixed by CNE and published every six months. The price equals the average value of retail market power-purchase agreements.

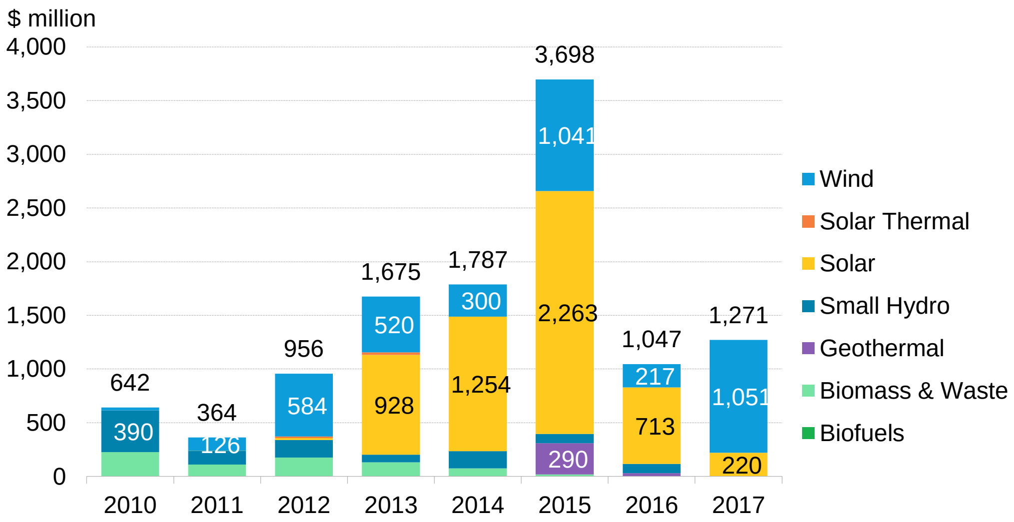
In Chile, even projects with signed, long-term PPAs to sell their power onto the main grids face price risk. By comparison, the PMGD scheme offers significant stability. The PMGD price of approximately $70/MWh has varied only by about 5% over the last five years. It is a relatively low-risk option for smaller projects to avoid selling power in the wholesale market where they can be exposed to significant spot price fluctuations.

Since it was introduced in September 2014, 596MW of clean energy capacity has been installed under the PMGD, or 24% of all renewable capacity added over this period. The boom of additions under the scheme reflects the drop in spot prices and high competition in auctions. Projects subject to the stabilized price scheme have already been successfully financed by multilateral banks and Chilean commercial banks, setting a precedent in the Chilean energy market and placing the PMGD projects as an alternative, viable option for developers and investors.

2.1.2. Clean Energy investment

Chile has attracted a cumulative $11.4 billion in investment in large-scale renewable energy projects since the start of 2010 and the country has proven to be among the hottest clean energy markets in the world at times during that period (Figure 12). For 2018, Chile ranked first in Climatescope, a survey on developing nations BNEF conducts annually with support from the UK Department for International Development. This reflects the country's overall attractiveness for foreign investment in clean energy. In particular, Chile has built a strong enabling framework as defined by a series of effective policies and relative overall economic stability. It is also home to a significant manufacturing value chain for clean energy components compared to many other developing countries.

Figure 12: Chile new-build clean energy investment by sector



Source: BloombergNEF

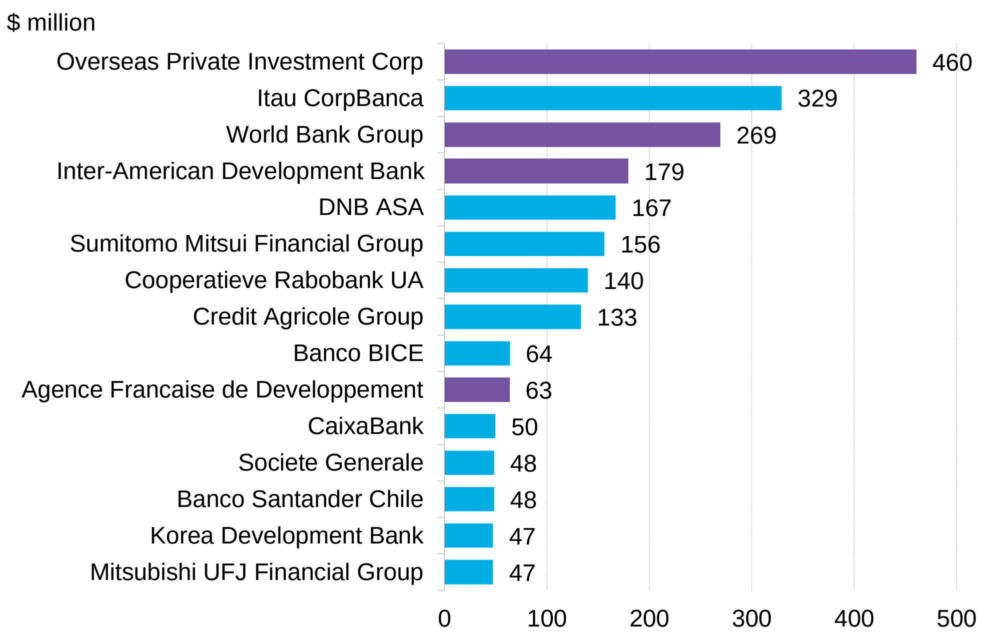
Investment in Chile clean energy peaked in 2015 at nearly $3.7 billion. With the outlook for new capacity less positive and with equipment costs down very substantially for PV since 2015, investment is unlikely to return to such a level for the foreseeable future.

Until 2012, funding for large-scale solar projects was virtually non-existent in Chile. That changed with the $60 million funding of Sky Solar's Arica I PV Plant (phase one). The first project to secure over $100 million came in September 2013 when SunEdison raised $260 million for its 101MW Amanecer Solar PV project, which was then commissioned in 2014. The project was funded with $213 million in debt from the International Finance Corporation and the U.S. Overseas Private Investment Corporation.

Investor types supporting solar

The Amenecer project represented the first of many large solar projects which have received support from a development bank. Development finance institutions from around the global have to date deployed capital there with OPIC the most active with $460 million invested. Chile has also attracted interest from commercial banks, most notably Itau ($329 million deployed), DNB ($167 million) and Sumitomo Mitsui ($156 million).

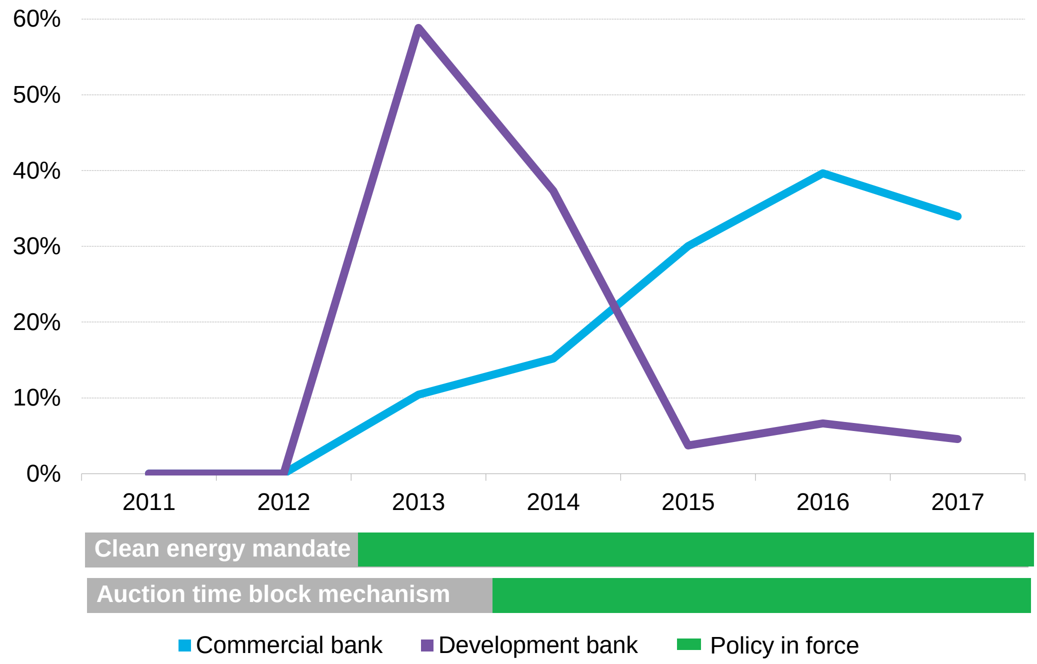
Figure 13: Chile lead debt providers for PV projects, 2010-2017



Source: BloombergNEF. Note: Development finance institutions are depicted in purple. All others are in blue.

While DFIs clearly played a critical part in kick-starting support for Chile's clean energy projects in 2013, their role has dimmed somewhat in recent years as commercial banks have made more credit available. In addition, as several of the world's larger utilities, including Enel and AES, have entered the Chile market, they have shouldered more of the finance load by tapping their own balance sheets. In 2013, DFIs provided 59% of all clean energy project finance in Chile. That fell to just 5% in 2017 as commercial banks and project developers provided most of the capital (Figure 14).

Figure 14: Chile share of new build PV investment by investor type



Source: BloombergNEF

CTF in Chile

In 2012, the CTF identified Chile as a market where its funds could help scale clean energy investment and deployment. At the time, the country had 1.3GW of total non-large hydro renewable generation on line. Of that, the majority (872MW) was small hydro; just 200MW was represented by wind and solar. There was no geothermal capacity on line.

Figure 15: Chile annual PV capacity additions

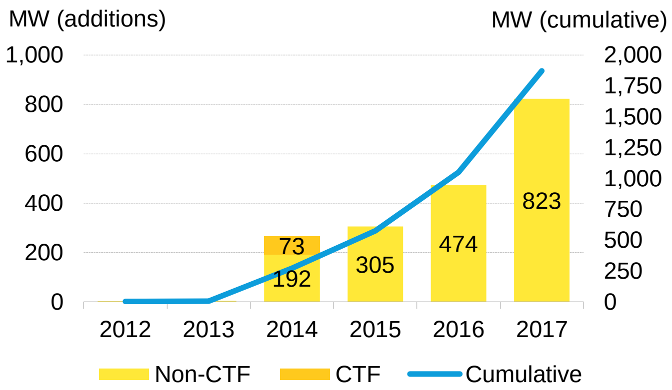
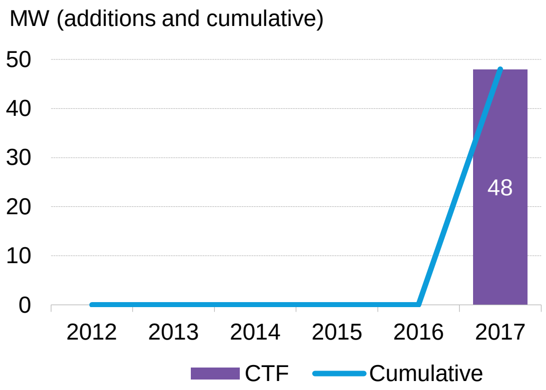


Figure 16: Chile annual geothermal capacity additions



Source: National Energy Comission (CNE), BloombergNEF

CTF's thrust in Chile was to have the power sector make a meaningful contribution to CO_2 reductions. Toward that end, CTF sought to support solar thermal development, potentially in the north where conditions are sunniest. CTF also sought to back large-scale PV development through the construction of projects across the country. Finally, CTF sought to boost consumer distributed generation and energy efficiency efforts. The CTF Investment Plan sought to have $1.2 billion deployed in Chile in support of these goals with CTF funds accounting for 15% of that, or $200 million. The rest was to come from partner development finance institutions.

CTF funds deployed in Chile to date have been well less than that, totaling $46 million. The capital has gone to support two quite different large-scale clean power plants: PV project Parque Fotovoltaico Maria Elena and Geothermal project Cerro Pabellon.

Each of these projects has followed a different path toward completion. The 72.8MW Parque Fotovoltaico Maria Elena plant was commissioned in November 2014 with $16m in CTF funds disbursed as part of a larger, $66.4 million loan from the Inter-American Development Bank. The capital came from CTF under its Large-Scale Photovoltaic Program. At the time, the expected capex for the project was $201 million. U.S.-based SunEdison served as project sponsor. In 2015, SunEdison sold a stake of undisclosed size in the project to Grupo Ecos.

Maria Elena was novel at the time of development for attempting to sell its power entirely on a “merchant” basis, i.e. without a signed PPA. Other such projects followed and merchant plants have generally since suffered from depressed power prices in Chile.

CTF capital also went to support the 48MW Cerro Pabellon geothermal plant, located in the Atacama Desert. Cerro Pabellon was at the time of completion the first geothermal project commissioned in South America and carried a total capex of $320 million. The project is owned by a joint venture controlled by Enel and Chile's Empresa Nacional del Petroleo. CTF capital was used to mitigate risks in the drilling of the first two units of the project and to mitigate exploration risks of unit three, not yet in operation.

The CTF funds ultimately went toward a project that resulted in a total of new 121MW of baseload capacity. The total combined capex for these projects came to $521 million.

In addition to the two projects, CTF funds were at one time contemplated for use in building the Cerro Dominador concentrating-solar project. Now under construction in the Antofagasta region, Cerro Dominador will use10,8000 concentrating mirrors to generate steam and turn a turbine. Its intended goal is to make 110MW of solar thermal power-generating capacity available. The project has signed a PPA to deliver electricity at $114/MWh with a total anticipated capex of $1.1bn.

Figure 17: Cerro Dominador

Credit: Cristobal Olivares, Bloomberg News, Aug 7.

Cerro Dominador has followed a circuitous route to development. In 2014, construction began. Approximately two years later, it was halted after original developer Abengoa of Spain ran into major financial difficulties. In 2018, Abengoa completed its exit of the project, selling its share to EIG Global Energy Partners, which in May secured $758 million in financing to complete the project. EIG now says it will be complete by the end of 2019. In the interim, separately, 100MW of PV power-generating capacity was completed at the site.

Cerro Dominador was launched with support from the Chilean government. CTF funds were used in a $470,000 grant that supported the government’s solar-related knowledge management activities (a web platform). There was also the potential for further support in the form of a loan through the Inter-American Development Bank though the IADB says those funds were not disbursed.

At the time of the CTF commitment in 2012, concentrating-solar technology was regarded to be roughly cost-competitive with photovoltaic technologies but had the advantage of being able to generate power into the “shoulder” hours of the evening. Had CTF funds been used, the intention was to help scale solar thermal deployment and push down the technology's costs.

2.1.3. Market impact

CTF's capital disbursements in support of clean energy projects came at an important point in Chile's market development -- relatively shortly after the government established new policies to support clean development but just before the market received a massive flood of new investment from outside investors. In two cases, CTF backed first-of-their-kind projects. In a third, CTF supported one of the earlier merchant PV plants to get built in country.

Solar thermal power

At the time CTF made the determination to support concentrated solar power development in Chile, the technology appeared to be at relative cost parity with PV generation on a levelized cost basis, as discussed above. That said, there were clear signs then that equipment prices for PV would soon collapse based on the volume of new manufacturing capacity being built in China. Similarly, there was belief that solar thermal capex prices would fall, so long as a meaningful number of new projects simultaneously started to get built.

But the question of which technology was superior was a more complex than that. Solar thermal technology offers a flatter, more consistent generation profile than PV. On a typical day, solar thermal projects can generate into the critical evening "shoulder" hours and their production patterns can be quite reliable, provided the equipment performs. By contrast, PV projects cease to generate when the sun goes down.

The extraordinary levels of sunshine in the Atacama make it a potentially very attractive place to develop solar thermal projects and the region is home to important customers in the form of major mining companies. All of this suggests that the CTF-supported Cerro Dominador plant could have helped trigger a wave of further solar thermal development in the Atacama, or perhaps in similar locations elsewhere around the globe.

Neither has come to pass, for two primary reason. First, solar thermal projects have proven to be technically quite challenging to build on time and on budget; and second, costs associated with solar thermal's most immediate technological rival, PV, have simply collapsed. Even solar thermal's main advantage – a smoother production curve – is being undercut by PV projects built with accompanying large-scale batteries that can discharge when the sun becomes obscured or goes down for the day.

Looking ahead, it appears quite unlikely that a massive new wave of solar thermal development will take place in Chile. BNEF has tracked a total of 12 solar thermal projects in Chile over the past 14 years. Two of the very smallest have been completed and directly provide power to local mines. A third has officially been abandoned. The fourth is the EIG plant now under construction once again. The rest appear to be making little progress and may now be defunct.

For a time, after construction was halted on Cerro Dominador, there was concern the project would stand as a white elephant in the desert. With the project apparently back on track, however, it could ultimately demonstrate the impact large-scale solar thermal can have in Chile and in similar markets around the globe.

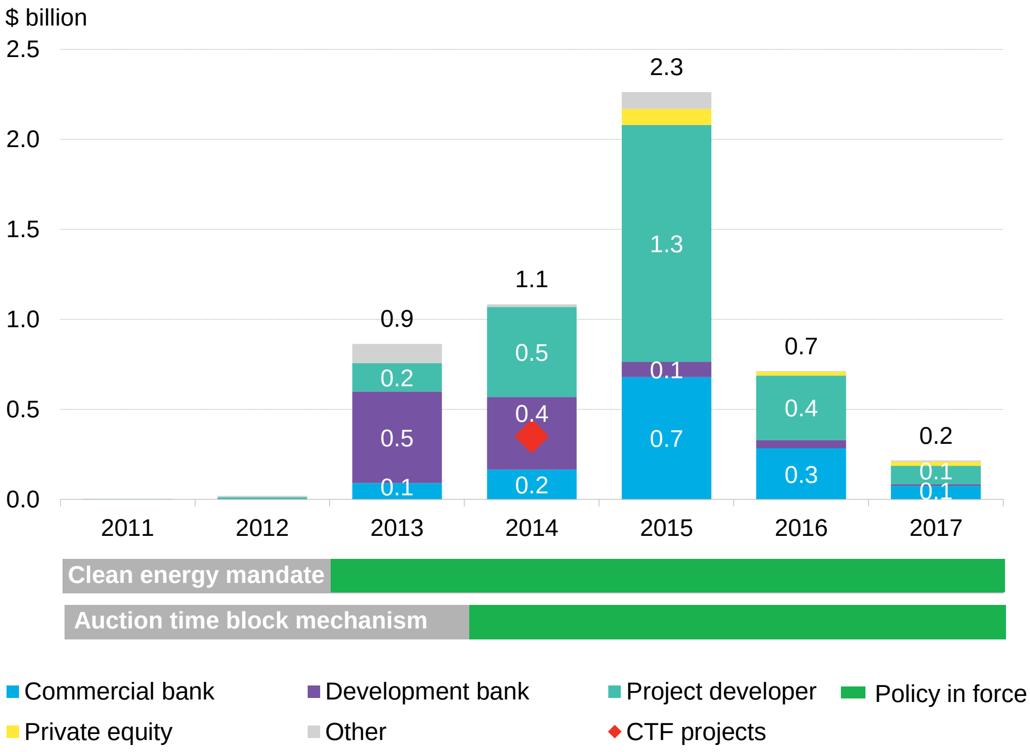
PV

As discussed, Chile's strong sunshine and large open spaces make it potentially very hospitable to PV power. However, until approximately five years ago, PV was simply not cost-competitive with incumbent fossil sources of generation in Chile and the technology lacked significant policy support.

The 73MW Maria Elena project CTF funds went to support was the 4th PV plant commissioned in Chile larger than 50MW in capacity, according to BNEF data. It was also the first large-scale project erected in the Antofagasta state. Today, there are 95 grid-connected PV projects on line in Chile, including 20 that are 50MW or larger.

While Maria Elena may not have been the very first PV project built in Chile, it was among the earliest crop to get on line. Until this decade, the country had seen virtually no PV capacity build. That began to change with the first <5MW projects built in 2012 and 2013. Only in 2014 did the larger plants reach completion, including Maria Elena. What followed was a surge of development as 75 additional project reached completion, including another 10 plants 50MW or larger.

Figure 18: Chile disclosed new build PV investment by investor type



Source: BloombergNEF

Geothermal

Unlike wind and solar, geothermal is not a variable source of power generation. For that reason, the technology has the potential to make greater contributions to the grid than similarly sized plants as measured on a nameplate capacity basis.

For developers, geothermal as a technology represents a unique set of risks. Unlike with wind and solar, determining whether the necessary natural resource exists at a potential geothermal site requires significant time and capital. Exploration risks associated with geothermal project resource discovery are more akin to prospecting for oil or gas than determining if a site has enough wind or sunshine.

Unfortunately for developers, however, the potential upside associated with a successful geothermal power plant is not as lucrative as with oil production. This can make raising early-stage capital to pursue exploration projects particularly challenging. It is also why capital provided from DFI's to geothermal developers in the emerging market context is so important. Finally, it is one of the reasons why geothermal as a technology has to date been unable to achieve major scale.

In Chile, the CTF-supported project co-owned by Enel and Chile's national oil company is today the one and one and only operating geothermal facility in the country. There is little to suggest that will change anytime soon, based on BNEF's assessment of the current pipeline of geothermal projects in Chile today. In all, BNEF has tracked 18 geothermal plants since 2008. Including Cerro Pabellon, only four have advanced past the planning stages. None of the other three have been completed and only one has secured permit more recently than three years ago.

2.1.4. Future ambitions and the role of CTF

BNEF interviewed a range of stakeholders deeply familiar with the Chile market, including developers, financiers, and a government representative. When asked, interviewees identified an intriguing variety of challenges currently confronting further deployment of wind, solar, and other clean technologies. Several of these we alluded to in earlier parts of this report, but others we raise here for the first time. They include:

- *Difficulty securing the necessary environmental and community permits to build.* Interviewees complained of an arduous environmental review process and the ability of local community groups to block projects indefinitely.
- *Uncertainty around Chile's current PPA system and the ability of buyers to decline to buy power.* "They only pay for what they need," one interviewee said. "And then you're stuck with it yourself and you have to sell it. And that's the biggest issue with this public PPA. It's very unusual."
- *Competition between the "regulated" and "free" market for power delivery.* "Anyone who is in the regulated market is trying to switch to the free market [now]," said an interviewee. Regulated offtakers are less keen to buy all the power committed to under the PPAs.
- *The need for greater financial support for smaller, projects located closer to sources of demand.* This could take the form of rooftop, commercial or residential PV systems. While PGMD projects are regarded as bankable, projects smaller in size struggle to secure financing today, interviewees said. "Everything is in place but the problem is developers are unable to scale under a debt instrument option," said one interviewee.
- *A mismatch between government estimates for electricity demand and reality, which has led to what is regarded as an over-tendering for new capacity.* "The problems with these PPAs is that the power demand projected by the government were very aggressive," said one interviewee. "What we're seeing is that demand is substantially lower than that."
- *Lack of local confidence and availability of capital to support projects that employ large-scale batteries.* "I think battery plus storage would be an excellent place to put funds," said one interviewee who has had a hand in funding large-scale renewable projects in the past. "We

can't quite do it because it's not yet competitive and not proven," he said. "The dollars spent there could build confidence in storage."

Given CTF's mission, mandate, and scope, it lacks the ability to influence each and every one of the above-mentioned challenges facing Chile today. In particular, macro concerns about the disappointing economic growth rates are beyond the control of any one entity.

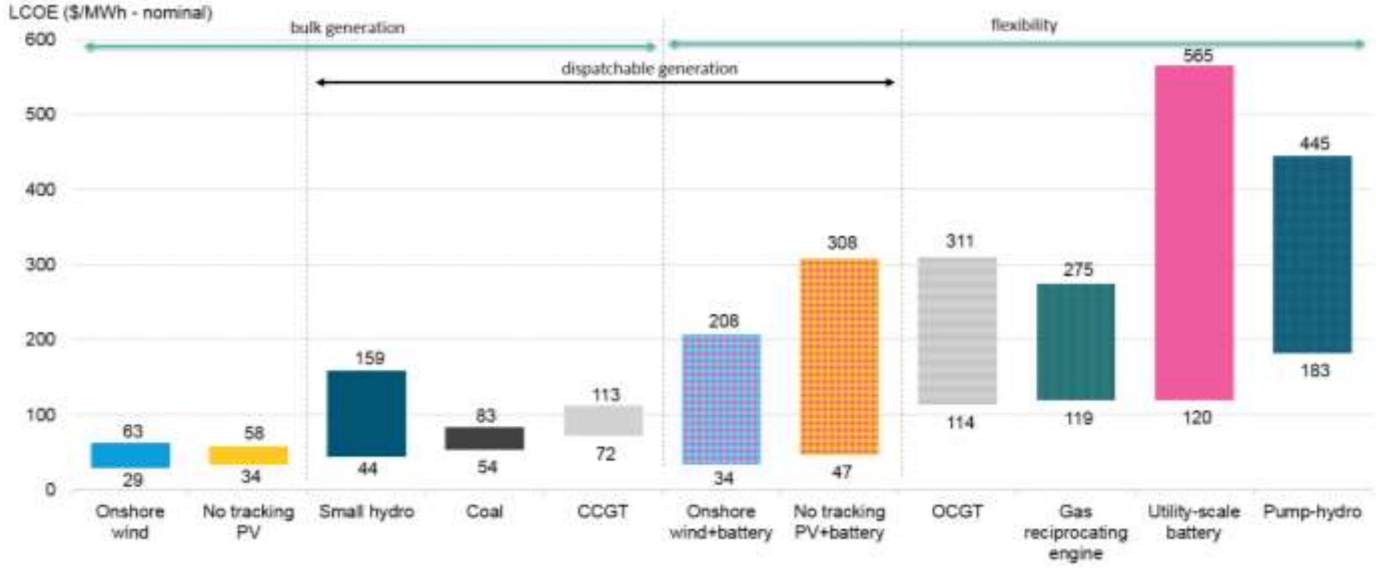
That said, given that overall demand for electricity may not grow at a spectacular pace, CTF could focus its efforts specifically going forward in Chile on deployment of new clean energy capacity that explicitly would *displace* incumbent fossil-fueled generation. In that regard, there are two areas where CTF might consider focusing its future efforts.

The first involves distributed solar generation. Chile would appear to have the two fundamental ingredients for a major rooftop PV boom – strong sun and high retail power prices. In addition, the country's net metering plan currently essentially allows PV system hosts to sell excess power generated back into the grid at the retail rate. With equipment prices sliding further in 2018 to as low as $0.25/W for Chinese-made modules, there are really only two obstacles to a major distributed solar build-out in Chile: lack of trained individuals to do the installations and a lack of capital to finance the systems. In more developed nations such as Australia and the U.S., consumer-facing banks have taken steps explicitly to make credit available to homeowners to finance the installation of new PV capacity. Such lines of credit are not generally available to Chileans. There may be a role for CTF to play in addressing this issue.

The potential for pairing large-scale batteries with renewables projects represents a separate opportunity. BNEF has tracked a decline of approximately 80% lithium-ion battery packs from 2010 to 2017 as a wave of new manufacturing capacity has come on line in China and elsewhere. The result is renewables paired with storage is becoming economically competitive. See 3.3.2 Energy Storage section for more details.

As part of its levelized cost of energy analyses every six months, BNEF now compares wind+storage and solar+storage with other power generating technologies in certain markets around the world (example below). While BNEF has not done such a survey specifically for Chile, it seems quite likely that PV+storage is becoming cost-competitive in that country as well. Given that battery storage technologies are just starting to gain a foothold in helping with renewables deployment, this could be an area for further exploration for CTF.

Figure 19: India levelized cost of electricity estimate, 1H 2018



Source: BloombergNEF

2.2. Kazakhstan

2.2.1 Country context

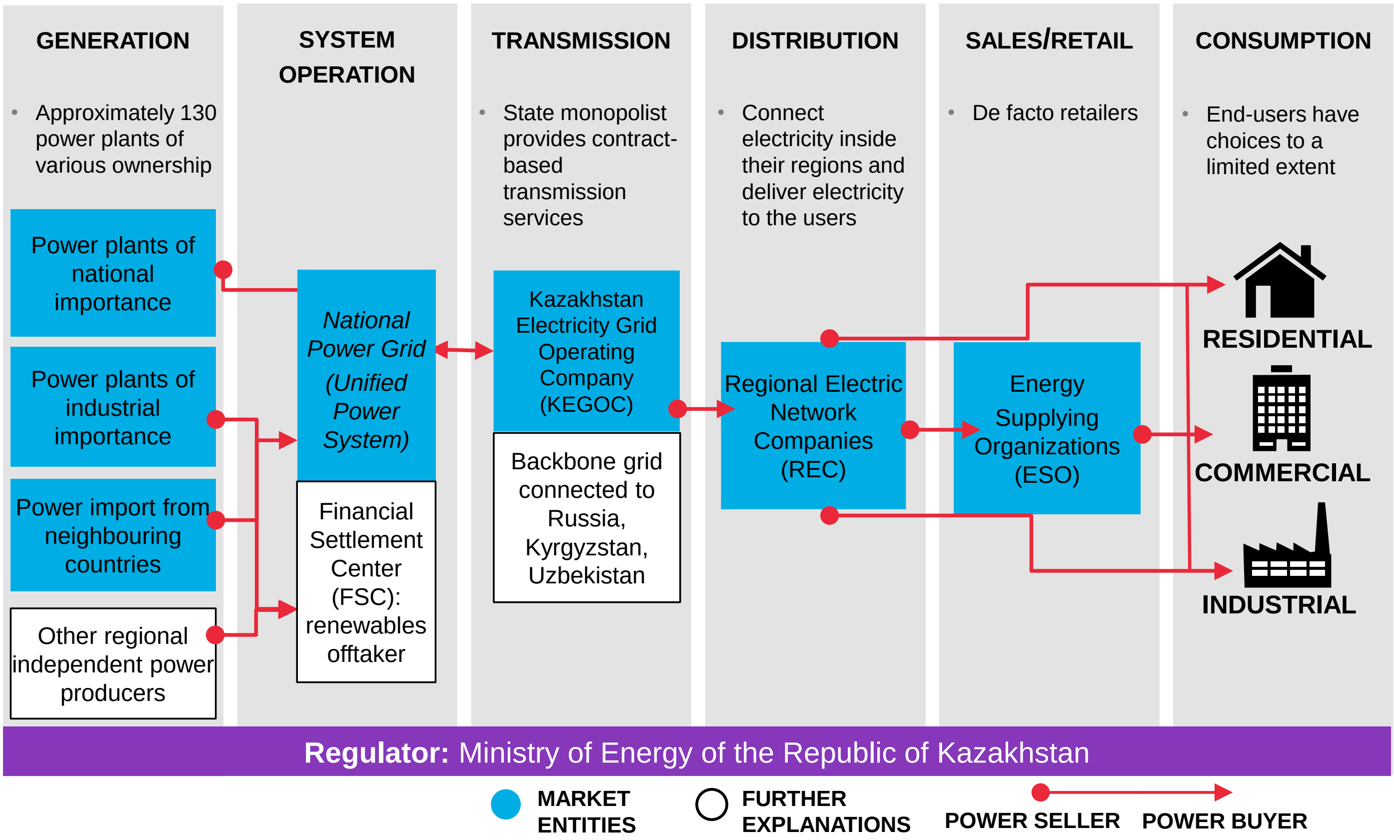
Overview

Kazakhstan is a landlocked middle income country and the world's 17th largest oil producer. It is a former Soviet republic and the current president, Nursultan Nazarbayev, has been in office since independence in 1991. Hydrocarbons are central to the Kazakh economy, accounting for over half of the country's exports. As a result, GDP growth has largely tracked the price of oil over the past decade leading to a prolonged investment boom across the Kazakh economy in the 2000s.

Market Structure

The Ministry of Energy (MoE) is Kazakhstan's key electricity sector regulator. Power in the country is generated by approximately 130 plants owned both privately and by the government. The Kazakhstan Electricity Grid Operating Company (Kegoc) is the sole operator of the national transmission and distribution grids.

Figure 20: Kazakhstan power market structure

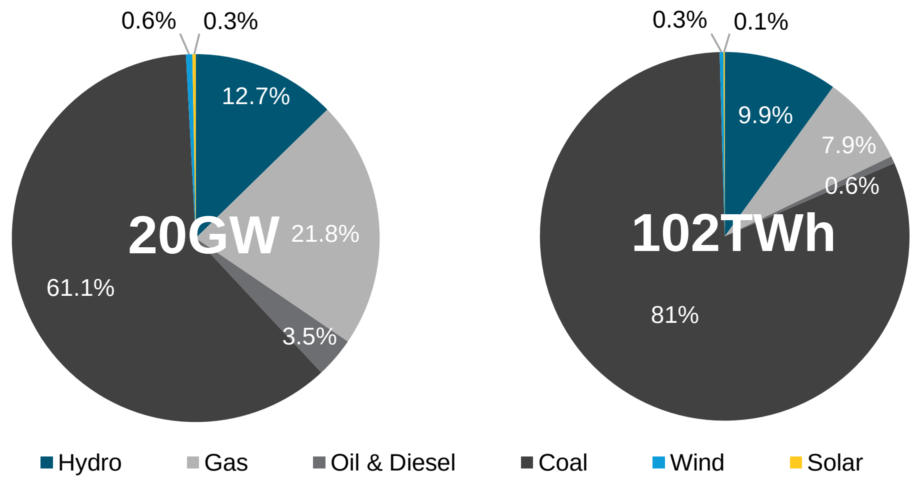


Source: BloombergNEF, MoE

Kazakhstan had an installed capacity of 20GW as of year-end 2017 and generated a total electricity of 102TWh in 2017. The country's generation matrix is dominated by coal, oil and gas, which account for over 90% of the total. Hydro represents 12% of capacity, but most that 2.5GW capacity was built during the Soviet era and offers limited potential expansion. The wind and PV sectors are just getting started in Kazakhstan with the first utility-scale plants commissioned in 2015. As of year-end 2017, wind and PV installations account for just 171MW, or 0.9%, of total installed capacity (Figure 21).

Figure 21: Kazakhstan's utility scale installed capacity

Figure 22: Kazakhstan's utility scale power generation



Source: Ministry of Energy, BloombergNEF

Policies

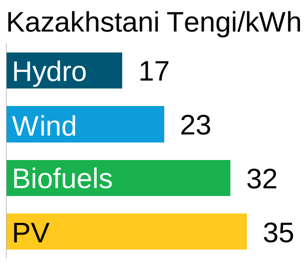
Kazakhstan's clean energy sector kicked off in 2009 when the government issued its overarching law "on supporting the use of renewable energy" (the "RES" law). Released in May of that year, Presidential Edict No. 577 set a goal of a "Transition of the Republic of Kazakhstan to a Green Economy" and has accelerated development of wind and PV.

The country ambitiously aims to have 30% of its electricity generated by PV, wind, hydro and nuclear by 2030 and 50% by 2050. In 2017, these technologies accounted for 10.5% of generation (Figure 22), with hydro as the major contributor. In addition, the edict requires that PV and wind account for 3% of power generation by 2020, up from only 0.4% in 2017.

In 2013, Kazakhstan amended the RES law to establish feed-in tariffs (FiT) for wind, PV, hydro and biofuel power generation projects, varying by technology (Figure 23). The policy succeeded in kick-starting Kazakhstan's renewable energy market and helped attract over $1 billion in clean energy investment.

While the Ministry of Energy is the body responsible for renewables policies, the quasi-governmental Financial Settlement Center (FSC)[5] serves as the official offtaker. The FSC collects renewable surcharge fees from the prevalent power tariff and pays feed-in-tariffs to renewable energy project owners based on generation.

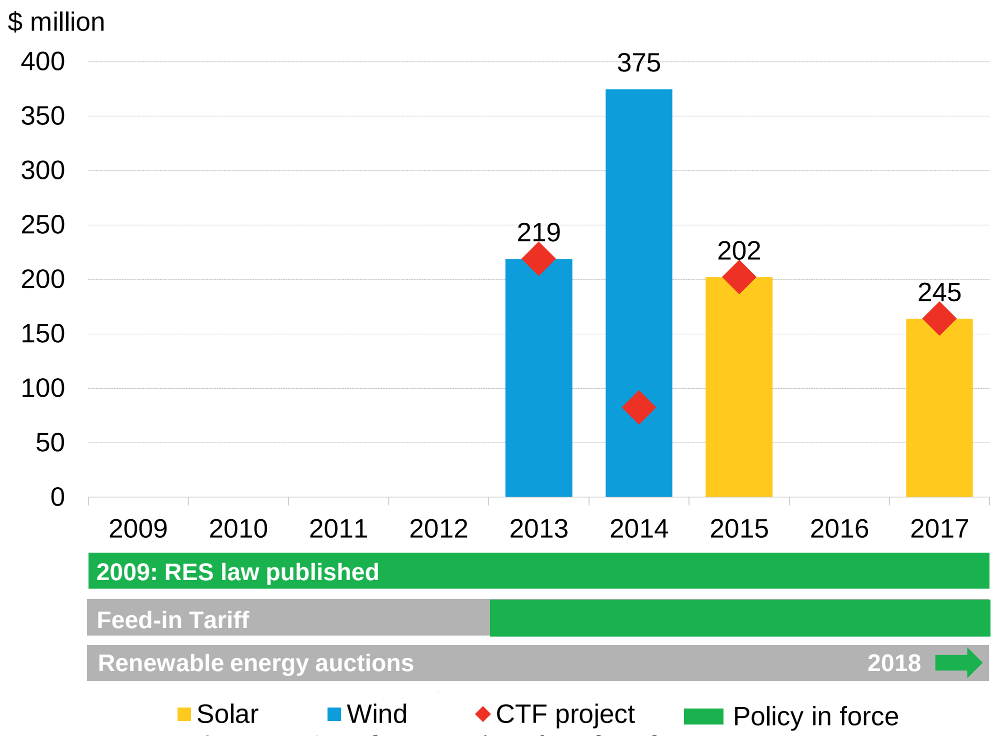
Figure 23: Kazakhstan's Feed-in Tariff



Source: Ministry of Energy, BloombergNEF

[5] Kazakhstan's Financial Settlement Center of Renewable Energy was created to stimulate investment in renewable energy sector and increase the share of renewable energy sources in total energy production by guaranteeing of centralized purchase by government of all electric energy produced by clean power plants. It carries out centralized purchase and sale of electric energy produced by renewable energy and supplies to electric grid of the unified electric power system of the Republic of Kazakhstan.

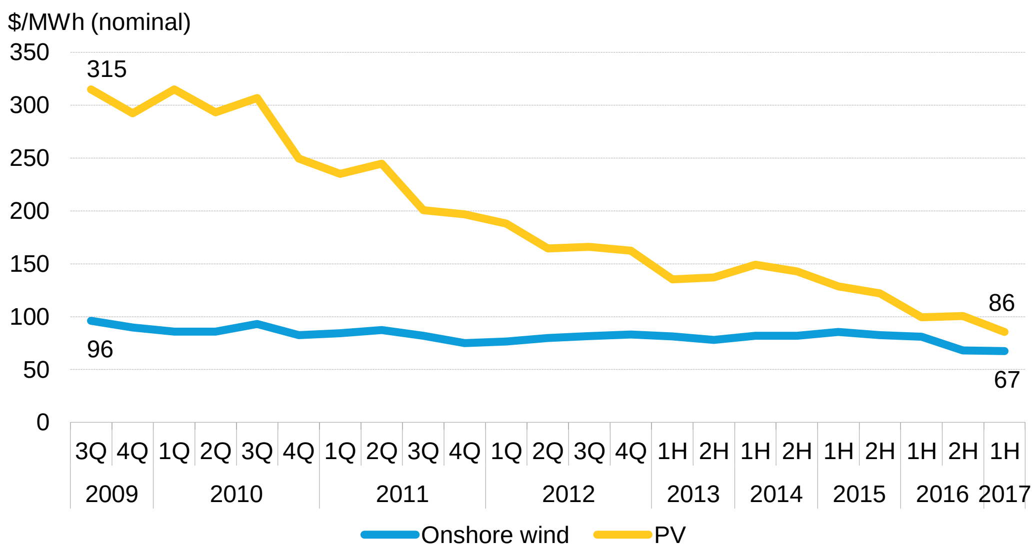
Figure 24: Kazakhstan disclosed wind and PV investment and key policies



Source: : BloombergNEF

Since the launch of the Kazakhstan FiT, estimated levelized costs of energy (LCOE) for wind and PV have dropped dramatically just as in other nations, reverse auctions have solicited record low bids to build new wind or PV capacity. On a global basis, BNEF's LCOE benchmark for wind onshore dropped 30% from $96/MWh in 3Q 2009 to $67/MWh in 1H 2017 while PV plummeted 73% over the same period, from $315/MWh to $86/MWh (Figure 25).

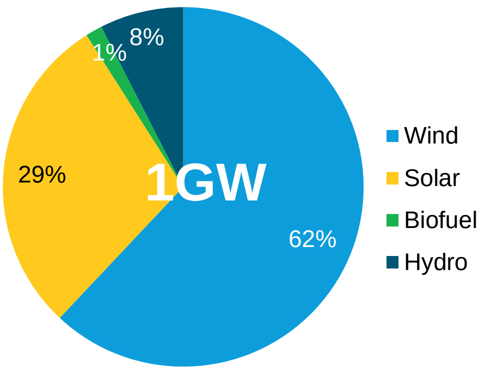
Figure 25: Global LCOE benchmark



Source: BloombergNEF. Note: BNEF defines LCOE as the long-term offtake price required to achieve a certain equity hurdle rate for a developer, considering its total capital, operating and finance costs over the lifetime of the project. This LCOE estimates exclude costs of grid connection and transmission. They also do not take into account subsidies or incentives as they are intended to assess the true economic viability of technologies outside the bounds of policy support.

In an effort to exploit these opportunities for Kazakhstan, in January 2018 the government unveiled what would be Central Asia's[6] first renewable energy tender. This reverse auction was slated to kick off in May 2018 and conclude in October 2018 while contracting 1GW capacity from wind, PV, biofuel and hydro (Figure 26). In June 2018, the FiT scheme ceased to be available for new-build projects that had not previously qualified. This move was intended to push developers to compete in the new auction mechanism to secure further PPAs.

Figure 26: Renewable energy mix in the 2018 first-ever auction in Kazakhstan



Source: Ministry of Energy, BloombergNEF

2.2.2 Clean Energy Investment

CTF in Kazakhstan

To date, the Clean Technology Fund (CTF) has invested approximately $55.5 million in Kazakhstan's clean energy sector and helped leverage $200 million of multilateral development bank co-financing plus another $412 million in follow-up[7] financing. CTF has had a hand in financing 85% of the country's current PV capacity and 40% of its wind capacity. Another 160MW of PV and 50MW of wind that received CTF financings are under construction and expect to be commissioned by 2025 (Figure 27 and Figure 28).

CTF financing played an important role in projects which have come to symbolize the viability of Kazakhstan's renewables sector. Specifically, CTF had a hand in financing the country's landmark first utility-scale PV project (Burnoye-1) and the country's first wind project (Ereymentau-1).

[6] Central Asia Includes Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

[7] Follow-up finance refers to additional investment provided (other than by CTF and MDB) to projects that received CTF concessional financing.

Figure 27: Kazakhstan annual disclosed PV investment, 2011-2017

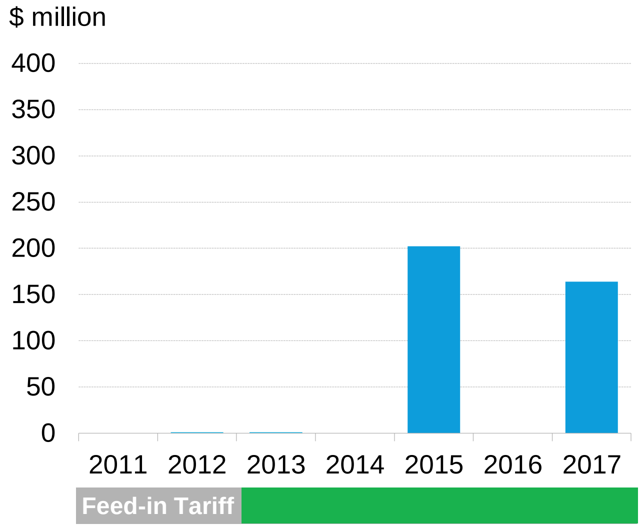
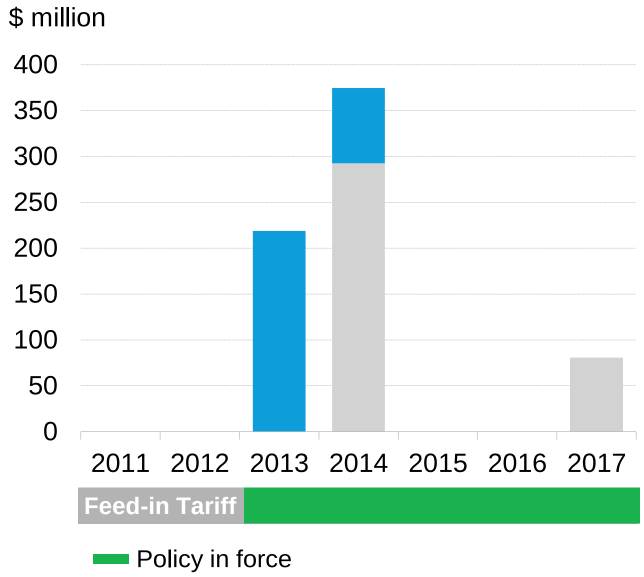


Figure 28: Kazakhstan annual wind investment, 2011-2017



Source: : BloombergNEF, CTF. Note: "CTF project" refers to full amount of financing received by projects partly financed by CTF.

As of 1Q 2018, Kazakhstan had only 59MW of installed PV, mainly from the 50MW Burnoye PV project, and 45MW of wind commissioned from the Ereymentau-1 Wind Farm (Figure 29 and Figure 30). A second wind plant, the 50MW Ereymentau-2 developed by Samruk-Energy JSC, is currently under construction and is expected to be commissioned by 2020.

Figure 29: Kazakhstan annual PV capacity additions

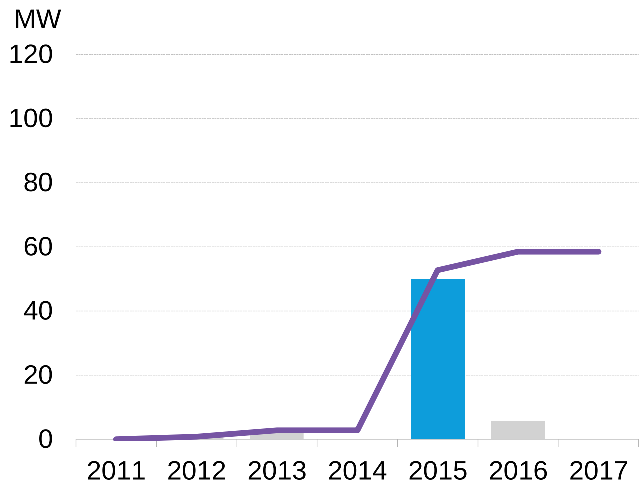
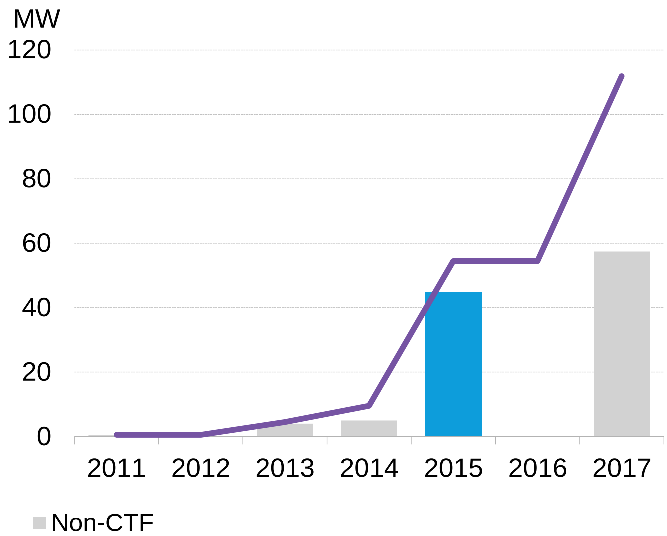


Figure 30: Kazakhstan annual wind capacity additions



Source: BloombergNEF, CTF. Note: Purple lines depict cumulative total volume. Capacity additions refer to projects commissioned in the given year.

While PV and wind are set to play significant roles in meeting the country's 2030 and 2050 renewable energy goals, no such plants were commissioned in 2017. Based on BNEF's project database, there are less than 272MW of PV and wind projects currently financed or under construction in Kazakhstan today (Table 1).

Table 1: Kazakhstan PV and wind project pipeline

Technology	Status	Capacity
PV	Financed/under construction	169MW
Wind	Financed/under construction	103MW
Wind	Permitted	29MW
PV	Announced	489MW
Wind	Announced	846MW

Source: BloombergNEF

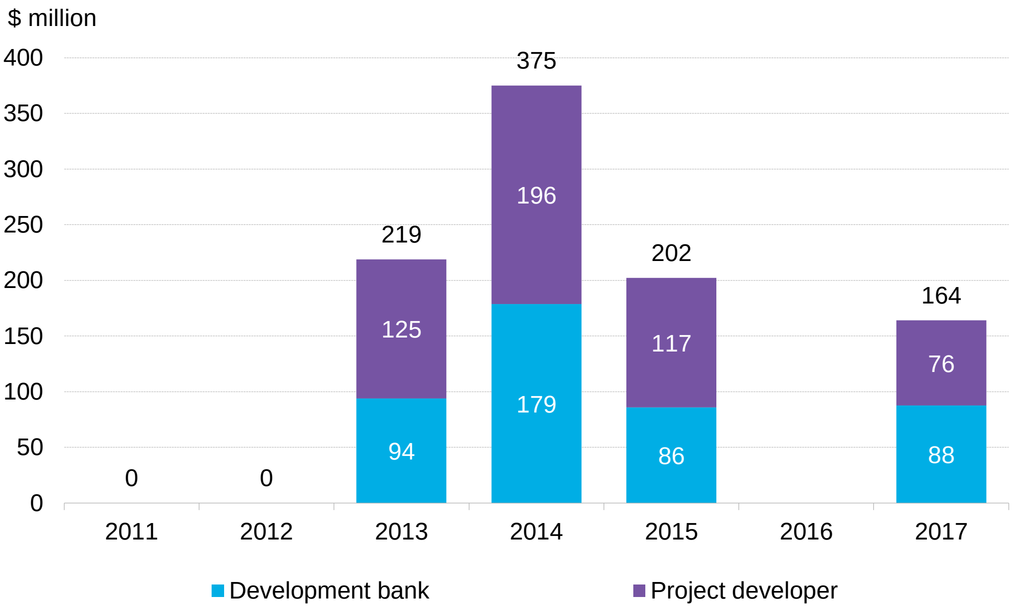
It typically takes 2-3 years for projects to get the legally required permits before starting construction. This suggests the most active period for build in Kazakhstan will be 2020-2025, assuming a substantial portion of the projects secure permits and finance to proceed.

Investor types

From 2013 through 2017, Kazakhstan saw $960 million invested in utility-scale wind and PV projects, 46% of which came from development banks. While MDBs have been critical to clean energy development in the country, market players mentioned during interviews with BNEF that these institutions can require more extensive paperwork, need more communication, and can be generally slow to issue loans.

Project developers play a leading role in providing equity for wind and PV projects. BNEF estimates that they have disbursed a total of $514m from 2013 to 2017 (Figure 31). Commercial banks in Kazakhstan to date have provided nearly zero investment to wind and PV as they often have liquidity constraints and hesitate when facing capital-intensive projects. During the Renewable Energy Summit 2018 in Astana held in June, some local commercial banks participating in the event said they were interested in renewables but would need to conduct further evaluations before issuing such loans.

Figure 31: Wind and PV investment by type of investor



Source: BloombergNEF

2.2.3 CTF results and market impact

Policy support

In advance of providing funds to wind and PV plants, CTF played a key role in supporting development of Kazakhstan's clean energy policies. CTF, EBRD and IFC allocated funds for technical assistance projects are detailed in Table 2.

Table 2: Technical assistance provided to the Kazakh government on renewable energy regulations and policy

Technical support	Year	Donor	Description
Assistance to the government for drafting of secondary legislation implementing the renewable energy law	2009	EBRD SSF	The assignment comprised reviewing, re-drafting and finalizing the secondary legislation related to the law. It focused on introducing a feed-in tariff system and transparent procedures for investor selection in accordance with international best practices.
Advice to the government on developing feed-in tariffs for renewable energy sources	2010	EBRD SSF	The assignment provided a methodology to develop feed-in-tariff levels. It recommended the adoption of a uniform feed-in tariff structure, providing identical tariff levels for projects based on technology, in order to increase transparency, investor certainty and ease of project approval.
Advice to the government on improving renewable energy primary legislation	2011	EBRD SSF	The assignment developed a set of rules and norms for the primary law on renewable energy to make the legal framework operational. The assignment focused on the possibility of introducing a cost allocation system, procedures for purchase of electricity from qualified energy producers, licensing, and supporting the Ministry of Industry and New Technology (MINT) in preparing draft amendments of the main law.
Modelling regional renewable energy feed-in-tariffs within Kazakhstan	2011	EBRD SSF	The assignment developed a methodology for the adoption of regional feed-in tariff schemes for wind and small-scale hydropower generation. The outcome was the implementation of this methodology.

Technical support	Year	Donor	Description
Kazakhstan renewable energy development framework and regulatory support	2012	CTF	The assignment supported the government with amending the primary legislation and developing the secondary legislation as well as supporting the Cost Clearing and Settlement Centre.
Advice to the government on a renewable energy sources (RES) allocation agreement	2013	CTF	The objective was to improve the legal framework of the renewable energy law by introducing clear and transparent rules for investors. This involved the introduction of fixed (feed-in) tariffs; the development of the Cost Clearing and Settlement Centre that would purchase renewable energy generation from eligible generators; calculating the average cost per MWh of generation purchased and selling this energy to suppliers and other load-serving entities; and drafting secondary regulations and model power purchase agreements.
Modelling the social impact of renewable energy feed-in tariffs in Kazakhstan	2013	CTF	The assignment consisted of calculating the gross impact of feed-in-tariffs on electricity end-use tariffs, estimating the impact of the new CO2 emissions law, and proposing mitigating measures to restrict price rises. One of the key conclusions of the assignment was that Kazakhstan should continue to fully index feed-in tariffs against inflation, as the least costly method of supporting renewable energy while promoting private investment.
Assisting the Ministry of Environmental Protection in the final stage of developing renewable energy legislation	2014	CTF, IFC	The assignment aimed to establish a legal and regulatory framework for the development and operation of bankable renewable energy projects in Kazakhstan, which fed into the development of the Green Economy Law. Monitoring work was carried out, focused on the status of renewable energy projects and the perceptions of developers. This highlighted weaknesses of the current renewable energy support framework.
Assisting the Ministry of Energy for improving renewable energy legislation and technical regulations	2015-2016	Joint Economic Research Program (JERP), IFC, World Bank	The World Bank Group provided technical assistance to the Ministry of Energy and the transmission system operator KEGOK in order to implement the Green Economy Law (developing secondary legislation and technical regulations) and strengthen the institutional capacity in Kazakhstan to improve bankability of RE projects. The assignment included tasks to improve monitoring and forecasting of RE penetration; raise awareness about the project development procedures and streamline the latter; improve RE development planning; develop a methodology for FiT review; develop a RE grid code and grid connection agreement; and raise awareness of network companies about RE plants.

Source: CTF case study: Green Economy Transition – Renewable Energy in Kazakhstan. Note: EBRD SSF, refers to EBRD's Shareholder Special Fund; IFC.

The technical assistance supported Kazakhstan in its kick-off its renewable energy sector. Additionally, the advice provided to the government by CTF was reflected in the country's 2013 renewable energy law, which introduced feed-in tariffs for renewable energy projects and established the purchase obligations for all power produced by renewable energy plants for 15 years. EBRD and IFC, with CTF support, have worked closely with Kazakhstan's Ministry of Environmental Protection to develop a Green Economy legislation, which includes rules for emission trading schemes and renewable energy support[8]. Finally, IFC and the World Bank supported Kazakhstan's Ministry of Energy, in the framework of the Joint Economic Research Program (JERP), to improve renewable energy legislation and technical regulations and build institutional capacity.

[8] EBRD, Kazakhstan and the Green Economy Transition approach

Economic factors

CTF has to date played a key role in helping Kazakhstan address four significant economic factors that had historically limited investment in the country's clean energy sector:

- **Lack of liquidity.** Since the global financial crisis in 2008-2009, inadequate access to capital has been a problem in Kazakhstan generally with significant impact on capital-intensive infrastructure projects in the country.
- **Limited loan tenor (maturity).** Local commercial banks and the Development Bank of Kazakhstan (KDB) have historically provided loans only 4-5 years in duration to projects they perceive as reliable, and 2-3 years to small and medium-sized businesses. Both terms are significantly shorter than the 15-20 year, or at least 10-year loans renewable developers typically need.
- **Inflation and currency fluctuation.** Kazakhstan saw annual inflation rates as high as 9% in 2008, due to the financial crisis, weak exports, and other factors. This drove depreciation of the Kazakhstani Tengi from 0.0083/USD in 2008 to 0.0031/USD in 2017 and created uncertainty for local renewable energy developers who need to convert foreign currency for purchasing PV panels, wind turbines or other equipment.
- **High interest rates.** In 2013-2015, when the majority of the CTF renewable energy projects were developed, the interest rate for commercial bank loans issued in Kazakhstani Tengi was as high as 12%-15%, because of the factors discussed above.

CTF helped address the liquidity issue, the most pressing challenge faced by developers, by providing finance and blending it with development bank capital from MDBs. "At least, we [now] have money available", one stakeholder interviewed by BNEF said.

CTF also worked with its MDB partners to address the issue of limited tenor loans. CTF and MDBs offered loans with 15-20 year repayment periods, which were substantially more favorable than those offered by Kazakh commercial institutions. This helped inform local players that renewables projects are not necessarily riskier than other investment opportunities, and that long-term loans are possible when risks are evaluated properly.

By providing financing in U.S. dollars and euros, CTF was able to partially address the currency risk issue. Although EBRD only provides co-financing in Kazakhstan in local currency, CTF foreign currency investment helps developers to some significant extent.

In terms of rates, according to local stakeholders, it is possible to secure loans at 10-12% on up to 65%-80% of a project's total debt from a development finance institution with concessional capital coming in alongside to lend at around 1.25% on the remaining 20%-35% of debt. The result: a blended overall rate of 8.3%.

Apart from specific issues related to the cost and availability of capital, some renewable energy developers in Kazakhstan have encountered other issues, which have proven problematic to local funders. Challenges around land preparation and technical adaptation have increased the cost of communications and delayed the application of best practice and best technologies in the industry.

2.2.4 Future ambitions and the role of CTF

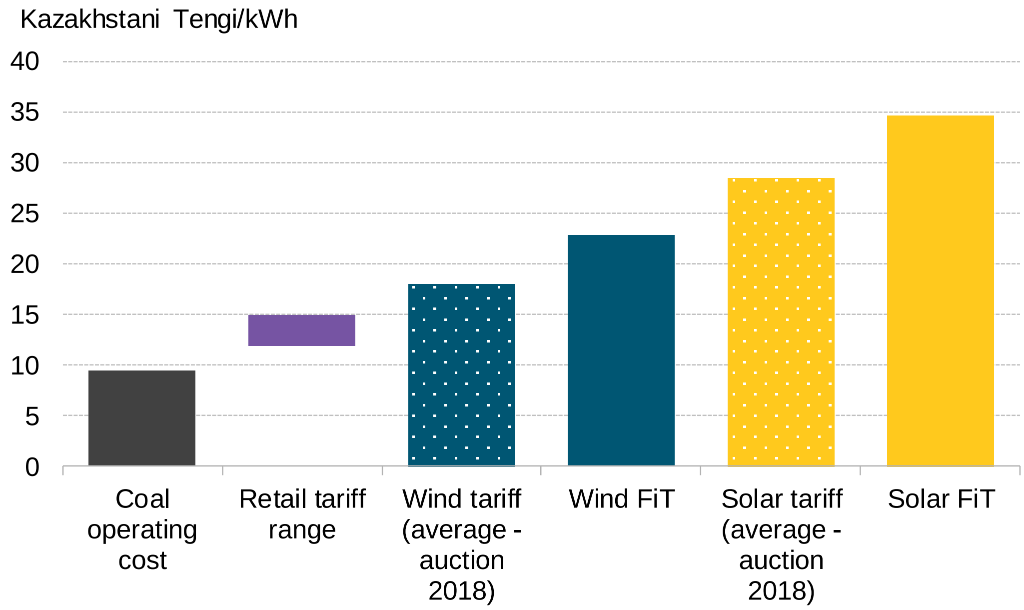
Kazakhstan is a long way from meeting its long-term goal of having 30% of its electricity generated from PV, wind, hydro and nuclear plants and 50% by 2050, given the country is at just 11.5% today. Its FiT mechanisms have since 2009 provided developers tariffs significantly above estimated levelized costs of running existing coal-fired power fleet, which mostly employs technology built during the Soviet era.

CTF has had a hand in financing 85% of Kazakhstan's current PV capacity and 40% of its wind capacity. Based on the interviews BNEF conducted with stakeholders, the initial PV and wind projects backed by EBRD with CTF funds did help attract commercial bank attention to the market and started to change how bankers perceive risks associated with these technologies. Still, Kazakhstan has yet to see a commercial bank make a major loan to such a project. This suggests that further work may still be required.

Furthermore, as Kazakhstan transitions from one clean energy support scheme (FiTs) to another (reverse tenders for clean power-delivery contracts), concessional capital remains potentially vital. The country is making the switch to avoid incurring new public sector liabilities and to procure clean energy at potentially lower cost. Thus far, things look promising in that regard.

Under its first auction program, Kazakhstan aims to contract 1GW of renewable energy capacity in 2018. As of June 2018, average auction prices for wind (17.9 Kazakhstani Tengi/kWh) and PV (28.5 Kazakhstani Tengi/kWh) were approximately 20% lower than their respective feed-in tariff levels.

Figure 32: Kazakhstan power-sector tariff comparison



Source: Kazakhstan Ministry of Energy, BloombergNEF. Note: auction prices as of June 2018

Given Kazakhstan's limited market experience and the economic issues presented above, concessional finance providers and development banks are poised to play a key role in providing funds to some of the first auction-winning projects. This could help prove the viability of the new auction program and support the "crowding-in" of commercial finance by improving investors' risk perceptions.

Historically, the switch from FiTs to tenders has caused uncertainty in clean energy markets and given commercial lenders pause. In Mexico, for instance, after the country implemented a landmark energy reform that included clean energy tenders, commercial bank support for renewables fell from 52% of total capital deployed in 2013, to 16% in 2015, and 0% in 2016. After commercial banks stepped away, concessional financiers stepped in.

In addition to the significant policy changes, the lower auction prices indicate that a similar scenario could be in the process of playing out in Kazakhstan. Those commercial finance providers that may have considered backing a clean energy project under the FiT are far less likely to do so under tenders.

Furthermore, while tenders for clean power around the world have been shown to be effective tools for driving deployment, they are hardly foolproof. They can at times prompt developers to make irrationally zealous bids to secure contracts. This, in turn, can result in projects that win PPA's but never get built because financing cannot be secured. Examples of this have been seen in Brazil, in particular, in recent years. History has also shown that if developers must secure financing before bidding, they learn lender expectations about interest rates, tenors and other aspect of potential loans. This, in turn, informs how they bid once the tender commences.

If Kazakhstan's first auction winners face challenges to secure financing and commission projects on time, CTF, EBRD and other development institutions could potentially provide additional technical assistance to review and improve auction rules to ensure the success of a future round, and to ultimately crowd-in commercial finance. However, development organizations need to be careful when providing concessional finance to auction-winning projects to avoid distorting markets or crowding out private finance.

2.3. Mexico

2.3.1 Country context

Overview

Comprising 31 states and a federal district, Mexico is a middle-income country in North America. The second largest economy in Latin America and the fifteenth largest in the world, Mexico had an estimated, nominal GDP of approximately $1.25 trillion in 2018 and a population of approximately 126 million. Mexico's economy has grown at an average rate of about 2% annually over the past decade, supporting growth in electricity demand that has averaged 3.4% per annum since 2010. Mexico's large export-oriented, manufacturing sector results in industry being the largest consuming sector. The national electrification rate is close to 99%.

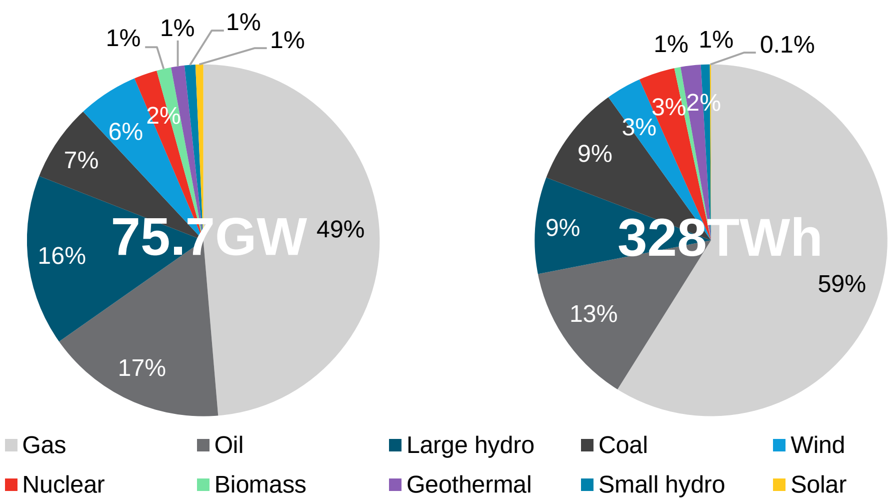
Mexico's July 2018 presidential elections resulted in a victory for veteran leftist Andres Manuel Lopez Obrador, who took office in December, ousting the long-dominant Institutional Revolutionary Party and stoking uncertainty regarding the future of the economy and historic energy reforms. Mexico's new president inherited slowing industrial activity, falling oil production, and an economy that is expected to expand marginally faster in 2018 than in 2017 albeit with a challenging outlook. Domestic shocks and uncertainty over ratification of the new regional trade agreement, U.S.-Mexico-Canada Agreement, have lowered official forecasts for 2019 growth.

Market structure

The second largest power market in Latin America, Mexico is also one of the top destinations for foreign investment in clean energy. While renewables today account for just 9% of Mexico's 76GW installed capacity (Figure 33), that share is expected to rise as capital inflows increase to exploit excellent solar and wind resources. Benchmark capacity factors for both wind and solar projects are high on both a regional and global basis, at 45% and 21%, respectively.

Mexico is also attractive for investors due to major reforms underway that are transforming the power sector structure and expanding opportunities for private companies. The country's main regulatory body remains the Energy Regulatory Commission (CRE), however central to the reform have been the unbundling of the state-owned utility, Comisión Federal de Electricidad (CFE). The reform has split CFE to create different companies for generation, transmission, and distribution. It has also established an independent system operator. While the CFE retains a monopoly over transmission and distribution and holds the vast majority of generation assets, the reform has opened access to new entrants.

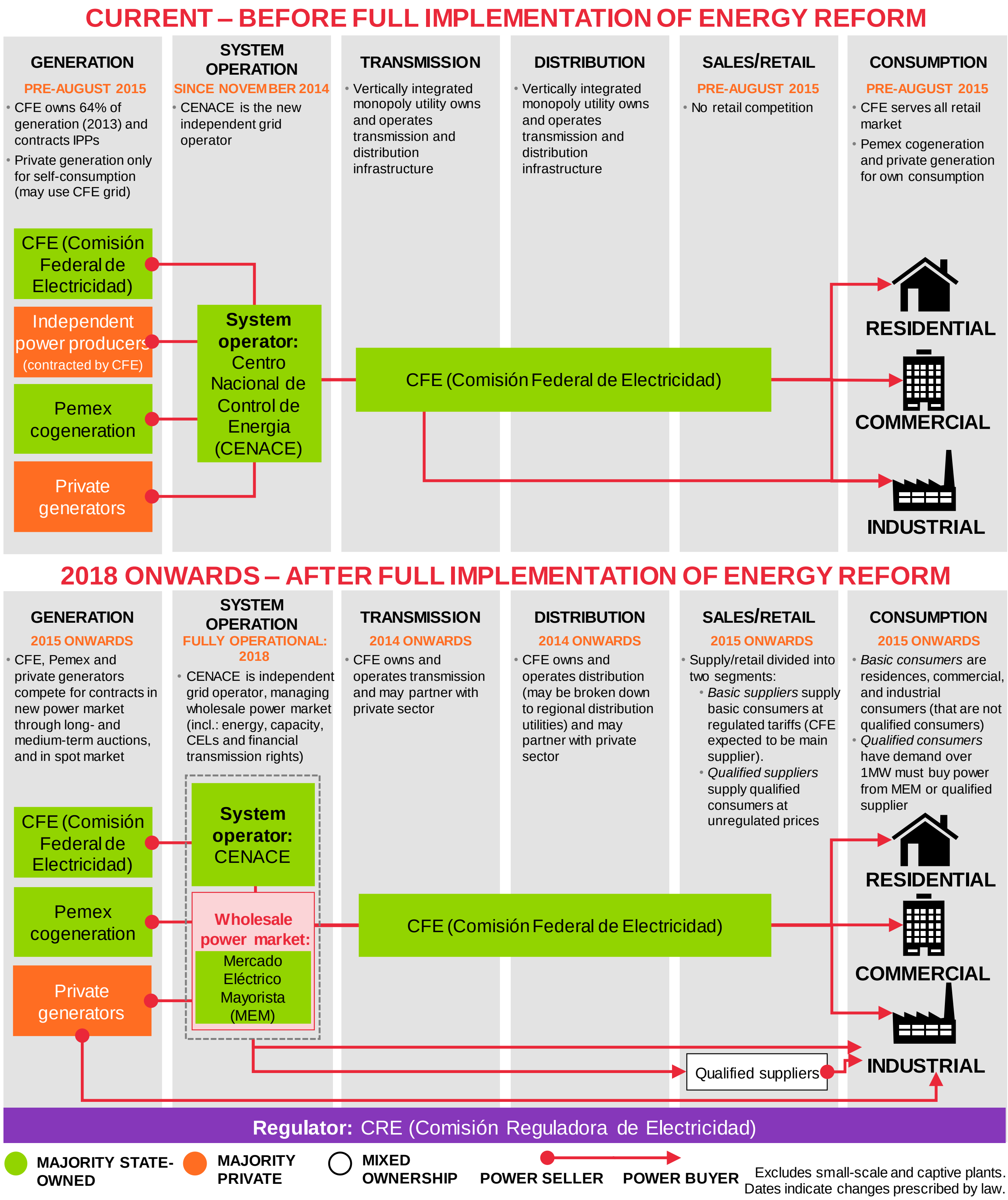
Figure 33: Mexico installed capacity, 2017 **Figure 34: Mexico Generation, 2017**



Source: PRODESEN, SIE, CENACE, BloombergNEF

Mexico's matrix is dominated by thermal sources, which represented approximately 85% of total generation in 2017, primarily in the form of natural gas and diesel. Large hydro accounted for approximately 9% of generation, followed by nuclear and geothermal at 5% and 3%, respectively (Figure 34). The wind and solar sectors are poised for strong growth due to auction mechanisms put in place by the energy reform. In 2017 Mexico attracted for the first time more clean energy investment than Brazil, the largest country in Latin America.

Figure 35: Mexico Power Market Structure



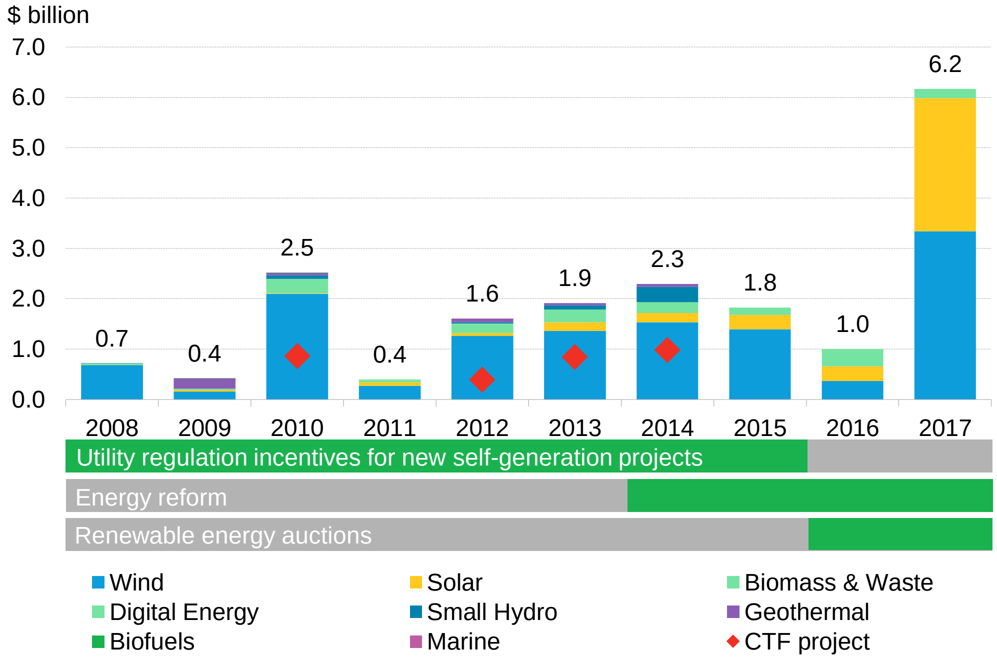
Source: SENER, BloombergNEF. Note: before full implementation of the energy reform, generators and large consumers could sign bilateral PPAs under the self-supply framework. The energy purchased was delivered to consumers through CFE grid.

Energy reform and new investment

Energy policy in Mexico has evolved substantially since CTF's first engagement in the country as a result of sweeping reforms begun in 2013. The changes have effectively ended the monopolies of state-owned vertically-integrated companies and enabled private sector participation in Mexico's oil, gas, and power markets. The country's electricity market has transitioned from a single, state-owned, vertically integrated utility (CFE) to a liberalized generation market and a new independent grid operator (CENACE) has been established. In pushing through the reform, President Peña Nieto strongly articulated support for renewable energy, energy efficiency, and sustainable transport actions aimed at both development and climate change mitigation.

There was policy support for clean energy even prior to the reform roll-out, however. In 2012, the government established a robust mandate to generate 35% of the country's power from clean sources by 2024. In 2014, it followed that by setting up a Clean Energy Certificates (CELs) market[9] to achieve the goal. A wholesale market started operating on a day-ahead basis in 2016 and in real time in January 2017. Only the last pillars of the reform are yet to be implemented, including the introduction of a second phase of the short-term energy market with an hour-ahead market. The CELs market is also entering into force, bringing to conclusion a period of fundamental change for the sector (for more, see section Pre-reform policies below).

Figure 36: Mexico new clean energy investment by technology and policies timeline



Source: : BloombergNEF Note: "CTF project" refers to full investment received by projects financed by CTF.

The reforms have resulted in a boom in clean energy investment in the country. Mexico held three highly successful long-term renewables auctions over 2016-17, contracting a total of 19.8TWh of clean power, 1.8GW of firm capacity and 20.6 million CELs. Clean power investment jumped

[9] Mexico's CELs mandate entered into force in 2018.

more than six-fold, from $1 billion in 2016 to $6.2 billion in 2017, driven by two auctions held in 2016. A fourth long-term auction, previously scheduled for November 2018, has been postponed.

The auctions have made headlines by producing promises to deliver clean power at record-low prices. In the country's third auction, held in November 2017, the average overall winning bid was $19.8/MWh, with the lowest wind bid at just $17.7/MWh. The highest winning bid came in at a paltry $23.3/MWh. This most recent auction was also Mexico's first in which private offtakers could participate. A clearinghouse (cámara de compensación) will facilitate long-term auctions' contracts and ensure buyers and seller's obligations and rights. In earlier auctions, CFE was the only entity that could buy power.

Pre-reform policies

Renewable energy projects in Mexico also benefited in the early days from two key, if somewhat unheralded incentives in place prior to major reform: the energy bank and 'postage-stamp' wheeling charges. Both were in effect in 2010 during CTF's early engagement. These incentives had an important impact on the economic viability of Mexico's early renewable energy projects and in particular wind projects. Two categories of renewables projects were able to qualify for these incentives: those registered under a self-supply (*autoabastecimiento*) permit and those registered under a cogeneration (*cogeneración*) permit as efficient cogeneration projects. These benefits extended to wind, solar, hydro, geothermal, marine, and bioenergy projects.

Under the self-supply and cogeneration frameworks, bilateral agreements could be struck between a generator and an off-taker. The two would then essentially be regarded as a single entity by the CFE. The energy bank's primary function was to ensure that the entirety of a project's production could be monetized by guaranteeing compensation for any excess electricity generated by a power plant registered under a self-supply permit. Excess generation occurred when the off-taker's consumption was lower than the plant's generation. This guarantee proved important due to the variable nature of renewables production, enabling developers to size projects beyond the customer's immediate baseload needs. Under this mechanism, the self-supplier was compensated at the prevailing retail price for excess energy, and owed the prevailing retail price at times of deficit. The actual transfer of funds did not occur in real-time. Rather, the excess-deficit balance was tallied each month, yielding a net credit (or deficit). The self-supplier was able to use a credit any time in the following 12 months. If the credit went unused for 12 months, the self-supplier was simply paid 85% of the CTCP, (*costo total de corto plazo* or total short-term cost, essentially CFE's wholesale electricity cost) for the credit. Importantly, the CTCP was almost always lower than retail electricity prices.

For wind in particular, which dominated renewables investment at the time of CTF engagement, the economics of the energy bank were important. In addition to intermittency, wind production is often inversely correlated with peak load, because wind tends to blow more at night and during 'shoulder months' – spring and fall – when electricity demand is low.

The second benefit, postage stamp rates, allowed renewable energy projects to benefit from a universal rate for transmission tariffs, enabling renewable energy projects to pay the same rate to send their electrons across the transmission grid regardless of distance travelled (analogous to a single price for postage for sending mail anywhere in the country). This typically resulted in significant discounting to the conventional transmission tariff. For example, for a 70MW project, conventional transmission costs may have ranged very widely from 0.0481-1.3183 Mexican pesos/kWh ($3.72-101.96/MWh), depending on project capacity, location of dispatch and consumption, voltage of transmission lines used, as well as CFE's operation and maintenance costs. By contrast, postage stamp-based costs were typically 0.03445 Mexican pesos/kWh ($2.66/MWh) for renewable power projects, a reduction of 28-97% ($1.06-99.29/MWh).

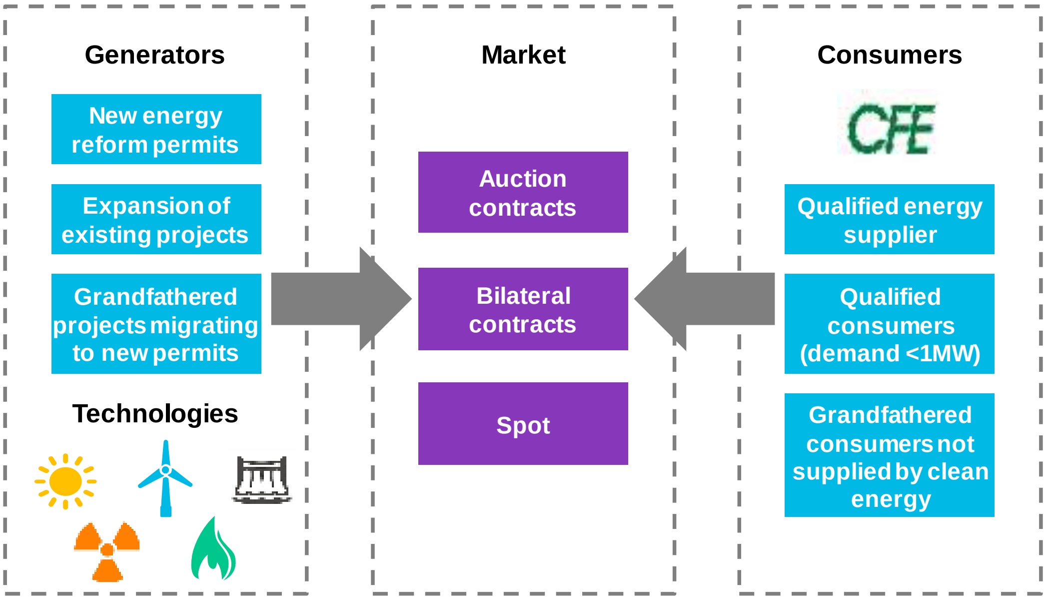
This benefit proved critical given the challenges facing projects generally at the time related to transmission. Prior to the reforms, interconnection lacked transparency and developers interested in moving ahead with a project needed to request a pre-feasibility study from CFE, requiring them to develop projects without certainty that they would have an interconnection contract at the time of interconnection.

Corporate PPAs were critical to the clean energy market in the pre-reform context. As private renewable energy plants paired with offtakers were allowed to be designated as independent producers, most clean energy projects in Mexico consisted of these types of partnerships. From 2008 to 2017, renewable energy capacity installed with corporate PPAs under grandfathered permits reached a total of 3.4GW.

Post-reform policies

Thanks to an evolving wholesale market and low-carbon mandates now imposed on large consumers, Mexico's corporate procurement landscape is expected to change. Under the new rules, private companies can request a 30-year license to generate electricity and large consumers can sign bilateral PPAs directly with power producers. Thus far, approximately 760MW of PPAs have been announced under the new mechanism.

Figure 37: Clean Energy Certificate market structure



Source: BloombergNEF

Post-reform, Mexico's CELs are the main incentive for clean energy generation. Mexico aims to generate 35% of its electricity from renewable energy sources by 2024 and CELs are intended to help achieve the goal. To set CEL quotas, the government estimates the total annual renewable energy generation it will need, then subtracts projected generation from clean power plants that will not be able to generate CELs. The balance is the CEL target for the year.

All projects registered under the government's new energy reform rules that generate electricity from clean sources are eligible to produce CELs with clean sources defined as biomass, geothermal, solar, wind, hydro (small and large projects), nuclear and efficient cogeneration. All major power buyers must comply with the CEL mandate with the exception of those operating under grandfathered interconnection contracts already involving electricity supplied by renewable sources. Certificates are accumulated through the year then liquidated in the first quarter of the calendar year after the power has been consumed.

New projects can no longer access energy bank and postage stamp policy supports, but existing plants may choose whether they wish to adopt new market rules or remain under the old rules. Grandfathered projects that previously benefited from these policy supports can now choose to change their permit status to *generadores* to generate CELs. A project that makes the switch to qualify for CELs may revert back at any time over the following five years.

According to projections from the Secretariat of Energy (SENER), certificate market demand is expected to total approximately 13.7 million CELs in 2018, 16.5 million in 2019 and 21.4 million in 2020. This amounts to a proxy for the total GWh of renewable power that will need to be delivered for Mexico to meet its national clean energy goals. The country's three auctions to date have been used to broker the sale of 5.4 million CELs for delivery starting in 2018, 9.3 million CELs for 2019 delivery and 5.9 million CELs for 2020 delivery. This leaves a gap of 8.3 million CELs for the first year (2018), 1.8 million CELs for the second, and 0.8 million CELs for the third, raising important questions around whether there will be an adequate supply of CELs to maintain the country's momentum.

Until recently, solar project development had been very limited despite Mexico's extraordinary insolation. At the time of initial CTF engagement, the high capital costs of solar and lack of preferential incentives for utility-scale projects meant that only subsidized projects could be implemented. Total installed PV capacity was just 19.4MW at the end of 2008. Though wind was more competitive on a level playing field and secured contracts first, the levelized cost of electricity (LCOE)[10] for both technologies has fallen dramatically since that time due to technological progress. In 2017 alone, Mexico LCOEs for wind fell 28% to $53/MWh from the prior year, BNEF estimates. On the solar side, an even greater drop has been observed, with an average LCOE standing at $60/MWh in 1H 2018. As recently as 2015, LCOEs for wind in Mexico stood at around $52-91/MWh, while solar PV was in the $106-202/MWh range.

2.3.2 Clean energy investment

CTF in Mexico

The renewable energy components of the CTF's first Investment Plan for Mexico, endorsed in January 2009, envisioned support for transforming the power sector by increasing wind power production in the country. The plan sought to take advantage of a window of opportunity created by a newly supportive regulatory framework.

The original CTF plan anticipated investment of $500 million in Mexico through three distinct renewable energy programs with a total allocation of $139.1M: the International Finance Corporation's (IFC) Private Sector Wind Development ($15.6M), the Inter-American Development Bank's (IDB) private sector Renewable Energy Program ($53.4M), and Proposal III of the IDB's Renewable Energy Program (the public sector Renewable Energy Financing Facility, $70.6M).

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[10] BNEF defines LCOE as the long-term offtake price required to achieve a certain equity hurdle rate for a developer, considering its total capital, operating and finance costs over the lifetime of the project. This LCOE estimates exclude costs of grid connection and transmission. They also do not take into account subsidies or incentives as they are intended to assess the true economic viability of technologies outside the bounds of policy support.

CTF and multilateral development bank (MDB) financing sought to provide financing instruments and capacity building for developers and local financial intermediaries to develop projects.

Wind projects have been the recipient of 95% of CTF investment in the country to date. This has encompassed eight distinct developments consisting of approximately 1,084MW of wind, with the balance allocated to a single, 39MW solar project. The first two CTF projects in Mexico were wind projects supported through IFC and the private sector window of the IDB, with a blend of CTF and MDB resources. The first was Acciona's Eurus Wind Project, supported with $30 million from CTF (via IDB). This project was commissioned in 2009 in the southern Mexican state of Oaxaca.

Figure 38: Mexico annual wind capacity additions

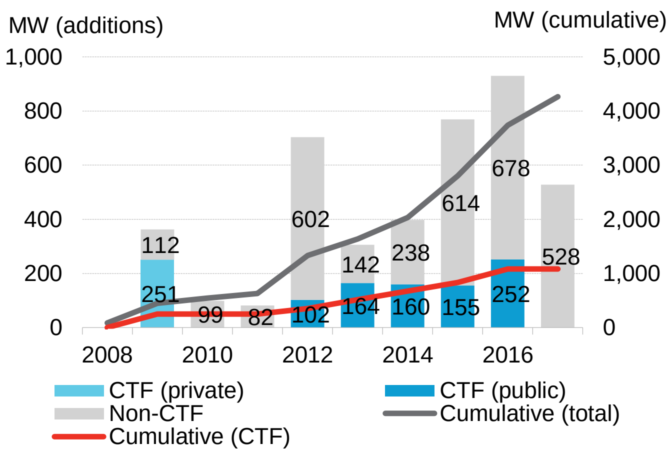
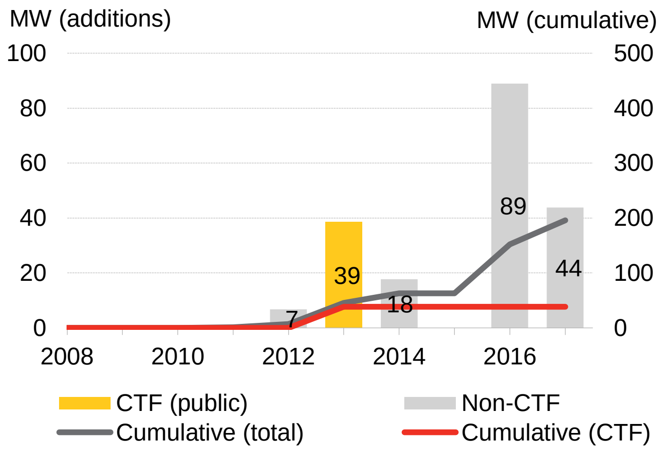


Figure 39: Mexico annual PV capacity additions



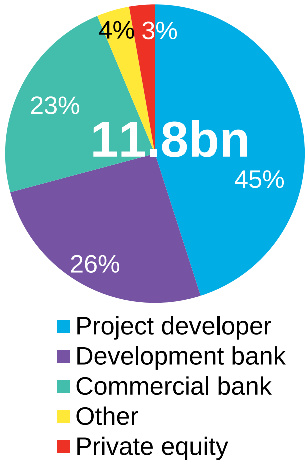
Source: BloombergNEF, CTF. Note: Projects are listed by date of commissioning. "CTF project" refers to full capacity of projects that were partly financed by CTF.

Eurus was one of the first private wind power projects in Mexico and therefore had an important demonstration effect. At 250MW installed capacity, it was the largest operating wind farm in Latin America at the time and the largest wind project in Acciona's portfolio. The project was developed under Mexico's self-supply framework and sells its energy to Cemex Mexico under a 20-year PPA. Eurus was followed by EDF's La Ventosa Wind Farm, a 67.5MW plant commissioned the following year and also located in Oaxaca. The project was supported with $15 million of CTF resources (via IFC).

After being invited to participate as a co-lender in the Eurus deal, Mexico public infrastructure bank Nafin became involved in renewables finance and would later become a key player in the use of CTF resources. In 2011, the IDB Board approved the Renewable Energy Financing Facility for Mexico, with $70 million of CTF resources that were channelled through Nafin.

With CTF support, Nafin financed five wind projects, and one utility-scale solar investment. The Aura Solar I PV Plant is a 38.6MW PV plant developed by Gauss Energia and located near La Paz City in the state of Baja California Sur. Of Mexico's currently defined eight transmission zones, Baja California Sur is among the most isolated as it is completely separate from both the neighbouring Baja California zone and the national grid. As the region is historically isolated and experiences very expensive electricity nodes, the Aura project was focused on strengthening the extremes of the grid rather than bulk generation. The project received a $25 million loan from the IFC, as well as a $50 million loan from Nafin blended with $10 million of concessional financing from the CTF.

Figure 40: Mexico new build wind investment by investor type



Source: BloombergNEF

In 2013 Mexico submitted a revised Investment Plan, and in 2014 a new geothermal program was approved by the CTF, utilizing a mix of reallocated IP resources ($34.3 million), plus $20 million from the Dedicated Private Sector Programs. In sum, out of a total of $519 million of CTF resources allocated for Mexico (excluding funding canceled for use in the country), $115 million has financed wind and solar utility-scale power projects. Another $74.3 million has been earmarked for future investment – $54.3 for geothermal projects and $20 million for distributed solar generation.

Investor types

CTF investments in Mexico were successful in leveraging additional resources. In what has been a diversified financing landscape, project developers, commercial banks, and multilateral and national development banks have all played important roles (Figure 40).

Wind has successfully attracted significant investment from project developers and commercial financiers. New-build wind projects received around $11.8 billion from 2011 to 2017, of which 45% came from project developers and 23% came from commercial banks. Experienced international project developers with sufficient balance sheet size, such as Acciona, helped provide finance along with development banks. At year-end 2017, Mexico had nearly 4.3GW of wind capacity commissioned.

Figure 41: Mexico new-build wind investment, by investor type

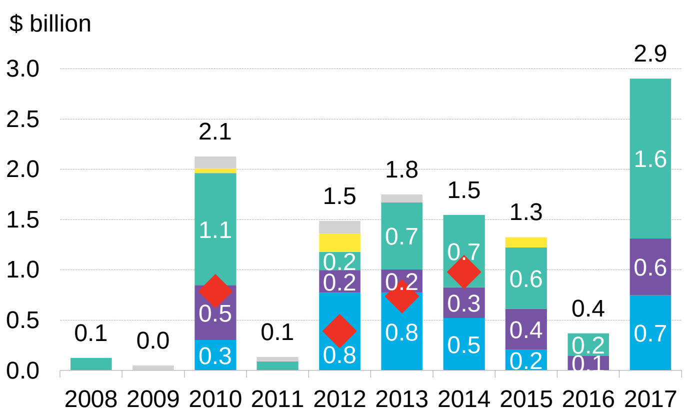
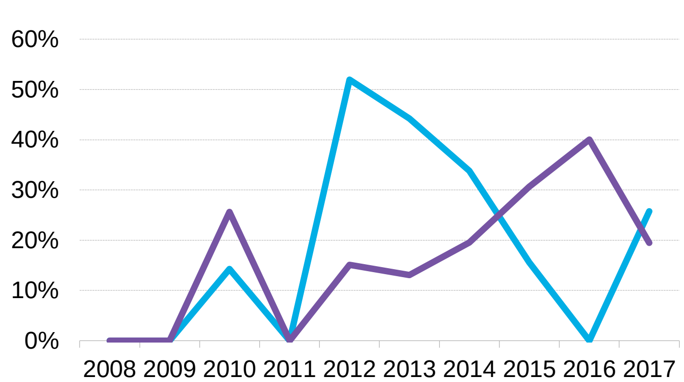


Figure 42: Mexico new-build wind investment share, by investor type



Source: BloombergNEF, CTF

The refinancing of early projects, such as the Eurus and La Ventosa wind farms, offered IDB the chance to leverage its resources and mobilize funds from other national development finance institutions and commercial banks. CTF loans played an important supporting role within the transactions by helping mitigate project-specific risks, including technological and cash flow risks, via the use of concessional long-term finance. For example, the 250MW Eurus project employed $30 million of CTF resources to leverage $345 million, with the remainder coming from the project developer (total project cost: $605 million). Another $15 million of CTF financing was used to finance the 67.5MW La Ventosa wind project. Together with IFC's own resources, this investment was able to mobilize an additional $173.6 million in co-financing from the project developer (total project cost: $312 million). Both projects were developed under Mexico's self-supply framework.

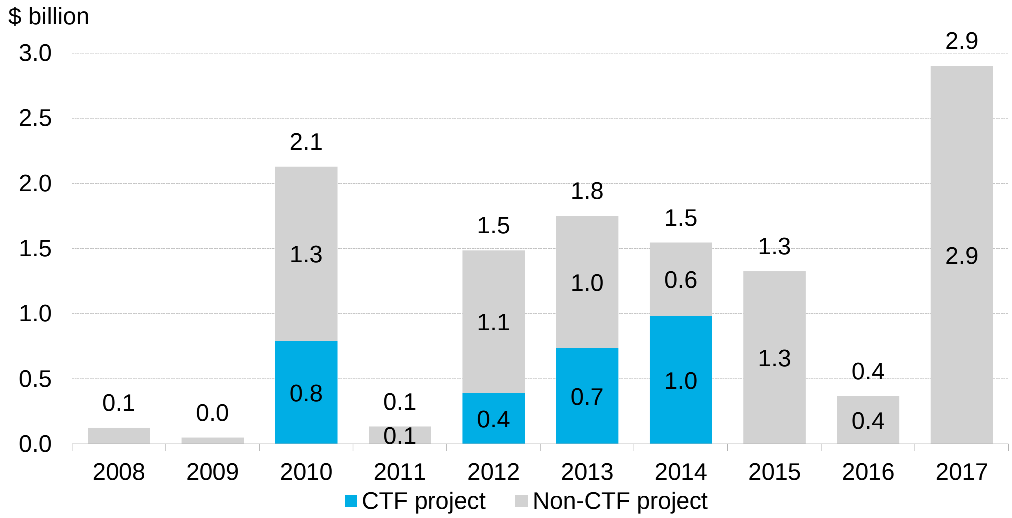
2.3.3 CTF results and market impact

At the time of CTF engagement, a significant constraint on clean energy development in Mexico was lack of access to finance, specifically long-term capital. In interviews with BNEF, stakeholders with experience in the market identified a variety of factors that were to blame: high initial investment costs; commercial bank apprehension about supporting new or unproven business/products lines; their general lack of capacity to analyze and structure energy projects with unfamiliar risk profiles; and insufficient regulatory incentives. In addition, as a consequence of the global financial crisis, the Mexican peso suffered a deep devaluation, falling from 10 per U.S. dollar in August 2008 to a peak of 15 in March 2009. These conditions cumulatively translated into elevated transaction costs, including higher interest rates or excessive collateral conditions. This combined to obstruct commercial investment and restrict the growth of Mexican clean energy.

Role in early development of the wind industry

Development finance institutions played an important, supportive role in the early years of development of Mexico's world-class wind resource. Though Mexico's wind market received investment as early as 2005 into projects such as CFE's La Venta II Wind Farm and Iberdrola's La Ventosa Wind Farm Phase I, early CTF involvement coincided with a significant jump in new build investment in 2010 (Figure 43). Prior to 2010, projects had been financed by project developers or CFE. Beginning in 2010, commercial banks began to play a role, while project developer capital also increased dramatically.

Figure 43: New-build wind investment in Mexico, by type of investor



Source: BloombergNEF, CTF

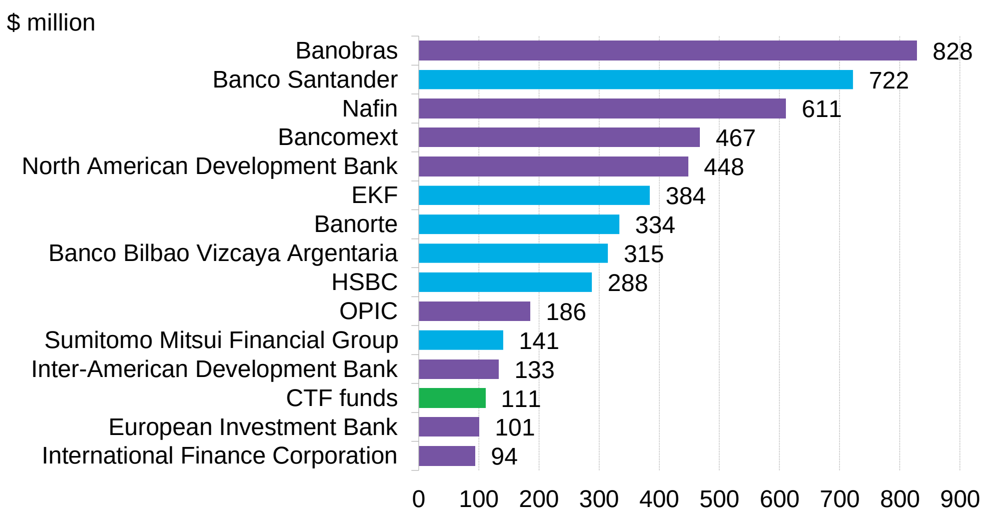
CTF contributed to catalyzing investment in renewable energy in Mexico at this time by refinancing the Eurus and La Ventosa projects, and also by engaging national development banks, such as Banobras and Nafin. While these two early wind projects received CTF support at the refinancing stage, CTF played a key role in facilitating the further development of the industry by providing an important level of security in assuming key risks and therefore enabling leverage of additional finance. The success of the wind industry in the ensuing years should be attributed to multiple reasons, but, absent CTF resources, securing finance could certainly have been significantly more challenging as CTF allowed other lenders to increase their exposure.

The 2008 financial crisis also played a key role as the backdrop to early CTF engagement in Mexico as developers struggled to replace suddenly lost bank financing. The CTF provided a useful, risk-mitigating function during this particularly turbulent period, in addition to the benefit of its concessional terms. Such risk-mitigation may have been as important as offering a discounted interest rate to early projects such as Eurus.

With its different debt-sizing functions, the CTF assumed more wind (technology) risk and its resources were used as subordinated tranches in loans, increasing the probability CTF would not be repaid. As a substantially less proven technology in Mexico at the time, wind projects such as Eurus were viewed as carrying technology risks, rather than market risks, which in this particular case were minimal as the PPA was signed with a highly reliable offtaker, Cemex. With the subsequent projects financed by Nafin, construction risk also factored prominently.

Concessional long-term finance terms made possible by the CTF through the Nafin RE Facility were distinguished from otherwise available capital at the time by both the interest rate offered and the long-term nature of the finance. By mitigating long-term risks, CTF enabled Nafin to offer projects full funding from inception through operation of the project. This filled an important gap in the market at the time, eventually contributing to the creation of a now robust project finance market for wind assets in Mexico on commercial terms. Indeed, commercial institutions factor prominently among lead debt providers in the wind sector over the past decade (Figure 10).

Figure 44: Mexico lead wind debt providers, 2008 – 2017



Source: BloombergNEF, CTF

Finance market impact

CTF investment had a discernible positive effect on the renewable energy finance market, according to interviewees. The role of CTF investment was particularly pronounced in early projects, such as Eurus, in which it greatly affected the blended capital structure of the financing. Subsequently, it was found to be helpful to route concessional financing through a national development bank, as it enabled leveraging of more funding.

Another notable market impact of the CTF Investment Plan was capacity building. CTF resources had a positive impact on Nafin's capability to invest in renewable energy, and wind in particular in the early years of its development in Mexico by developing human and organizational capital. IDB support enabled the establishment and staffing up of a new dedicated unit, the Sustainable Energy and Climate Change group, whose first project was Eurus, funded in early/mid 2010. The group hired and trained young professionals who developed strong technical and project development skills, leading to the development of a highly analytical and efficient team.

Impact of reform, 2016-18

In fundamentally rewriting the rules of the energy sector and with specific bearing on renewables, Mexico's reform greatly affected the trajectory of the market. Investment in wind projects experienced a boom beginning in 2010 that extended through 2015. Reform, the major tenets of which were enacted in 2013, created significant uncertainty with respect to the evolution of the legacy incentives in place. Prior to reform, national development banks had been working with projects under the previous legal and regulatory frameworks, self-supply or cogeneration.

As reform progressed, substantial uncertainty around rules for the new power market and, in particular, the fate of two important incentives – the energy bank and the postage stamp rates for transmission – appeared to stunt wind development in Mexico over 2016. Uncertainty also triggered a rush for requests for permits from projects looking to be grandfathered under the old incentives, as project owners were unsure how the new incentives would be favorable compared to the existing ones.

In addition to reform, the impact of auctions created uncertainty with respect to prices, which were effectively halved. This price uncertainty had the effect of stalling the market as commercial and public banks and other market participants attempted to manage their exposure to the evolving market conditions. New bank capital adequacy requirements imposed under Basel III during this time also had a restrictive effect, reducing the tenure of commercial bank financing and therefore rendering development bank finance relatively more important.

As of August 2018, with three successful, large-scale auctions completed and a markedly different PPA in place, the banking sector is more comfortable with renewable energy projects than even a few years ago. One indicator of this is that banks are now more focused on mitigating market risk, as opposed to wind risk, i.e. mitigating exposure to projects in which repayment is tied to spot market revenues. Management of market risks remains relevant even for projects that have won PPAs at long-term auctions due to the limited (15-year) term of contract.

An important factor in the evolution of the commercial cost of capital in renewables development in Mexico is the more recent entry of larger players able to borrow on a portfolio basis, as opposed to smaller players that need the capital from one project to finance the next. This shift in the competitive landscape can be attributed to auctions, in turn a product of successful energy reform.

2.3.4 Future ambitions and the role of CTF

As the wind market has matured, the share of investment from commercial banks has increased significantly. This has allowed development banks to focus more on the financing of solar projects. IDB investment in Mexico, for instance, has transitioned from wind in 2010-2012 to solar over 2013-2017, having supported six auction-winning solar projects in 2017. However, as the solar market rapidly develops in Mexico, development bank finance in solar projects with long-term PPAs is less likely to be needed. Aggressive results from the recent auctions suggest that developers are not counting on cheaper finance from development institutions, but rather finding other ways to be competitive. Large European utilities with lower costs of capital, such as Enel, have moved aggressively into both Mexican wind and solar. This trend is expected to continue, and taken together with diminished global technology risk, suggest potentially reduced opportunities for development institutions in the scaling up of the Mexican solar market.

Rapid cost declines for utility scale solar seen in recent years are expected to continue, supporting an expansion of the technology (Figure 45 and Figure 46). The levelized cost of generation from new solar and wind in Mexico today is broadly equivalent to that of a new combined-cycle gas (CCGT) plant on a $/MWh basis. BloombergNEF expects by 2020 solar and wind to become the most competitive sources, with utility-scale PV declining to $48/MWh and wind falling to $47/MWh. By 2025, we expect utility-scale PV plants to become 28% cheaper than new combined-cycle gas and onshore wind costs to be 22% lower than CCGT.

Figure 45: Mexico levelized cost of energy of new plants ($/MWh, real 2017)

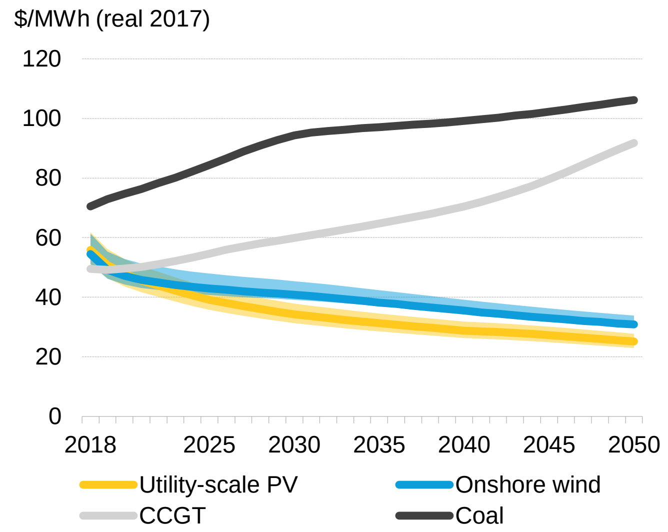
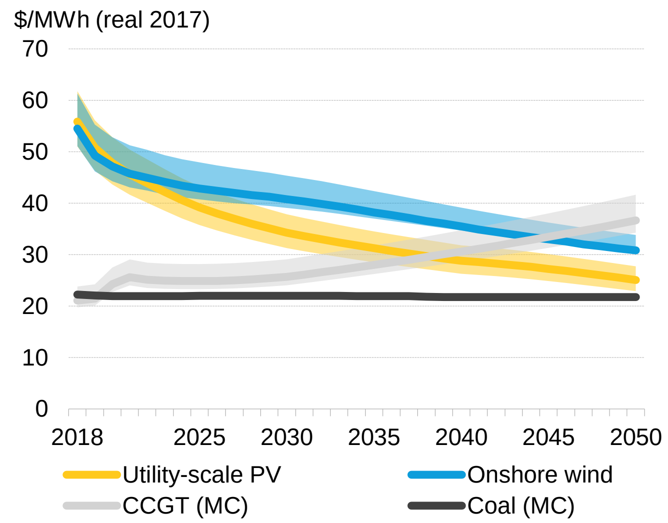


Figure 46: Mexico levelized cost of new PV and onshore wind vs. running costs of existing coal and gas ($/MWh, real 2017)



Source: BloombergNEF

However, increasing penetration of intermittent clean energy technologies in Mexico will also create associated demands for new, complementary technologies to facilitate Mexico's transition to a low-carbon economy. Examples of this include riskier, emerging technologies, such as bi-facial solar panels, as well as battery storage, energy efficiency, technologies associated with advanced mobility such as electric vehicle (EV) charging stations, and geothermal, which provides an important source of baseload that wind and solar cannot offer on their own.

Geothermal represents an area in which IDB has already been engaged, having provided investment and capacity building efforts, such as finance for a Center of Excellence on Geothermal Energy designed to promote knowledge creation and technical advisory and a Geothermal Exploration Risk Mitigation Project. The Geothermal Financing and Risk Transfer Program, with $54.3 million of CTF resources, was designed to encourage investment in geothermal energy by offsetting exploration phase risks.

The growing Mexican economy is forecast to more than triple in size by 2050, from an annual GDP of $1 trillion to $3.7 trillion, according to IMF and OECD projections. Strong economic growth is expected to boost Mexico's net electricity demand by 21% to 2035 according to projections from BloombergNEF's 2018 New Energy Outlook. But to reduce CO2 emissions deeply and meet the government's target of a 50 percent reduction by 2050, significant energy efficiency improvements will be needed, and clean energy will need to revolutionize the power-generating mix. As such, opportunities to assist Mexico to develop viable alternative energy projects that harness its abundant resources and meet growing energy demand should prove plentiful. See the Forward looking analysis section of this report for more details.

2.4. Morocco

2.4.1 Country context

Overview

Morocco is Africa's 5th largest economy and thanks to strong ties to Europe is often viewed as offering a gateway to the rest of the African market. The country's excellent solar and wind resources, combined with a heavy reliance on energy imports, mean that domestic renewable power generation often has a competitive advantage and can attract foreign attention. Morocco's political stability and business-friendly legal frameworks have fuelled speculation about exporting clean, inexpensive power to other African nations and even to Europe. Strong trade winds provide Morocco with an excellent resource and have allowed the 300MW Tarfaya wind farm to achieve exceptional capacity factors topping 45%. Moroccan PV installations can produce similarly outstanding capacity factors of 20% or higher, while insolation in the country's desert areas offer ideal opportunities for solar thermal development.

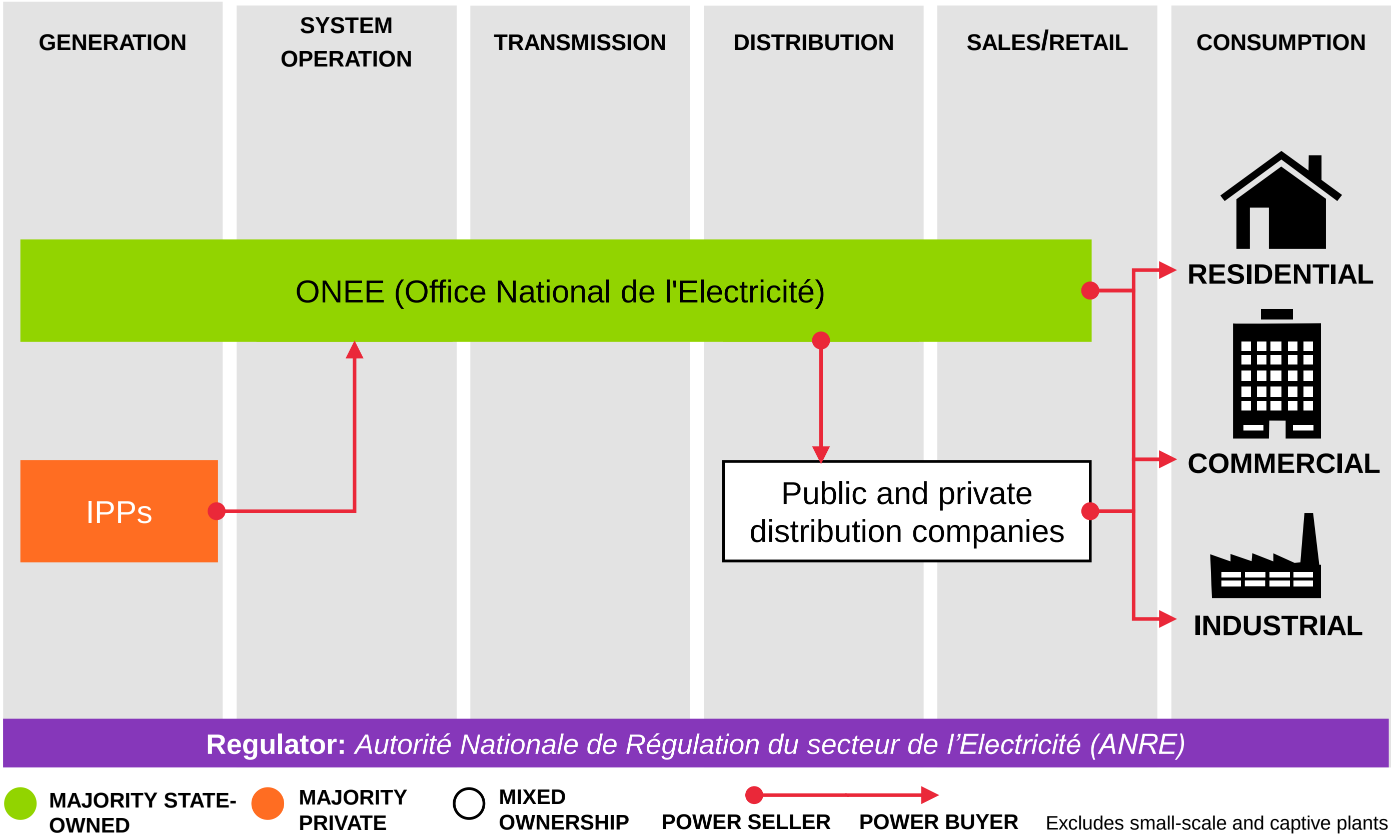
Power sector structure

Morocco's power generation sector consists of several independent power producers that sell electricity to state-owned utility, the Office Nationale de l'Electricité et de l'Eau potable (ONEE). In addition to controlling all transmission assets in Morocco, ONEE also own approximately half the country's generation. And ONEE oversees retail sales to half of all end customers. The other half is delivered by several smaller private and public distribution companies that focus on specific areas, but the responsibility for the grid rests with ONEE.

In terms of renewables, ONEE has been involved with the development of new solar projects in the past but these responsibilities have gradually been transferred to the Moroccan Agency for Sustainable Energy (Masen). Masen was originally created in 2010 to focus on solar development but has seen its remit expand to cover other renewables. ONEE is still charged with rural electrification efforts, which include smaller-scale PV projects.

Defining characteristics of the Moroccan power grid include a sharp spike and peak in electricity demand during evenings and a high overall rate of electrification. Commercial electricity tariffs reflect this evening demand peak with higher prices while residential consumers pay a flat rate throughout the day. Morocco lacks major fossil fuel reserves but is home to excellent sun and wind, and a good hydropower resource. Coal capacity and generation have grown in recent years on account of being relatively inexpensive compared to other imported fossil fuels.

Figure 47: Morocco power sector structure



Source: BloombergNEF

Morocco had a total installed capacity of 8.9GW as of year-end 2017, and generated 31.6TWh of electricity, equivalent to 85% of its demand. Wind and solar account for 14% of Morocco's capacity and 11% of the country's generation (Figure 72 and Figure 73).

Figure 48: Morocco's installed capacity, 2017

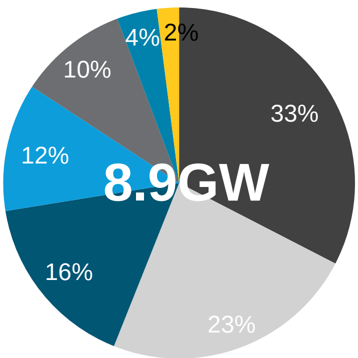
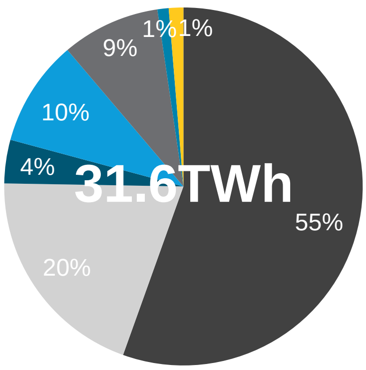


Figure 49: Morocco's power generation, 2017



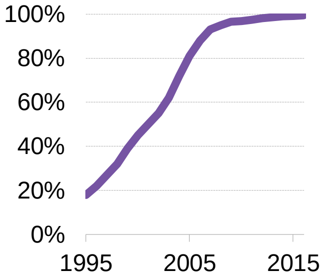
Source: Office National de l'Electricite, BloombergNEF. Solar figures include both PV and thermal (Noor I was commissioned in 2016).

Policies

In 2010, Morocco committed to reach 42% installed renewable capacity[11] by 2020, with sector-specific targets of 2GW of solar, 2GW of wind and 2GW of hydro. At the time of this announcement, the country had 1.7GW of hydro on line, two wind farms with a combined capacity of 283MW, and 20MW of solar.

Given the initial lag in solar development, the Moroccan authorities launched an ambitious Solar Plan and founded Masen to implement it in 2010. Contracts were awarded in 2012 under Masen's first tender, the Noor I solar plan.

Figure 50: Morocco rural electrification rate



Source: ONEE

In order to reach the wind target, ONEE launched a tender for 850MW of new capacity in 2012 distributed across five wind farms. The tender attracted record low bids estimated at $30/MWh with commissioning of the projects planned by 2020. In 2015, the Moroccan government extended its targets, setting an objective of 52% renewables by 2030.

At about the same time, Morocco undertook efforts to liberalize its energy sector to be more receptive to renewables. Promulgated in 2010, Law 13-09 created a legal framework for the development of renewable projects by independent power producers. Finalized at approximately the same time, Law 16-08 provided a framework for self-generation from renewables. Under the former, energy can be sold directly to clients over the medium or high-voltage grid, with the purchase of any excess generation by ONEE, which remains involved in all sales of electricity within Morocco.

The publication of Law 58-15 in 2015 aimed to open medium- and low-voltage network access to small enterprises or private individuals to sell power. However, this act still needs to be fully implemented. Moroccan policy-makers have made improving energy access a major focus over the last two decades and achieved substantial progress in this area. ONEE managed to connect more than 99% of the Moroccan rural population to the grid by 2014, up from just 20% in 1995 (Figure 50).

Energy plan motivations and solar thermal power

Morocco's reliance on fossil fuels and electricity imports was a primary concern when formulating its energy plan in 2010. In particular, the country relies on burning heavy fuel oil to meet its evening peak demand and global crude prices exceeded $100 at the time of the plan.

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11 In Morocco's definition of renewable energy includes hydro, solar, wind, geothermal, wave energy, tidal energy, biomass, landfill gas, sewage treatment plant gas and biogas.

Figure 51: Morocco hourly peak demand

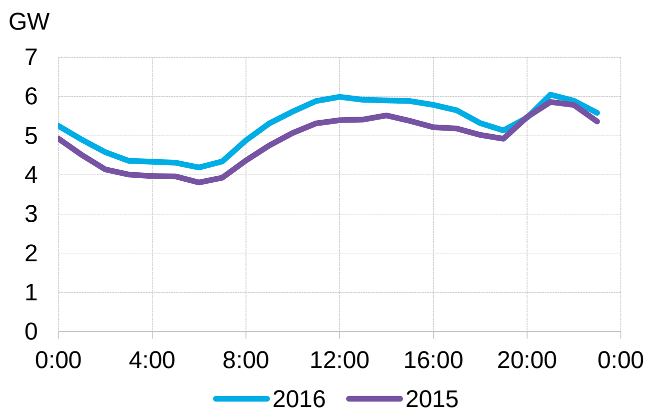
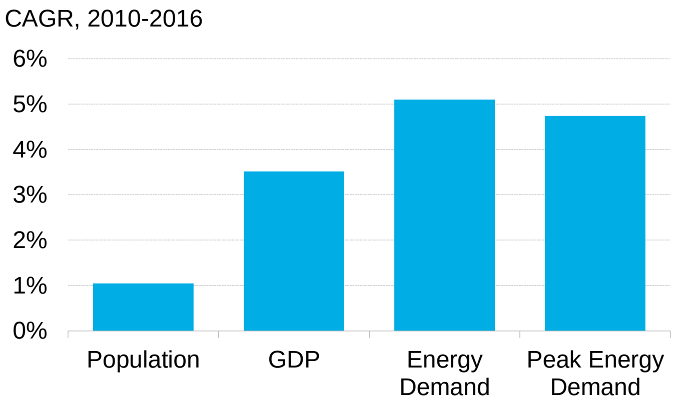


Figure 52: Morocco growth rates



Source: ONEE, BloombergNEF. Peak demand is given for day of maximum instantaneous demand; 28th July 2015 and 26th July 2016.

Morocco's energy demand has grown at an average of 5.1% per year from 2010-2016, which outpaces both population and GDP growth as Moroccan standards of living rise (Figure 52). Of particular importance to the energy sector, is peak electricity demand which tends to materialize in the evening. Peak demand grew by around 4% on average since 2010 and jumped around 4.8% from 2015 to 2016 (Figure 51). This led Masen to commission a technologically agnostic analysis focusing specifically on finding the most cost-effective way to meet this evening peak. It concluded that solar thermal combined with storage was the best option, and that it could already compete on cost with the peaking thermal capacity (imported heavy fuel oil) used to meet evening demand at the time.

While the technological advantage of solar thermal in the Moroccan context was already clear at the time, barriers to development remained. The risks associated with a relatively novel and nascent technology exacerbated the already significant capex costs of the technology. Potentially offsetting these risks in the eyes of Moroccan policy-makers was the projected high local manufacturing content of solar thermal plants. Ultimately, however, local manufacturing was viewed as an added bonus not a primary motivation for selecting a technology. The main motivation was always to find a reliable, clean and cost-effective way to meet evening peak demand.

2.4.2 Clean Energy Investment

CTF in Morocco

Significant CTF concessional capital has been invested in both the Moroccan wind and solar sectors. In fact, to date, Morocco has received more CTF funding than any other country, except India. It has benefited from three CTF funding mechanisms: the Country Investment Plan, the regional CSP Program, and the Dedicated Private Sector Program (DPSP). Utility-scale renewable energy projects alone received around $600 million of CTF concessional finance and almost $950 million in co-finance from partner multilateral development banks, which helped attract another $4.4 billion in additional investment.

Among clean energy sectors, solar thermal has been the largest recipient of CTF capital to date. Of the $600 million in CTF funds directed to utility-scale clean energy projects, the vast majority

($435 million) went to solar thermal projects Noor I, II and III. More recently, another $25 million was announced for the Noor-Midelt solar project, which combines solar thermal and PV.

Excluding Noor-Midelt, only $25 million of CTF concessional finance was awarded to PV projects under the Clean and Efficient Energy Project. It is therefore difficult to assess CTF's overall impact on Moroccan PV. One thing is apparent, however: most of these PV projects were designed to improve supply conditions in areas of the grid where there are shortfalls rather than to supply bulk generation.

In the wind sector, $125 million of concessional financing was awarded to projects under the One Wind Energy Plan. Of this, $95 million went to five wind farms, with the balance provided to the Abdelmoumen STEP (pumped hydropower storage) project.[12] Additionally, the CTF awarded $10.7 million of concessional financing to the Khalladi wind farm in 2015. While this sum is small in the Moroccan context, Khalladi set precedent for future project finance deals under the Law 13-09 framework.

It is clear that CTF concessional financing has been instrumental in kick-starting the Moroccan solar thermal. By contrast, the wind industry was a good deal more mature at the time of CTF engagement in the country. Prior to CTF engagement Moroccan wind projects had already secured $654 million in commercial finance.

In auction timetables and project pipelines, both wind and solar capacity additions are weighted towards 2020, potentially to capitalize on cost reductions. CTF-funded projects will account for approximately 1,450MW of solar projects by 2020 and 820MW of wind projects (Figure 53 and Figure 54).

Figure 53: Morocco annual solar (thermal and PV) capacity additions

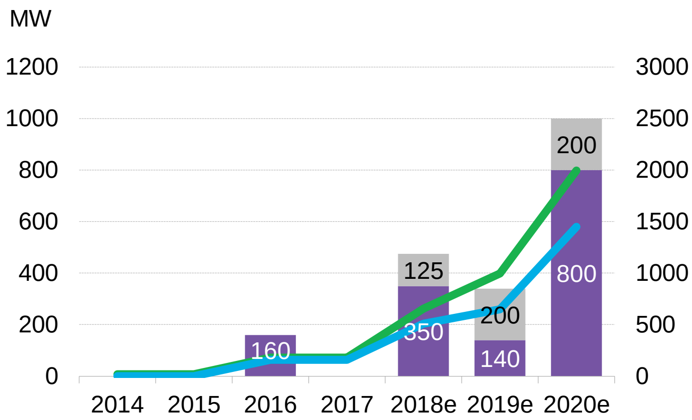
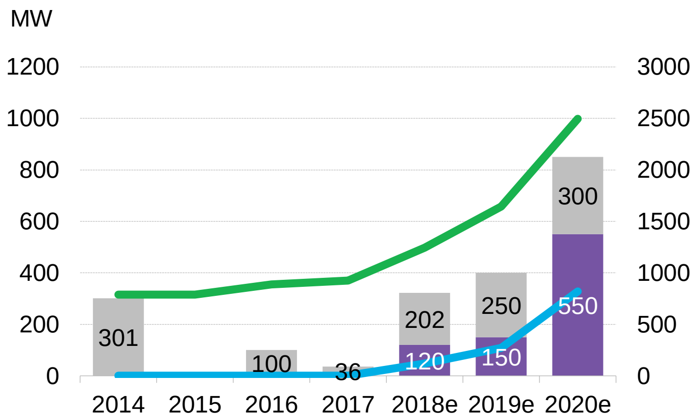


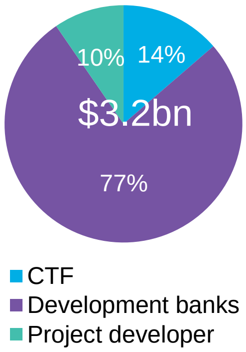
Figure 54: Morocco annual wind capacity additions



Source: BloombergNEF, CTF. Note: Projects are listed by (expected) date of commissioning. Blue lines depict cumulative total capacity. "CTF project" refers to full capacity of projects that were partly financed by CTF.

[12] Morocco: One Wind Energy Plan Proposal

Figure 55: Noor plant investment by investor type



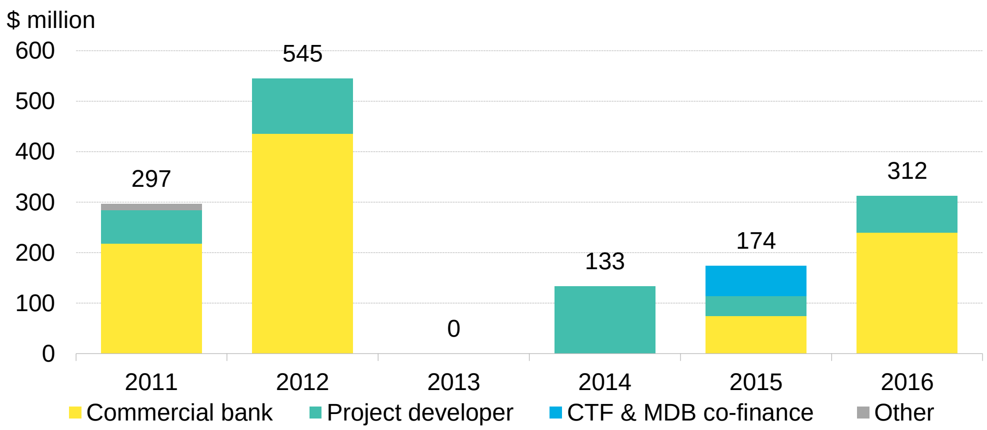
Source: Includes Noor I, II & III

Investor Types

Uncertainty surrounding the reliability and costs of solar thermal has resulted in other MDBs and development banks picking up most of the remaining finance of the Noor projects (Figure 55). CTF investments alone totalled $435 million across Noor I, II & III out of a total of $2.4 billion provided by development banks. The few PV projects that have been able to close finance so far have also raised debt from development banks.

In contrast to the solar sector, wind projects have successfully attracted significant amounts of commercial finance. The sector secured around $1.5 billion from 2011 to 2016, of which 66% came from commercial banks (Figure 55). Commercial financing has followed a cheaper and well proven technology to unlock the world-class wind resource but Morocco has so far failed to deliver at the scale or pace needed to meet its national ambitions. The country only had 887MW of wind commissioned as of 2016 – well below the 2GW by 2020 target. The CTF-funded 850MW Integrated Wind Energy Plan and the 300MW Kouida El Baida projects should get Morocco to its target, even if commissioning dates slip past 2020.

Figure 56: Morocco wind finance by investor type



Source: BloombergNEF. Shown are projects that have achieved financial close of which all financing is known. The CTF funded project is the Khalladi wind farm. Not shown are the CTF-funded 850MW Integrated Wind Energy Plan and 300MW Kouida El Baida projects.

2.4.3 CTF results and market impact

Solar thermal power

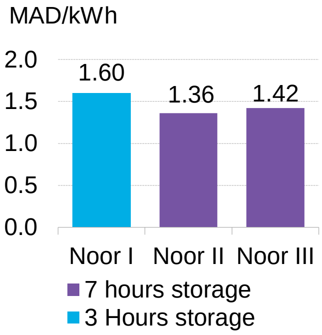
CTF support has been instrumental to the growth of Morocco's solar thermal sector, according to the interviews BNEF conducted for this project. All interviewees stressed the criticality of concessional financing in securing other investment and enabling cost reductions in the power prices offered by developers.

When forming its energy plan in 2010 Morocco's large reliance on imported heavy fuel oil to meet much of the evening demand peaks was a primary concern and a major expense. In terms of renewable technologies, wind was not regarded as sufficiently reliable to generate every evening. PV could offset fossil generation during daylight hours, but it could not reduce fossil capacity demand in evening hours. Solar thermal with storage was therefore an attractive option.

Morocco had no significant investment in large-scale solar thermal prior to 2010 and at the time no large-scale solar thermal towers had been constructed anywhere in the world. As a result, CTF concessional financing not only added credibility to Morocco's aspirations to expand into this sector, it lent credibility and support to a new technology. Masen already knew that solar thermal was the best fit for its needs, but required backing when choosing a nascent technology.

In addition to technological risk, solar thermal also suffers from a problem of scale. The minimum feasible size for a tower plant is generally greater than 100MW. But due to their high capacity factors, such plants offer high levels of generation. The 150MW Noor III solar thermal tower is equivalent to approximately 225MW of wind and 300-450MW of solar PV capacity, for instance. That said, other technologies can be developed piecemeal, segment by segment. For solar thermal, a major financial commitment is required from the very start. It is for this reason that CTF concessional financing was important in attracting the right stakeholders to finance the remainder of the projects.

Figure 57: Changes in tariffs across Noor I, II & III



Source: BloombergNEF

Another feature of the funding awarded by CTF was that it allowed Masen to sculpt repayment according to the seasonality of revenues. This is important for solar thermal projects that produce more or less power depending on solar radiation of different seasons.

Masen was also able to assume other risks due to concessional financing. The foreign exchange risk for the developer was taken on by Masen who allowed bids in the developer's currencies. Allowing for payments in hard currency is critical in lowering bids in markets that are not mature. International investors tend to be averse to currency risk.

In light of all of this, CTF support for Noor can be regarded as a success. Masen estimates that CTF concessional financing reduced the bid price for Noor I by 20-30%, while emphasizing the attractiveness of both the rate and tenor of the loan. Noor developer, ACWA Power, gave an even more pessimistic view of the projects financial viability in the absence of CTF concessional financing, stating in no uncertain terms that the projects would not have advanced without the CTF. Concessional financing gave credibility to a new technology in a new market, mobilized more financing and delivered a competitively-priced source of generation that is available when the system needs it the most. The projects also delivered on their local content promises, with 30-35% of the equipment costs going to local manufacturers.

However, the effect on the wider market is harder to judge. Given the very large financing requirements of solar thermal, further projects are unlikely to proceed outside of specific tenders issued by Masen that require storage. Additionally, detailed cost reductions for the project so far remain confidential, preventing the sharing of lessons learned on where and how cost savings are being made with the wider sector. At a project level Masen has reported cost declines for solar thermal bids 15% from Noor I to Noor II (Figure 57). However, a slight cost increase was observed from Noor II to III which is accounted for in the leap from parabolic trough to solar power tower designs. Noor I to III saw a 12% tariff reduction. If sustained, these numbers are encouraging if modest compared to cost reductions seen in the PV sector.

Noor II and III were commissioned on schedule in 3Q 2018, with the world paying particular attention to Noor III. The successful performance of the tower plant may go some way to restoring confidence in solar thermal as a technology. While announced price developments have recently been encouraging, as low as $73/MWh in Dubai, many investors will still be thinking of the severe technical troubles with the flagship Crescent Dunes project developed by SolarReserve in 2015. Any setbacks in Morocco would be another major blow for an industry seeking success stories. A major component of CTF's value in Morocco – the de-risking new technologies – has yet to play out completely.

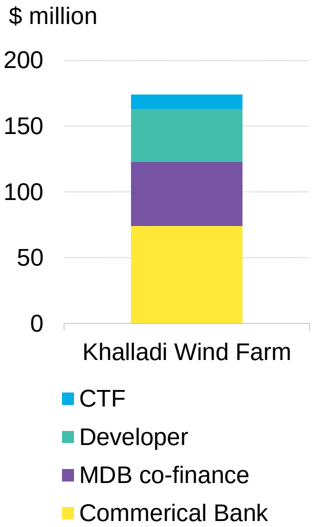
The ultimate impact on the Moroccan market remains to be seen, of course. While Noor I-III projects are likely to be judged as successes, the real evidence of impact would come with continued project development and associated cost declines for solar thermal. Success of CTF concessional financing will therefore be more accurately measured once bids for the Noor-Midelt project are unveiled.

Beyond Noor-Midelt, there is the question of whether new projects will be able to attract commercial finance. Recent PPAs signed with the Aurora and DEWA solar thermal projects suggest that cost improvements are being achieved though. However, neither has yet closed financing and full details are unknown. The hybridization of Noor-Midellt with PV and the existing solar thermal supply chain in Morocco give further weight to expectations of a competitive bid price. It remains to be seen whether private lenders are interested given concerns raised with the technical troubles in the first-of-its-kind Crescent Dunes plant. Potential investors will therefore watch the performance of only the second utility-scale solar thermal tower plant, Noor III, with great interest.

Wind

CTF support for Moroccan wind has been far more limited, partly because the country's world-class resources were already attracting significant foreign investment when CTF first became active in the country. Still, the $106 million of CTF funds deployed has been used to leverage further support from MDB partners and private financiers. That, in turn, has helped Morocco meet its 2020 capacity goals.

Figure 58: Financing for the Khalladi Wind Farm



Source: BloombergNEF

The CTF awarded $10.7 million to the Khalladi wind farm in 2015. Upon financial close, this project had attracted $74 million in commercial finance (Figure 58). Additionally, as mentioned above, while this sum is small in the Moroccan context, this project played a key role by setting a precedent and reference for project finance deals under the 13-09 regulatory framework.

On the other hand, in terms of value deployed and capacity financed, CTF played a much more important role in the 850MW projects of the Integrated Wind Energy Plan. CTF capital was awarded to three of those five projects. Arguably, this project has been the most significant wind project Morocco has seen to date. Leveraging CTF concessional financing the winning consortium was able set a world record price of $0.30/kWh.

To satisfy local content requirements for this tender, Siemens Gamesa built a blade factory in Tangier, which was commissioned in 2017. The presence of this facility on Moroccan soil should not only enable further cost reductions, but could offer export markets in MENA and Europe for Moroccan-made blades.

Finally, it is worth noting the $30 million of CTF funds awarded to the pumped hydropower storage project Abdelmoumen STEP. The project addresses the variability of Morocco's wind generation by shifting power from non-peak to peak hours. Investment in pumped hydropower should be seen as an enabling factor for the Moroccan grid to reliably absorb more renewable generation, and a great benefit to wind developers. Shifting some of the attention that has gone to concessional funding in new generation capacity towards projects that support the integration of more renewables is increasingly critical to the energy transition in emerging markets as grid constraints arise.

The role of Masen

The success to date of CTF concessional financing in Morocco owes much to the exemplary stewardship of Masen in managing both funds and projects. Masen performed many critical functions. First and foremost, Masen blended CTF concessional financing with other capital to provide a single loan with a debt profile ideally suited to both the developer and Masen. Masen also performed the following other key functions, including:

- Producing environmental studies and securing the land
- Acting as the offtaker to the project
- Taking a minority stake in the project
- Taking on most of the foreign exchange risk

All of these have contributed to the success of projects to date and have helped maximize the impact of CTF concessional finance. Outside the scope of the CTF, Masen has even issued green bonds to fund PV projects. Masen has been so instrumental in clean energy's success in Morocco that it should perhaps be emulated in other countries with similar ambitions.

2.4.4. Future ambitions and the role of CTF

Morocco still has some way to go to reach its short-term 42% renewable energy installed capacity target and its 52% by 2030 goal. This will require a significant ramp in clean energy deployment and create a large capital requirements as installed capacity from other technologies and demand continue to grow.

Support from CTF has been fundamental in nurturing Morocco's first strides in renewables. The growth of clean energy has given Morocco's market operators essential experience in integrating renewables into their grid, which they can now share with other countries in the region with similarly ambitious clean energy goals. They have also allowed Morocco to establish itself as a key market for the solar thermal sector while addressing a very specific power supply challenge it was facing.

That said, the renewables market in Morocco has still not sufficiently evolved to sustain a rich domestic development and financing industry that can truly stand on its own. In particular, the lackluster deployment of PV projects to date is perhaps the most flagrant indication of the fact that Morocco's renewables sector is not yet mature. Small-scale PV developers must still wait for the implementation of regulation needed to tap into the sector's potential, but afterwards will likely need support in expanding into this market. CTF and partners still have a role to play in Morocco, specifically to convert it from a market defined by a very few, but very large deals to one where smaller projects proliferate and can secure private financing.

Technology costs for evening peak

Since the announcement of Morocco's solar plan, costs associated with solar in the country have dropped precipitously. While the local scale-up has contributed to this primary driver has been a worldwide decline in PV module prices, which have fallen 83% since 2010, according to BNEF surveys.

Lower prices for PV in the form of lower levelivized costs of electricity (LCOE)[13] are certainly good news for Morocco. However, a number of the same dynamics that impacted the market in 2010 remain relevant today. Specifically, any new PV added today that is not coupled with some form of power storage does nothing to meet evening demand.

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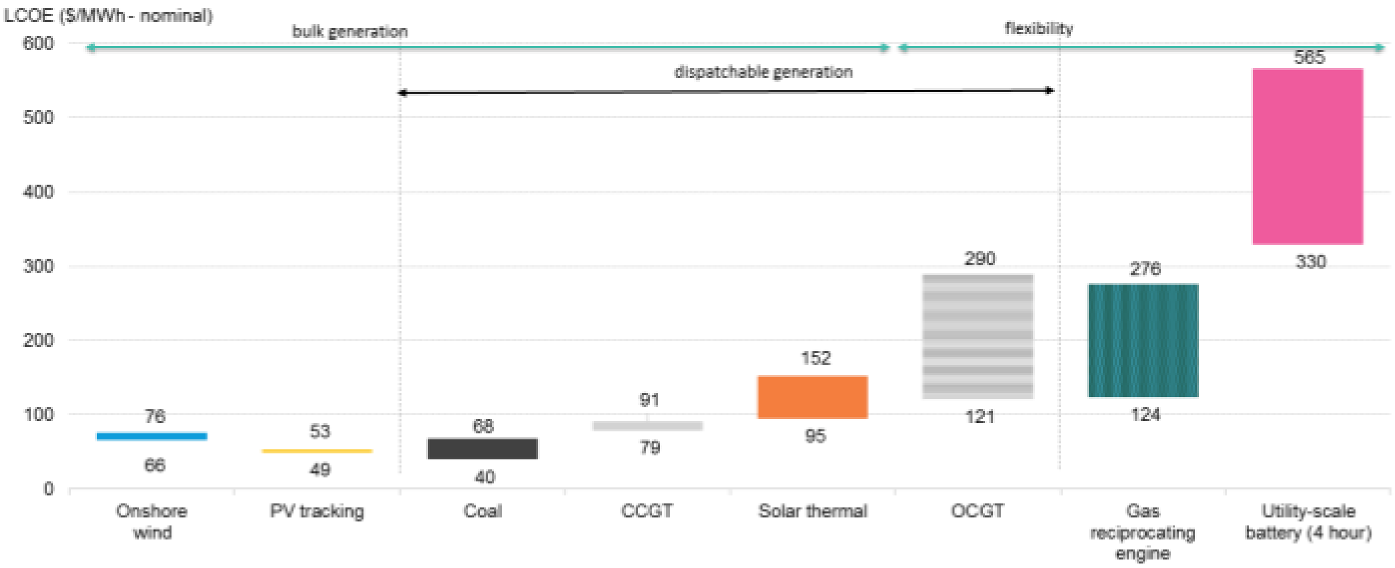
[13] BNEF defines LCOE as the long-term offtake price required to achieve a certain equity hurdle rate for a developer, considering its total capital, operating and finance costs over the lifetime of the project. This LCOE estimates exclude costs of grid connection and transmission. They also do not take into account subsidies or incentives as they are intended to assess the true economic viability of technologies outside the bounds of policy support.

The good news in that regard is that battery prices are following a similar price trajectory to PV and costs have dropped 80% from 2010. Nonetheless, they remain far from being a truly cost-effective solution for meeting the country's evening demand (Figure 59).

Figure 59: LCOE ranges for various technologies, MENA region, 1H 2018



Source: BloombergNEF. LCOE ranges for Onshore wind and coal are for Turkey. LCOE ranges for PV tracking, CCGT, OCGT, and Gas reciprocating engines are for Jordan, which has similar fuel prices to Morocco. Solar thermal LCOE range is BloombergNEF estimates for the United Arab Emirates. Utility-scale battery LCOEs are unavailable for MENA; range is based on values for 4-hour batteries in Australia (lower estimate) and India (upper).

Billions are currently being invested in battery manufacturing capacity around the world, principally to serve demand from electric vehicles. However, in most markets, batteries will remain suitable only for niche applications until costs fall further by the 2030s. Additionally, while it is possible that batteries could become cost-competitive in providing eight or more hours of storage sometime before 2030, BNEF currently sees no clear path to achieving that goal without some substantial technological breakthroughs. Therefore, despite the cost declines for PV and batteries, solar thermal with storage remains attractive for Morocco. Projects that employ that technology need only to generate at lower cost than the peaking generation they compete against, which they should be able to for the short to medium-term.

However, solar thermal on a standalone basis is today not competitive in providing cheap bulk generation. This was reflected in the power dispatch structure of the tender for the Noor-Midelt project, which generates from cheap PV during the day, and only generates from the more expensive solar thermal storage during evening hours.

Technology costs for bulk generation

BloombergNEF expects the cost of new-build wind and utility-scale PV to be competitive with generation from seaborne coal in MENA within the next few years (Figure 60). Masen gave estimates of utility-scale grid parity for PV in 2020 and Morocco's excellent wind and solar resources should put it ahead of the region's curve in this regard.

Figure 60: LCOE forecasts for MENA – New-build renewables vs new-build fossil generation

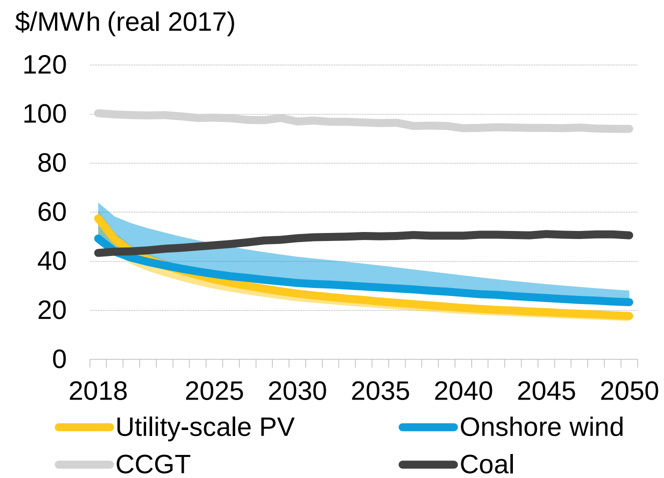
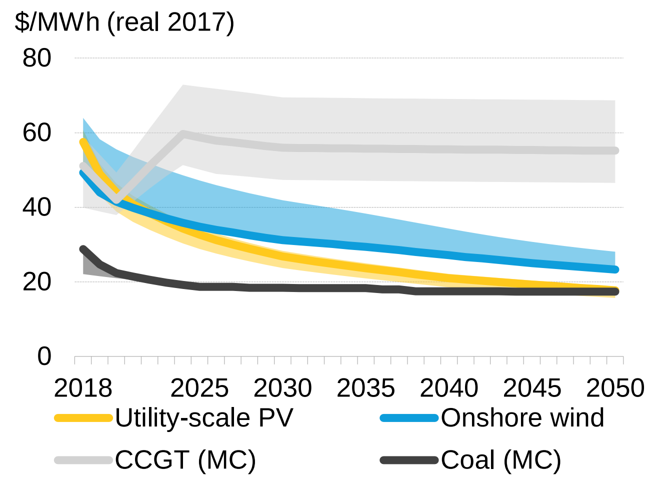


Figure 61: LCOE forecasts for MENA – New-build renewables vs. incumbent fossil generation



Source: BloombergNEF

The LCOE forecasts present two clear messages for the Moroccan energy sector. First, wind and solar generation from *new-build* power plants will soon be cheaper than generation from new coal and gas plants. Second, generation from new PV and wind plants will not become cheaper than power from *existing* coal plants until 2050 or later. Therefore, new coal has only a few years of price advantage over PV and wind. That said, if new coal generation does gest built, PV and wind will not be able to displace it during the entire course of that coal asset's lifetime. If any new coal gets built in the near term, it will likely run for decades to come, barring some form of policy intervention.

PV

Global price declines for PV have yet to result in a large uptick in Moroccan installations. While PV has an important role in Morocco's current energy plan (e.g. stabilizing the extremes of the distribution networks, its potential has yet to be realized. Regulatory barriers have to date largely restrained installations to date. But once Law 58-15 is fully implemented and the smallest players are allowed greater access to medium- and low-voltage networks PV development could well take off.

For now though, the economics of self-generation are best for larger-scale industrials. PV installations on commercial rooftops can offer pay-backs of 6-9 years, interviewees told BNEF. These installations could present opportunities for CTF as interviewees expressed doubt on the availability of local finance to support such projects.

The next few years will see commissioning of the first major utility-scale PV developments in Morocco with more than 500MW expected to come on line from the Tafilalt, Argana and Atlas projects. How these projects secure financing will be indicative of private investor willingness to deploy capital in Morocco for PV. And there could well be a role for CTF concessional financing in accelerating utility-scale PV.

Whilst the total planned PV capacity is significant, these projects consist of small plants of 30MW or less reinforcing the extremes of the distribution network. If desired Morocco could greatly expand the role of PV in providing cheap bulk electricity to its major demand centers. Large projects here may test the limits of local finance, and there would therefore be a case for the CTF to help establish a larger-scale utility PV sector in Morocco.

Wind

In 2016 Morocco set a world record with the lowest average bids seen in an onshore wind tender with bids at $30/MWh for the 850MW in capacity that was offered at the time. Morocco was already well known for its wind resources but the tender results established the nation as a market for substantial future development. The local content requirement of the 850MW tender also resulted in Siemens-Gamesa constructing a blade factory in Morocco. As the only facility of its kind in Africa, the plant should enable further cost reductions for local projects in Morocco while potentially creating export opportunities.

Morocco has a strong pipeline of wind projects under development until 2020. Further successes beyond that are likely to be contingent on when Masen holds more auctions, and the ability and willingness of ONEE to accommodate further private developments under Law 13-09. Given the relative maturity of the industry, and recent price developments, if investment momentum is maintained then it is unlikely that the CTF has any further major role to play in Morocco's wind sector.

Hydropower

Morocco's hydropower resource is already well exploited and future deployments are not expected on a grand scale. Output is dependent on rainfall and therefore annual and seasonal reliability issues will preclude heavy reliance on these resources. Another gigawatt or so of hydropower may be available in Morocco, but there is more pumped hydropower resource to be exploited.

Pumped hydropower will continue to be sought after as a balancing mechanism to address the variable nature of generation from renewables. It should also prove valuable in extending the market penetration of clean energy than would otherwise be possible. In the short to medium term, batteries will not be cost competitive in performing this function.

The Abdelmoumen STEP project recently received some CTF concessional finance as part of the Integrated Wind Energy Plan, reflecting the importance of pumped hydropower in balancing the variability of wind. ONEE did not indicate that financing for hydropower projects was currently a significant issue, but developing such projects requires long lead-times. Therefore, while this technology is unlikely to require much concessional financing in its own right, the CTF may have a role in accelerating deployment to ensure that any flexibility needed by the grid can be supplied in a timely manner.

Summary

BNEF projects that wind and PV equipment costs will continue to fall globally, including in Morocco, with or without concessional financing support. While Morocco has not purposefully delayed PV deployment at scale specifically to wait for cost declines, it does stand to benefit substantially from them. At the same time, the Moroccan wind sector has gone from strength to strength and delivered low prices.

For Morocco, and virtually all countries, it becomes a matter of when, and not if, solar and PV become the cheapest source of bulk electricity generation. In this context, concessional finance could shift these tipping points forward in time, making the inevitable occur sooner. In the short- to medium-term context, the highest value proposition for deployment of concessional finance is mostly found where it encourages renewable capacity installations instead of investment in new fossil fuel generation. Practically speaking, this means kick-starting renewables investment in countries where the resource is large but investment is nascent or non-existent. By these metrics, CTF has had a positive impact on the Moroccan renewable market, and accelerated wind deployment significantly. Despite world record low tariffs in the wind sector, Moroccan energy demands are growing faster than can be currently met with renewables alone. This underscores the scale of the challenge that Morocco faces.

The effectiveness of the CTF can be judged on many metrics, including megawatts constructed, technologies de-risked and the establishment of a growing industry. There is also the question of total power-sector CO2 emissions impact. In that regard, as the cheapest technologies in Morocco on a levelized basis today, PV and wind can displace the most emissions from the power sector in the short term.

That said, their variability exacerbates the need for other forms of dispatchable generation, which in the absence of better alternatives, necessitates fossil fuels. In that regard, the most alarming developments from Morocco in recent years have involved the signing of new 30-year PPAs with planned coal-fired power plants. CTF certainly bears no responsibility for the addition of new coal, but these new plants highlight the need for additional work in Morocco. Simply adding more renewables is insufficient when it comes to total emissions reduction. Rather, the fundamental economics of fossil-fueled generation must be undermined, as every unbuilt coal plant potentially avoids more than 30 years' worth of emissions.

The success and opportunities for CTF in Morocco, in the context of solar thermal, could therefore be viewed in the context of these longer timeframes. While wind and PV will meet most of bulk generation there will be windless and dark periods where other solutions are required. Thanks to its exception insolation, solar thermal can continue to be the low-cost provider of power storage for 8-12 hours of many days – and is unlikely to be challenged on cost for some time.

A complementary mix of PV+solar thermal can provide the certainty required to forego investment in fossil generation in Morocco. The Noor-Midelt projects reflect this thinking, and represent the only type of zero-carbon power projects that can fully undercut new-build coal in Morocco today on an around-the-clock basis. If success in Morocco is judged not just on new clean energy build, but on overall market impact and emissions reductions, opportunities for further CTF involvement abound as the country looks to continue to grow its power-generating capacity – but not its emissions.

2.5. Thailand

2.5.1. Country context

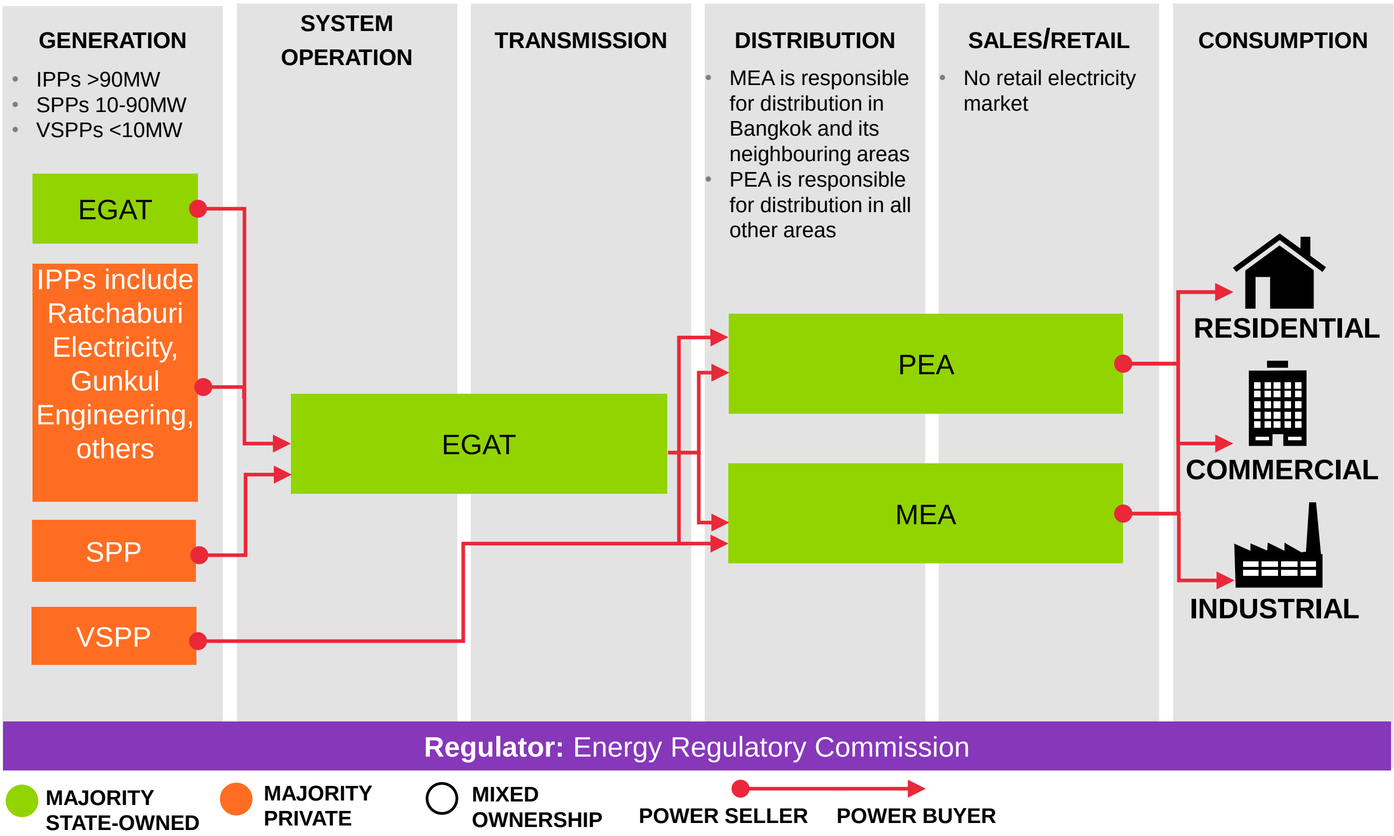
Thailand is the frontrunner in total installed solar and wind capacity in Southeast Asia. It was the first in the region to implement a supportive feed-in premium policy for utility-scale solar and wind projects. A report by United Nations Industrial Development Organization (UNIDO) estimates that the country could potentially host 4,000GW of solar capacity.

Thailand has experienced steady, 3-4% per year growth in electricity demand since 2007 as its GDP rose 4% per year and its population grew 0.3-0.5% per annum over the same period. Today, the country's electrification rate is nearly 100%. Thailand's electricity grid is relatively robust with limited supply interruptions as the country ranks third in the region after only Singapore and Malaysia in power supply quality indices. In recent years, however, power demand has grown at a slower pace than over the previous decade. In response, the government has slowed plans for capacity additions as the country's supply-demand balance has tilted towards oversupply.

Market structure

Thailand's power sector has a semi-unbundled structure with only the generation segment of the value chain open to private player participation (Figure 62). To promote decentralization of generation and clean energy use, Thailand has introduced both a Small Power Producer (SPP) program and Very Small Power Producer program (VSPP). SPP plants are defined as 10-90MW in size with VSPP plants smaller than 10MW. SPP and VSPP that utilize solar, wind, biomass, biogas, waste and hydro qualified for the Adder incentive scheme which closed in 2016 (for more on this see Policies section below).

Figure 62: Thailand power market structure



Source: BloombergNEF. Notes: IPP is Independent Power Producer; SPP is Small Power Producer and VSPP is Very Small Power Producer; EGAT is the Electricity Generating Authority of Thailand; MEA is the Metropolitan Electricity Authority; PEA is the Provincial Electricity Authority.

State-owned utility Electricity Generating Authority of Thailand (EGAT) is the system operator and owns the country's transmission assets. It is the single buyer for all the electricity produced by power plants larger than 10MW. VSPP projects sell directly to the Metropolitan Electricity Authority (MEA) and Provincial Electricity Authority (PEA). MEA distributes electricity in the Bangkok metropolitan area and PEA is responsible for electricity distribution in the rest of the country. There is no retail competition in Thailand.

As of 2017, Thailand had an installed capacity of 44GW and generated 176TWh (Figure 63). Gas accounts for the majority of the installed capacity after having increased from 13GW in 2007 to over 25GW today. Around 70% of generation comes from natural gas with coal providing an additional 20%. Wind and solar account for 2% and 7% of the installed capacity, respectively, while biomass is still the largest renewables source of electricity with 5% of generation.

Figure 63: Thailand installed capacity, 2017

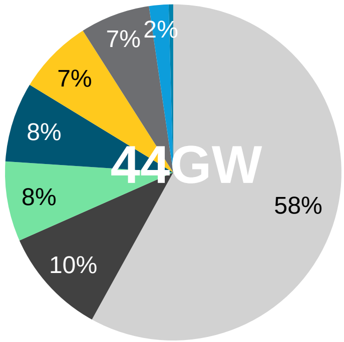
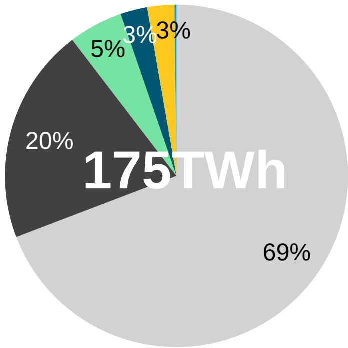


Figure 64: Thailand power generation, 2017

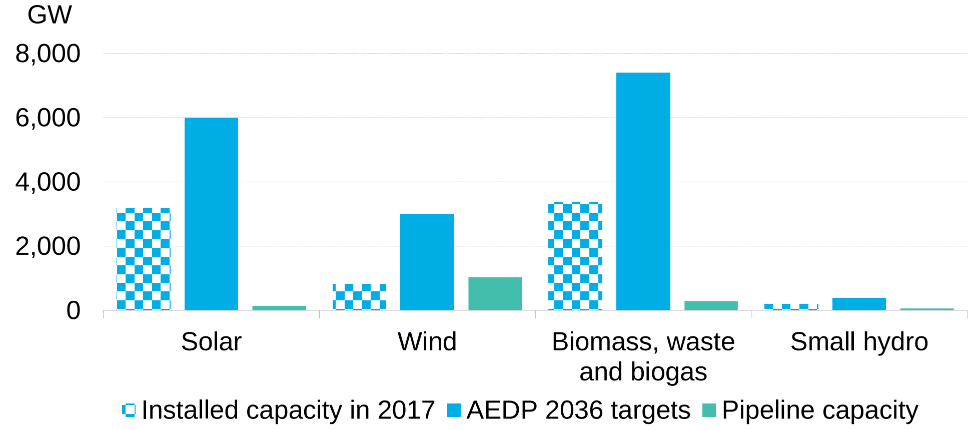


Source: Energy Policy and Planning Office, Thailand, BloombergNEF

Policies

Thailand's Energy Policy and Planning Office (EPPO) is responsible for the design of power sector policies. Under the 2015 Alternative Energy Development Plan (AEDP), the country set the objective of installing 6GW of solar and 3GW of wind by 2036. Currently, installed solar capacity is more than 3GW and around 900MW of wind power plants have been commissioned as of May 2018. Based on the trajectory of renewables deployment in recent years and the long lead time to 2036, AEDP's current set of targets should be well within reach (Figure 65).

Figure 65: Installed capacity, AEDP targets and pipeline capacity in Thailand



Source: BloombergNEF. Note: Pipeline capacity includes only projects with power purchase agreements.

A new Power Development Plan (PDP) is being drafted at the time of writing. The new PDP will propose new targets for solar and wind that are likely to be more ambitious than those set currently and reflect the continually improving economics of renewables. Solar and wind developers are eagerly awaiting the PDP's release.

Figure 66: Thailand utility-scale PV capacity additions

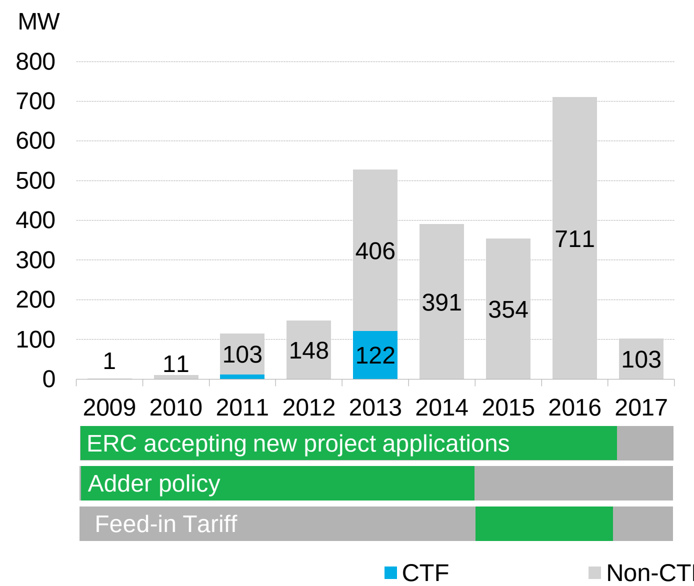
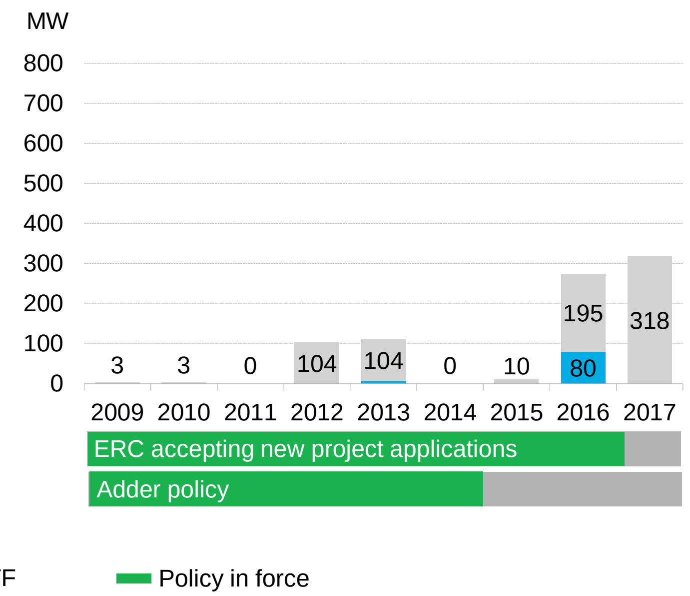


Figure 67: Thailand wind capacity additions



Source: BloombergNEF, CTF

The majority of utility-scale PV capacity was installed during 2013-16 (Figure 66) while there was relatively little wind activity until 2015 before a small boom in 2016-17 (Figure 67). Below is an overview of the policies that created these dynamics.

PV

Policies supporting utility-scale PV development in Thailand have undergone a number of changes since 2007:

- In 2007, the government introduced its feed-in premium ("Adder") policy granting PV projects a fixed premium of THB8/kWh ($0.24/kWh) [14] above the wholesale tariff for 10 years.[15] In response, more than 2GW of solar projects secured power purchase agreements (PPAs) through 2009 as companies rushed to secure contracts.[16] Many PPAs were secured by small companies, which lacked the capability to actually develop the projects. This led some to sell their projects and PPAs and created headaches for regulators and system operators to anticipate project commissioning dates. The resulting delays meant that very few projects were installed before 2010.
- In 2010, the energy ministry cut the Adder rates to THB6.5/kWh ($0.20/kWh) to keep retail tariffs in check.[17] The government also created stricter rules to approve solar projects and required developers to submit work plans, progress reports and project bonds before receiving PPAs. This led to a lull in project approvals and a drop in new PPAs after 2010.
- In 2014, after two years of delay, the government implemented a Feed-in Tariff (FiT) regime open only to Adder projects that were approved but not yet developed, with a commissioning deadline of 2016. It allowed 1GW of Adder approved projects to transition to the FiT scheme, which awarded an all-in THB 5.66/kWh ($0.17/kWh) under 25-year PPAs. By 2014, 1.1GW of projects were constructed under the Adder. The 2016 deadline led to a record year for solar installations in Thailand at 711MW. Developers continued to develop under both the Adder 10-year fixed premium scheme and the all-in 25 year FiT in 2014-2016.
- In 2015, the government released the 'Agro-Solar' scheme to promote development of projects smaller than 5MW. Agro-solar projects rely on public-private partnerships under which government agencies and agricultural cooperatives collaborate with private companies to build PV. A total of 430MW of projects have been awarded under the scheme to date with 276MW commissioned. Agro-Solar projects receive a FiT of THB5.66-4.12/kWh ($0.12-0.17/kWh) for a period of 25 years.
- In April 2016, Thailand stopped accepting new solar applications across all incentive programs. The government paused new FiTs to control costs in light of its headline target for the technology being achieved. Instead, the government prefers to wait for further solar cost declines to ensure better priced systems.
- Thailand's solar sector is, in effect, on pause today. No new utility-scale solar projects are currently under construction except those under the Agro-Solar scheme. In 2017, the government launched a smaller scheme for hybrid SPP and VSPP projects. It aims to procure 569MW by 2020 but introduced a firm capacity factor requirement in the 65-100% range, rendering it unattractive for solar or wind. Unsurprisingly, the tender awarded support to 559MW of biomass and just 10MW of PV hybridized with biomass projects.

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[14] 1 US$=33THB as of 12 July 2018

[15] Wholesale tariff in Thailand was roughly 2.7THB/kWh ($0.08/kWh) in 2007

[16] Tongsopit S., Greacen C., An assessment of Thailand's feed-in tariff program. Renewable Energy 60 (2013) 439-445

[17] Adder is a pass-through component in electricity tariffs and is included in the Ft charge which is a quarterly adjusted component in monthly electricity bills reflecting changes in fuel prices in generation.

Wind

Thailand has offered clean energy policy support to onshore wind since the start in 2007, but the tariffs have been relatively low as the government viewed the technology relatively mature. What policy-makers apparently did not take into consideration were the complex challenges often involved with developing wind in Thailand due to terrain and that the country's wind resources are far less attractive than its insolation. The relatively slow pace of wind activity has meant that the sector has suffered less dramatic ups and downs related to policy uncertainty compared to solar.

- In 2007, the government introduced an Adder rate of THB 3.5/kWh ($0.10/kWh) for the onshore wind sector. As with PV, the wind Adder tariff is added on top of wholesale tariff for a period of 10 years. The first utility-scale commercial wind project was only installed six years after the launch of the support program in 2012 as the financial viability of projects under the lower tariffs was harder to prove. Most of the Thailand's wind resources are in difficult terrain such as mountains with poor or no access to the grid. Land acquisition in the mountain regions is also difficult and was a major cause of project delays.
- In August 2014, a FiT of THB 6.06/kWh was approved for 20 years but was never open for application as there was more than 1.3GW of Adder-approved wind projects in various phases of development in the pipeline. These faced delays due to terrain and difficult grid access.
- In 2016, ERC announced it would stop accepting new wind project applications by the end of the year as the installed and approved capacity was already close to the AEDP 2036 target. General oversupply issues described in the solar section above also encouraged the system operator to pause onshore wind procurement. As of June 2018, roughly 1GW of wind projects are still under development from the Adder scheme. If all of this capacity is commissioned, it will take the total installed wind capacity to 1.9GW, and leave a 1GW gap to the AEDP target. The government has yet to announce what additional policies it may implement to foster further wind beyond the current pipeline.
- Like those in the solar sector, wind developers have been left with little prospect for new development in the short term, pending the release of the new PDP. No wind project was able to secure a contract in the hybrid tender launched in 2017.

Economics

The levelized costs of electricity associated with new utility-scale solar and wind in Thailand have declined rapidly since 2014 as the sector matured. This has significantly narrowed the gap between the LCOEs[18] for new build utility-scale solar and wind, and those for coal and gas (Figure 68). However, new-build coal and gas are still essentially lower than solar and wind in Thailand as of 1H 2018.

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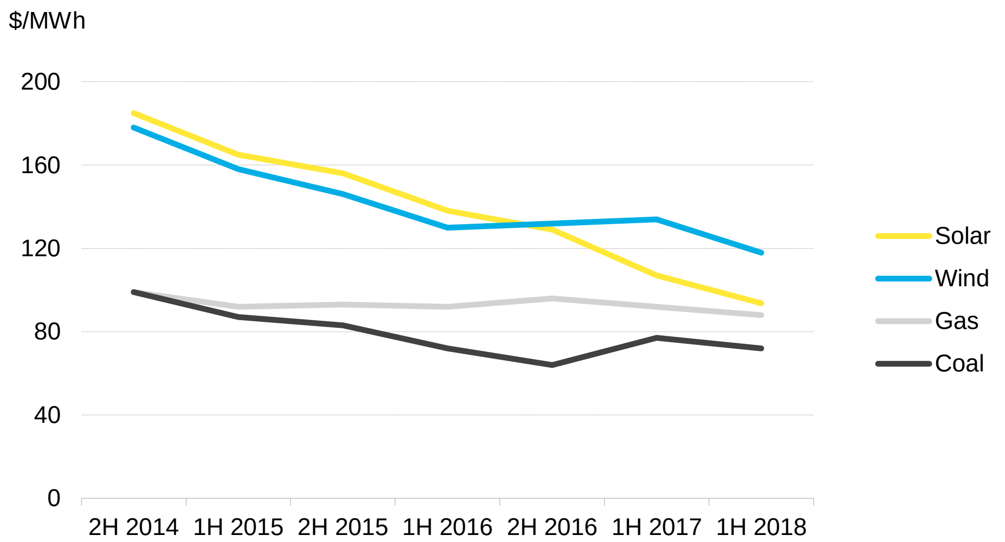
[18] BNEF defines LCOE as the long-term offtake price required to achieve a certain equity hurdle rate for a developer, considering its total capital, operating and finance costs over the lifetime of the project. This LCOE estimates exclude costs of grid connection and transmission. They also do not take into account subsidies or incentives as they are intended to assess the true economic viability of technologies outside the bounds of policy support.

Figure 68: LCOE of different generation technologies for new-build projects in Thailand



Source: BloombergNEF. Note: Solar LCOE refers to PV non-tracking.

The main drivers behind the drop in the LCOE for PV are the decline in solar module costs globally, a switch to cheaper Chinese modules from Japanese and European modules that started in 2013, and a reduction in development and balance-of-plant costs as developers gained experience. As the number of commissioned projects rose, bankers became more comfortable with solar technology which reduced debt costs and improved debt-to-equity ratios.

Compared to solar, wind's LCOE has seen a less continuous decline. The main drivers of the drop in LCOE over 2014-18 have been the fall in turbine costs, along with lower development charges and balance of plant costs. However, the LCOE rose in 2016, reflecting higher development costs related to securing land and delays in getting grid connections. In January 2017, project developers developing wind projects on lands designated as 'Sor Por Kor' suffered a setback. Such lands can only be used for agricultural purposes and hence a legal order was issued to put a temporary ban on its use. The issue was resolved in 1H 2017 and developers were allowed to resume project development in these areas. Thailand's wind LCOE has since resumed its decline we expect it to follow the trends in global wind LCOE.

2.5.2 Clean energy investment

CTF in Thailand

In 2012, the Clean Technology Fund Investment Plan[19] proposed $170 million in financing to help Thailand to transition to a cleaner power mix by providing financial support to renewables projects in the private and public sectors. The funds were deployed through:

1. The private sector renewable energy program – a $100million CTF co-financing initiative to be implemented through the Asian Development Bank to accelerate private sector investment in utility-scale solar, wind and waste to energy projects.

19 The first Investment Plan, published in 2009, committed to $230 million.

2. The renewable energy accelerator program – a $40million CTF co-financing initiative to be implemented through the International Finance Corporation (IFC) to support solar market development by financing solar projects.
3. The sustainable energy finance program – a $30million CTF co-financing initiative implemented through IFC to provide investment and advisory services for energy efficiency, renewable energy and energy service company projects in Thailand.

This chapter focuses only on the CTF co-financing of renewable power projects implemented in the country (programs 1 and 2 above).

Renewables supported by CTF in Thailand

CTF has invested a total of $51 million in 10 PV projects with a total capacity of 134MW and $34 million in two wind projects with a total capacity of 87.5MW (Figure 66 and Figure 67). All the solar and wind projects supported were developed under the 10-year Adder feed-in premium scheme. The Adder tariff was able to provide attractive returns at the then prevailing project costs (including development, equipment and balance of plant). The CTF funds were deployed for solar and wind projects developed by Bangchak Public Company (BCPG), Electricity Generating Public Company (EGCO) and SPCG Public Company Limited. BCPG and EGCO were among the best established energy companies in Thailand at the time of disbursement, whereas SPCG was a newer and smaller project developer.

At the time when CTF funds were deployed, the biggest barrier facing solar and wind developers was the challenge of securing sufficient debt to fund projects. Project finance teams in local commercial banks had relatively little understanding of how solar modules or wind turbines generate power or how to conduct clean energy project valuations. As a result, local banks were willing to provide debt amounting only to around 30-40% of a project's cost – much less than the 70-75% typically made available for fossil-fueled plants. CTF funds helped boost the debt-equity ratio of the solar and projects. Local banks also demanded collateral from project sponsors. Thailand also lacked experienced engineering, procurement and construction (EPC) players with proven track records in developing clean energy projects.

The Thai commercial banking sector was already well established when CTF funds were disbursed. The main attraction of CTF debt was that it was awarded with a longer tenor and it allowed higher debt:equity ratios for project sponsors. Higher leveraging offered by development finance institutions accelerated a culture change among Thai commercial banks who adopted the leverage ratio expectations of their public sector peers for solar and wind projects.

Investor types

From 2008 to 2017, solar projects in Thailand received total investment of $5 billion, of which 42% came from commercial banks and 41% in the form of equity from project developers. CTF and MDBs together provided a total of $141 million to PV plants, most of it in 2013. Concessional finance from CTF helped projects to attract another $122 million in follow-up[20] finance from developers including SPCG, Bangchak Corporation, Electricity Generating PCL and banks including Mitsubishi UFJ, Kasikorn Bank, Bangkok Bank and Thanachart Bank. CTF & MDB co-finance and follow-up finance accounts for 7-14% of the total solar investment over 2011-13.

[20] Follow-up finance refers to additional investment provided (other than by CTF and MDB) to projects that received CTF concessional financing.

Figure 69: Thailand disclosed PV investment by type of investor

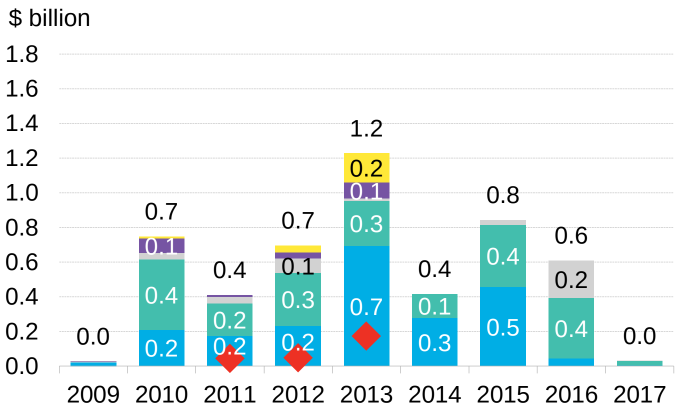
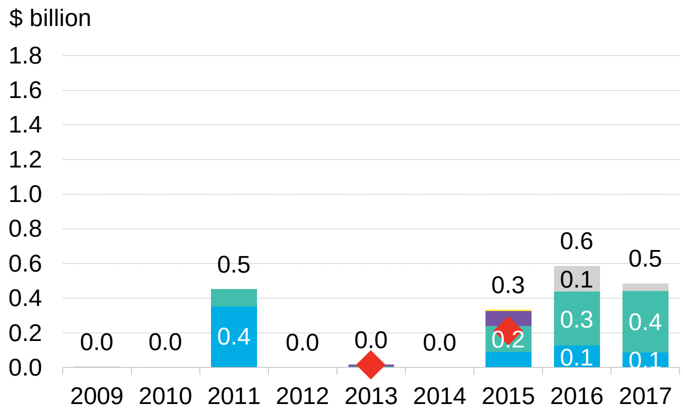


Figure 70: Thailand disclosed wind investment by type of investor



Commercial bank Project developer Other Development bank Private equity CTF project

Source: BloombergNEF, CTF. "CTF project" refers to full amount of financing received by projects partly financed by CTF.

Over the same period, the wind sector attracted $3 billion, with nearly 27% provided by project developers and 60% by commercial banks. CTF and MDBs together provided $94 million for two wind projects, and $132 million were further raised by these projects in follow-up financings. Thailand's wind sector kicked off in 2011, with $500 million invested in two 103.5MW wind projects (First Korat and KR two Korat). Investment was provided by Kasikorn Bank, Siam Commercial Bank and Wind Energy Holdings. However, from 2012 to 2014, Thailand's wind sector saw a hiatus of investment with the $9 million CTF loan for the Theppana wind farm by Electricity Generating PCL and Pro Ventum International the only investment in that period. Follow-up finance for Theppana of $6 million came from Pro Ventum International.

The slowdown was due to the land acquisition and grid interconnection issues described in above. The sector started accelerating again in 2015, when the country recorded $333 million of financing. Of this, 8% came from project developers and 27% from commercial banks. CTF & MDB co-finance provided 26% of the total, with $85 million invested in the Chaiyaphum wind farm. Follow-up finance was provided by Electricity Generating PCL.

Figure 71: Thailand disclosed PV sector investment, by investor type

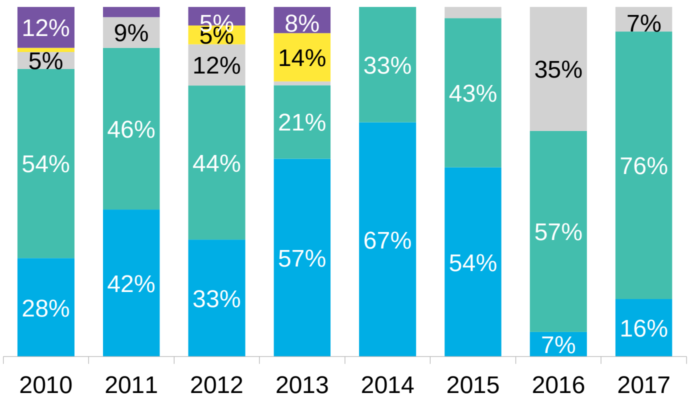
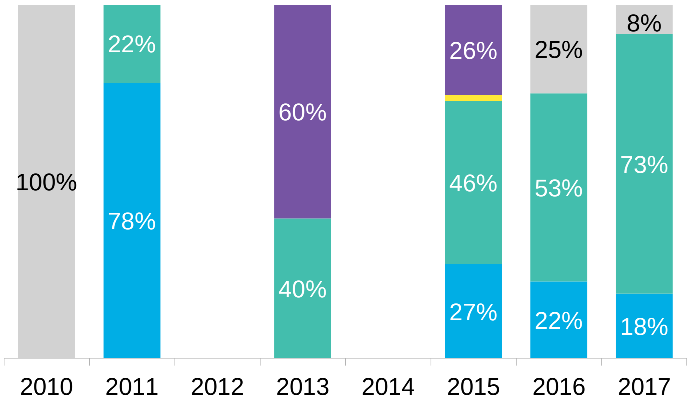


Figure 72: Thailand disclosed wind sector investment, by investor type



Commercial bank Project developer Other Private equity Development bank

Source: BloombergNEF. Note: other includes industrial user, manufacturer, utility and sovereign. Thailand's wind sector did not receive investment in 2012 and 2014.

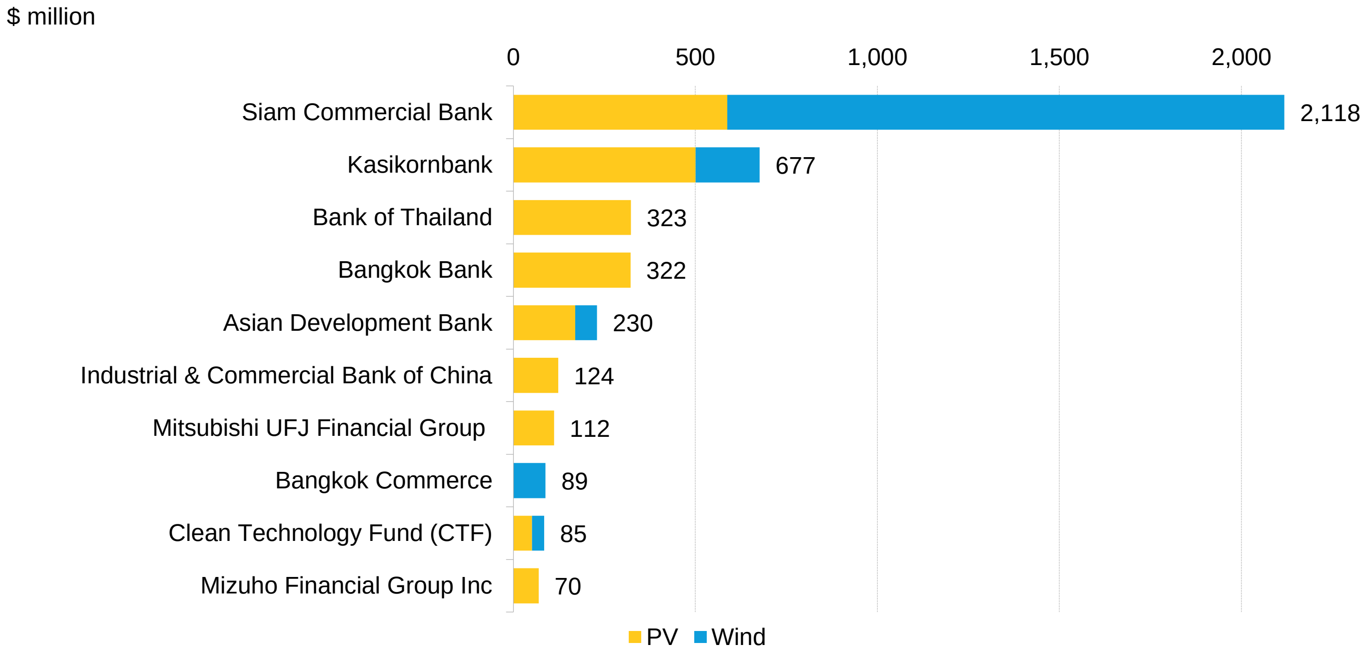
The share of investment provided by commercial banks to PV plants has fluctuated significantly over the past seven years from 28% in 2010 to a peak of 67% in 2014. Commercial banks in Thailand are generally considered to be well-capitalized and have project finance divisions with significant experience in underwriting fossil-fueled power projects. They have supported the large power sector expansion plan of Thailand over 2008-2016, during which installed capacity increased by more than 50% from 28GW to 44GW. Hence, once the local banks became comfortable with PV technology as a result of their first deals, they were willing to increase their exposure to solar projects.

The share of developers employing project finance increased in 2015-16 compared to 2013-14. This was due to the impending 2016 deadline to commission projects. In response, developers used balance sheet capital to meet the deadline. BloombergNEF expects that projects commissioned in this window will seek refinancing from commercial banks.

Financing trends in the wind sector are more difficult to capture as a result of a far more limited deal flow. Additionally, interviews conducted by BNEF with developers suggested that issues that have hamstrung wind development in Thailand to date are not just financing related. As discussed in prior sections, wind resources are low in the country and located in mountainous regions. Delays in project construction due to difficult terrain and the high costs of grid interconnection have hampered progress.

The Siam Commercial Bank is by far Thailand's lead debt provider with over $2.1 billion invested in wind and solar projects 2008-17. Siam is followed by Kasikornbank with $677 million invested in both technologies and Bank of Thailand with $323 disbursed to PV projects.

Figure 73: Lead PV and wind debt providers, 2008-2017



Source: BloombergNEF

2.5.3. CTF results and market impact

CTF has to date supported 134MW of utility-scale PV and 87.5MW of wind projects in Thailand. Compared with total installed clean energy capacity in the country, the share of CTF projects represents around 5% for solar and 10% for wind. During interviews BNEF conducted with key stakeholders for this project, CTF specifically and development finance more generally were credited with having improved financing conditions for clean energy in Thailand.

CTF played a particular role in addressing problems related to loan tenors. As most of the capital expenditures associated with solar and wind projects comes upfront, loans with longer tenors can help bring down a project's LCOE significantly. With fuel costs effectively zero for solar and wind, upfront capital costs are critical over the life of the project. Longer-term loans offer more time for project developers to repay and can improve cash flows and ultimately equity returns.

The 10-year applicability of Thailand's Adder scheme originally proved to be a barrier to attracting project finance loans with longer tenors. Banks simply did not want the risk exposure once the Adder's benefits would sunset. With the 57MW Central Thailand Solar Project developed by Yanhee EGCO Holdings, the Asian Development Bank and CTF sought to overcome this. The ADB/CTF financing allowed local commercial banks for the first time to offer 12-year tenor loans. ADB co-financing helped the banks lengthen tenors as the revenue risk beyond the Adder duration was shared by both local bank and ADB.

The application of CTF capital in various projects served to influence commercial banks in other ways as well. Projects with CTF funds enjoyed higher debt-equity ratios. This demonstrated to commercial banks that such financing structures were possible. On interest rates, CTF-funded projects demonstrated in simple terms that lower-cost capital could be deployed to support renewables. CTF funding was made available at a fixed interest rate, which was lower than the floating rate loan offered by commercial banks and MDBs. Blending lower-priced CTF capital with loans from MDBs and commercial banks allowed those banks to finance riskier projects and improve the debt-equity ratios of the projects. MDB involvement in transactions also provided additional comfort to local banks, which were at the time less familiar with financing wind and solar projects.

In addition, the IFC also played a significant role in educating local banks[21] on the merits and particularities of projects using renewables by organizing educational seminars on PV and wind. These sessions helped bankers gain a better understanding of the technologies, and comfort in investing in solar. This was borne out in their growing investment in the sector from 2010 through 2015.

It is worth contextualizing the role that CTF played in Thailand. Developers in the market interviewed by BNEF said that the Adder and FiT schemes created conditions where they could secure financing and earn potentially acceptable returns 2010-2016. Larger developers with proven track records and sufficient capital could have, in theory, financed projects through their balance sheets, given the generosity of these schemes.

The goal of CTF is, however, broader than supporting the commissioning of a project of two. Rather, it is to help build a self-sustaining market. The thesis is that CTF funds that reduce debt costs allow project sponsors to improve equity returns. This, in turn, allows them to develop

[21] In the private sector proposal program for use of CTF funding by IFC, it is mentioned that terms of CTF funds could include some portion for advisory services and capacity building. However, interviewees were not able to identify if the seminars that they attended received some funding from CTF.

additional projects. In that regard, the CTF capital deployed appears to have had its intended effect. Furthermore, development finance deployed into the market clearly helped smaller, less capitalized players such as SPCG[22] that might not have been able to build projects otherwise.

Finally, CTF's efforts on policy development in Thailand are worth noting. That said, during interviews conducted by BNEF key stakeholders in the country did not cite CTF's role in this area. In a sense, this should come as no surprise as CTF's policy contributions came at the beginning of the process in Thailand. The lack of recognition may also reflect the fact that BNEF interviewees were largely from the private sector.

2.5.4. Future ambitions and the role of CTF

The decline of clean energy costs, the maturing of the sector in country, and the now-proven willingness of commercial banks to support development raise the question of whether further concessional finance is needed in Thailand to support renewables. Indeed, the country appears well along the path to meeting its current long-term clean energy goals.

Interviewees mentioned that local banks such as Kasikorn and Siam Commercial are today quite willing to finance utility-scale wind and solar projects on pure commercial terms and that concessional finance is no longer needed to build conventional wind and solar. Thailand's total renewable capacity target is close to 17GW, with 50% from wind and solar. Interviewees generally agreed targets for wind and solar could be easily overshot once the country's regulator ERC starts to accept new project applications.

The country's own targets need not determine CTF's strategy, however. It is entirely possible that Thailand could both meet its clean energy targets *and* see its power-sector CO2 emissions rise dramatically in coming years. Along those lines, the country is currently planning to add coal-fired plants in the south to meet growing electricity demand. The motivation stems partly from lack of transmission capacity to wheel generation from north to south. For some policymakers, coal appears the best option to meet the south's growing baseload power requirements. Solar and wind are regarded to be of limited use due to their intermittency while gas-fired plants would require LNG imports as domestic gas supplies are dwindling. Given that context, it is difficult to envision CTF support for conventional utility-scale wind and solar projects (with no associated storage) in the southern part of Thailand as addressing the overall need for growing round-the-clock generation.

That said, there potentially important areas of the clean energy market where concessional capital could make a difference in Thailand. These include wind farms in areas with lower wind speeds, rooftop solar facilities, biomass plants and energy storage projects.

Low wind speed projects

Wind speeds in Thailand are lower than in neighboring countries such as Vietnam. Historically, this restricted project capacity factors and capped equity returns for developers. However, in recent years, wind turbine manufacturers have designed new equipment specifically intended to maximize resources at low-wind speed sites. This could unlock new areas to wind development in Thailand where land acquisition issues have limited development to date. As is the case with most new technologies, concessional financing could support early adopters and demonstrate that the new wind turbine designs can operate at low wind speeds and offer new commercial prospects.

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[22] At the time of receiving funding from IFC in 2011, SPCG was a small developer. It is now a big developer in Thailand and has a market capitalization of roughly $600million

Rooftop solar

Rooftop solar development in Thailand is still at an early stage due to the lack of a mechanism to sign offsite power purchase agreements (PPA) between project developers and consumers. The current power market design only allows EGAT to buy power from generation projects, and PEA and MEA to retail it. A lack of net-metering or self-generation incentives has also hindered the development of projects. Net-metering could help generate additional revenues for C&I users who close their operations on weekends and for residential users who lack sufficient demand to absorb all the power their rooftop systems generate. The lack of a framework to assess the credit risk of end users also makes it difficult to finance rooftop solar projects. Availability of cheaper financing could encourage developers to accept the higher off-taker risk for rooftop projects.

Biomass

Sufficient availability of feedstock is a major problem for biomass projects in Thailand. Lack of knowledge among farmers about fast-growing energy crops is one reason for this. If farmers are encouraged to grow such crops, feedstock production and hence availability could improve. Education programs organized by government or ODAs could raise awareness about these crops, help resolve feedstock availability issues, and seek to insure such crops are grown in a sustainable and environmentally-conscious manner. Farmers would also need financial help to fund this transition.

Storage

As shares of solar and wind rise in future, battery storage will increasingly be needed to smooth output from renewables. Storage could shift excess generation from periods of low to high demand, and help 'firm' output from solar and wind projects. Currently, there is no commercial scale solar or wind project using battery storage in Thailand.

Most of the interest around new battery manufacturing in Thailand to date has centered on electric vehicles as the country braces for impending changes in the automotive market. Thailand is one of the world's leading exporters of small pick-up trucks and automotive sector contributes more than a tenth to the country's GDP. The government has sought to promote electric vehicle use, and local businesses such as Energy Absolute have expressed interest in establishing manufacturing facilities for Li-ion batteries in Thailand.

In addition, interviewees said it is too early to predict if concessional financing will be required to deploy battery storage projects. They noted that industry is waiting to see what policy supports the government might offer to promote or subsidize large-scale batteries. Based solely on economics, the BloombergNEF long-term New Energy Outlook suggests that Thailand will have roughly 80GWh of batteries by 2050. See 3.3.2 Energy **Storage** section for more details.

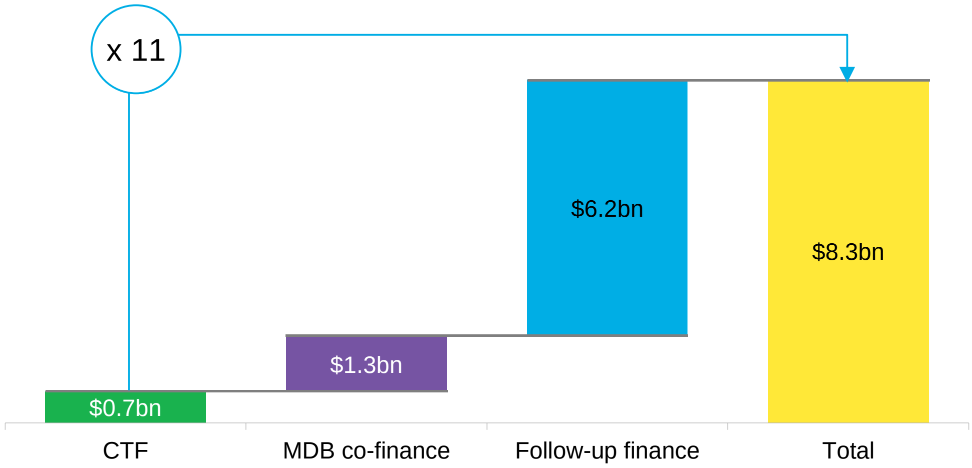
Other technologies

Interviewees also cited blockchain as a promising technology that will need regulatory and financial support in the future. However, they also mentioned that it is too early to know how blockchain could be deployed in the Thai context and that more policy guidance from the government on its application would be needed before they would consider investing in the sector. There are no specific policies supporting blockchain applications in energy today making the outlook for such projects quite uncertain. Currently, only pilot projects are running for blockchain application. For example, BCPG is conducting peer-to-peer trading of electricity generated from rooftop PV in residential premises.

2.6. Key findings and lessons learned

In Chile, Kazakhstan, Mexico, Morocco and Thailand alone, CTF has invested $749 million in 2.3GW of utility-scale clean energy projects as of year-end 2017. This, along with $1.3 billion in co-financing from multilateral development banks (MDBs) helped achieve total leveraged investment worth $6.2 billion, with project developers, commercial banks and other development banks providing the rest of the capital (Figure 74). This investment has translated into over 2.3GW of new build PV, solar thermal, wind and geothermal plants across the five countries.

Figure 74: New-build investment in CTF projects in Chile, Kazakhstan, Morocco, Mexico and Thailand by investor



Source: BloombergNEF, CTF. Note: follow-up finance refers to additional investment provided (other than by CTF and MDB) to projects that received CTF concessional financing.

The markets analyzed are at different stages of clean energy policy development, but all have made significant progress in establishing policy frameworks that foster clean energy deployment. Before 2012, clean energy polices in these countries (with the exception of Thailand) were mainly limited to clean energy targets and self-generation incentives. Today, all of the markets have introduced more support measures with the exception of Thailand, which has met its renewables target early (Figure 75).

Figure 75: Renewable energy policies

Renewable energy policies, pre-2012

	Chile	Kazakhstan	Mexico	Morocco	Thailand
Energy target	Yes	No	No	Yes	Yes
Feed-in tariff/premium	No	No	No	No	Yes
Renewables auctions	No	No	No	No	No
Utility regulation	No	No	No	No	No
Self generation incentives	No	No	Yes	Yes	No

Renewable energy policies, Aug 2018

	Chile	Kazakhstan	Mexico	Morocco	Thailand
Energy target	Yes	Yes	Yes	Yes	Yes
Feed-in tariff/premium	No	Suspended	No	No	Suspended
Renewables auctions	Yes	Yes	Yes	Yes	No
Utility regulation	Yes	No	Yes	Yes	No
Self generation incentives	Yes	No	Yes	Yes	No

Yes No Suspended

Source: BloombergNEF, Climatescope. Note: includes relevant/nation-wide policies only. Utility regulation includes renewables procurement mandates and green certificates schemes.

Due to the different market realities and stages of development, the strategy and impact of CTF concessional finance varies from country to country.

- **Morocco:** CTF financing has been instrumental in kick-starting the solar thermal and PV sectors locally. Concessional financing lent credibility to a new technology in a new market, mobilized more capital and delivered a competitively-priced source of generation that is available when the system needs it the most.
- **Mexico:** CTF support, along with incentives for large-scale self-generation from renewable energy plants, was key to developing a local wind market and attracting substantial investment from commercial banks. Uncertainty around new policies introduced by a landmark energy reform led to an investment decline from commercial banks and raised the need for renewed development bank support. However, as confidence in the government's reforms grew in 2017 (including the much-lauded auctions program), wind investment jumped to record levels and commercial financing returned to the market.
- **Kazakhstan:** In advance of providing funds to wind and PV plants, CTF played a key role in supporting development of Kazakhstan's clean energy policies. Today, 85% of Kazakhstan's installed PV capacity and 40% of its wind capacity received CTF financial support. Since early 2018, the country has been transitioning its clean energy support scheme from feed-in tariffs to reverse tenders for clean power-delivery contracts. Mexico's experience indicates that significant policy changes can cause market uncertainty and give commercial lenders

pause. Therefore the support CTF and development finance institutions could play in backing Kazakhstan auction-winning projects may prove critical.

- **Thailand:** CTF has to date supported 134MW of utility-scale PV and 87.5MW of wind projects in Thailand representing 5% and 10% of each technology's overall capacity there, respectively. The share of investment provided by commercial banks to PV plants has fluctuated significantly over the past seven years, from 28% in 2010 to a peak of 67% in 2014 and finally to just 16% in 2017, when project developers accounted for 76% of the amount invested. Still, commercial banks in Thailand are generally regarded as well-capitalized and have project finance divisions with significant experience underwriting fossil-fueled power projects. They supported a large power sector expansion in Thailand from 2008-2016, during which installed capacity jumped more than 50% to 44GW. Once these local banks became comfortable with PV technology from doing first deals, they were willing to increase their exposure to solar.
- **Chile:** While CTF has provided limited investment, DFIs clearly played a critical part in kick-starting support for Chile's clean energy projects in 2013. As the markets have matured, commercial banks have made more credit available. The market has also seen the presence of large, multinational developers who have been able to finance directly from their balance sheets. Both factors have reduced the demand for DFI capital for conventional, large-scale wind/PV projects.

The cases of Thailand and Chile show that as technology costs decline and clean energy sectors become more dynamic, CTF and DFI's must adjust their strategies in markets to avoid creating market distortions. The results CTF achieved in the markets BNEF surveyed suggest that its strategy can effectively work in different contexts. Concessional financing channelled through partner MBDs, combined with MDBs' local expertise (and in some cases with public national institutions' expertise), has proven it can be effective. Such a set-up has the advantage of being relatively flexible and capable of adjusting to different market needs at different times.

Moreover in countries with an unfavorable enabling environment for clean energy deployment, policies that help de-risk the market, make renewables economically attractive and increase competition have proven to be key boost investment from commercial investors. In these markets, technical support from development institutions may be even more relevant than direct investment in clean power plants (See sections Clean Energy Economics and Identifying new opportunities and for more details).

Most recently, clean energy auctions have proven to be the most effective mechanism for boost clean energy investment. In Mexico, for example, auctions helped renewable energy investment spike six-fold from 2016 to 2017 and in Chile investment doubled from 2014 to 2017.

What is next?

The potential opportunities for concessional finance to make a difference certainly vary by country. Clean energy policies, power sector structures, the maturity of sectors locally, and overall demand all can play a role.

- Despite key structural differences across many aspects of their power markets, the experiences of **Chile, Mexico,** and **Thailand** suggest a common potential path for concessional finance. As a result of successful clean energy policies, all three have boosted wind and PV capacity, which have become cost competitive and no longer need extensive support from cheaper sources of financing. However, increasing penetration of intermittent renewables has brought new challenges in each country. Pressing issues related to the functioning of power markets, namely short-term grid flexibility and long-term reliability of supply, underscore the need for adoption of new technologies, such as battery storage, demand response, and flexible generation. Such high cost emerging technologies are unlikely to achieve competitiveness in the short-term if financed on a commercial basis alone, opening the door for concessional finance to provide vital support to accelerate their viability and deployment. (See new technologies section for more details)

- In **Morocco**, onshore wind is also mature enough to attract commercial investment on its own, but with nearly no PV capacity added in 2017, the country has yet to see a large uptick in installations. This is because PV not coupled with some form of power storage in Morocco does little to meet the country's peak electricity demand during evenings. As Morocco needs at least five hours of energy storage to meet its peak, batteries are expected to remain uneconomical in the short-term. A complementary mix of PV + solar thermal can provide the certainty required to forego investment in fossil generation in Morocco, but would likely require cheaper financing to compete with fossil fuel sources in the short term.
- **Kazakhstan** is the only market surveyed that is likely to require concessional finance support for both its conventional wind and PV sectors as these technologies have yet to mature sufficiently in the country. Unlike in the other four markets surveyed, in Kazakhstan the focus for concessional capital can appropriately remain on wind and solar rather than on newer sources. With most of Kazakhstan's generation coming from fossil sources, the country is unlikely to need batteries and other technologies to allow deeper penetration of intermittent renewables in the near future.

This retrospective analysis provides valuable lessons about the five countries studied and help us understand the potential impact[23] of concessional finance in other markets with similar realities. However, the economics of clean energy have been transformed radically since the founding of the Clean Technology Fund a decade ago. Therefore, to assess how future CTF funds (or other concessional financing) could be optimally utilized in fast-growing, high emitting developing countries, the next sections of this report delve into how the economics of clean energy have shifted in recent years and stand to progress further in the short and longer term.

[23] See the World Bank report Strategic Use of Climate Finance to Maximize Climate Action for proposed framework for deciding how to use international public finance with a concessional component to maximize the impact of climate action.

Section 3. Forward looking analysis

The clean energy sector today finds itself at an important juncture. Costs associated with wind and solar, in particular, have fallen sufficiently so that both technologies are today regularly cost-competitive (*un*-subsidized) when competing against their fossil-fueled rivals. Meanwhile, thanks to millions of logged operating hours and the associated data, investors and lenders are far more comfortable with these technologies' technological risks than they were five years ago.

Middle-income developing countries represent some of the very hottest markets for clean energy deployment today. Mexican clean energy investment, for instance, has been ignited by a combination of market reforms, growing demand for electricity, and exceptional natural resources. There is no shortage of other examples of developing nations where clean energy development has either taken root or is in the process of doing so.

Other factors are also shaping the landscape for clean energy financing. Large institutional investors are pouring billions either directly or indirectly into projects through green bond offerings. Newly launched private funds specifically seek to finance developing nation clean energy while other existing funds are shifting focus in that direction. Finally, there is the Green Climate Fund, which appears to be ramping (albeit slowly).

All of this raises fundamental questions about what comes next for the CTF and other concessional finance funds. What markets and what technologies are today most in need of support?

This forward-looking analysis seeks to assess how future CTF funds and concessional financing from other key players could be optimally utilized in fast-growing, high-emitting developing countries. The analysis is split in three sections:

- Clean Energy Economics
- Identifying new opportunities
- New Technologies

To develop the analysis, BloombergNEF has leverage two of its ongoing research projects and one of its evaluation tools:

- **Climatescope:** Since 2012, BNEF has conducted this comprehensive survey of clean energy development market conditions (www.global-climatescope.org). The project in 2018 included over 100 nations and over 12,000 data points collected by more than 50 BNEF analysts during international trips.
- **Neo Energy Outlook (NEO):** BNEF each year releases NEO, a view to 2050 on where power sector investment and deployment will occur. As part of the process of producing NEO, BNEF leverages its understanding of technology learning curves, market growth rates, and other factors to project the viability of clean energy technologies to compete with fossil generators. NEO projects when renewables can underprice fossils on a new-project vs new-project basis, then forecasts when renewables can displace existing fossil generation. (In essence, NEO projects future points in time where it simply becomes most economical to shutter an existing coal plant and replace it with a new wind or solar plant.)
- **Energy Project Asset Valuation Model (EPVAL):** BNEF's EPVAL is an open-source model that BNEF uses to assess the economics of individuals projects. It includes the latest assumptions derived from BNEF's knowledge of the markets, but also gives users the opportunity to adjust all important inputs, including those related to financing costs.

3.1. Clean Energy Economics

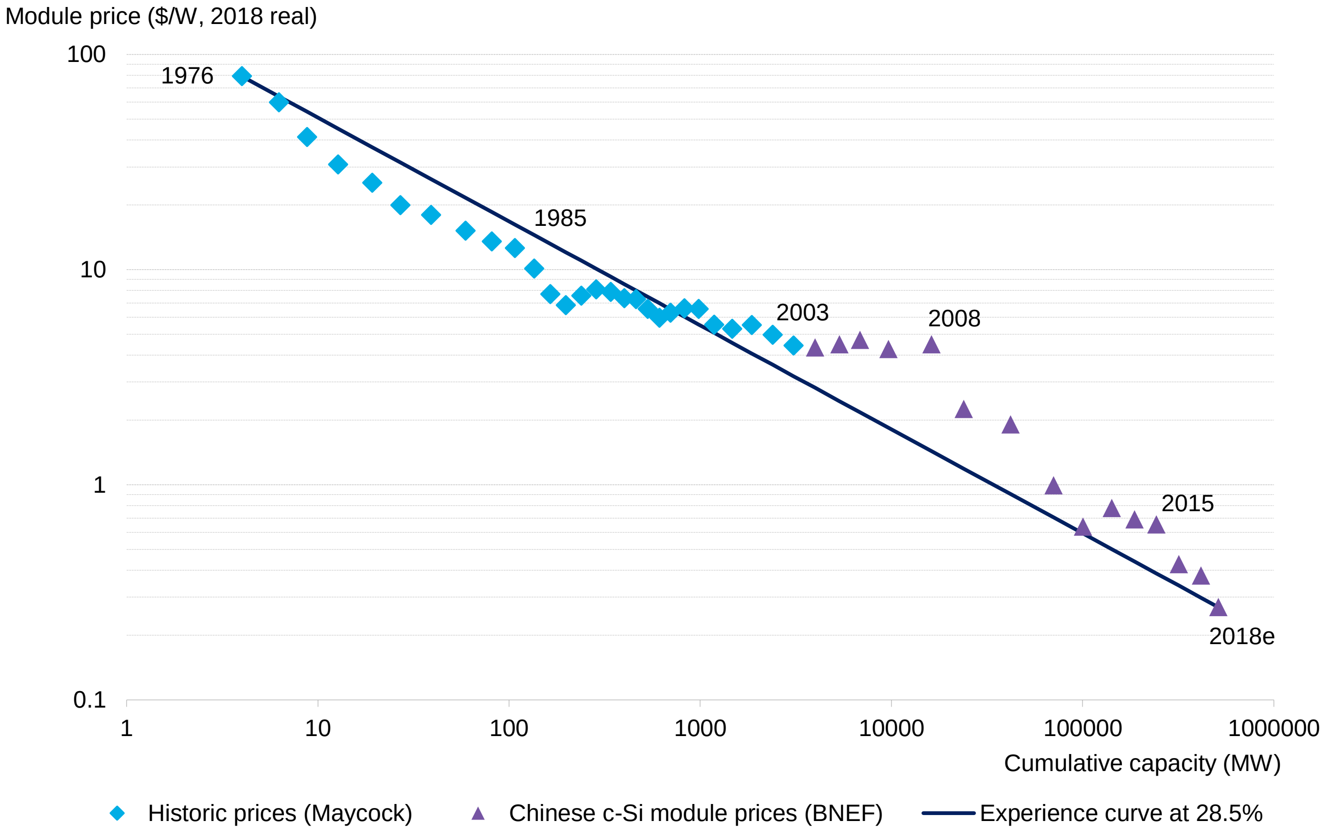
3.1.1. Short-term economics

Recent renewable energy technology cost declines have been staggering. Cheaper turbines, smarter operations and maintenance, lower cost of finance and better performing machines have combined to lower the cost of wind energy. In 2007, wind turbines cost 1.32 euros per watt. Fast forward to 2018, and that figure is 0.86 euros per watt.

However, the most dramatic cost declines have come in the solar sector. Dating back to 1976, crystalline silicon photovoltaic (PV) module prices have plummeted from $79/W (in 2018 dollars) to $0.37/W in 2017. And BloombergNEF expects prices to fall further, to around $0.27/W in the last quarter of 2018.

The curve below (Figure 76: PV module experience curve) illustrates solar's "learning rate" – i.e. the cost declines per each doubling of deployed capacity. In essence, each time the total amount of PV out in the world doubles, the prices per Watt drops by about 28.5%. This is arguably the most important data set in energy economics today. It has been made possible by a combination of technology innovation, economies of scale and manufacturing experience.

Figure 76: PV module experience curve



Source: Paul Maycock, BloombergNEF

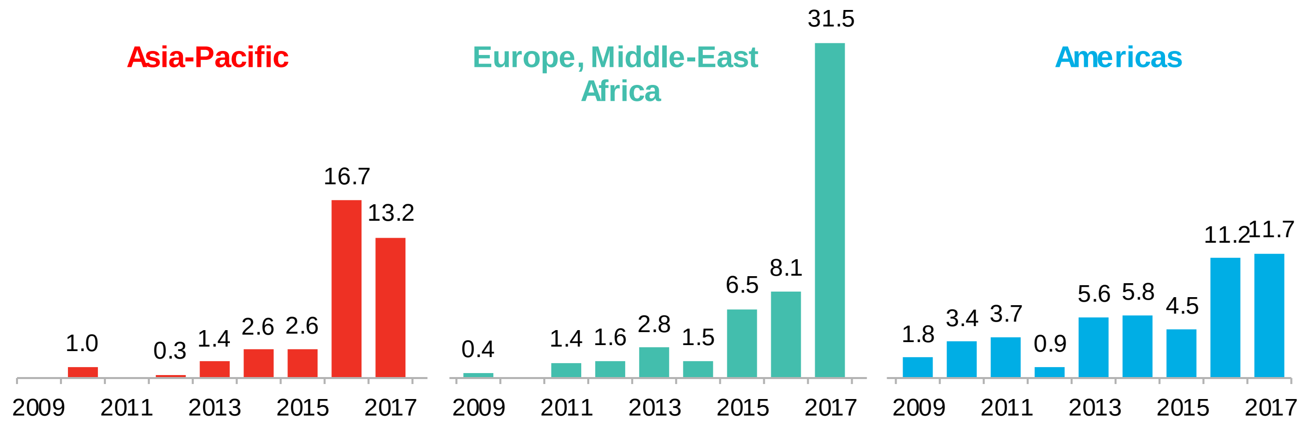
The pace of the cost decline brought by the scale of clean energy deployment since the turn of the 20th century, in particular from 2008 for solar, has at times left policy makers grappling with the challenge of setting the right remuneration levels to incentivize renewables developers while optimizing the use of public funds. Countries that employed fixed feed-in tariffs set by regulators on the basis of their understanding of costs found this created risks of over-subsidization. It also often left them with limited control over budgets and project pipelines.

This problem was acute during the solar investment boom of 2007-2011 and the subsequent retroactive policy changes in the European Union, however it has also affected markets outside the OECD. In June 2018, China announced that it would control the volume of new solar installations by switching away from tariffs set by regulators after the government accumulated a $19 billion deficit related to payments owed to renewables project owners. In less mature markets, liberal availability of feed-in tariffs (FiT) led to an accumulation of project proposals that ministries struggled to process. In the worst cases, this led to a standstill in renewables deployment. Kazakhstan or Senegal, for instance, both halted development after being swamped with FiT applications.

Clean energy auctions

Hoping to better manage overall build while keeping a lid on public liabilities, governments have increasingly turned to reverse tenders or auctions for procuring new clean energy supply. Auctions have repeatedly proven effective at driving down clean-energy tariffs awarded to projects while giving regulators better control over volumes of renewables added to the grid. As a result, they are often policy-makers' mechanism of choice and the primary way contracts get awarded globally today (Figure 77).

Figure 77: Clean energy contracts signed annually under organized auctions, by region (GW)



Source: BloombergNEF. Note: includes contracts signed with wind, solar, geothermal, biomass, and small hydro projects to deliver power. Contracts signed are typically for a target capacity (MW). When the target is for generation, BNEF aggregates, totals, and converts these to capacity figures using expected capacity factors by technology.

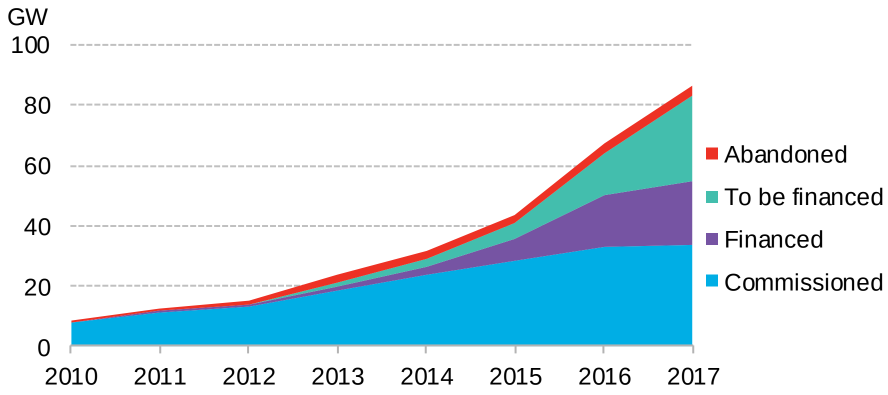
Countries that have opted for auctions were able to look to across Latin America to learn about tenders, but particularly at Brazil, Chile and Mexico. There, regulators have been using auctions in parallel with wholesale power markets to drive investment in power-generating capacity from both renewables and fossil-fueled generators for decades. See Appendix A for additional information and country studies.

Capital requirements

Auctions have been a critical contributor to the growth of the renewables pipeline globally. BloombergNEF tracked 57.7GW of capacity new capacity contracted in 32 countries in 2017 alone, with two thirds in non-OECD nations. This is equivalent to all of the world's annual solar and wind installations for 2010, or the global cumulative installed capacity of solar and wind in 2005.

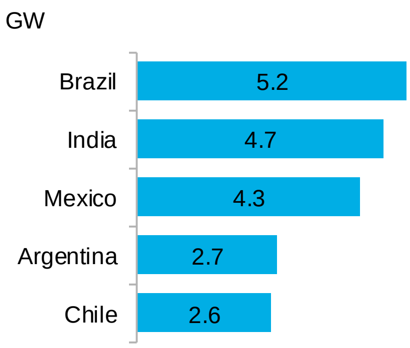
The bulging pipeline of tender-contracted projects has also substantially expanded the need for financing. As of 1H 2018, BNEF was aware of 29GW of renewables projects seeking financing after winning contracts in auctions (Figure 78).Several nations, including Mexico, have attracted high investor interest as a result of energy market reforms and auction design have built up pipeline of projects to be financed that are larger than their current installed renewables capacity (Figure 79). Outside of auctions, 2018 is set to beat the 2017 record of new project announcements. As of 1H 2018, BNEF tracked 41GW of wind project announcements in the emerging world against a 2017 total of 57GW, and the around 39GW of PV project announcements over the same period already exceeded the 38GW of 2017. A bit more than half of this pipeline is located in China.

Figure 78: Development stage of auction-winning projects



Source: BloombergNEF

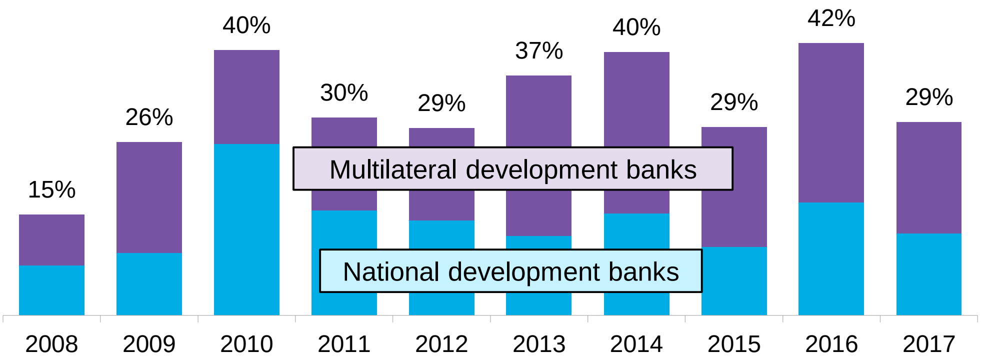
Figure 79: Top five countries with largest auction pipelines to finance, 1H 2018



With capital requirements of the clean energy sector in emerging markets today at an all-time high, it is certainly an open question as to who will provide the required funding.

Multilateral and national development banks have accounted for a third of all the foreign direct investment into clean energy in emerging markets from 2008-2017

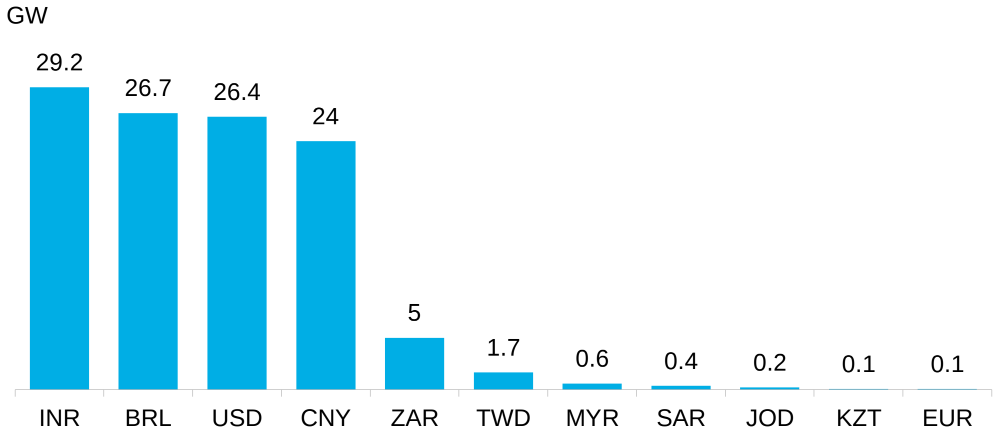
Figure 80: Development finance share of foreign direct investment in clean energy



Source: BloombergNEF

Development banks have been critical in providing debt to clean energy projects in emerging markets over the last decade. Between them, multilateral and national development banks have accounted for a third of all the foreign direct investment into clean energy in emerging markets from 2008-2017 (Figure 80).

Figure 81: Emerging markets volume of auctioned contracts in capacity by the currency in which they are denominated, 2003-1H 2018



Source: BloombergNEF. Note: the U.S. is not a country included in the data. INR = Indian Rupee, BRL = Brazilian Real, CNY = Chinese Yuan, USD = US Dollar, ZAR = South African Rand, TWD = Taiwan New Dollar, MYR = Malaysian Ringgit, SAR = Saudi Riyal, JOD = Jordanian Dinar, KZT = Kazakhstani Tenge, EUR = Euro.

The size of the capital flows does not tell the whole story, however. Development banks can also access capital denominated in hard currencies at a cost and scale that most commercial banks based in emerging markets cannot. This makes them uniquely positioned to help clean energy project developers mitigate currency risks.

Concessional finance awarded by development banks can play a critical role in bridging the funding and confidence gaps that can arise from temporary financial headwinds in emerging markets

A key factor of developers offering competitively priced renewables in developing countries that do not have a large and mature clean energy market yet has been that regulators have agreed to sign PPAs in U.S. dollars, or to index the local currency payments to it (Figure 81). Currency risk remains the main barrier to increasing the interest of project developers in emerging markets. In the short to medium term in particular, the combination of increasing central bank policy rates in the U.S. and the Eurozone, and growing dollar denominated debt in emerging markets has led to volatility in emerging market currencies and interest rates.

At the time of writing, Turkey and Argentina were two of the major emerging market economies going through such a difficult monetary cycle. The Turkish Lira and the Argentinian Peso lost a third of their value between January and August 2018, forcing central banks to respond with large increases in interest rates. Such events are affecting the funding capacity of commercial banks in emerging markets, and tend to push foreign investors to reduce their exposure. In this context, concessional finance awarded by development banks can play a critical role in bridging the funding and confidence gaps that can arise from temporary financial headwinds in emerging markets. This is particularly valuable as the broader fundamental outlook for economic growth and associated power demand needs in emerging markets continues to be more positive than in the OECD.

3.1.2 Long-term economics

As a result of the dramatic cost declines and technological improvements, the composition of the world's power grids has changed dramatically in recent years. Since 2014, 422GW of variable renewable utility-scale capacity – wind and solar, mostly – have been installed with 44% of that in

China. Propelled by the introduction of competitive auctions in most markets, the scale of this deployment has allowed manufacturers, developers, financiers and operators to test new designs and strategies to reduce costs. Most recently, the record low winning bids seen in renewable power auctions held both in OECD and emerging economies have underlined the vital importance of lower-cost capital.

In this section, we review the progression of levelized costs of electricity (LCOE) for renewable power-generating technologies since 2014 and examine how they are influenced by financing costs. We then look forward to explore how concessional finance might affect future LCOEs for renewables in four developing nations: Brazil, Thailand, Mexico and India.

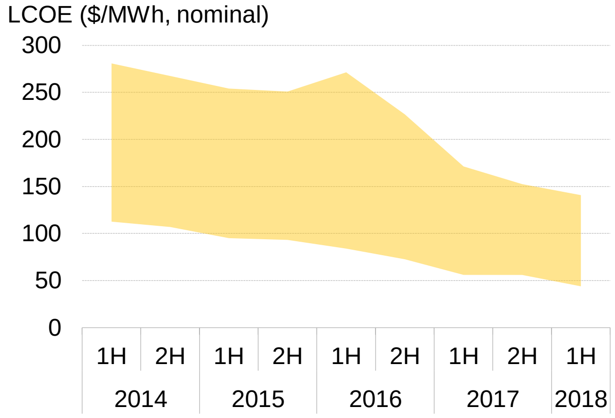
We define LCOE as the long-term offtake price required to achieve a certain equity hurdle rate[24] for a developer, considering its total capital, operating and finance costs over the lifetime of the project. Our LCOE estimates exclude costs of grid connection and transmission. They also do not take into account subsidies or incentives as they are intended to assess the true economic viability of technologies outside the bounds of policy support.

Evolution of LCOE benchmarks

In 2014, the benchmark levelized costs for utility-scale PV in emerging economies ranged between $113-281/MWh (Figure 82). Since then, capex declines have reduced solar levelized costs by an average 47% in developing nations. Today, LCOE benchmarks for utility-scale PV range from $44-141/MWh.

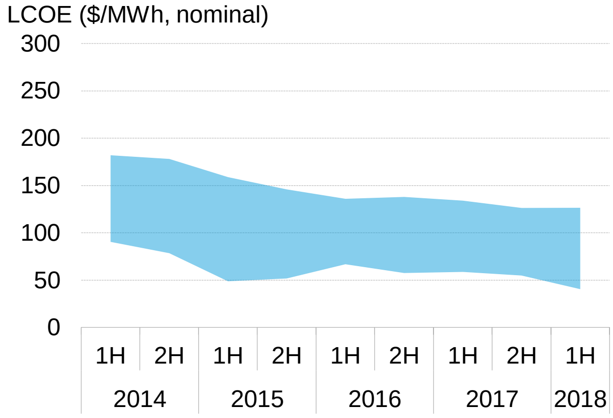
Similarly, for onshore wind, the benchmark levelized costs in emerging economies have dropped 38% on average, from $90-182/MWh in 2014 (Figure 83). This is mainly due to technology improvements, including larger turbines that have allowed for higher capacity factors and driven down the levelized costs through economies of scale.

Figure 82: LCOE benchmarks for utility-scale PV in select emerging markets



Source: BloombergNEF. Note: Emerging markets include Argentina, Brazil, Honduras, Panama, Jamaica, Peru, South Africa, United Arab Emirates, India, China, Indonesia, Malaysia, Philippines, Thailand, Vietnam

Figure 83: LCOE benchmarks for onshore wind in select emerging markets



Source: BloombergNEF. Note: Emerging markets include Argentina, Brazil, Honduras, Panama, Jamaica, Peru, Kenya, South Africa, India, China, Indonesia, Malaysia, Philippines, Thailand, Vietnam

[24] The equity hurdle rate is the post-tax return that sponsors (investors) require on the equity capital they provide.

Also since 2014, financing costs for renewables projects have fallen as lending institutions and sponsors have become more familiar with these asset classes and their risk profiles. In mature markets like Germany, the U.S. or China, financiers are every bit as comfortable backing clean-energy projects as they are fossil-fueled generation – sometimes even more so.

The impact of financing costs on the economics of renewables

Costs of financing a project typically amount to 40-55% of the LCOE both for utility-scale PV and onshore wind projects. This makes access to cheap financing a top priority for developers across the world.

Capital costs are critical to the economics of renewable power assets. Such projects have nearly no operating costs meaning their profitability can largely be determined at the time of commissioning with virtually all costs related to capex. Costs of financing a project typically amount to 40-55% of the LCOE both for utility-scale PV and onshore wind projects. This makes access to cheap financing a top priority for developers across the world.

The cost-competitiveness of renewables in developing countries has historically been hampered by higher-priced domestic capital.

As renewable power projects are capital-intensive, the cost of finance available to project developers has historically resulted in a segregation between wealthy and less developed nations. Thanks in part to the low-interest rate environment, OECD countries have had cheap domestic financing capabilities. In those countries, the benchmark weighted average cost of capital (WACC)[25] we tracked for 2017-18 ranged from 2.5-6.5%. Meanwhile the emerging economies, the benchmarks were 5-11% (Figure 84 and Figure 85).

This difference in financing terms translates directly to a discrepancy in the total levelized cost. As a result, developing economies have tended to be home to some of the highest LCOEs across the world.

There is a direct relationship between the cost of capital that developers can access in each country and the benchmark levelized costs for renewable assets (Figure 84 and Figure 85). Specifically, for each percentage point rise in the cost of capital, levelized costs rise today on average by:

- $3.3/MWh for utility-scale PV plants
- $3.6/MWh for onshore wind farms

Lower system costs or better renewable resources can compensate for an unfavorable investment environment. A good example for this is India, which despite its relatively high weighted average costs of capital for renewables (around 8% today for wind and solar, down from 12% in 2017) has some of the lowest levelized costs for solar and wind at around $40/MWh. This is mainly due to the very competitive environment which forces renewable developers to achieve comparatively low capex and opex by global standards.

Similarly, new onshore wind projects in Brazil offer some of the lowest LCOEs globally at $38/MWh in 2018, despite high financing costs. Brazil's exceptional wind resource allows projects to achieve capacity factors of up to 50%. This, in turn, 'squeezes' all the component costs on a MWh-basis.

[25] WACC: weighted average cost of capital.

Figure 84: Impact of financing costs on the country LCOE benchmarks for utility-scale PV

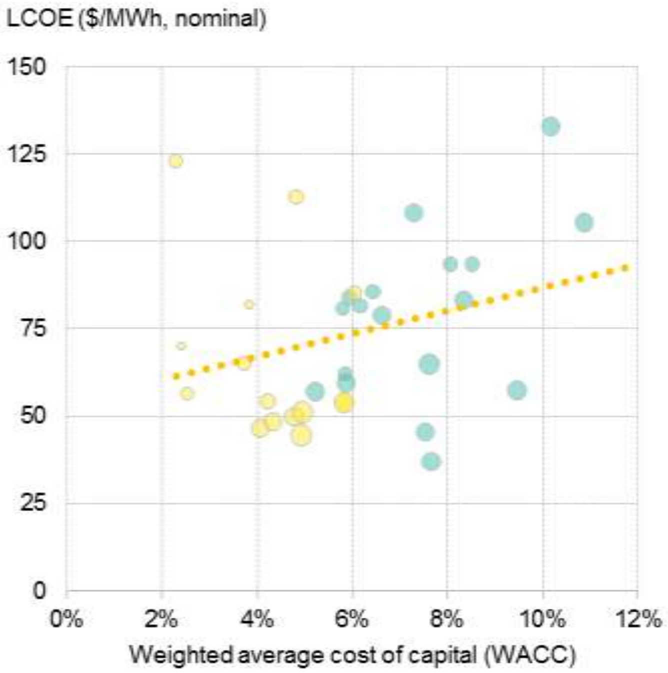
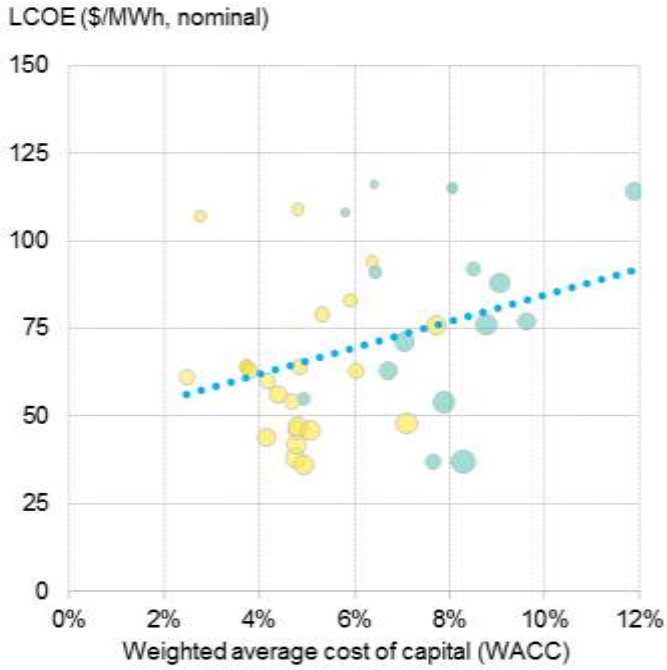


Figure 85: Impact of financing costs on the country LCOE benchmarks for onshore wind



OECD Developing economies Bubble size: capacity factors

Source: BloombergNEF

As a clean energy project's capex falls, capital costs have less impact on LCOE

Based on our analysis, in 2017, LCOEs for utility-scale PV rose at a rate of $5.8/MWh for each percentage point increase in the cost of finance. By 2018, this dropped to just $3.3 per MWh. As capex drops, the rate at which levelized costs escalate slows.

The potential role for concessional finance

Concessional finance can contribute to making capital-intensive renewable assets more competitive faster.

As the vast majority of future power demand growth is expected to come from emerging economies, cost-competitive decarbonized power generation in these countries will be critical to limiting global CO2 emissions growth. In the previous section we highlighted the significant influence that the cost of capital has on levelized costs for PV and onshore wind globally, and in emerging markets in particular. Concessional finance thus can contribute to making capital-intensive renewable assets more competitive faster.

In this section, we identify the potential impact of concessional finance on future levelized costs of renewable power assets in four emerging economies: Brazil, Thailand, India and Mexico. Specifically, we explore a range composed by two hypothetical capitalization structure scenarios (*high LCOE and low LCOE*) detailed in Table 3 and compare the LCOEs including concessional capital against our benchmark LCOEs with commercial debt only.

Table 3: Capitalization structure

Country	LCOE scenario	CTF loan	MDB	Local commercial lenders	Commercial sponsors (equity)
Brazil	High	15% with 200bps discount to MDB rates	20%	45%	20%
Brazil	Low	25% with 400bps discount to MDB rates	25%	30%	20%
India	High	15% with 200bps discount to MDB rates	20%	40%	25%
India	Low	25% with 400bps discount to MDB rates	25%	25%	25%
Mexico	High	15% with 200bps discount to MDB rates	20%	35%	30%
Mexico	Low	25% with 400bps discount to MDB rates	25%	20%	30%
Thailand	High	15% with 200bps discount to MDB rates	20%	40%	25%
Thailand	Low	25% with 400bps discount to MDB rates	25%	25%	25%

Notes: For more details on MDB rates, see the Appendix. Local commercial lenders' rate is based on BNEF debt interest rate benchmarks. Commercial sponsors' rate is based on BNEF equity rates benchmark. We assume the CTF loan tranche is subordinated to other more senior tranches (local commercial debt and the MDB loan). Additional research is warranted to better understand different capitalization structures. High scenario indicates higher LCOE while low scenario indicates lower LCOE.

Impact on the cost of new utility-scale PV and onshore wind projects

The benchmark scenario in each of the four markets assumes that renewable projects are financed only on local commercial terms. Local commercial financing terms are based on BloombergNEF data collected on the ground in 1H 2018. The two concessional capitalization scenarios presented above are tested using BloombergNEF's proprietary project finance model: *Energy Project Asset Valuation Model* (EPVAL 8.5.6). The results of the modelling are presented in Table 4.

The impact of the blended concessional finance is a function of the prevailing cost of capital available to renewable project developers locally as well as the lending rates that multilateral development banks are likely to offer. Under the *high scenario*, the reduction of the LCOE for utility-scale PV in 2018 ranges from 2.0% (Mexico) to 5.6% (Brazil). In Thailand, the cost reductions incurred by the integration of concessional capital amount to 5.3% for a solar PV project under the high scenario, while it is 3.3% for a similar project in India. Under the *low scenario*, the cost reductions for solar PV compared to our benchmark scenario range from 2.1% (Mexico) to 8.3% (India).

The reduction of LCOE for onshore wind ranges from 4.1% (Brazil) to 6.1% (India) in the *high scenario.* In the *low scenario,* projects are found to be 4.4% (Brazil) to 8.3% (India) cheaper than our benchmark (Table 4).

Ongoing reductions in equipment costs, improving efficiency and declining financing and development costs are expected to cut the global benchmark LCOE for onshore wind by around 60% by 2050. Similarly, we expect the lifetime cost of a standard utility-scale PV project with competitive equity returns and commercial debt to come down by around 70% between 2018 and 2050.

Table 4: Impact of concessional capital on the LCOE benchmark for projects financed in 2018

Technology	Country	LCOE Benchmark (USD/MWh)	High scenario (compared to benchmark)	Low scenario (compared to benchmark)
Utility-scale PV	Brazil	64	-5.6%	-7.2%
	Mexico	54	-2.0%	-2.1%
	Thailand	81	-5.3%	-7.0%
	India	43	-3.3%	-4.5%
Onshore wind	Brazil	38	-4.1%	-4.4%
	Mexico	50	-5.1%	-6.8%
	Thailand	111	-5.4%	-7.2%
	India	38	-6.1%	-8.3%

Source: BloombergNEF. CTF: Clean Technology Fund.

Tipping points

The dramatic decline in the cost of PV and onshore wind technology means that we can anticipate two tipping points in the competitive economics between different energy technologies.

The **first tipping point** occurs when the cost of new-build wind and solar becomes cheaper than the cost of building a new gas or coal plant for bulk generation. From this point on, wind and solar would be built preferentially for bulk generation.

The **second tipping point** occurs when it gets cheaper to build and operate new onshore wind or solar PV than to run an existing amortized coal or gas plant providing bulk electricity. Once the LCOE of solar or wind falls below the short-run marginal cost of an existing fossil fuel plant, it makes economic sense to replace that fossil plant with a new unit of renewables capacity.

Here, we examine when these tipping points can be achieved in each of the four countries.

Thailand

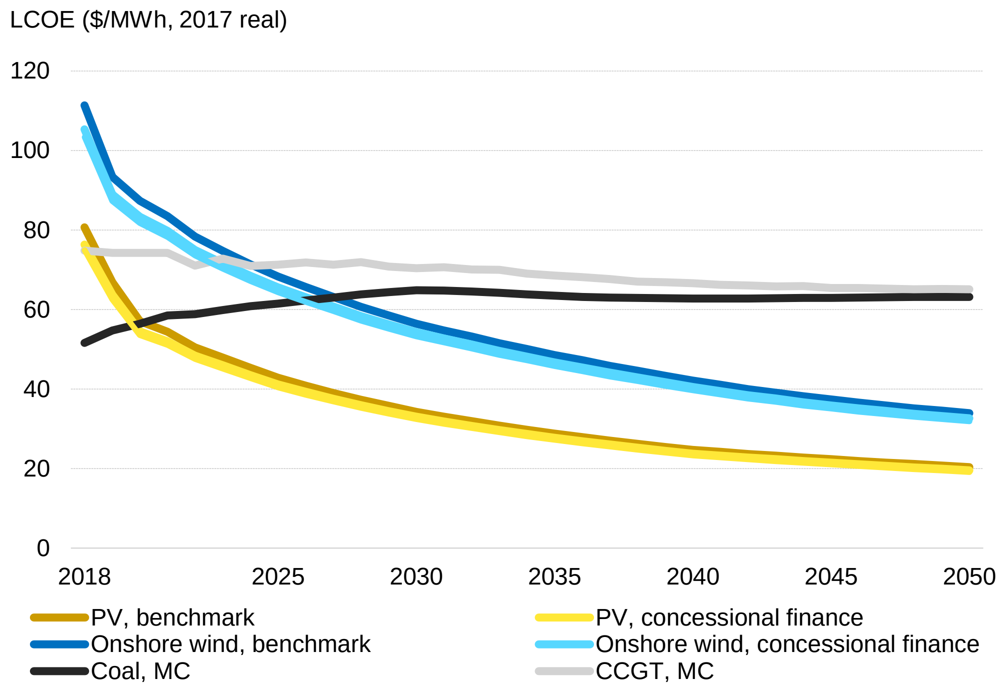
Under the CTF scenarios analyzed, these crossover points for gas and coal could occur two years earlier than in the benchmark scenario, in 2023 and 2026, respectively. This shift may be crucial as the Thailand is currently planning to add coal-fired plants in the south to meet growing electricity demand.

In Thailand, we expect the cost of new utility-scale PV financed on commercial terms to cross the cost of new combined-cycle gas turbine plants (CCGT) by 2019 and coal-fired power plants by 2020 (first tipping point) (Figure 86). The presence of concessional capital in the scenarios analyzed reduce the levelized cost of solar by 5.3%-7%. This would put those PV plants on par with new CCGT just a year or so earlier.

Wind farms in Thailand have historically had higher levelized costs compared to those elsewhere. This owes to the relatively low capacity factors that projects achieve there. Our benchmark LCOE forecast sits at $93/MWh for a wind farm reaching financial close in 2018. We expect the generation costs to drop steeply as equipment and O&M costs drop and the turbines allow for increased generation per MW installed.

As the benchmark levelized cost for wind power drops, we expect that new onshore wind farms will be more competitive than new gas plants by 2025. For new coal capacity, we anticipate this crossover with wind occurring by 2028. Under the CTF scenarios analyzed, these crossover points for gas and coal could occur two years earlier than in the benchmark scenario, in 2023 and 2026, respectively. This shift may be crucial as the country is currently planning to add coal-fired plants in the south to meet growing electricity demand (see Thailand section for more details). In 2017, coal and gas together accounted for 90% of the power generated in Thailand.

Figure 86: Cost of new onshore wind and utility-scale PV vs. new coal and gas, Thailand



Source: BloombergNEF

India

India is home to some of the lowest levelized costs globally for utility-scale PV and onshore wind today. This owes mainly to India's extremely competitive auctions which have prompted developers to squeeze capex as much as possible. Still, in 2017 coal-fired plants represented 58% of India's capacity and 75% of the generation.

In India, concessional financing has the potential to shift the crossover point for new onshore wind with existing coal by at least two years (high scenario) or four years considering the highest share of concessional finance (low scenario). This shift is fundamental considering India installed 94.3GW of coal over 2012-2017.

Our latest analysis suggests that onshore wind and utility-scale PV are already more competitive, on an LCOE basis, than new coal- and gas-fired power plants today. Therefore in Figure 87, we explore how and when new solar and wind capacity are likely to outcompete *existing* coal and gas-fired power plants (second tipping point).

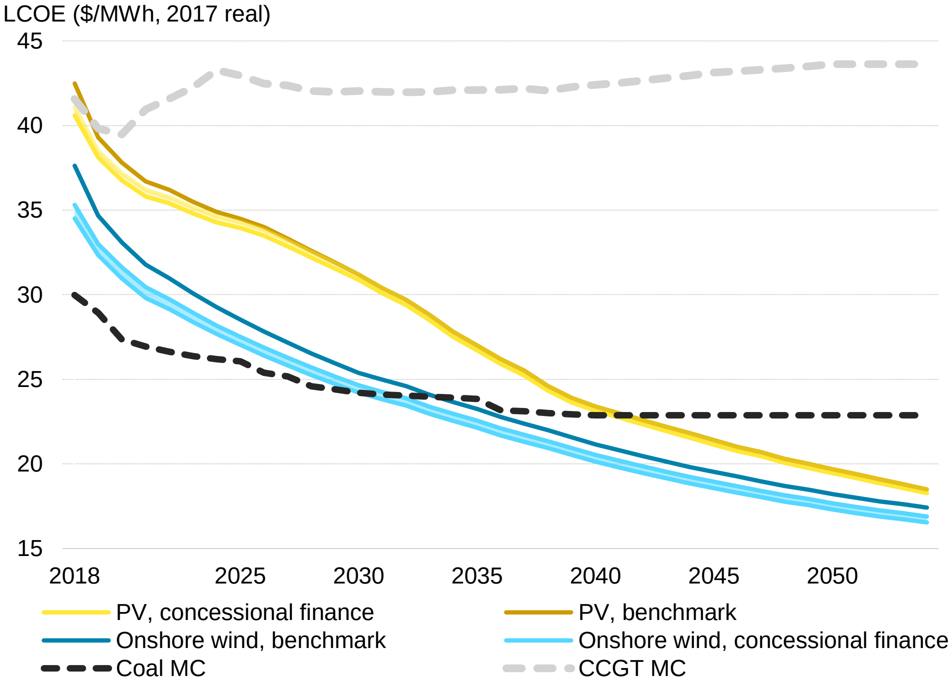
In our benchmark scenario we expect new wind capacity to start competing with the marginal cost of coal plant only by the mid-2030s. Onshore wind is already competitive comparing marginal cost of existing CCGT plants. For new solar power plants, the competitive tensions are likely to occur only by the beginning of the 2040s.

Concessional financing has the potential to shift the crossover point for new onshore wind with existing coal by at least two years (*high scenario*) or four years considering the highest share of concessional finance (*low scenario)* This shift is fundamental considering India installed 94.3GW of coal over 2012-2017.

For solar, we expect the gap between commercial financing and the CTF scenarios to be much narrower as both financing conditions seem already to be very close. This is likely to be a consequence of two elements: the very competitive environment for both renewable developers and financing institutions, which has pushed down commercial financing cost in India recently, as well as the high premium required to hedge against the fluctuations of the Indian rupee compared to the U.S. dollar (CTF and MDB loans are assumed to be denominated in U.S. dollars).

As a consequence, after 2025 the CTF capitalization structures have little impact compared to the LCOE benchmark. With the highest share of concessional finance *(low scenario)* we expect the tipping points with existing coal to occur about one year earlier than in our benchmark scenario.

Figure 87: Cost of new onshore wind and utility-scale PV vs. existing coal and gas, India



Source: BloombergNEF. MC: marginal cost.

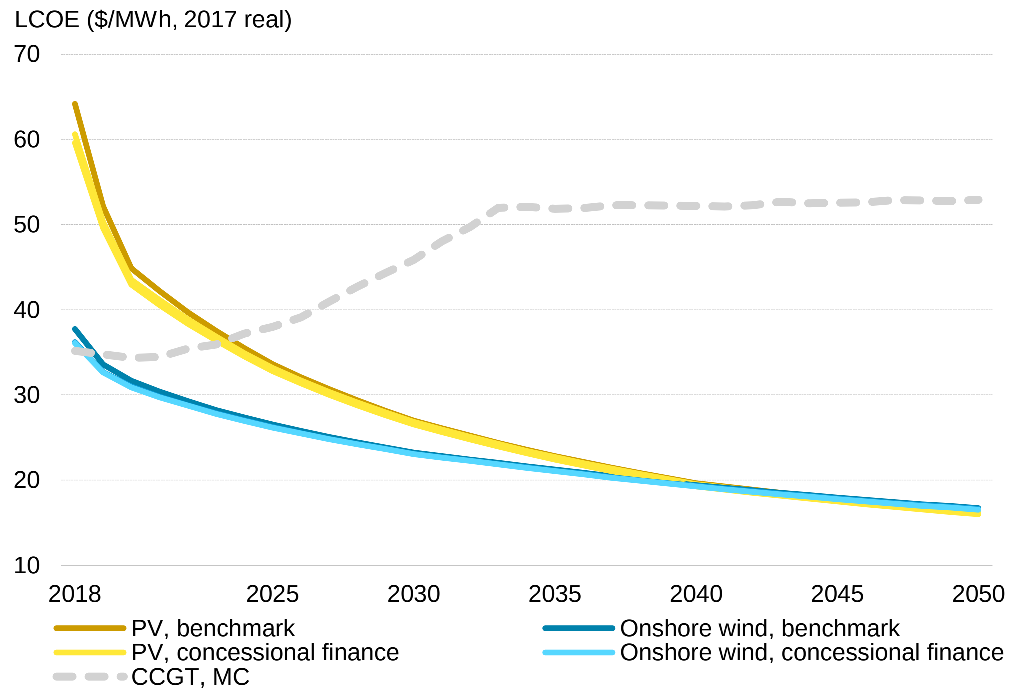
Brazil

Under all scenarios, we expect new onshore wind and PV plants to become more competitive than running existing CCGT plants by 2019 and 2024, respectively. Therefore, in Brazil, concessional finance is likely to have a higher impact if directed to newer and less mature technologies.

In Brazil today, new solar and wind already outcompete new thermal power plants on cost. Therefore in Figure 88 we look at the economics of tipping point 2 – how new renewable capacity competes against the marginal cost of *existing* thermal plants.

Because of the market maturity and the key role played by the Brazilian Development Bank (BNDES) in financing renewable energy plants, we don't expect concessional finance to shift significantly the LCOE curve (see Appendix A for more details). Under all scenarios, we expect new onshore wind and PV plants to become more competitive than running existing CCGT plants by 2019 and 2024, respectively. Therefore, in Brazil, concessional finance is likely to have a higher impact if directed to newer and less mature technologies.

Figure 88: Cost of new onshore wind and utility-scale PV vs. existing gas, Brazil



Source: BloombergNEF. MC: marginal cost.

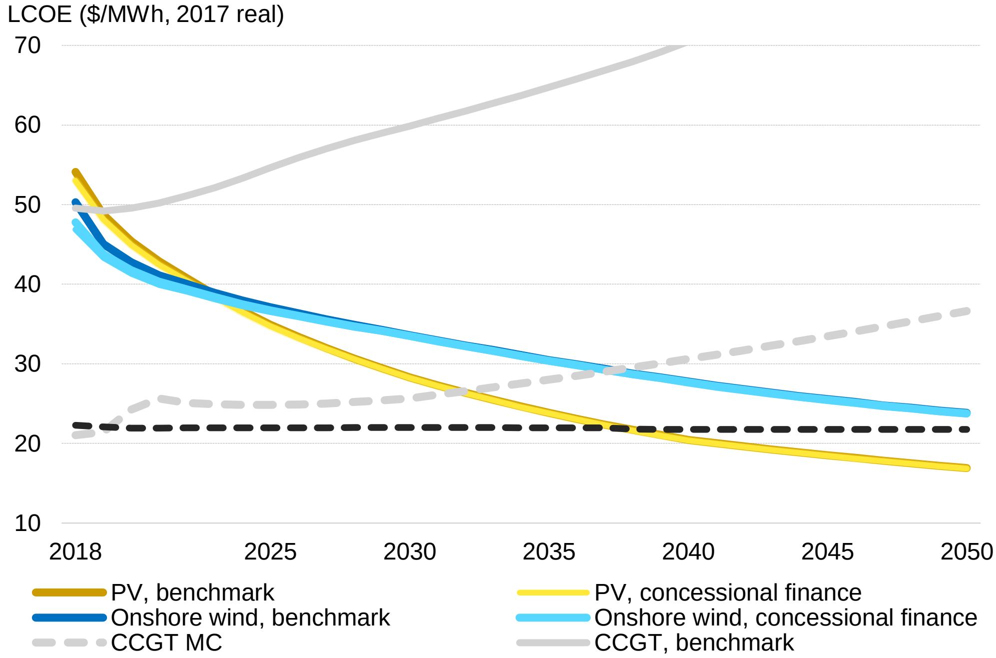
Mexico

In Mexico, we find that even lower levels of concessional capital (*high scenario)* have the potential today to make onshore wind a cheaper option than new CCGT plants. In all scenarios, both new build PV and onshore wind plants will outcompete new CCGT plants by 2019. This is noteworthy as Mexico has historically heavily relied on gas-fired plants by bulk generation. In 2017, gas accounted for 49% of the country's installed capacity and 59% of generation, while coal represented 7% and 9%, respectively (see Mexico section for more details on the market).

As the market matures, commercial lenders should offer better financing terms. As a consequence, the gap between the concessional finance scenarios and our benchmark for onshore wind narrows during the early 2030s. By the end of that decade, concessional capital has a limited impact on costs as commercial lending rates are more competitive. Concessional capital availability for utility-scale PV in Mexico in both scenarios seems to have very little impact on costs. This is likely to be the result of prevailing competitive capital available in the country for renewable assets.

In all scenarios, we expect new PV plants to become more competitive than running existing CCGT and coal plants by 2032 and 2038, respectively. We forecast that building a new onshore wind plant will be cheaper than running an existing GGCT plant by 2038, but we do not expect this tipping point occur for coal before 2050 (Figure 89).

Figure 89: Cost of new onshore wind and utility-scale PV vs. new and existing fossil fuel power plants, Mexico



Source: BloombergNEF. Note: CCGT LCOE is based on realized capacity factors from the New Energy Outlook 2018 dispatch analysis. MC: marginal cost.

Accelerating de-carbonization

In countries where new PV and onshore wind plants are still more expensive than new gas and coal plants (the first tipping point has not yet been reached), concessional finance may be best deployed to encourage that renewables get built rather than new fossil generation. This would result in preventing new coal plants from coming on line that could potentially spew CO2 for years to come until the second tipping point occurs.

In markets where the second tipping point is not expected to occur for some number of years, policy support from development institutions may be a solution to help reduce LCOEs and accelerate the arrival of tipping points.

For countries where building a new PV or wind plant is already cheaper than building a new gas- or coal-fired plant, concessional finance can accelerate the country's energy transition by speeding the retirement of fossil fuel plants. However, in markets where the second tipping point is not expected to occur for some number of years, policy support from development institutions may be a solution to help reduce LCOEs and accelerate the arrival of tipping points.

For instance, the development of clean energy auction mechanisms can heighten market competition, drive down costs, and reduce LCOEs. When well structured, tendered PPAs can also boost investor confidence, and lower investor demands about equity returns. That, in turn, can make a very important and positive impact on LCOEs.

In emerging markets facing macroeconomics crises, guarantees from development institutions can be key to boosting investor confidence. In Argentina, the Renewable Trust Fund FODER backed by the World Bank, provided guarantees of PPA payments for auction-winning projects. The new mechanism boosted confidence among foreign debt providers and helped the country attract $ 3.1 billion into the sector.

In some cases, strong measures from key stakeholders involved in the power sector will be also needed to allow de-carbonization. In Chile, for instance, we do not expect the second tipping point to occur with coal generation before 2040. Still, the country's government and utilities have made great commitments to ensure emission reductions from the power sector.

Chile's measures towards energy transition

In 2016, Chile announced its energy policy, committing to have 70% of renewable energy generation by 2050. Two years later, in January 2018, the four generators that own coal assets (AES Gener, Colbún, Enel and Engie), signed a voluntary agreement with the government pledging not to invest in or build new coal plants that lack carbon capture and storage (CCS) or equivalent technologies. The companies will also constitute a work group that, coordinated by the Chile Ministry of Energy, will plan the gradual retirement or conversion of the coal assets. Aspects such as security of supply, electricity prices, grid stability, environment and employability will be considered to determine the decommissioning schedule, which will become available in the beginning of 2019. Engie already announced two units that will be retired by the same period.

Chile's new President Sebastian Piñera took charge in March 2018, after the agreement was signed. Despite his differences with the previous government, he is not expected to walk away from deal as efforts to address climate change are generally popular across the political spectrum in Chile. The 2018-2022 agenda under Piñera's new Ministry of Energy includes de-carbonization among its top 10 priorities.

The current government is already studying the deployment of storage technologies, specifically green hydrogen, concentrated solar power, geothermal, batteries and pump hydro.

3.2. Identifying new opportunities

Three key factors can potentially help determine whether a specific technology in a specific country should be supported with concessional finance. In BNEF's view, the following should be taken into account when considering opportunities for deploying capital in support of clean energy in a country:

- The *enabling environment* including policies, power markets, and other attributes
- The *opportunities*, including current and future electricity demand
- The *experience* of clean energy development, including volumes already installed

While none of these three factors can be comprehensively measured, BNEF has sought to quantify each of these for individual nations through data collected for its annual *Climatescope* project.

A strong, stable **enabling environment**, which includes clean energy policy mechanisms (auctions, feed-in tariffs, net metering, tax incentives, etc.), an unbundled power sector not monopolized and open for private generation, as well as ambitious renewable energy and emission reduction targets, has historically proven to be most welcoming for renewable energy investment.

The **clean energy opportunities** presented by a nation comprises the levels of demand growth for electricity, energy consumption, and emissions from power sector, along with overall price attractiveness (higher prices are better), short- and medium term opportunities for renewable energy procurement, and history of corporate commitment with sustainability and existing electrification rates (lower rates make a market more attractive).

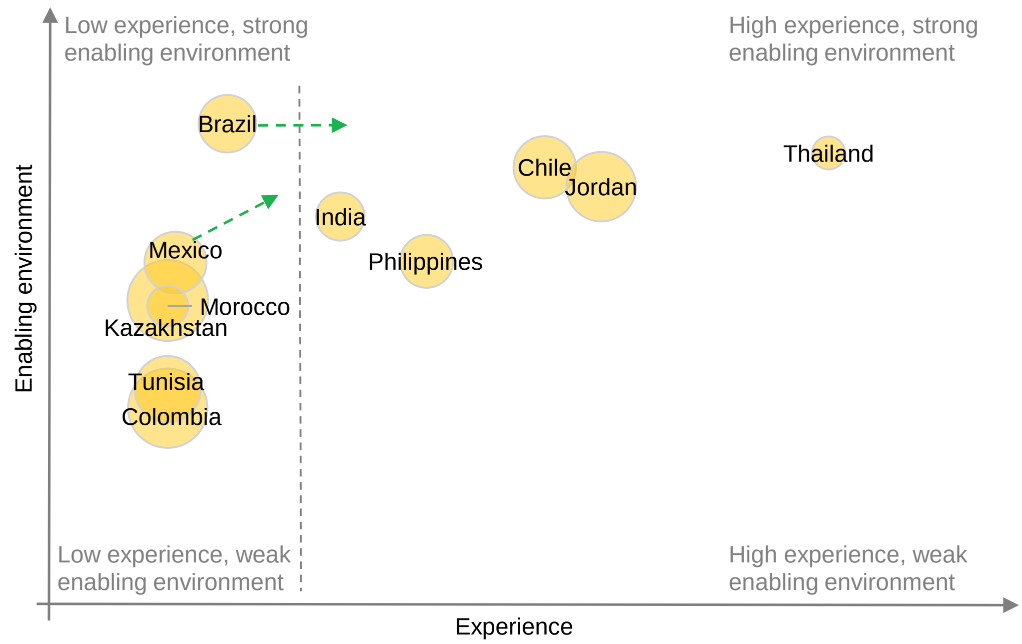
Markets with greater **experience** in actually deploying renewable energy capacity typically offer lower risks, lower technology costs and lower costs of capital. For this analysis, we quantify experience by considering the share of overall capacity a technology accounts for in a country, and the share of commercial finance invested in that technology vs. the total capital the technology attracted from 2012-2017.

It is not uncommon for a country with a strong enabling environment, plentiful opportunities, and substantial experience in deploying onshore wind and PV to offer excellent opportunities for investment. However, such markets can get overheated and when they do, they raise questions of how to prevent market distortions and crowding out of private sector funds.

Market opportunities

In this analysis, we consider these variables in select countries to contemplate what markets may be best for CTF today to support PV (Figure 90) and onshore wind (Figure 91) investment and where it may be time to shift investment to newer, less mature technologies. With this purpose, we grouped 11 select countries into categories to assess how concessional finance could potentially have the greatest impact[26].

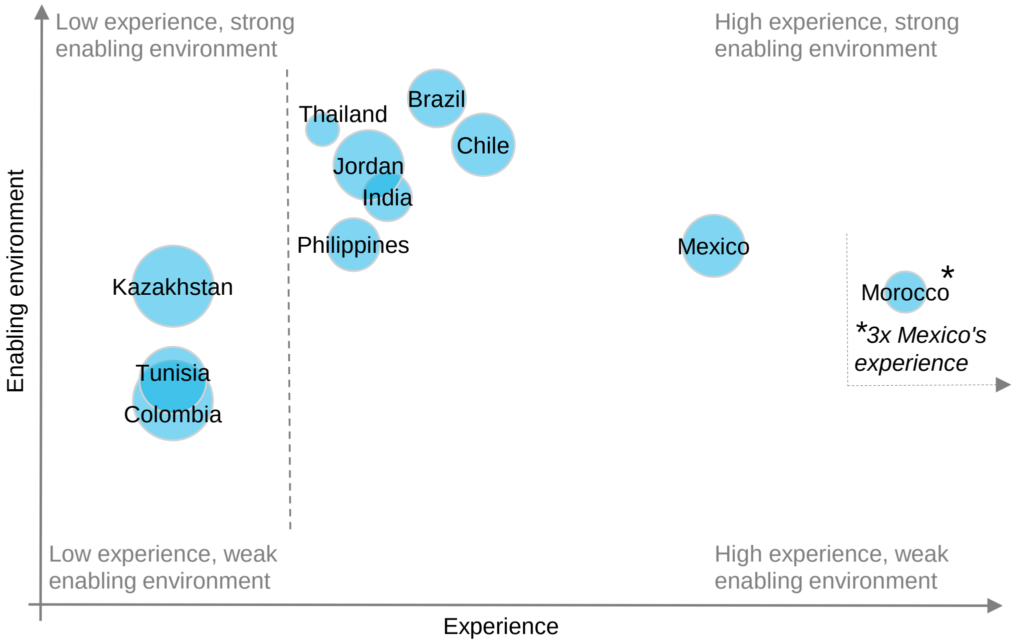
Figure 90: PV market experience vs. enabling environment



Source: BloombergNEF, Climatescope. Note: Bubble refers to size of potential. Enabling environment and opportunities based on Climatescope 2018 scores. Experience refers to share of solar capacity multiplied by share of commercial investment in PV projects in 2013-2017. Green arrow represents expected progress.

[26] See the World Bank report Strategic Use of Climate Finance to Maximize Climate Action for proposed framework for deciding how to use international public finance with a concessional component to maximize the impact of climate action.

Figure 91: Onshore wind market experience vs. enabling environment



Source: BloombergNEF, Climatescope. Note: Bubble refers to size of potential. Enabling environment and opportunities based on Climatescope 2018 scores. Experience refers to share of solar capacity multiplied by share of commercial investment in PV projects in 2013-2017. Morocco's experience score is three times Mexico's experience score and six times the average experience score.

As fast-growing and high emmiting developing nations, all the countries analyzed present good opportunities for clean energy deployment. Virtually all fall into one of two buckets: they have high levels of experience and intermediate-to-strong enabling environments; or they have low levels of experience and intermediate enabling environments. We examine each of these combiniations below.

Countries with low experience + intermediate enabling environments

- **PV:** Morocco, Kazakhstan, Tunisia, Colombia
- **Onshore wind:** Kazakhstan, Tunisia, Colombia

See retrospective analysis for more details about Kazakhstan and Morocco.

Countries in this category have low or zero experience in the sectors, but are currently implementing new policies to incentivize clean energy build out, especially through auctions and tenders.

For instance, after several years of unsuccessful policy development, Colombia is expected to hold its first clean energy auction in February 2019 to contract 1,183GWh per year to be supplied from December 2021 onwards. As of year-end 2018, the country had less than 30MW of wind and PV capacity and the auction is expected to kick start Colombia's clean energy sector.

Countries that are implementing new clean energy policies and transitioning towards less monopolized power sectors are likely where concessional finance for PV and onshore wind can have the greatest impact. By supporting the first-movers in these countries, concessional finance can help de-risk the market, reduce capital costs and help crowd-in commercial finance.

In March 2018, Tunisia's Ministry of Energy released its updated Renewable Energy Action Plan, which aims, among other things, to move toward a cleaner power matrix. In particular, the country plans to jump from 3% of renewable energy generation in 2016 to 12% in 2020, then to 30% by 2030. Moreover, in May 2018 the country announced its first large-scale clean energy tender, which aims to contract a total of 1GW, equally split between wind and PV plants.

Countries that are implementing new clean energy policies and transitioning towards less monopolized power generation sectors are likely where concessional finance for PV and onshore wind can have the greatest impact in crowding-in more immediate commercial finance. By supporting the first-movers in these countries, concessional finance can help de-risk the market (and all new market characteristics created by the new policies), reduce capital costs and help crowd-in commercial finance.

Countries with high experience + intermediate-to-strong enabling environments

- **PV:** Thailand, Jordan, Chile, Philippines, India
- **Onshore wind:** Morocco, Mexico, Chile, Brazil, India, Jordan, Philippines, Thailand

See retrospective analysis for more details about Chile, Mexico and Thailand.

Countries in this category have implemented policies that have successfully fostered substantial capacity for PV, onshore wind, or both technologies. In most cases, these markets are mature enough and have effectively attracted significant shares of commercial investment (Figure 92 and Figure 93).

Figure 92: 2012-2017 share PV investment by type of investor

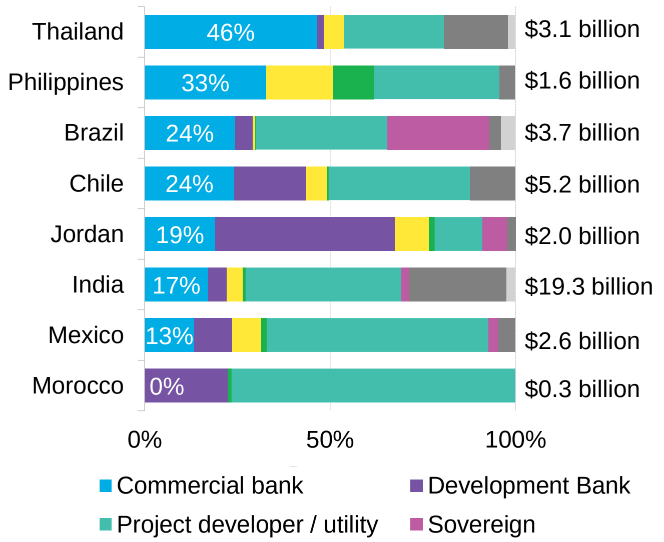
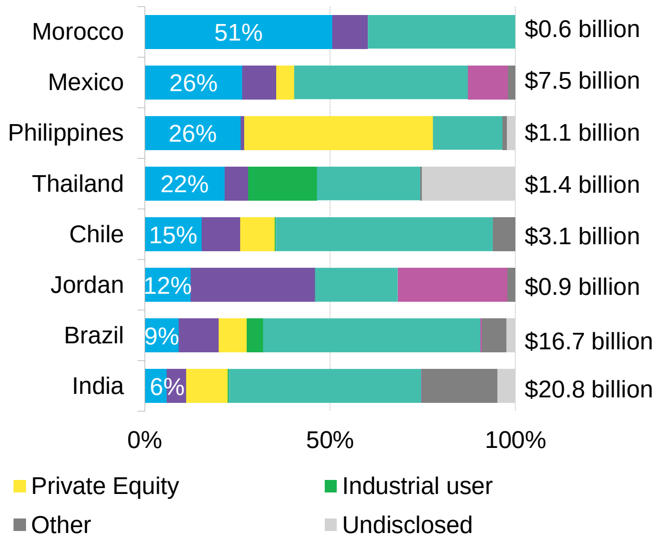


Figure 93: 2012-2017 share wind investment by type of investor

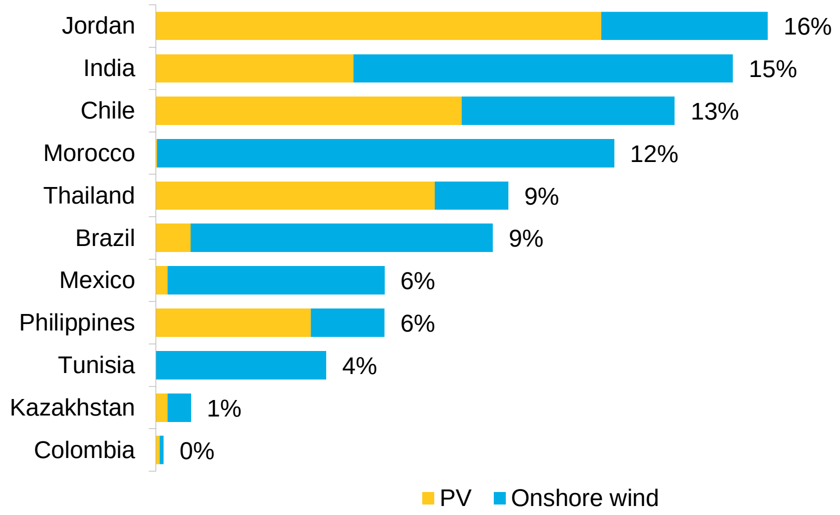


Source: BloombergNEF

The market maturity along with high amount of capacity from intermittent sources (Figure 94) indicate that concessional investment is no longer needed for these technologies. In these countries, concessional finance is likely to have a higher impact in less mature technologies that will allow higher penetration of intermittent sources in the future (see the New Technologies section for more details).

The market maturity along with high amount of capacity from intermittent sources indicate that concessional investment is no longer needed for these technologies. In these countries, concessional finance is likely to have a higher impact in less mature technologies that will allow higher penetration of intermittent sources in the future.

Figure 94: Share of PV and onshore wind vs. total commissioned capacity, 2017



Source: BloombergNEF, Climatescope

For PV, Brazil and Mexico remain in the low experience category, but this is due to change soon as new capacity comes online as result of successful auctions. As detailed in the Clean Energy Economics section, in Brazil and Mexico PV and onshore wind plants already outcompete new fossil fuel power plants on cost.

Countries with low enabling environment + low fundamentals

Concessional finance provided to countries with a weak enabling environment is likely to result in a lower impact in crowding-in commercial finance than in markets with a stronger enabling environment. This is because these markets have less (or no) clean energy policies and a more monopolized power market. As a result, it presents more barriers to private investors and provision of concessional finance would hardly help crowding-in commercial investment. Because of the weak enabling environment these countries also present a low to zero experience in wind and solar. None of the countries selected fall into this category in Figure 90 and Figure 91, but Turkmenistan, Angola and Tajikistan are examples of markets that would fall into the "low experience and weak enabling environment" category.

As mentioned in section 3.1, development institutions can play a crucial role in providing technical assistance to create new clean energy policies or even to support a power sector reform in these markets.

3.3. New Technologies

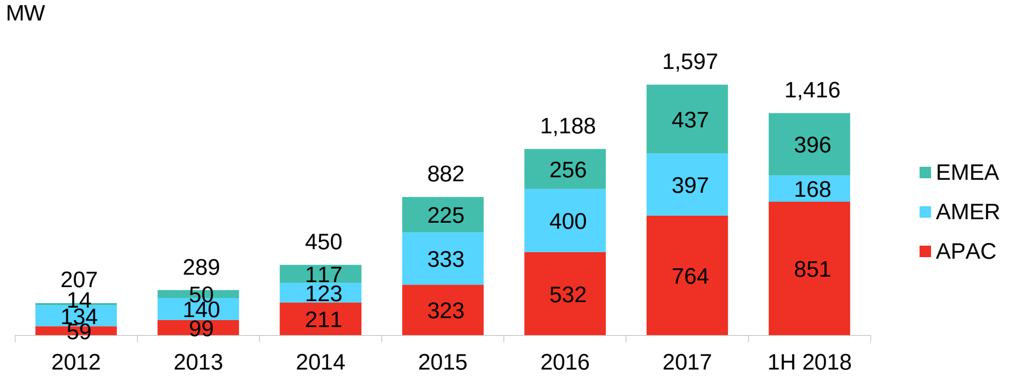
3.3.2 Energy Storage

As generation of intermittent sources grow, storage will be key to integrate renewables, allow deeper penetration of variable clean energy and ensure resilient supply in emerging markets.

As generation of intermittent sources grow, storage will be key to integrate renewables, allow deeper penetration of variable clean energy and ensure resilient supply in emerging markets.

As of 1H 2018, the world had installed over 6.5GW of behind-the meter and utility-scale storage systems, excluding pumped hydro. Annual installations have spiked at least 34% every year since 2012 and deployments in the first half of 2018 have almost matched 2017's total (Figure 95). Still, almost 70% of the total capacity is concentrated in Korea, the U.S., China and the United Kingdom. In emerging markets, deployment of energy storage has been limited due to high technology costs and lack of adequate policy frameworks.

Figure 95: Combined behind-the-meter and utility-scale storage deployments



Source: BloombergNEF. Note: Excludes pumped hydro

Energy storage is a broad term that encompasses tens of different technologies, including flow batteries, lead-carbon, sodium sulphur, and compressed air energy storage to name a few. Despite the wide range of options available, we expect the market to converge around lithium-ion. No other technology benefits to the same extent from the ramp-up in research and development, and manufacturing capacity of lithium-ion for electric vehicles.

Figure 96: Commissioned energy storage breakdown based on power output

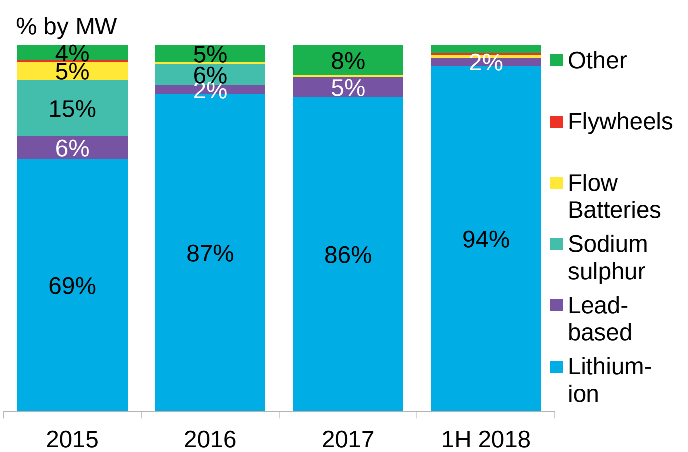
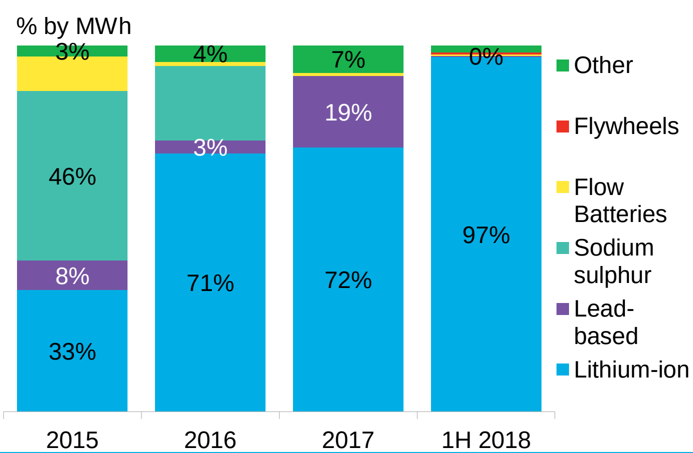


Figure 97: Commissioned energy storage breakdown based on energy capacity



Source: BloombergNEF. Note: Pumped-hydro is excluded from this list

Flexibility requirements

Storage has multiple applications, but we believe that those related to flexibility present the greatest short and medium-term potential in emerging markets.

Storage has multiple applications, but we believe that those related to flexibility present the greatest short and medium-term potential in emerging markets. Ensuring sufficient system flexibility will become a priority for system operators as variable sources of supply grow and traditional sources of flexibility decrease. A flexible system is one that can respond to planned and unplanned variations in order to balance supply and demand over multiple time frames. Electricity demand and supply need to be matched at all times yet currently power systems have limited storage capacity, and imbalances can result in blackouts. Below, we reviewed specific subsets of increasing flexibility requirements.

Table 5: Frequency regulation

Definition	How can storage help?	Policy
When mismatches between power supply and demand occur on the grid, the frequency of the system will start to change. To avoid equipment damage or blackouts, it is crucial that the frequency is maintained close to its target at all times. System inertia, which is the resistance of grid-synchronized masses like turbines to changes in rotating speed, provides a buffer against frequency fluctuations. Also, as more renewable energy generation come online, inertia-supplying generators, such as thermal plants, are forced out. New resources and market designs will be required to maintain grid stability.	Energy storage resources are faster-responding and more accurate resources than conventional thermal generators. Some energy-storage resources such as batteries are able to provide instantaneous response, despite having charge limitations. Faster and more accurate response is beneficial to the system since it may require less overall resources to be available or contracted for that purpose.	Enabling energy storage for this application often requires market reform. In competitive markets there typically needs to be some kind of premium compensation for faster-response and accuracy or a carve-out. In some cases, such as in Chile, high energy prices encouraged generators to invest in lithium-ion on their own accord. They were then able to ramp up their thermal assets without worrying about their reserve obligations.

Table 6: Peaking capacity

Definition	How can storage help?	Policy
Power systems need to ensure electricity is available even during extremes in supply or demand. Peaking capacity resources are often contracted to ensure they are available in scenarios of peak demand. Increased share of renewable generation supply can intensify the demand for peaking capacity as the renewable energy output may be unavailable during peak demand times. Managing extremes is getting increasingly complex. As the penetration of variable wind and solar increases, the instances of very high or very low supply need to be more carefully managed as they pose a greater threat to security of supply. The system needs to balance on a windy, warm, sunny day, as well as on a still, cold night.	Regardless of the way in which capacity is procured, energy storage could be a competitive alternative to other peaking capacity resources: It can respond rapidly and can arbitrage against the variability of renewable generation. The duration of the peak is crucial to the economics of batteries in this application. The longer the peak, the more expensive it will be to shave the marginal megawatt with battery storage compared to a gas peaker. This is because you need more batteries as duration increases. Whether energy storage is able to provide other services throughout the year is also crucial to its viability. Gas assets by contrast are struggling with lower forecast utilization over this period, making them less competitive.	There are a number of market design mechanisms that are being deployed to either incentivize new capacity build or to ensure that existing capacity stays online, including: • Energy-only market, with a carbon market linked to a strong carbon constraint. This may include a strategic reserve or capacity payment, in order to guarantee reliability and ensure that backup plants are kept in the money • Central auctions for renewable energy, accompanied by centrally-administered capacity markets or reserves. • Energy supplier obligations for de-carbonization. More radical still would be to mandate energy suppliers both to de-carbonize and to guarantee resource adequacy.

Table 7: Renewable energy integration

Definition	How can storage help?	Policy
As renewable energy resources become more widespread, system operators are grappling with how to efficiently integrate them without compromising reliability. This becomes more challenging, and probably more costly as penetration rises. Concerns include: **System-level constraints**: Total wind and solar output may exceed demand in certain periods across the day. System operators may need to curtail output from these technologies to manage the overall supply-demand balance or to maintain minimum inertia levels. **Network congestion management:** Even if the system-level supply-demand balance is acceptable, insufficient grid capacity at either the transmission or distribution level may necessitate curtailment. This can be due to limits on power-line capacity or limits on the capabilities of certain elements of the grid.	Energy storage is a way to manage these challenges. Co-siting energy storage with PV could, for instance, lead to a reduction in overall system costs. Energy storage can be added on-site to charge up when and if a system operator requests the asset to curtail. It can also help to smooth output of solar and wind projects since it can charge when the sun is shining or the wind is blowing and can discharge at the required ramp rate when a cloud passes by or when the wind slows. Finally, energy storage can be paired to renewable sites to make them dispatchable.	In developed economies, energy-storage policies that support renewable energy integration have generally been reactive to broader targets that prompted clean energy build. The renewable portfolio standard targets in South Korea and the feed-in tariffs in Japan and Italy have each been specifically generous to renewables and eventually led to utilities exploring energy storage as a response to increased renewable penetration levels. In the Southwest U.S., PV-plus-storage is now competitive against new-build combined-cycle gas turbine projects as a source of capacity, in the absence of any state level support. Because of the wide scope of renewable-energy integration, this will continue to be a significant driver for new policies that support energy storage.

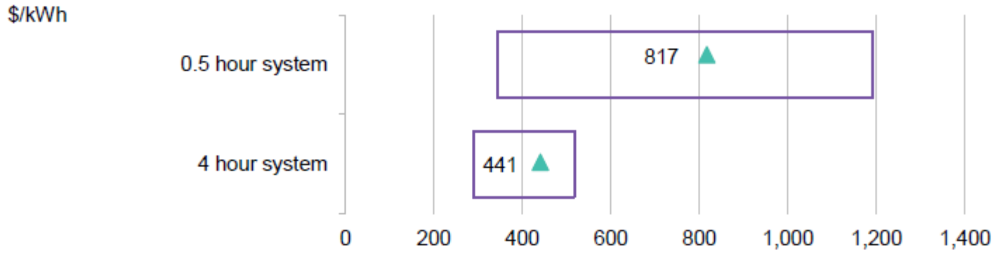
Table 8: Transmission and distribution network management

Definition	How can storage help?	Policy
Transmission and distribution (T&D) network operators constantly extend and upgrade their infrastructure. Transmission utilities need to ensure transmission lines continue to transport electrons from centralized distant power plants to load centers, while expanding capacity to do so in new locations. Distribution utilities also upgrade their networks on an ongoing basis as infrastructure ages or as demand in certain locations increases, but they are also adapting to increasing levels of distributed energy resources (DERs) and changing demand patterns. Distribution utilities are overhauling their management of the network, moving from a static seasonal approach to active grid operations which, to date, has been achieved by modernizing grid equipment, and deploying advanced software and sensors. Increasingly though, DERs are viewed as offering part of the solution to the challenges they pose.	Energy storage, along with other distributed energy resources, can be used to defer or offset big investments in transmission and distribution equipment and provide grid services. Additions to T&D infrastructure are rarely incremental and can involve adding 25-50% more capacity to a given site. The case for energy storage to defer grid investments depends on factors such as the cost of the T&D infrastructure that needs to be upgraded, the peak to average demand ratio, the demand growth rate at the site, whether energy storage can also be used to provide other services, and if the regulatory framework incentivizes alternatives to traditional capital investments. Energy storage will not be competitive at all T&D sites on a network but be limited to those with high marginal costs.	In order to use energy storage for this application, utilities or network operators will need regulations that provide a framework to consider energy storage when doing resource planning. The regulator will need to allow the utility to rate base investments in energy storage assets in the same way it would pass through the costs for traditional network reinforcement. In deregulated markets, the main obstacle to the uptake of energy storage for this application is a disagreement over whether network operators should be allowed to own and operate storage, and whether the storage assets can also participate in wholesale energy markets.

Technology costs

A turnkey energy storage system is made up of a number of components: the battery pack, a power conversion system (PCS), an energy management system, and the balance of system. Associated with these are engineering, procurement, and construction (EPC) costs. Based on a new BloombergNEF industry survey, prices for a fully-installed four-hour utility-scale storage system in 2018 range from $290-517/kWh. Half-hour utility-scale systems are more expensive and range from $343-1,191/kWh, with an average price of $817/kWh.

Figure 98: Range and average costs of fully-installed grid-scale energy storage systems, 2018

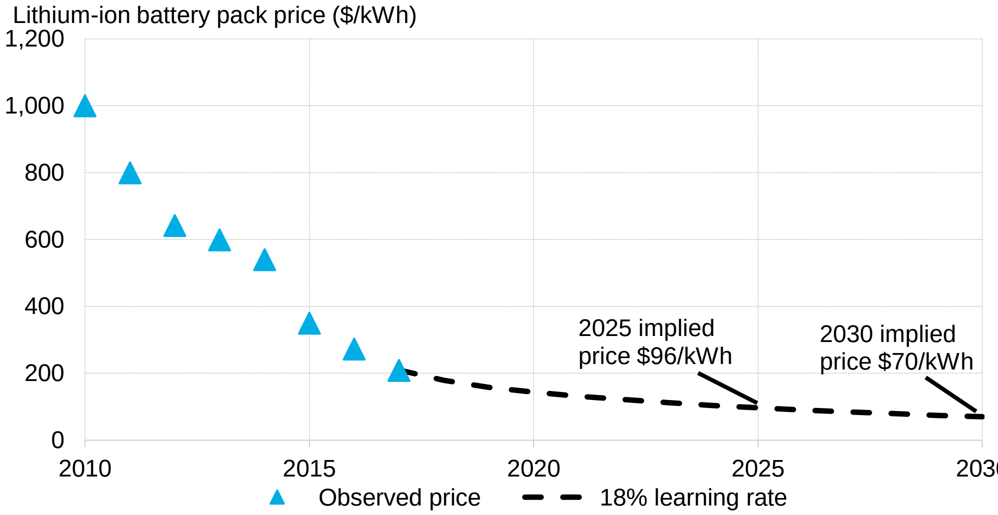


Source: BloombergNEF, survey participants. Note: Includes developer and EPC margin but excludes grid connection costs and tax, augmentation or salvage value.

The battery rack is the most expensive component of the storage system. We estimate that in 2018, it represented 57% of the four-hour system's average cost and 39% of the 30-minute system.

Battery prices fell almost 80% from 2010 to 2017. Our most recent battery price survey showed a weighted average price of lithium-ion battery packs of $209/kWh. This represents a 24% drop from our 2016 survey and is lower than we had initially projected at the beginning of 2017. We expect the ongoing build out of battery manufacturing for electric vehicles to continue to drive down their prices for stationary applications, so that they reach $96/kWh by 2025 and $70/kWh by 2030, 97% down from today (Figure 99).

Figure 99: Lithium-ion battery pack prices, historical and forecast, $/kWh



Source: BloombergNEF. Note: Prices are for EVs and stationary storage, and include both cell and pack costs. Historical prices are nominal, future prices are in real 2017 U.S. dollars.

This has profound implication for power grids across the world that are seeing the share of variable renewable energy penetration grow, making the need for flexibility a top priority. Cost competitive batteries mean that variable renewables will increasingly be able to run when the wind isn't blowing and the sun isn't shining and make storage increasingly competitive with coal and gas plants that have historically provided dispatchability and flexibility.

In India, for instance, paired wind-plus-battery and solar-plus-battery systems sized to make 50% or less of the installed renewables capacity dispatchable, are already competitive at $34-208/MWh and $47-308/MWh respectively. Coal and CCGT plants range from $54-83/MWh and $72-113/MWh, respectively.

The role of concessional financing

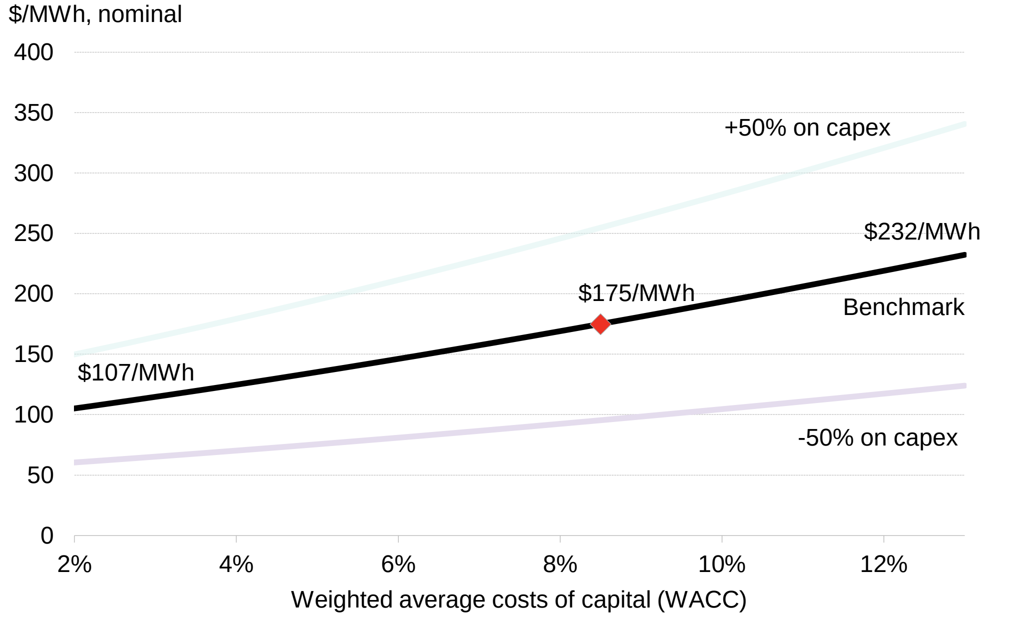
Concessional capital can have a greater impact improving the cost-competitiveness of lithium-ion battery projects than PV and onshore wind projects. In BNEF's benchmark scenario, for each percentage point rise in the overall cost of capital for a lithium-ion battery project, its LCOE rises by $10/MWh. This is three times higher than the impact on onshore wind and PV LCOEs.

Many standalone energy storage projects have been financed to date on the balance sheets of their developers. Even in established storage markets, revenue uncertainty associated with these projects has deterred investors. Third-party financing is likely to remain available only to investors who are able to provide a high degree of certainty over both technology availability and revenues.

Lower costs of capital for lithium-ion battery projects would result in significant lower energy storage levelized costs of electricity. At the extremes, a project with a 2% weighted average cost of capital would have an LCOE $125/MWh lower than one financed at a 13% cost of capital (Figure 100).The availability of finance, especially concessional finance, could prove crucial in incentivizing new-build storage globally.

Due to limited size of energy storage markets in developing countries, estimating country-level LCOEs for batteries with any degree of precision is not possible. However, as discussed in the Clean Energy Economics section, the higher the capex of a technology, the greater the potential impact concessional finance can make. This implies that concessional capital can have a greater impact improving the cost-competitiveness of lithium-ion battery projects than PV and onshore wind projects. Specifically, in BNEF's benchmark scenario, for each percentage point rise in the overall cost of capital for a lithium-ion battery project, its LCOE rises by $10/MWh. This is three times higher than the impact on onshore wind and PV LCOEs (as detailed in the Clean Energy Economics section). This also suggests a potentially greater impact on LCOE tipping points. That said, given the relative paucity of information about battery costs in developing nations, further inquiry is likely needed in this area to determine potential results with greater specificity.

Figure 100: 2H 2018 energy storage LCOE sensitivity analysis for a 4-hour duration lithium-ion battery



Source: BloombergNEF

Additionally, as intermittent renewables grow, the impact of energy storage goes beyond simply the new capacity installed. Over the next decade, one of the main benefits should be the additional capacity of wind and solar that batteries will allow fast-growing and high emmiting developing nations to add.

3.3.3 Small-scale PV

Unlike the deployment of utility-scale power stations, the uptake of small-scale PV is a decision predominantly taken by households and businesses looking to offset retail power tariffs, to reduce their bills or, particularly in emerging markets, to improve the reliability of their electricity supply. Both economics – in the form of payback periods or return on investment – and penetration effect drive adoption.

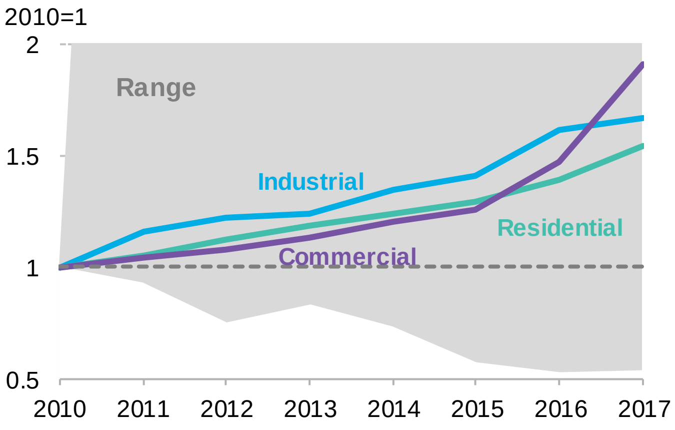
Key trends

Cheaper technology, innovative financing models, consumer marketing and government subsidies have led to a dramatic uptake of small-scale solar PV in some OECD countries. Since 2010, Germany has added 15GW of new distributed capacity, Australia 5GW and the U.S. 13GW. Examples of emerging markets with high penetration of small-scale PV are quite limited, however. Those that have progressed include countries where electricity costs are prohibitive as due to over dependency on costly energy imports. These tend to be island nations heavily reliant on costly fuel imports for power generation, or countries like Lebanon with sufficiently wealthy segments of their population willing to spend to reduce dependence on a dysfunctional retail electricity sector.

Retail electricity prices

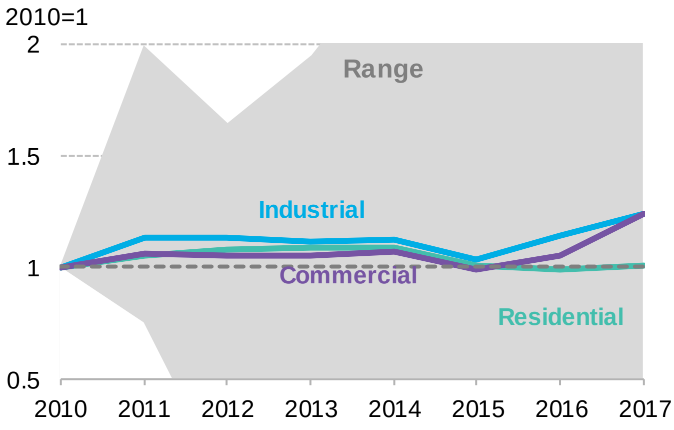
In general, retail rates include wholesale generation, transmission, and distribution costs, plus taxes and retailer marketing. This means that while small-scale PV today is around 35% more expensive than utility-scale systems on a per-kilowatt capex basis, it can be economic as it competes against grid-supplied power at retail rates rather than wholesale-priced electricity.

Figure 101: Evolution of retail electricity prices across emerging markets in domestic currencies



Source: BloombergNEF. Note: sample of 103 markets.

Figure 102: Evolution of retail electricity prices across emerging markets in U.S. dollars



Source: BloombergNEF. Note: sample of 103 markets.

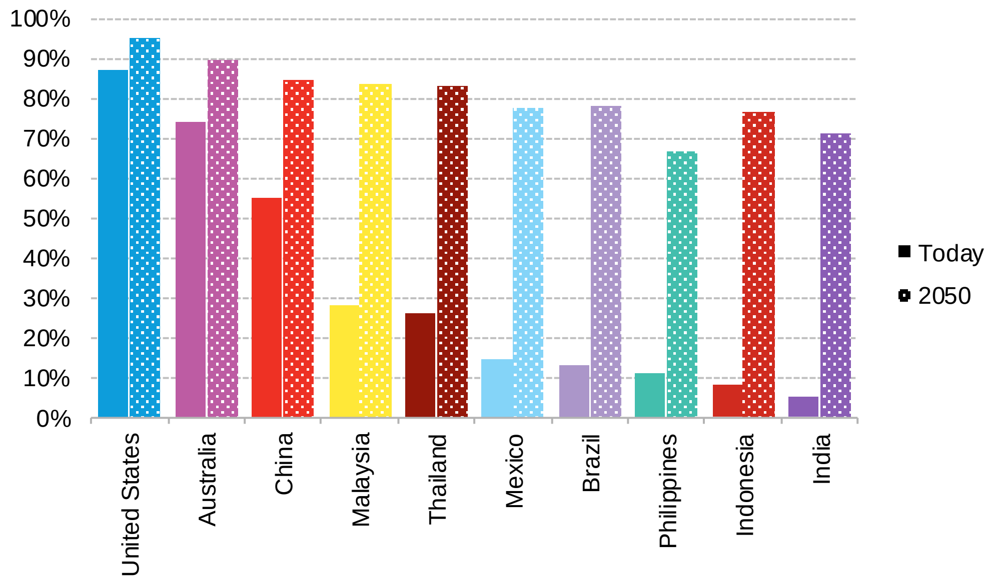
As retail prices are carefully regulated, they are sometimes set below the utilities' own operating costs thanks to government subsidies. This is particularly true in emerging markets. However, this has not prevented retail electricity prices to rise significantly across developing nations in recent years (Figure 101 and Figure 102). Two thirds of the 103 markets surveyed by BNEF recorded retail rate increases in domestic currency, showing that governments and regulators are hiking rates in response to inflation, higher power system investments or currency depreciation despite risks of public backlash.

Changing consumption patterns

One of the key drivers of demand and thus of power system investment in emerging markets has been the adoption of air conditioning (AC). Further growth is all but certain as populations grow, incomes rise and urbanization advances.

Under BNEF's New Energy Outlook projections, the percent of households that use AC for cooling in emerging economies increases rapidly through 2050, with the biggest changes in Indonesia, India, Brazil and Mexico (Figure 103). In Indonesia and India, AC penetration rises from below 10% today to 76% and 71%, respectively, by 2050. Translated into total electricity consumption, by mid-century air conditioning demand reaches 1,280TWh in India, or 27% of total demand; 650TWh in China, or 6% of demand, 260TWh in the United States (6%) and 200TWh in Indonesia by mid-century (26%).

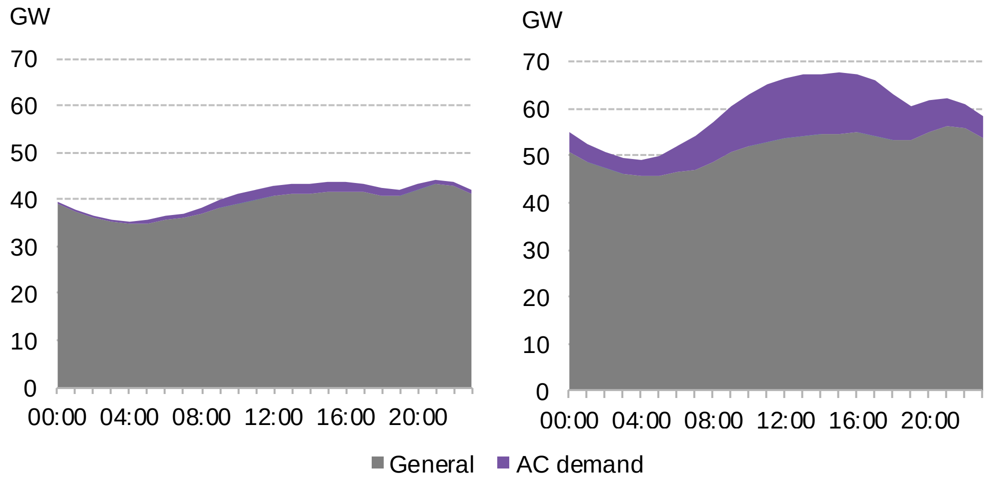
Figure 103: Percent of households with air conditioning, sample group, today vs. 2050



Source: BloombergNEF

Besides boosting total electricity demand, AC also contributes to changes in seasonal and daily peak demand for power, with the majority of new demand growth concentrated during the hottest parts of the year. We expect the intraday load peak for most countries with high AC penetration to move from the evening to the middle of the afternoon, when residential and commercial cooling demand coincides. In Mexico, for example, the AC load we project for 2040 easily overwhelms the historical evening peak, which is the result of consumers using appliances when they get home (Figure 104).

Figure 104: Intraday load profile for a typical summer day in Mexico, 2017 and 2040



Source: BloombergNEF

A shift of intraday peak demand to midday hours aligns very well with PV generation. In Mexico again for example, solar projects start generating meaningful quantities of power by 9am and perform best during summer afternoons –when air-conditioners run at full load. This correlation between peak demand and solar generation not only supports deployment of PV, but also reduces the need for new fossil fuel plants to meet the growing peak.

This same rapidly growing peak has prompted regulators in some developing nations with high AC penetration to introduce peak hour retail power price surcharges and invest in new capacity. Algeria, for example, has seen its peak demand nearly double from 7.7GW to 13.2GW, but also seen it shift from the evening hours to midday due to rapid AC uptake. The resulting added cost, if passed on to customers through retail prices, will further improve the competitiveness of small scale PV for commercial and residential customers.

Economics

Today, commercial-scale PV already makes economic sense without government support programs in many developing nations. Push forward to 2035 and it makes sense almost everywhere for businesses to add PV to offset their electricity costs.

While PV modules have become a globalized commodity with similar prices in most countries, final small system prices can vary substantially. This is often due to higher soft costs such as wage differentials, roofing and electrical standards, customer acquisition efforts and a lack of competition. However, we anticipate regional small-scale PV prices will converge over the next five years amid ongoing declines, breaking through the $1 per installed Watt milestone worldwide in around 2025. By 2040, we expect residential and commercial PV to be available for $0.54/W and $0.42/W, respectively.

Retail power prices and rate structures vary considerably across countries, utilities and customer classes. This alone means that residential and commercial customers are incentivized to install solar panels to different extents in different places. Over time, we expect retail tariffs to rise as investments in new transmission, distribution and grid management are pushed through to ratepayers. However, it is likely that much of this will be captured in the fixed, rather than the variable component of tariffs, as questions about who will pay for the grid resonate with regulators and policy-makers.

The amount of electricity directly consumed, or the “self-consumption” rate, is the final key ingredient to understanding the economics of consumer PV. For households, this rate is relatively low, as electricity use is generally highest in the evening when people get home from work. In contrast, businesses use most energy during the day when they are open, and this enables more self-consumption. In emerging markets where grids are often unreliable, commercial and industrial consumers will see the value of self-consumption increase by the opportunity cost of not being able to generate revenue during periods of power cuts.

Today, commercial-scale PV already makes economic sense without government support programs in many developing nations (Figure 105). Push forward to 2035 and it makes sense almost everywhere for businesses to add PV to offset their electricity costs (Figure 106).

Figure 105: Commercial PV socket parity with 70% onsite consumption, 2018

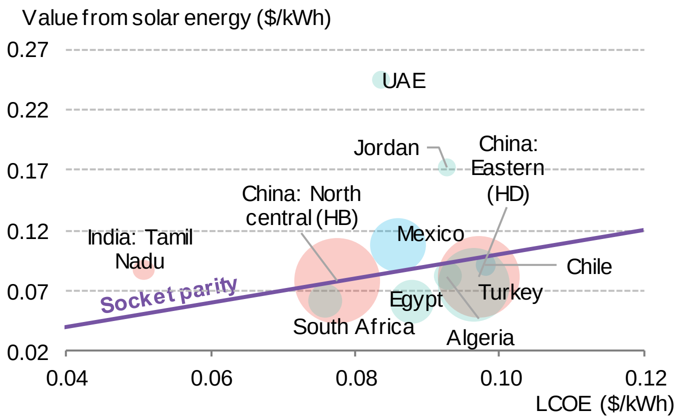
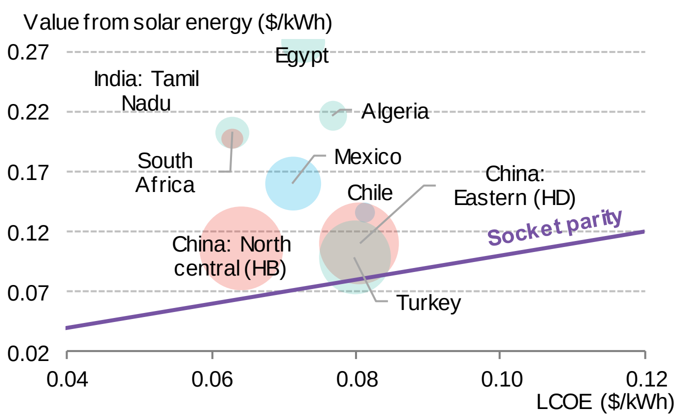


Figure 106: Commercial PV socket parity with 70% onsite consumption, 2035



Source: BloombergNEF

However, people and businesses do not decide to “go solar” based on socket parity economics alone. They are also strongly influenced by the behavior of their friends and neighbors. This combination of cost and penetration creates adoption "s-curves" for solar that we think will ultimately look similar to those seen historically for other consumer goods.

A similar potential trend should hold for the financial community. As banks make more small loans to small businesses and households, they will become more familiar with the risks associated with distributed PV systems. Further, as they see their competitors make such loans their comfort level will rise, along with their desire to compete for new business.

The role of concessional financing

With overall high level of solar irradiation, emerging markets have great potential for a small-scale PV boost. However, in the short-term, availability of financing will remain the main challenge to reach full potential.

With overall high level of solar irradiation, emerging markets have great potential for a small-scale PV boost. However, in the short-term, availability of financing will remain the main challenge to reach full potential.

As of today, there are limited resources for funding distributed energy resources in developing nations. The vast majority of concessional finance in the renewables sector to date has instead flowed towards -scale assets. This has allowed development finance institutions to deploy capital at scale and target their technical assistance and de-risking efforts. However, the economic and technological outlook in the energy sector is increasingly leaning in favor of PV deployed at a smaller scale. This trend is already allowing more emerging markets to record clean energy investment than ever before. As of 1H 2018, 82 of 103 developing nations surveyed by BNEF have recorded an investment in the PV sector against 59 for the wind sector, and the trend is accelerating.

For investors, the main challenge of moving from utility-scale solar assets to smaller scale is the shift from an offtake agreement backed by a government or a utility, to one that is backed by one or many customers that will use the electricity directly. However, this does not affect the fundamental value small-scale PV has and increasingly will have described above. This value is what has driven adoption among customers in developed markets, and led lenders to develop financing products adapted to this new asset class.

The best business model to scale-up distributed generation in emerging markets has yet to be identified, but developing nations have been creating different mechanisms to incentivize small scale PV installations.

Development finance institutions could up their use of concessional capital to support lending programs for small-scale solar projects, potentially in collaboration with domestic banks who may have better information on would-be borrowers and their bankability.

Development finance institutions could up their use of concessional capital to support lending programs for small-scale solar projects, potentially in collaboration with domestic banks who may have better information on would-be borrowers and their bankability. One example of such partnership that has delivered results can be found in Lebanon. The Lebanese central bank, with the support of the European Union and the United Nations Environment Program, has enabled six commercial banks to offer quasi-interest free loans (at 0.6%) for periods of up to 14 years to clients that are looking to finance self-consumption PV projects and energy efficiency measures.[27] Given the sheer size of the potential market, there are potentially many other opportunities for development finance institutions to play a role in this area and ignite greater lending to distributed energy projects.

On the other hand, in Mexico, the state-owned utility CFE and the National development bank NAFIN have joined efforts in 2017 to support installation of small scale PV systems while reducing CFE's expenditure on subsidies. Low income families, which receive high levels of subsidies for electricity, could get around $2,600 from NAFIN to purchase small-scale PV systems. The monthly quotas could be paid in the CFE's electricity bill.

3.3.1. Offshore wind

Total offshore wind capacity installed globally is expected to reach 21.4GW by year-end 2018, with almost 68% of the total concentrated in the U.K., Germany and China alone. Annual offshore wind installations are set to nearly double in the 2020s. With a yearly run rate of around 9.5GW compared to 4GW in 2018, global capacity is forecast to reach 129GW in 2030 (Figure 107).

The growth in the sector overall will, in no small part, be driven by expansion in developing nations. Europe's share of new installations falls from 75% in 2017 to less than half by 2030. Still, China, Taiwan and India are the only non-OECD markets where BNEF anticipates a substantial offshore wind build-out by over the next decade. By 2030, we expect China, Taiwan and India to reach 35.6GW, 8.2GW and 5.5GW, respectively, of offshore wind capacity.

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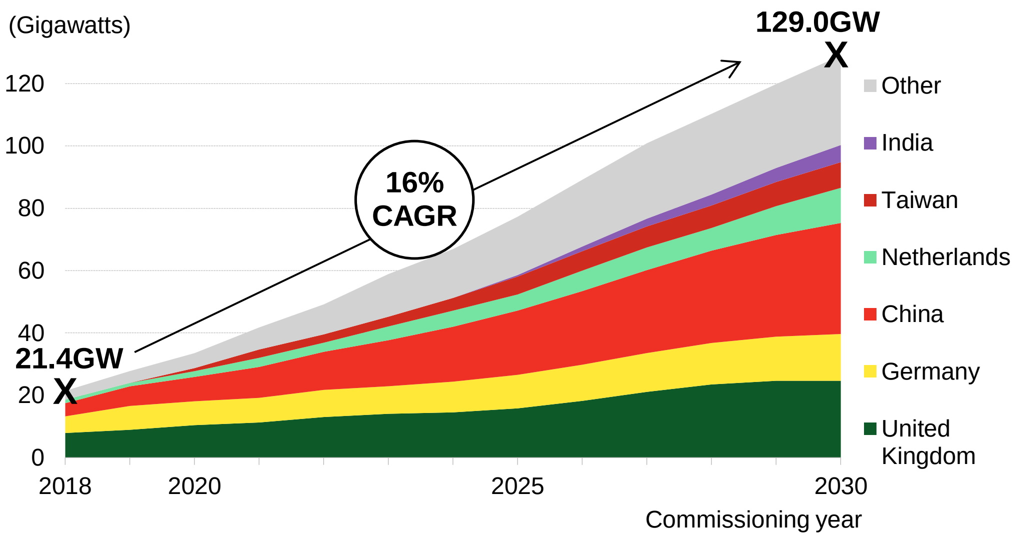
[27] For more on Lebanon's National Energy Efficiency and Renewable Energy Action, read the policy overview here.

Figure 107: Global cumulative installation forecast



Source: BloombergNEF

Not every new market for offshore wind will see competitively low prices from the start. Some are likely to suffer from one or more of the following: a lack of local supply chain; complex permitting processes; a lack of port infrastructure or specialized vessels; and relatively few 'market makers' to undertake full project scope. Such markets are also likely to be filled with pioneers expecting higher returns for the risks of entering a new market. As such, we currently see not one, but two curves that will define offshore wind costs in the global market, with a step change occurring when a market transitions from one curve to the other (Figure 108).

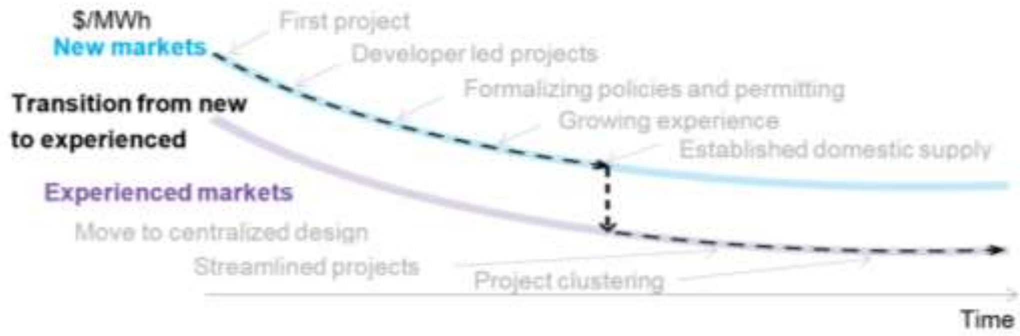
Access to discounted financing in the form of concessional capital could help lower costs and accelerate a country's jump from the higher to the lower cost curve.

In theory, we expect new offshore wind markets to follow the higher cost curve while most established markets will sit on the lower curve. We believe the switch from one to the other occurs once a market has achieved 3-4GW cumulative offshore wind installed capacity. This means that new markets will have to invest heavily in offshore wind at first in order to achieve the lower cost curve later. Even to just make downward progress along the upper cost curve, they will need supportive policies.

In new markets, domestic banks can be either hesitant to lend to offshore wind projects or will only offer capital at a substantial premium. Such institutions may also allow only lower leverage on projects and financing under more restrictive terms compared to how they operate in more established markets. Offshore wind is a capital-intensive technology. As a result, expensive money up front significantly impacts the cost per megawatt-hour developers can sell their power for to earn reasonable returns. All of this suggests that access to discounted financing in the form of concessional capital could help lower costs and accelerate a country's jump from the higher to the lower cost curve.

India is one of the few developing countries where offshore wind appears poised to grow in the short term. This is mainly due to its ambitious government commitments. (See Appendix B for a case study on offshore wind in India).

Figure 108: Offshore wind cost curves – moving from being a new to an established market

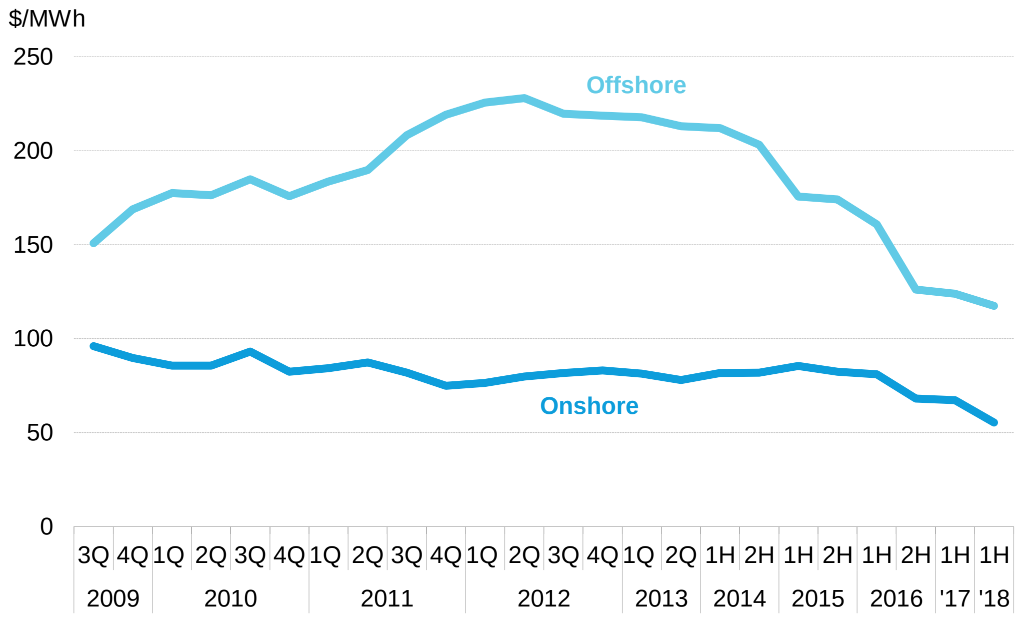


Source: BloombergNEF. Note: This diagram is a generalization; in reality not all markets will sit explicitly on one curve

Technology cost

BloombergNEF's global offshore wind cost curve shows a learning rate of 16%, meaning that historically the levelized cost for the technology falls 16% for each doubling of cumulative installed capacity. Global offshore wind benchmark LCOE dropped 5% from 2017 reaching $118/MWh in 1H 2018. Still, it remains 114% above our onshore wind benchmark (Figure 109).

Figure 109: Global wind benchmark LCOE



Source: BloombergNEF. Note: Our global weighted benchmark represents a capacity-weighted average of all country level LCOE benchmarks; for onshore we weight last annual installations, for offshore we weight cumulative build.

LCOEs[28] for offshore wind differ widely. Benchmark LCOEs around the world range from $75 to $146/MWh and, when including low and high cases, the spread widens to $55 to $168/MWh. These varying LCOEs reflect project characteristics (e.g. distance from shore), allocation mechanism (e.g. competitive auction), whether transmission to shore is included, and how permits and environmental assessments are issued.

The cost of offshore wind generation is declining faster than most had expected, although other technologies are moving down rapidly, too. As important as cost, however, is the value that generation from a project delivers to the grid. Offshore wind can be deployed close to coastal load centers and the technology offers a unique load profile. Wind speeds off the coast are much higher, more stable and more predictable than inland. This makes the average generation profile much flatter, even when adjusting for seasonality.

These properties make offshore wind particularly disruptive in demand-led energy models: the sector has rapidly evolved and can now credibly compete with coal and gas on both cost and generation profile in many markets. In the tight race between mature technologies, even small offshore cost reductions can lead to signals that encourage gigawatt-scale build-out.

3.3.4 Digitalization

Once a pathway for an energy systems' de-carbonization is established, the next challenges are integration and optimization, to ensure that the transition can happen as smoothly and cheaply as possible. This is where digital technologies can contribute.

Once a pathway for an energy systems' de-carbonization is established, the next challenges are integration and optimization, to ensure that the transition can happen as smoothly and cheaply as possible. This is where digital technologies can contribute.

Ideal business models for investment on digitalization of energy systems in emerging markets have yet to be identified. However, as power systems become more complex, these new technologies cannot be ignored. Therefore, this sub-section in included in the report to provide some food for thought rather than a path for concessional finance deployment.

Digital systems have several components:

- Connected machines fitted with sensors to record data
- Communications networks and software to transmit data
- Cloud or local servers to store the data
- IoT platforms to organize information and host software programs
- Applications software, like analytics and machine learning, to create insights and recommendations for operators

Many of these components require physical infrastructure (sensors, communications networks) and expertise to operate and install (data centers, IoT platforms, applications software). This can be a barrier to adoption in some emerging economies.

Applications for digitalization

Digital systems are currently used in developed markets to monitor and optimize generation assets, reduce O&M costs through predictive maintenance, and aggregate and control distributed assets to provide power and services to the grid. These technologies can offer the same benefits

[28] BNEF defines LCOE as the long-term offtake price required to achieve a certain equity hurdle rate for a developer, considering its total capital, operating and finance costs over the lifetime of the project. This LCOE estimates exclude costs of grid connection and transmission. They also do not take into account subsidies or incentives as they are intended to assess the true economic viability of technologies outside the bounds of policy support.

to emerging nations' energy systems, while also helping to address challenges specific to new markets:

Monitoring and controlling remote assets – Digital systems allow a fleet of remote assets and devices to be monitored and operated from a single control center. This removes the requirement for local expertise to manage systems like rooftop solar, or generation assets like power plants.

Flexibility – As countries increasingly become reliant on renewable power generation they will depend on baseload power generation and a knowledge of when solar and wind power resources are and are not available. Digital systems, through artificial intelligence and sensors, can forecast weather patterns and predict industrial asset failures to enhance system reliability, reduce the need for overcapacity, and ultimately keep power affordable.

Mapping the grid – An accurate, real-time picture of power flows on the grid is critical to managing it, especially where intermittent renewables and microgrids create additional complexity. Sensors on transmission lines can give operators information about how much capacity is being used, and how best to route power at peak times, when congestion is high. This is a particular concern where grid infrastructure is lagging an increased build-out of generation.

Effective microgrids – Microgrids connected to the grid need to have a way to communicate with the central system. They also need to optimize their own generation, storage, and local transmission. Digital systems offer a way to effectively manage these issues.

Connected customers – The earliest digital systems in many emerging energy markets have been payment platforms related to rooftop solar. More sophisticated systems can now help customers to manage their demand, give them details on how much power they are supplying, and help the companies supplying the equipment to optimize their operations and maintenance and offer new services.

Energy efficiency – Digital technologies, particularly machine learning, can help building managers, data center operators and industrial companies learn more about their energy consumption and optimize electricity and heat use. This can reduce overall demand, relieving pressure on the national energy system.

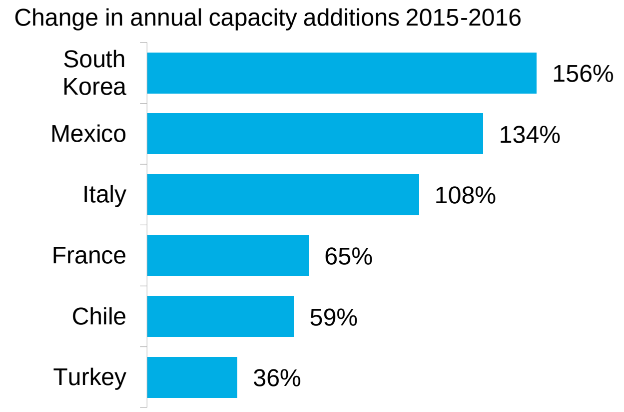
Key drivers and enablers in emerging markets

BNEF studied the potential of several emerging markets to digitalize their energy systems. We identified several factors that will increase demand for these systems, and the enabling factors that were required to supply and operate digital systems.

Energy drivers

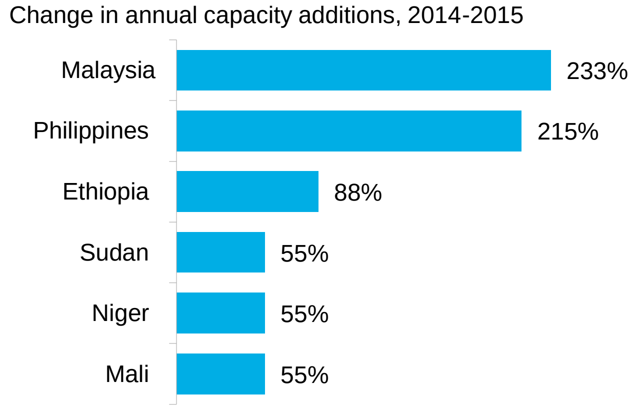
Given the capabilities of digital systems listed above, and the opportunities for better integration and cost reductions, we believe that new renewable and distributed generation will be key drivers for digital technologies. We assume that most new systems will either be fully digital, or digital-ready, fitted with sensors and supplied with software to allow them to be monitored and run remotely. Countries with higher penetrations of these assets will digitalize quicker, and countries that are planning to add significant capacity could accelerate digital technologies as well. Many of the countries adding the most new generation are emerging markets (Figure 110 and Figure 111).

Figure 110: New generation capacity additions in mature markets



Source: BloombergNEF. Note: Capacity additions refers to power generation capacity additions measured in MW.

Figure 111: New generation capacity additions in emerging markets



Source: BloombergNEF. Note: Capacity additions refers to power generation capacity additions, measured in MW.

Digital enablers

We considered several demographic, infrastructure, and investment enablers for digital technologies. The presence of a significant grid and communications network are important, as are widespread literacy and technological education. One of the biggest differentiators between markets where digital technologies can take hold in the energy sector and where they cannot is the availability of venture capital or private equity (VC/PE) funding for startups, and the presence of a large innovation community. In developed markets, a great deal of both digital supply and demand comes from startups. As a result, a local VC/PE community can be critical to accelerated adoption in emerging markets.

Figure 112: VC/PE funding for digital startups in emerging markets, 2016 ($m)

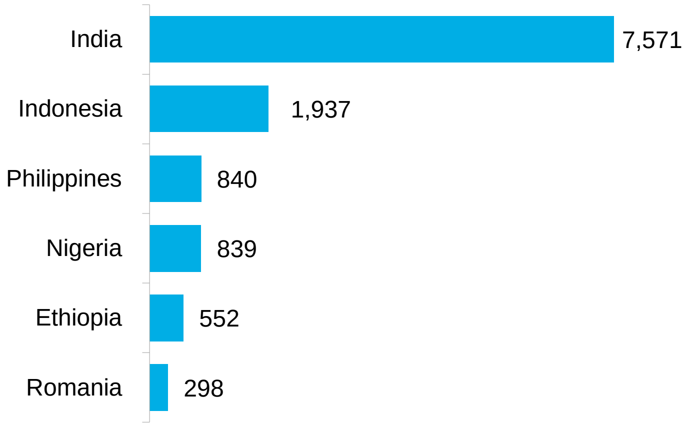
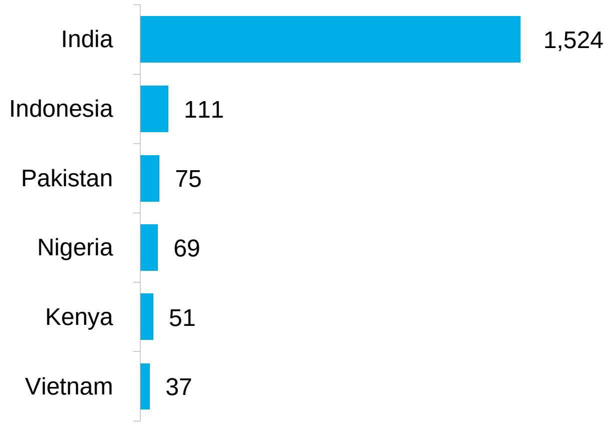


Figure 113: Startups in emerging markets focused on digital technologies



Source: BloombergNEF, CB Insights

Digital technologies in emerging markets

Emerging markets have a unique opportunity to leapfrog more developed countries in terms technology adoption.

Emerging markets have a unique opportunity to leapfrog more developed countries in terms technology adoption. In the same way as landlines were 'skipped' in favor of mobile phones, traditional energy systems of centralized power, flowing in one direction, on a large grid network, could also be replaced by smaller community grids running on decentralized assets, automated with digital systems. There are several key markets that have the potential to digitalize quickly, based on our forecasts for their energy demand and capacity, and the existing infrastructure and demographics. See Appendix C for a country-specific digitalization analysis.

How can digital systems be paid for?

Even in developed markets it can be difficult to finance digital systems. Often their financial benefits are secondary or the payback periods have yet to be understood well, making budget hard to allocate for large software projects. Where utilities are heavily regulated and vertically integrated, digital systems may be rate-based, meaning the costs can be passed directly to consumers, if they can demonstrate clear benefits to the grid and the consumer, and if the utility can pay for them upfront.

Digital systems are often sold as a service, however. This means they are paid for via ongoing operating expenditures ('opex'), which preclude regulated utilities from claiming a return on investment on them. Non-regulated utilities have more freedom but they still are struggling with knowing whether getting compensated as service providers is better than simply getting paid up front. Developing digital technologies in-house can be cheaper but utilities often lack the requisite data science expertise.

Demand and supply for digital technologies

Emerging markets have a huge potential appetite for digital products and services in their power systems. Most are expecting continuous electricity demand growth, which will drive capacity additions and grid expansion, both of which benefit from digital capabilities. Countries with frequent power outages could, in particular, see benefits from grid digitalization.

Demand will also be driven by growth in renewable capacity. Under BNEF's projections, most emerging markets will have over 20% intermittent power-generating capacity by 2030 (Figure 114), which will need to be managed by digital technologies to maintain grid stability. Small-scale solar will surge in Southeast Asia, Mexico, and other parts of the world with exceptional insolation, allowing them to overtake many OECD countries on a proportional basis (Figure 115). Most of this new capacity will come in the form of micro-grid or off-grid projects, where digital technologies are needed to control and optimize the systems.

Figure 114: Intermittent capacity (% of total capacity)

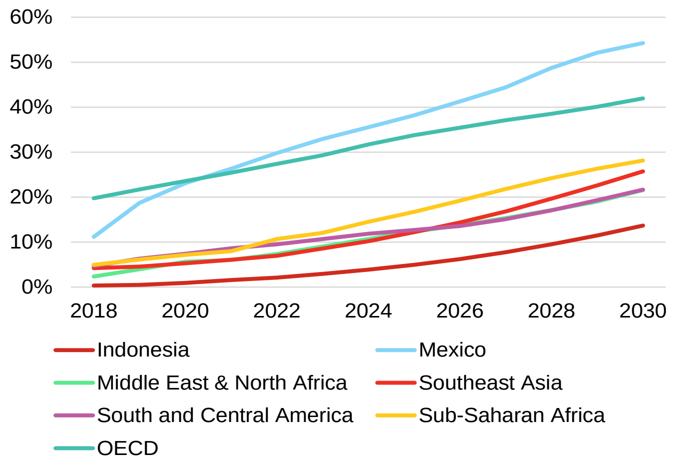
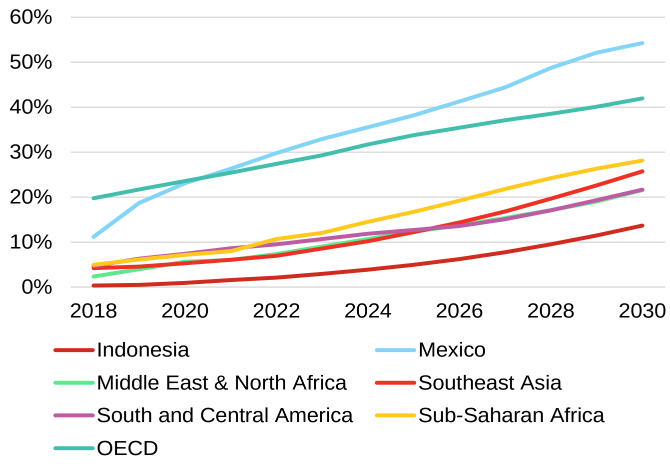


Figure 115: Small-scale solar PV capacity (% of total capacity)



Source: BloombergNEF New Energy Outlook. Note: Intermittent capacity is defined primarily as wind and solar capacity.

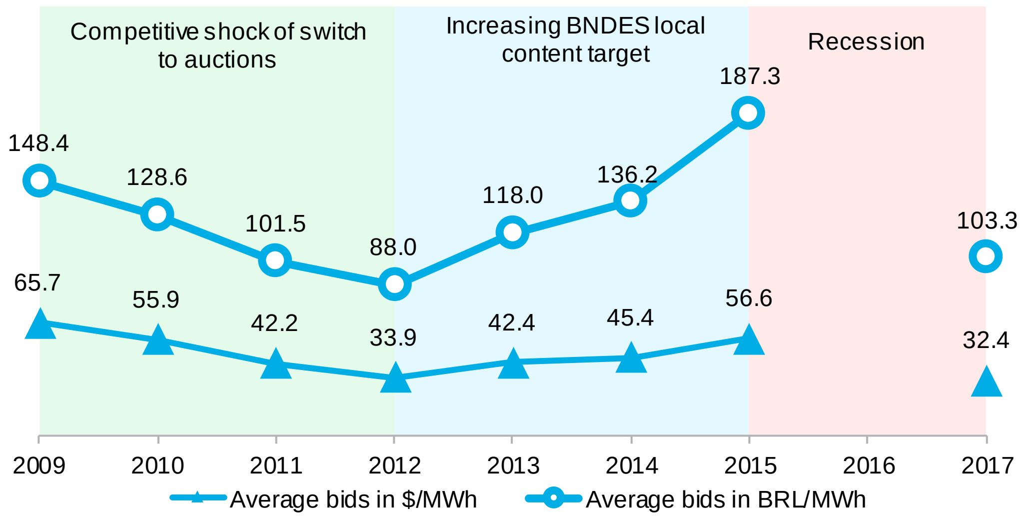
Emerging markets are improving their infrastructure and supply chain for digital technologies. Policy plays a key role in this, with governments launching technology-centric policies to support local startups, and driving demand for infrastructure projects.

Appendix A. Clean Energy Auctions

A.1. The Brazil example

Brazil is among countries with the longest track record of using auctions to greenlight power projects of all kinds and procure generation. Most recently, the mechanism has succeeded in delivering price signals indicative of market conditions faced by clean energy developers (Figure 116).

Figure 116: Brazil onshore wind average annual clearing prices



Source: BloombergNEF, BNDES. Note: BRL is Brazilian Real.

From 2004-2008, prior to instituting auctions to support clean energy development, Brazil offered its Proinfa feed-in tariff priced at BRL 300/MWh to support wind build. The first auction the country held in 2009 showed just how dramatically market competition could depress prices as developers signed wind-power delivery contracts at an average of BRL 148.4/MWh ($65.7/MWh). Further auctions continued to drive down prices until 2013 when Brazil development bank BNDES's domestic-content rules began to ratchet.

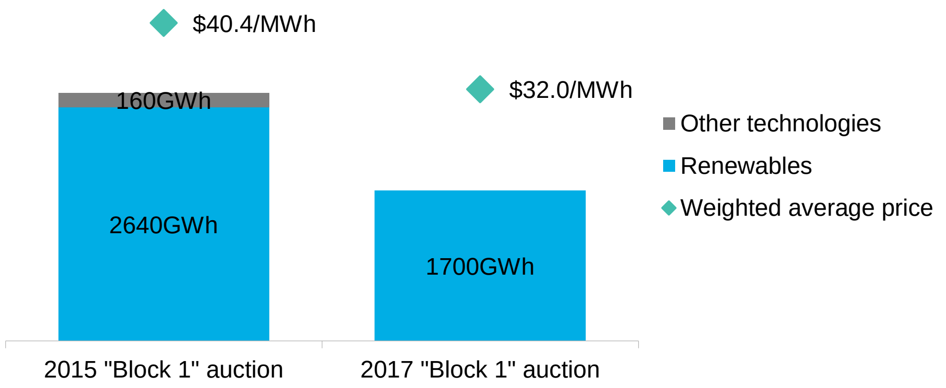
Those regulations required that Brazilian project developers source ever greater percentages of their equipment from domestic manufacturing plants in order to access BNDES capital. In exchange, BNDES offered concessional loans in local currency priced at around half the rate of typical commercial loans and became the world’s largest lead provider of clean energy asset financing. In all, BNDES supplied 70% of all project finance for clean energy from 2012-2015. BNDES remains the dominant debt provider in Brazil to clean energy and was behind approximately half of all such capital deployed in 1H 2018.

The local content targets had the effect of lifting auction-clearing prices as demand for equipment manufactured domestically exceeded supply, while developers using kit sourced abroad faced higher financing costs. The government then halted the auction program from 2015-2017 in the face of a deep economic recession which depressed electricity demand and created generation over-supply. A number of developers, in particular of solar projects, also saw their projects become uneconomic as the assumptions they used to build their bids did not materialize. The cost of finance increased because of Brazil's wider economic struggles and the cost of imported solar equipment increased as a result of the Real's sharp devaluation.[29] When auctions returned in 2017, they delivered again the lowest price for wind Brazil had ever seen, as measured in $/MWh (not in BRL/MWh, due to the depreciation of the Real). The 2017 auction reflected the appetite of project-starved Brazilian developers and manufacturers to secure contracts, improving credit conditions, and continued technological improvements.

A.2. Tenders go global

Results produced from tenders in Latin America and elsewhere have caught the eye of policy-makers elsewhere and encouraged them to introduce auctions in their markets. What has followed has been a series of competitions in which clean and fossil-fueled generators have squared off – and renewables have prevailed on price. For example in Chile, renewables already secured the majority of the majority of generation contracts in some of the technology neutral auctions in 2015, and took all of the contracts in the same auction in 2017 (Figure 117).

Figure 117: Technology neutral auction results for around the clock electricity delivery in Chile

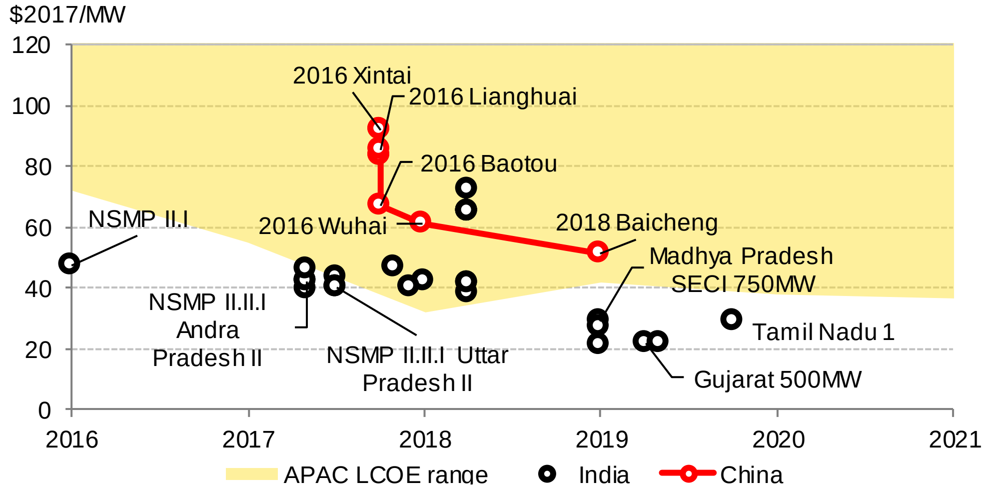


Source: Comisión Nacional de Energía, BloombergNEF. Note: "Renewables" includes solar, wind, biomass and geothermal. "Other technologies" includes generation that does not use renewables.

An important lesson to draw from Brazil's experience is that regulators were comfortable with auction prices moving in both directions as market conditions shifted. However, today, there are signs that certain regulators are not anticipating this eventuality. In India, for instance, the state of Uttar Pradesh cancelled a 1GW PV auction held in July 2018 because the clearing price of 3.48 Rs/MWh was much higher than the 2.44 Rs/MWh tariff discovered in the national solar auction held concurrently. The decision came as the government was rolling out 25% duties on imported solar modules, which not surprisingly, resulted in higher auction bids.

29 Brazil's regulator also organised the world's first auction to cancel contracts awarded in previous auctions in 2017 and address the issue of oversupply. 576MW of contracts were cancelled.

Figure 118: Levelized auction bids for India and China, and APAC 1H 2018 LCOE forecast



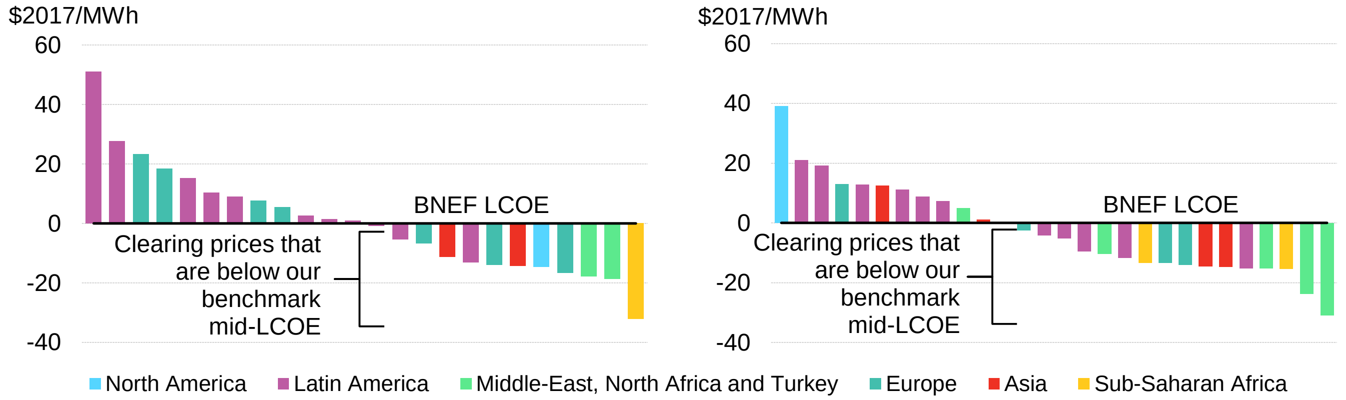
Source: BloombergNEF

In general, India has seen cutthroat competition between solar developers. Projects behind the most aggressive bids are unlikely to withstand a sudden adverse change in market conditions, such as an unexpected increase in equipment costs.

Indeed, the main caveat of auctions is that they ask developers to submit a bid that reflects their projections of how the cost and revenue of the project will evolve over its lifetime, from the development phase all the way to its decommissioning. Figure 118 plots the lowest bids submitted by projects in auctions in India and China by their anticipated commissioning date against the BloombergNEF 1H 2018 levelized cost of electricity (LCOE) forecast range for the APAC region. Plotting bids against LCOEs requires to correct for the construction date, the asset's lifetime revenue, and for inflation if the tariff awarded to the project is inflation-linked (which the Indian tariffs are not).

The chart indicates that several Indian bids are well below our most aggressive LCOE forecast for the region. Developer bets in auctions have played out in their favor a number of times as they continued to capitalize on renewables technologies cost declines and the maturing sector saw the cost of capital decrease. However, a growing number of auctions are clearing at prices way below BloombergNEF's estimates of the tariffs needed to warrant project profitability. Figure 119 shows the deviation of levelized auction clearing prices from our benchmark mid-case LCOEs at time of anticipated project delivery for 52 auctions across the globe for projects to be delivered by 2023.

Figure 119: Levelized PV (left) and wind (right) bids vs. BloombergNEF mid-case LCOE benchmarks at dates of planned project completions



Source: BloombergNEF. Note: sample of 52 auction results across 21 markets in Latin America, Europe, Africa, the Middle East and Asia.Source, with project delivery deadlines ranging from 2017 to 2023. Regional benchmarks used for four countries.

The most extreme deviation from our LCOE benchmarks have almost all been a result of policy design. For example in the U.K., a single auction was used to contract projects across three delivery years. This allowed developers to bid projects for the latest delivery window on offer and bet on continued technology cost declines to increase the profitability of their projects.

Conversely, Turkey and a number of countries in the Middle East (in light green in Figure 119) have reported record low bids that are the result of incentives offered to developers that allow them to bid below what would be an all-in cost reflective bid. This can include the provision of concessional finance by a public bank, agreements on the investment into manufacturing capacity or other projects, all of which can push developers to sweeten their bid.

Some extreme bids are also a result of market conditions not playing out the way developers had envisioned. Bidders in South Africa's auctions, for example, had bet on an appreciation of the Rand against hard currencies as the country was showing good prospects of economic growth. However, the Rand almost halved in value between 2010 and 2016. The fact that the contracts were linked to inflation somewhat softened the impact on project profitability but the country's levelized bids still fell below our LCOE benchmark for the expected time of commissioning.

In India, regulatory risk arising from the sudden announcement of import tariffs on PV modules plus the insolvent status of off-takers (distribution companies, or "discoms") have caused solar project economics to diverge sharply from developer expectations.

Appendix B. Offshore wind in India

Excluding China and Taiwan, India is the only developing nation where BNEF expects to see substantial offshore wind build over the next decade. India currently has no offshore wind farms, but in June 2018, the country set aggressive targets of installing 5GW offshore wind by 2022 and 30GW by 2030. These goals were set in addition to the larger, existing 175GW renewable capacity by March 2022 commitment, adopted in 2015. India's current total onshore plus offshore wind target for 2022 is now 65GW.

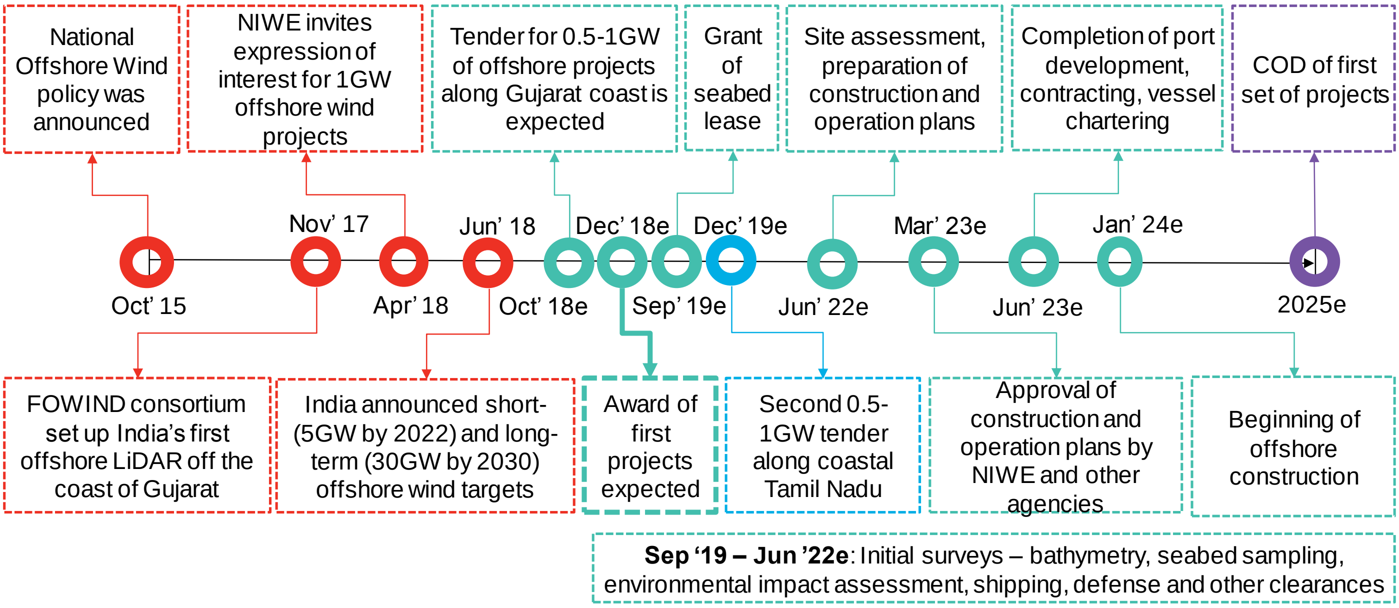
The government's decision to adopt offshore wind targets comes from a desire to accelerate the use of renewable energy and diversify India's existing electricity supply mix. Some project developers had also complained about the difficulty in acquiring land for onshore wind and petitioned the government to open the market more for offshore development. The government hopes the new goals will accrue other benefits locally, such as the establishment of offshore wind equipment manufacturing hubs leading to jobs and development in coastal zones. However, these additional benefits may not be realized immediately.

Current status of offshore wind in India

India adopted an offshore wind policy in 2015. Since then, the government's National Institute Wind Energy (NIWE), along with consortiums as such as Facilitating Offshore Wind in India (FOWIND)[30] have been engaged in resource assessment and geophysical and geotechnical studies. In April 2018, NIWE invited an expression of interest for developing 1GW of offshore wind along the coast of Gujarat. The government received 36 proposals from various domestic and international project developers, utilities, manufacturers, supply chain companies, institutional investors and oil & gas players. A formal tender for setting up projects is expected in 4Q 2018. We believe that under the right circumstances, with continuing policy support, the first offshore wind farms can be commissioned by 2025. Figure 120 provides an estimated timeline of offshore wind project development in India based on the prevailing market situation.

30 A consortium of the Global Wind Energy Council; the Centre for Study of Science, Technology and Policy; DNV GL; Gujarat Power Corporation Limited; and World Institute of Sustainable Energy.

Figure 120: Anticipated timeline of offshore wind project development in India



Source: BloombergNEF

Offshore wind provides new market opportunities to existing companies and new entrants looking to diversify their core businesses. As companies and investors interested in the nascent Indian offshore wind industry seek new opportunities for growth, they should also be mindful of the potential risks and challenges they may face in construction and operation of offshore wind projects in India.

Table 9: Snapshot of positives, neutral aspects and concerns for offshore wind in India

Positives	Neutral aspects	Concerns
• New market – level playing field for all players	• Access to some wind resource, geophysical and geotechnical studies from FOWIND and NIWE	• Unclear permitting and leasing procedures and costs
• Availability of cheaper labor	• Expected continued long-term growth in power demand	• Policy and regulatory uncertainty for offshore wind
• Offshore wind targets – indicating strong ambition	• Potential opportunities for alternative offtake through corporate PPAs and sale of electricity in wholesale power market	• Access to cheap rupee denominated project financing
	• Presence of offshore oil & gas supply chain – interim auxiliary supply chain	• Credibility of power offtaker
	• Presence of other manufacturing industries and support services	• Competition from onshore wind and solar because of low LCOEs
	• Availability of multiple ports near proposed offshore wind site (although not yet ready for offshore wind)	• Lack of dedicated domestic supply chain
		• Low wind resource
		• Possible withdrawal of government support in case of high project tariffs

Source: BloombergNEF

The offshore wind resource in India is expected to be weaker than in Europe

Wind resource data for offshore sites in India is relatively limited. However, since November 2017, NIWE and FOWIND have conducted a wind resource assessment at the proposed site of India's first offshore wind projects, in the Gulf of Khambhat, near Gujarat.

The collected data indicates wind speeds of around 8 meters/second along the Gujarat coast. These wind speeds are lower than those observed across offshore wind sites in Europe, where average wind speeds can top 10m/s. Therefore, the capacity factors (CFs) of offshore wind farms along coastal Gujarat in India are expected to be lower than those of European wind farms. Lower CFs will lead to higher levelized costs of electricity, and could make offshore wind uncompetitive vs. onshore renewables in India.

The Gujarat coast is also prone to cyclones, where wind speeds can exceed 50m/s. It is likely a new class of wind turbine will be needed to efficiently capture the lower average wind speeds and to handle the threat of cyclones.

Low offshore wind LCOE will be extremely important to remain competitive

India is an extremely cost-conscious power market. The country is today building some of the world's lowest cost onshore wind and solar power projects. The prime reason utilities in India are increasingly willing to buy renewable energy is that it is becoming cheaper than all other forms of power generation in India. For offshore wind to make real progress, demonstrating cost-competitiveness will be critical.

Leveraging our understanding of existing costs for offshore elsewhere and our knowledge of supply chains BNEF estimated potential LCOEs for India's first offshore projects. Our capex assumptions are based on the expected turbine prices for delivery in 2024. We assume offshore turbine costs to be around 92 million rupees ($1.35 million)/MW. Development and balance of plant costs have been estimated based on the inputs from the industry. In all, we expect project capex to be $2.03-2.83 million/MW depending on under-sea transmission costs and choice of turbines. But as the industry matures and starts establishing a local supply chain, the costs will further decline, similar to the trends observed in global offshore markets (Figure 108).

First year offshore wind project LCOEs for India are expected to be the following:

- if developers build generation stations and sub-sea transmission: **$123/MWh**
- if developers construct generation stations, and the sub-sea transmission costs are equally shared by the developers and the government: **$110/MWh**
- if developers only build generation stations and sub-sea transmission costs are completely borne by the government: **$96/MWh**

Figure 121: Expected first year nominal offshore and onshore wind LCOEs for projects commissioning in India in 2025

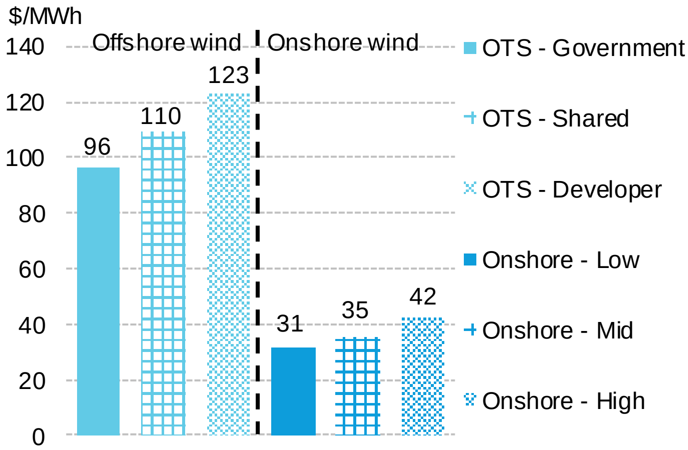
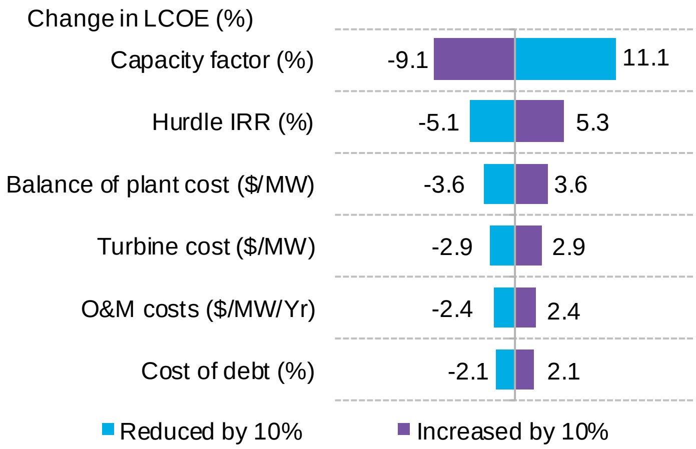


Figure 122: Sensitivity of levelized cost of electricity to various project design parameters for offshore wind in India



Source: BloombergNEF. Note: OTS refers to offshore transmission system. LCOEs have been derived using BNEF's EPVAL model. Presented LCOEs represent the nominal first-year tariffs. USD 1 = 68.16 rupees.

Compared to onshore wind projects expected to be commissioned in 2025, offshore wind can be 3-4 times expensive (Figure 121) offshore wind LCOEs are very sensitive to capacity factors and equity IRR expectations. LCOE also vary widely based on the cost of offshore transmission to the developers (Figure 122).

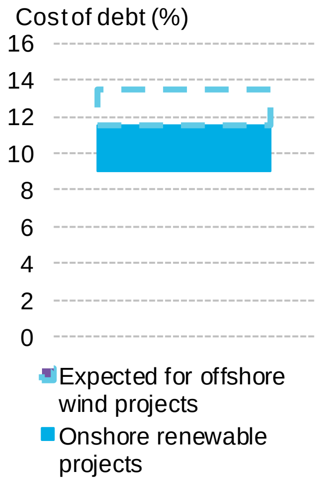
Our LCOE calculations for the first few offshore wind projects assumes debt financing at a rate of 8.5%. Local currency commercial finance for first plants could be available at 11.5-13.5% on account of higher risk exposure to early projects. This can make the LCOEs go higher than our estimates. We estimate that every 10% increase in cost of debt would inflate the expected LCOEs by 2.1% (Figure 122).

Table 10: Key assumptions in LCOE calculations

Parameter	Unit	BNEF estimate
Capital expenditure	Million rupees ($ million)/MW	138 (2.03) – 193 (2.83)
Opex	Million rupees ($ million)/MW	6.05 (0.09)
Cost of debt	bps	850
IRR expectation	%	12
Capacity utilization factor	%	37 (P90 considered at 8m/s)
Technical availability	%	98
Debt-equity ratio		70:30
Debt tenor	Years	18
Inflation	%	5.03

Source: BloombergNEF

Figure 123: Expected cost of local commercial debt



Source: BloombergNEF

Mobilizing domestic project finance will be challenging

India is new to offshore wind, and so are its financial institutions. With zero experience in the sector, the banks are unfamiliar with offshore wind's construction and operational risks. Seeking domestic project finance for offshore wind projects will be challenging and expensive. The expected cost of commercial debt for offshore wind projects is expected to be between 250-450 bps higher than those for onshore wind projects (Figure 123).

We believe that the government may push state-owned lenders to become stakeholders in the first few offshore wind projects by providing recourse loans to developers. The national offshore wind policy provisions government support to offshore wind projects through public-private partnerships. The government has also previously indicated its intention to facilitate offshore wind project finance through dedicated renewable finance non-banking financial institutions like the Indian Renewable Energy Development Agency (IREDA).

India will likely require support from multilateral development finance institutions to achieve its offshore wind goals and this, in turn, may present opportunity for CTF. However, sourcing dollar-denominated multilateral development bank debt for offshore wind projects in India could potentially be quite expensive for developers due to high hedging costs. Assuming a 12-month LIBOR of 291bps plus a 350bps margin to LIBOR, the unhedged cost of multilateral bank finance might be as low as 6.41%.

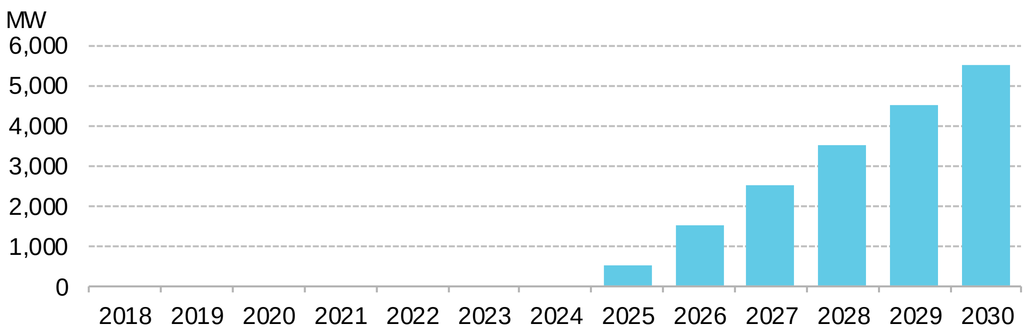
That does not take into account costs associated with hedging the Indian rupee, however. Under current conditions, hedging costs for financing in rupees are much higher than in other developing countries in Asia. We expect hedging costs to be up to 491bps. High hedging costs can make sourcing foreign developmental finance up to 33% more expensive than domestic concessional finance (850bps). For foreign capital to support an Indian offshore build-out some mechanism will be required to address the currency issue.

Conclusion and outlook

The Indian government is keen to kick-start offshore wind development after the success of its onshore wind and solar auction programs. Along those lines, it may seek to auction offshore wind capacity before federal elections in 2019.

Such enthusiasm should be tempered with realism, however. The current offshore targets are highlight ambitious and will rely heavily on policy implementation from the government. BNEF believes India will miss its short-term goal of commissioning 5GW by 2022, and may achieve no more than a fifth of its proposed 30GW by 2030. Still, even a partial adoption of India's targets by 2030 would make the country among the largest offshore wind markets in the world.

Figure 124: Projected cumulative India offshore wind capacity



Source: BloombergNEF

Given current market conditions, we estimate India to achieve only up to 5.5GW of cumulative offshore wind capacity by 2030 (Figure 124) with the first set of projects coming online only by 2025. Even these capacity additions will be highly dependent on securing cheap debt and continued support from the government in the form of subsidies or other fiscal/non-fiscal incentives. Action by the government over the coming months around issuing guidelines for the award of projects, regulatory mechanisms, issuance of clearances and incentives offered to the developers will define the actual uptake of offshore wind in India.

Offshore wind development can help diversify India's renewable energy mix and accelerate the adoption of clean energy overall in India. India's growing population will continue to require more land for agriculture and other essential economic activities in future. This will make land acquisition for onshore renewable energy projects even more difficult. Offshore wind development essentially sidesteps these issues.

Concessional finance can be an enabler to the development and growth of offshore wind industry in India if it can support the potential developers of offshore wind farms with cheap financing of early offshore wind projects. However, deploying innovative financing mechanisms to lower the hedging costs will be the key to make foreign debt affordable to the developers in the country.

Appendix C. Country digitalization analysis

BNEF assessed the readiness of 128 nations to quickly digitize their energy sectors. The higher the score, the higher the potential for progress in this area. This section provides greater detail on key developing nations and the factors that will drive their energy digitalization. Note that for the tables, green color indicates the country has a favorable condition for this metric, yellow an average condition, and red a poor condition.

Table 11: Chile

Metric	2017
Intermittent capacity	13%
Digital VC/PE	$209m
Comms network coverage	76%
Peak demand	50%

Source: BloombergNEF. Comms network means communication network.

Chile

Chile currently has one of the highest penetrations of intermittent capacity among all emerging market nations, raising its potential for accelerated energy digitalization. The country also has positive attributes for digital technologies: the presence of multinational foreign utilities with deep expertise and a liberalized retail power market. Both are spurring competition and adoption of new technologies. Chile's government is also keen to transform the country into a Latin America tech hub. It has established a new ministry for science to drive research and development, and introduced favorable policies to support startups.

Table 12: Chile energy digitalization summary

Digitalization demand	Capacity additions	Power market liberalization	Digital grid potential	Government policy
Digitalization supply	Network coverage	Supply chain	Government policy	VC/PE funding

Source: BloombergNEF. Note: Dark green means very favorable condition for this metric, light green means favorable condition, yellow means average condition, and red mean poor condition.

Mexico

Table 13: Mexico

Metric	2017
Intermittent capacity	6%
Digital VC/PE	$523m
Comms network coverage	58%
Peak demand	57%

Source: BloombergNEF

Mexico has unique challenges across its energy system that create a huge potential market for energy digitalization. It needs to counter rising fuel costs for generation and has one of the world's highest rates of power theft on the grid. Both are fundamental drivers for the adoption of digital technologies. Behind-the-meter solar and other renewables are also expected to grow significantly by 2030. Mexico has high VCPE investment in digital technologies, and benefits from access to the U.S. supply chain for both hardware and software products. Poor network coverage is a major constraint for digitalizing distributed projects, though it could create opportunities for digital microgrid projects.

Table 14: Mexico energy digitalization summary

Digitalization demand	Capacity additions	Power market liberalization	Digital grid potential	Government policy
Digitalization supply	Network coverage	Supply chain	Government policy	VC/PE funding

Source: BloombergNEF. Note: Dark green means very favorable condition for this metric, light green means favorable condition, yellow means average condition, and red mean poor condition.

Colombia

Colombia has a booming market for small-scale and off-grid projects, which is driving demand for energy digitalization. There are also favorable policies for grid digitalization: the government published a smart grid roadmap in 2016, aiming to reduce annual outages from 30 hours to 5.4 hours by 2030. The government also has policies to support technical education, which has spurred the creation of over 2,000 local companies in network and software applications. Low VC/PE investment is currently the biggest obstacle to technology innovation but the government is trying to fill in the gaps through public grants.

Table 15: Colombia

Metric	2017
Electrification	98%
Intermittent capacity	0%
Digital VC/PE	$69m
Comms network coverage	100%
Peak demand	62%

Source: BloombergNEF

Table 16: Colombia energy digitalization summary

Digitalization demand	Electrification rate	Power market liberalization	Digital grid potential	Government policy
Digitalization supply	Network coverage	Supply chain	Government policy	VC/PE funding

Source: BloombergNEF. Note: Dark green means very favorable condition for this metric, light green means favorable condition, yellow means average condition, and red mean poor condition.

Nigeria

Nigeria is a leading country in terms of energy digitalization potential. Nigeria distinguishes itself with a low electrification rate, a high peak demand, and a highly decentralized electricity system. This points to another path to energy digitalization, which is to have a diversified group of players competing to deliver mini-grid or off-grid solutions with digital technology embedded in order to manage customers' needs. The government has ambitious plans to develop renewable energy, aiming for 30% capacity by 2030. Nigeria also has one of the highest levels of VC/PE investment in the developing world, an active local startup community, and excellent network coverage, all of which contributes to a good ecosystem for digital technology.

Table 17: Nigeria

Metric	2017
Electrification	57%
Intermittent capacity	0%
Digital VC/PE	$839m
Comms network coverage	99%
Peak demand	101%

Source: BloombergNEF

Table 18: Nigeria energy digitalization summary

Digitalization demand	Electrification rate	Power market liberalization	Digital grid potential	Government policy
Digitalization supply	Network coverage	Supply chain	Government policy	VC/PE funding

Table 19: Egypt

Metric	2017
Electrification	100%
Intermittent capacity	2%
Digital VC/PE	$169m
Comms network coverage	99.8%
Peak demand	80%

Source: BloombergNEF

Egypt

While Egypt has the potential to accelerate digitalization in energy, there are some uncertainties about how fast and how far the country can go. Egypt kicked off a tariff-reform program that led to electricity prices spiking 44% in July 2017. This effectively created incentives for the adoption of renewable energy and digital technologies. The government also launched a net metering policy for distributed resources, which could increase distributed energy assets and encourage digital energy management, but its long-term commitment to renewables is uncertain after the discovery of natural gas reserves. Technology is the fastest growing sector in Egypt but it will be limited by the moderate VC/PE investment in the long term.

Table 20: Egypt energy digitalization summary

Digitalization demand	Electrification rate	Power market liberalization	Digital grid potential	Government policy
Digitalization supply	Network coverage	Supply chain	Government policy	VC/PE funding

Source: BloombergNEF. Note: Dark green means very favorable condition for this metric, light green means favorable condition, yellow means average condition, and red mean poor condition.

Morocco

Morocco has a high demand for energy digitalization but lacks the requisite technologies to keep up. The country has one of the highest electrification rates and levels of intermittent renewable capacity penetrations among developing countries, and the government aims to have 42% renewable capacity by 2020. Nevertheless, there are some major regulatory restrictions on the application of digital technologies and very little VC/PE investment. This is expected to change in the long term and the government launched the "Digital Programme for 2020" in 2017 aiming to invest $750 million in improving free public wifi and train digital professionals.

Table 21: Morocco

Metric	2017
Electrification	97%
Intermittent capacity	14%
Digital VC/PE	$0.4m
Comms network coverage	99.2%
Peak demand	N/A

Source: BloombergNEF

Table 22: Morocco energy digitalization summary

Digitalization demand	Electrification rate	Power market liberalization	Digital grid potential	Government policy
Digitalization supply	Network coverage	Supply chain	Government policy	VC/PE funding

Source: BloombergNEF. Note: Dark green means very favorable condition for this metric, light green means favorable condition, yellow means average condition, and red mean poor condition.

Indonesia

Table 23: Indonesia

Metric	2017
Electrification	88%
Intermittent capacity	0%
Digital VC/PE	$1.94bn
Comms network coverage	95%
Peak demand	60%

Source: BloombergNEF

Indonesia has excellent access to digital technologies and growing demand for them from its energy system. The country is also emerging as a regional technology hub: it has received more VC/PE funding than any other developing nation, and the government aims to create 1,000 local startups to be valued at a total of $10 billion. A shaky power grid and the rise of small-scale solar deployment should be the biggest factors driving energy digitalization. Indonesia has very common outages and needs to modernize the grid. The government is also working to electrify the remote islands through grid expansion and off-grid solar installations, which will create market demand for the adoption of digital technologies. The September 2018 earthquake will put many of these plans on hold, but also offers an opportunity to introduce new, more efficient, digital technologies as the power sector gets rebuilt.

Table 24: Indonesia energy digitalization summary

Digitalization demand	Electrification rate	Power market liberalization	Digital grid potential	Government policy
Digitalization supply	Network coverage	Supply chain	Government policy	VC/PE funding

Source: BloombergNEF. Note: Dark green means very favorable condition for this metric, light green means favorable condition, yellow means average condition, and red mean poor condition.

Vietnam

Table 25: Vietnam

Metric	2017
Electrification	98%
Intermittent capacity	0%
Digital VC/PE	$98m
Comms network coverage	94%
Peak demand	65%

Source: BloombergNEF

Vietnam is an emerging market in terms of energy digitalization, but there are some major constraints. The country's electricity demand is expected to grow 9% annually by 2030, driving capacity additions with new technologies embedded. However, the government is conservative in its aspirations for renewable growth, targeting just 10.7% clean energy capacity by 2030. The power market is vertically integrated and dominated by one utility, with no plan for liberalization in the short term. This raises a concern over how digital projects will be financed, and how much of an incentive the utility and operators have to introduce the technologies.

Table 26: Vietnam energy digitalization summary

Digitalization demand	Electrification rate	Power market liberalization	Digital grid potential	Government policy
Digitalization supply	Network coverage	Supply chain	Government policy	VC/PE funding

Source: BloombergNEF. Note: Dark green means very favorable condition for this metric, light green means favorable condition, yellow means average condition, and red mean poor condition.

Appendix D. Concessional finance scenarios

Table 27: Multilateral development banks interest rates assumptions (18 year loan tenor)

Country of project	Brazil	Thailand	Mexico	India
Margin to LIBOR (USD)	400bps	275bps	275bps	350bps
Project currency	BRL	THB	MXN	INR
Margin to swap (local currency through cross currency swap)	825bps	216bps	349bps	491bps

Source: BloombergNEF.

Concessional finance scenarios

Table 28: Concessional finance scenario – Capitalization structure for renewable projects

Financing	Debt			Equity
Lenders / Sponsors	CTF loan	Development bank loan	Local commercial loan	Commercial sponsors
All-in rates	200bps discount to MDB rates (*high scenario*) and 400bps discount to MDB rates (low scenario)	MDB rates	BNEF country benchmark	BNEF country benchmark
Tenor	20 years	18 years	BNEF country benchmark	BNEF country benchmark

Source: BloombergNEF. MDB stands for multi-lateral development banks. CTF: Clean Technology Fund

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