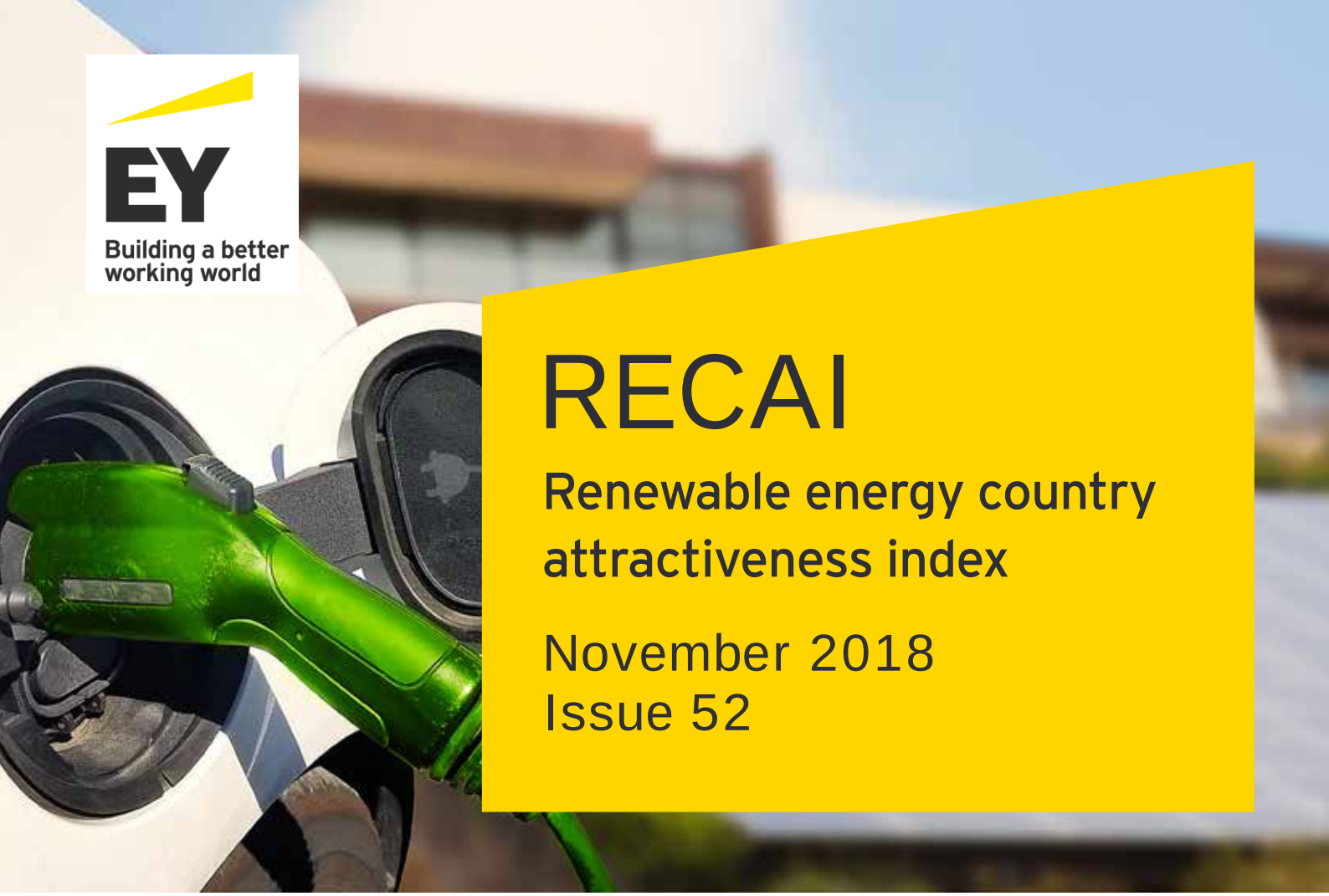

RECAI

Renewable energy country attractiveness index

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Electric dreams: investing in the all-electric future

Within the next decade, the price of electric vehicles (EVs) will fall below that of their conventional equivalents, as their performance continues to improve. Sales, while currently small, will accelerate rapidly.

Car manufacturers are preparing, with many presenting plans, for an all-electric future. Governments are playing their part too, with a growing number pledging to ban sales of new internal combustion engine vehicles. Some, including the United Kingdom, are helping to fund the charging infrastructure upon which the EV revolution will depend. As we consider in this edition's main article, the outlines of this new infrastructure are becoming clearer, as are the challenges it presents.

One of the major challenges to the power and utilities sector is the huge increase in power demand that electric mobility will create. If managed properly, this demand could help resolve the challenge of over-supply of renewable power, which is intermittent and sometimes generated when need is low. Price cannibalisation is taking place where renewable energy threatens its own economic viability. We also discuss how EVs could be part of the solution.

Further in the future, batteries in millions of EVs will be harnessed as an enormous pool of stored power, forming just one part of an ever more integrated and optimised value chain. How the power sector decides to respond to the EV opportunity now is set to define the industry over the decades to come.

To read our featured articles in full click on the links below.

Featured articles:

- Index country rankings: China remains top, with United States and India completing the top three and Argentina enters the top 10 for the first time
- The predicted rise in EVs bringing challenges and opportunities particularly with the provision of charging infrastructure
- Price cannibalisation – merchant projects potentially not delivering expected returns if too much renewable energy generation depresses the wholesale power price
- An in-depth look at the latest renewable energy developments in Colombia, Peru and sub-Saharan Africa, alongside nine other key country updates

Renewable energy country attractiveness index

recai

November 2018

Our index ranks 40 markets on the attractiveness of their renewable energy investment and deployment opportunities.

Methodology

The index was recalibrated in September 2018, with all underlying datasets fully refreshed. To see a description of our methodology, please visit to ey.com/recai.

Legend

- ▲ Increased attractiveness compared with previous index
- ▼ Decreased attractiveness compared with previous index

The Argentinian energy ministry has announced the third round of its RenovAr auction programme. This, coupled with the first PPP tender for transmission, demonstrates political support for renewables in the country.

Egypt's Ministry of Electricity and Renewable Energy is making strides towards implementing wind energy in a big way, with plans for wind schemes up to 1.8GW and total capacity expected to expand by 3.3GW by 2027.

As Spain embarks on its subsidy-free journey, it enjoys significant investor interest combined with a ramping up of corporate PPAs and 'merchant' solar projects. Also, a tax has recently been abolished from onsite solar.

After great hopes for Poland in our previous RECAI, recent government announcements are supporting greater levels of coal generation and offering no subsidies for offshore wind farms.

1	China (mainland)	▼
2	United States	▼
3	India	▲
4	Germany	▼
5	France	▲
6	Australia	▼
7	Japan	▲
8	United Kingdom	▼
9	Netherlands	▼
10	Argentina	▲
11	Chile	▼
12	Morocco	▲
13	Mexico	▼
14	Denmark	▼
15	Egypt	▲
16	Canada	▼
17	Spain	▲
18	Turkey	▼
19	Italy	▼
20	Brazil	▼
21	Belgium	▼
22	Pakistan	▲
23	Ireland	▲
24	Philippines	▼
25	Portugal	▼
26	Israel	▲
27	Taiwan	▲
28	Greece	▲
29	Jordan	▼
30	South Africa	▲
31	South Korea	▼
32	Sweden	▼
33	Peru	▼
34	Thailand	▼
35	Kazakhstan	▲
36	Indonesia	▲
37 (new)	Uruguay	▲
38	Poland	▼
39 (new)	Saudi Arabia	▲
40	Kenya	▼

Australia's new Energy Minister has been branded the most anti-renewables politician yet, as he takes the reins amid political upheaval and an uncertain renewables environment in the country.

Following the success of Noor 1 CSP, Morocco is building two more plants (Noor 2 and 3). Stable and successful project delivery will retain investor interest and government support, particularly in a push away from imported hydrocarbons.

The Premier of Ontario has vowed to scrap the Province's Green Energy Plan and reduce electricity tariffs, generating investor concern for the future of the renewables market and the health of project deployment in the country.

In a shift away from its previous FIT regime towards a more competitive process, Greece looks to auction 2.6GW worth of wind and solar projects, aiming to hit its EU-prescribed target of 18% renewables by 2020.

Large amounts of onshore wind will cause forward prices in power and green certificates to plummet in 2021, when the 2030 target is likely to be reached. This is causing strain in the market, with a lack of drive for further installations.

Electric vehicle charging infrastructure

Driving the electric vehicle revolution

The predicted rise in electric vehicles will bring challenges and opportunities for utilities and providers of charging infrastructure – so who is best placed to meet them, and how?

The electric vehicle (EV) revolution is getting into gear. In September, cumulative global EV sales reached four million; the next million EVs will be sold in just six months, according to figures from Bloomberg New Energy Finance (BNEF). In 2008, there were just four models of electric vehicle available for sale in the US: by 2022, Volkswagen (VW) alone plans to have 27 models in production.

EVs still account for a tiny fraction of total car sales. But when an inflection point is reached on price and performance with internal combustion engines – likely in the mid-2020s according to tipping points research from EY – sales will accelerate rapidly.

This presents challenges and opportunities for the power and utilities sector, as well as for providers and operators of charging infrastructure. The Rocky Mountain Institute (RMI), a US clean energy think tank, calculates that just three million EVs in the US would add 11,000GWh of load to the grid, generating around US$1.5b in annual electricity sales.

According to analysis conducted for EY by a team from the University of Melbourne, EVs in the UK would require around 1.5 million public charging points, costing almost £7b (US$9.5b). With limited government mandate and financial incentives, much of this investment is expected to come from the private sector. Swiss bank UBS has estimated that, globally, US$360b will need to be invested in charging infrastructure over the next eight years to keep pace with demand.

The Edison Electric Institute (EEI), the association that represents US investor-owned electricity companies, forecasts that five million public and private charging points will be required in the US by 2025, to serve the estimated seven million EVs expected to be on the road by that date. The EEI warns of “a growing infrastructure gap that will need to be addressed. ” This gap could be exacerbated by government policy, observes Nick Molho, Executive Director of the Aldersgate Group, a business and policy alliance that advocates for a sustainable economy in the UK. “If we are going to meet our carbon targets, we need to have charging infrastructure that is aligned with 100% sales of electric cars and vans. Governments need to ensure that charging infrastructure rollout is compatible with that degree of take-up.”

So, who is best placed to make sure that rollout happens? Or is multi-industry convergence the only way for EV penetration to succeed?

Role of Utilities

The original assumption by many regulators was that market forces would encourage thirdparty providers to step forward. Indeed, US public utility commissions (PUCs) initially blocked utilities from using ratepayer funds to build charging points.

"There's been a shift," says Kellen Schefter, Senior Manager, Sustainable Technology, at the EEI in Washington, DC. He gives the example of California, where, in 2011, the PUC issued a ruling preventing power companies in the state from investing in EV charging, leaving the floor clear for third-party providers.

"They then saw that the EV infrastructure wasn't keeping up with EV deployment, putting at risk the state's goals for EV adoption," Schefter says, leading the PUC to reverse the decision and, subsequently, make it the responsibility of utilities to undertake EV charging investments. In May, it approved plans from utilities in the state for US$750m worth of investments in EV infrastructure and rebate programmes.

Similarly, in Europe, many utilities are jumping into the EV market. Sweden's Vattenfall announced plans in April to become the largest operator of EV charging infrastructure in northwest Europe within five years, targeting turnover of SEK1b (US$119m) by that point. E.ON's electric vehicle charging offering, E.ON Drive, provides its customers with design, installation, operation and maintenance of EV charging points. Last year, Italian utility Enel bought Californian e-mobility solutions provider eMotorWerks.

There are good reasons why utilities are well placed to make such investments. Not only do EVs present a new source of demand in markets where sales are often flat or declining, but they also offer a means to deepen relationships with customers.

However, for utilities (especially those that also operate distribution networks), this new demand poses challenges. A study by the Vermont Energy Investment Corporation found that, if EV penetration reached 25% – and if those EVs were charged in an uncontrolled fashion – they could increase peak demand by almost a fifth, requiring massive investment in generation, transmission and distribution capacity. If the load could instead be spread out over the evening hours, the increase in peak demand could be cut to between zero and 6%.

Indeed, if EVs are intelligently integrated into existing grids, they can be transformed into an asset for network operators, helping to address stability issues that are looming as electricity systems add growing volumes of intermittent wind and solar power. If consumers can be encouraged – or required – to adopt smart chargers, EVs can soak up surplus supply from solar power plants during the middle of the day, or from wind farms at night. In future, as 'vehicle to grid' (V2G) technology is rolled out, EV batteries could partially discharge to the grid to help network operators manage spikes in demand.

In the meantime, there are other strategic actors with an interest in building out EV infrastructure.

The transport sector Incumbents

Given that a lack of charging infrastructure represents an impediment to EV sales, the automakers themselves have an interest in investing. Tesla, for example, is building a network of fast-charging points around the world, with 1,360 in place as of September, according to Supercharge.info, which tracks their locations.

VW, meanwhile, has been compelled by US regulators to invest US$2b in zero-emission vehicle infrastructure and education through its Electrify America programme, as part of its settlement over the 'Dieselgate' emissions cheating scandal.

VW has also teamed up with BMW Group, Daimler and the Ford Motor Company to form IONITY, a joint venture that is working to build an EV charging network along Europe's major motorways.

The oil companies represent a third set of strategic investors. In June 2018, BP announced it is to acquire Chargemaster, operator of the UK's largest network of public charging points, for £130m. It follows Shell, which bought NewMotion, Europe's largest electric charging operator, in 2017, and Total, which has acquired PitPoint, a company that combines natural gas and electric fuelling options.

"It's a hedging strategy for the electrified future," says Aleksandra O'Donovan, Head of Electrified Transport at BNEF. "It's important for them to maintain their customer relationships, and they have the advantage of near-perfect sites for charging infrastructure."

While all these actors have their own motivations for participating in EV infrastructure development, they are increasingly working together, notes Maria Bengtsson, Director, Valuation, Modelling and Economics at EY. "Multi-industry convergence will be the fastest way to achieve EV rollout," she says.

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Examples are proliferating:

- Daimler has taken a US$82m stake in ChargePoint, which claims to be the largest EV charging network.
- National Grid is working to develop a £1.6b, 2GW network of grid-scale batteries and rapid EV charging stations along the UK's motorway network.
- IONITY, the alliance of carmakers, is working with owners of petrol stations, including oil companies and specialist owners, to realise its EV charging network.

Investing under uncertainty

The challenge for investors in EV infrastructure, however, is that they are operating in the context of considerable uncertainty – not only regarding how quickly EVs will displace internal combustion engine vehicles, but also how usage of charging infrastructure will evolve. The risk is that overinvestment now will lead to heavy losses if utilisation doesn't meet expectations – or, even worse, if the market moves in a different direction, leaving investments stranded.

"No-one's figured out the optimal placement of EV infrastructure, whether DC fast-charging or traditional vehicle Level 2 charging," says Garrett Fitzgerald, Manager, Mobility Transformation, at RMI. "We're still in the 'test and see' phase."

"Most people project forward what we see today – single-family homes, with a garage and a place to plug in your car overnight," says Schefter, at the EEI. "That's the starting point for a lot of models and assumptions … we're going to see more EV drivers living in multifamily dwellings, where there isn't somewhere to plug in an EV."

Such a scenario would require public charging points or networks of fast chargers that mimic the current behaviour of drivers, who are used to quickly filling up their cars at petrol stations. This is the thinking of The EV Network, which is backed by a £500m EV infrastructure fund to deploy a network of fast-charging stations, initially in the UK, powered by onsite batteries, which are charged with 100% renewable power.

"People are used to pulling into a petrol station and filling up within six or seven minutes – we're copying that. We're not trying to change 100 years of motoring habits," says co-founder Reza Shaybani. As well as appealing to potential EV buyers without the ability to charge at home, he believes that many of those who can will, nonetheless, tire of the inconvenience involved with plugging in their EV.

Other variations anticipate large numbers of slow-charging points on business premises, offered as an employee perk, while some charging companies see potential in retail outlets offering fast chargers as a way to attract custom.

Meanwhile, alternative business models are emerging that stand to alter how electric vehicles interact with the grid, and how consumers approach their use.

For example, in places such as India – where the grid is generally less reliable than in OECD countries – battery-swapping models may become commonplace, suggests Fitzgerald, at RMI. The advantage they offer is that battery-swapping stations can be located where the grid is more robust or where they can tap into local generation (such as from renewables).

Meanwhile, some car companies are developing fleet businesses – currently aimed at workers in the gig economy – that anticipate future autonomous vehicle businesses. "They are renting out fleets of vehicles, including electric vehicles, and are exploring whether they would be better off with their own, dedicated charging networks," rather than relying on the local utility, says Fitzgerald.

However, he adds that EVs are only likely to be truly disruptive in terms of changing use and business models when autonomous vehicles become ubiquitous. At that point, the economics are likely to undermine rapidly the attractiveness of private vehicle ownership.

Mitigating risk

Whatever EV ownership and charging patterns emerge, there is a growing sense of urgency in the market: “Given the typical lead time on utility infrastructure investments, [the mid-2020s] might as well be tomorrow,” says RMI in a recent report. “In our view, the balance of risk now tilts toward deploying charging stations too late and with insufficient advance planning, not too early.”

“If they don’t invest now, it’s highly likely they’ll be late to the party,” says Michael Cahill, Management Consultant at EY, especially with investments in infrastructure, where it can be a question of snapping up attractive sites before the competition. “But, equally, players might not want to risk investing too early and narrowly in a market where technology and policy is constantly developing.”

Investors in charging infrastructure need to exercise caution when it comes to extrapolating from early experience in the EV market. For a start, ‘early adopters’ will behave differently from mass-market consumers, notes Erika Myers, Director of Research at the Smart Electric Power Alliance (SEPA), a US-based educational and research non-profit. As well as being less price sensitive than the public as a whole, they tend to have space at home to charge an EV, but are also likely to tolerate more inconvenience when it comes to charging.“If you’re basing your business model on the first one million electric vehicles deployed in the United States, that’s probably not a good idea,” Myers says.

O’Donovan, at BNEF, adds that current assumptions about the appropriate ratio of charging points to EVs may overstate need. “Once a minimum threshold [of charging infrastructure] and a certain geographical density is achieved, the incremental value of charging infrastructure diminishes,” she says. “There is a risk of overestimating the need and having underutilised assets.”

There are ways for investors and regulators to mitigate some of these risks, note observers.First, molding infrastructure rollout to local markets will be vital. “It won’t be one size fits all,” says O’Donovan, “it will be highly regionalised,” depending on average battery sizes, types of chargers and “even how peopleget to work in specific cities. What works in Oslo won’t necessary be sufficient in Beijing.”

Regulators could step in to ensure greater interoperability between different charging point providers, says Molho. While V2G technology may be some years from wide uptake, utilities could integrate EVs into existing demand-response programmes, says Myers. She adds that making sure EVs come with sufficient intelligence at the vehicle level – rather than only at the charging point – would help future-proof them in this regard.

For utilities, a focus on longer-duration, lowervoltage charging, where the utility is able to manage when the charge goes into the vehicle, would probably be optimal, says Myers, at SEPA. “Faster charging brings up a whole host of challenges in terms of how the distribution system could handle short-duration, high-volume charging, and all the infrastructure that would be required.”

“What I’d like to see is utilities using EVs as a grid asset – that would be the optimal outcome.” she adds. “We need to make sure that the distribution and transmission network owners and operators are empowered to be able to maximise the flexibility of the grid. That will significantly reduce the extra power generation capacity we need, as well as additional grid strengthening investments we need to make,” agrees Molho, at the Aldersgate Group.

“Investing in those demand-side solutions, storage, flexibility and interconnections is essential so we can operate the grid as efficiently as possible – otherwise we’ll have to commission additional, unnecessary investment on the power generation and distribution side,” he adds. “A lot hinges on government policy, but utilities need to show they are willing to invest as well.” Not all analysts believe uncertainty needs to pose a problem for infrastructure investment, however: “Although most people do consider it to be a ‘chicken and egg’ question, that’s not the case,” says O’Donovan. “We think chargers will follow sales of EVs, not the other way round. Utilities and carmakers will respond to rising EV demand.” She adds that “car companies and utilities are in a privileged position – they know where they are selling cars and know most about customer behaviour.”

Pressure builds to act

Regardless, pressure is building on participants in the EV ecosystem to act but, as the market evolves rapidly, they risk backing the wrong horse.

"In this uncertain but promising market, rapid in-market experimentation with businesses and consumers is the key first step to test the value and growth hypotheses of new EV business models," Cahill adds, then investment can be quickly scaled or pivoted based on validated learning.

Bengtsson, from EY, believes that, in a marketplace where industries are converging, it is important to identify targets that provide complementary capabilities. "It's a very complex value chain, and it's vital to do your homework before committing."

That complexity extends beyond the technology itself, adds Samuel Pachoud, Senior Manager, EY Advisory, necessitating the involvement of government, consumer groups and environmental agencies as well as industry: "Fundamentally, investors in the space need to understand the full ecosystem – electric vehicles, charging infrastructure, grid services, energy storage and connected services – before identifying commercially viable business models and injecting investment at scale. Convergence at the customer, technology and infrastructure level will provide the opportunity."

Price cannibalisation article

Victims of their own success

Merchant projects may not deliver their expected returns if too much generation depresses the wholesale power price.

As the costs of building renewable energy capacity continue to fall, a growing number of projects are coming on line around the world without the need for government subsidy. Indeed, policymakers in several jurisdictions are banking on the development of large volumes of subsidy-free, 'merchant' renewable energy projects to meet longer-term clean energy goals.

However, the renewables industry risks becoming a victim of its own success, with the growth of energy capacity in danger of undermining its own economic viability through a process known as 'price cannibalisation'. This is where too much generation, producing power at near-zero marginal cost, depresses the wholesale power price to the extent that merchant projects – without subsidies, and without long-term price guarantees, such as corporate power purchase agreements (PPAs) or government-backed contracts for difference (CfDs) – do not deliver their expected returns.

"Price cannibalisation is a big concern," says Daniel Radov, a Director at NERA Economic Consulting in London. "We're already seeing solar eroding peak prices in Germany and California … There are big risks to merchant generation and investment in renewable energy."

The problem is two-fold: the limited ability of generators to store electricity, and the fact that generation from renewable energy technologies is highly correlated – when the sun is shining, all solar farms generate power at high capacity, while strong winds benefit wind farms equally.

Cannibalising the capture price

Consulting firm Cornwall Insight has calculated the potential effect of price cannibalisation on the 'capture price' that wind and solar farms can earn from the wholesale market. Its analysis shows wind earning 34% lower revenues from the wholesale power market in 2031, compared with 2018, and solar plants earning 22% less.

The challenge for those operating merchant renewable energy projects is that their investments are vulnerable to decisions made by other developers in the future. "Your received revenues are clearly based on other people's investment decisions," notes Richard Slark, Director – Energy Practice at Pöyry Management Consulting.

Currently, the effects in Europe are masked by high power prices, supported to the mid-2020s by Germany's coal-power phase out. However, forecasts from the likes of analysis firm ICIS suggest prices will decline towards 2030 as a result of renewables capacity additions and a lower carbon price. But, with renewable energy costs continuing to fall, projects coming on line in the future will be profitable at lower wholesale power prices than at present.

"The real threat is to scale deployment and to traditional financing models," says Mike Mahoney, Head of Wholesale and Modelling at Cornwall Insight. Without some sort of assurance of minimum revenues, developers won't be able to raise as much low-cost project debt, forcing up their financing costs, he adds. This is likely to restrict development to those able to fund projects with greater proportions of equity, such as big utilities and oil companies. they are willing to invest as well."

Solutions at hand

There are some potential remedies, however. Cornwall Insight, for example, suggests that CfDs – as used in the UK and other markets – be amended to become "one-way floor price contracts". At present, they pay generators if the wholesale price falls below a certain level, but if it rises above a higher level the Government reaps the benefit.

Mahoney argues that generators should profit from high prices, but only once the Government has been repaid for any payments made to the project when prices are low. "This becomes a backstop rather than a subsidy," he adds, offering price certainty and allowing renewables generators to bid lower floor prices in auctions.

Slark, at Pöyry, also notes that support programmes can be designed to mitigate the effects of cannibalisation. "Differences in the way those CfD support schemes have been implemented have a big impact on the way in which projects are exposed to cannibalisation," he says. For example, he notes that Germany's EEG renewable energy support scheme uses a monthly average reference price, leaving generators much more exposed to price cannibalisation than in the UK system, which is based on hourly prices and the volume of generation. "Not all CfDs are created equal," Slark says.

Capacity markets to the rescue?

There is also potential for renewable energy projects to benefit from emerging capacity markets. These offer subsidy payments to generators in exchange for commitments to supply power during periods of high demand. Most of these markets are, at present, restricted to "dispatchable" capacity – generators that, unlike intermittent wind and solar projects, can guarantee to supply power on demand.

This is under discussion in the UK, notes Anthony Tricot, Assistant Director, Economic Advisory, at EY. "This could provide a more stable revenue stream alongside the more volatile power price … but it would still be a challenging investment decision, as any capacity payments to renewables projects would be quite small" compared with those to equivalent dispatchable capacity, given the intermittency of renewables.

Meanwhile, there are avenues developers can pursue to reduce their projects' exposure to price cannibalisation. Developing more diverse portfolios – combining renewables, storage and, possibly, fossil generation – offers protection, notes Tricot. Access to balancing markets, under which generators are paid for providing grid-balancing services, can also help, he adds.

Checks and balances

While price cannibalisation could slow down the deployment of merchant renewables, it may not pose as serious a threat to existing projects as some fear. Slark, at Pöyry, argues that it would act as "a natural check" on the rate of subsidyfree deployment. He says Pöyry's modelling suggests there "will be a balance struck" between falling technology costs and declining capture rates, preventing "the runaway deployment of renewables on a subsidy-free basis".

Radov, at NERA, echoes the view that markets will, to a certain extent, provide the appropriate signals. If renewables are generating power at times when it is not needed, they should expect to be devalued as a consequence. "I'm not sure that the remedy is to further shield renewables from fluctuating prices," he says. "If you're looking for policy remedies, we should be looking at incentives to shift demand or encourage energy storage."

One way is to ensure that batteries have full access to wholesale markets, so they can take advantage of surplus power and sell when demand is high, Radov adds. The assumption that wholesale power prices are likely to continue to decline under pressure from evercheaper renewables raises questions about the prospects of less mature clean energy technologies, notes Tricot, from EY. "The lower the wholesale power price, the harder it is to demonstrate the value for money of innovative technologies. It will encourage different ways of supporting less mature technologies", moving from payment for generation towards research and development support.

However, over the longer term, the answer to problems of price cannibalisation are likely to come from the next waves of the low-carbon transition – the electrification of transport, cooling and heating. Using smart grids to charge electric vehicle batteries, heat water and cool freezers when power prices are low will help shift demand and better reward renewable energy generators. "This will work to mitigate the worst effects of cannibalisation," says Slark.

Colombia and Peru – Country focus

Different directions

As much of Latin America embraces renewable energy, Colombia and Peru provide a tale of two markets. The former is on course to offer considerable opportunities for developers while, in the latter, cheap gas and a current excess of capacity are leaving renewables largely frozen out.

In terms of new renewables, Colombia is starting from a low base and sits just outside the RECAI top 40. Hydro plants supply 70% of its electricity, with most of the rest coming from gas and coal. At the end of 2017 it had just 20MW of wind and 104MW of solar photovoltaics (PV). However, drought caused by El Niño almost resulted in power rationing in 2016, putting pressure on the Government to increase reliability and security of supply.

In June 2018, Colombia elected Iván Duque as President, who had promised, during the election campaign, to install 1.6GW of new renewables by 2022. Meanwhile, the outgoing Administration issued a decree on 1 August to contract 3.4TWh per year of power over 10 years from 2022, equivalent to around 700MW of capacity, which includes thermal generation. The move continues the policy of the previous Government, which decided in 2017 to host an auction, working with the United States Agency for International Development and the US National Renewable Energy Laboratory on auction design.

The auction rules were due from the Ministry of Mines and Energy in October, shortly after this article went to press, with qualified bidders for a first auction to be announced in mid-December, and power purchase agreements – which will be peso-denominated and inflation-linked – to be signed midJanuary. According to EY analysis, as of midSeptember there were around 85 potential projects, totalling 3GW of capacity, eligible for the tender.

Bidders circle for Colombia auction

Although Colombia has limited installed renewable energy capacity, a handful of international and domestic companies have a toe in the market. Italian multinational Enel Green Power, for example, is developing the 86MW El Paso PV project in the north of the country, while local renewables developer Celsia (who already operates 104MW of solar) is likely to participate in the auction. Canadian infrastructure giant Brookfield Asset Management, which has a large global renewables portfolio, owns electricity distribution and generation businesses in the country.

However, Colombia's main utility, Empresas Públicas de Medellín, which operates the 20MW Jepirachi wind farm, may play a smaller role than expected. Problems in construction at the US$4b Ituango hydro project mean it is unlikely to have the financial firepower to participate to any great extent.

The market in Colombia is not without its challenges; there is limited experience among local banks in financing renewables projects, and the environmental and social licensing processes are new – so, again, there is limited experience, which could lead to delays in getting approvals.

Nonetheless, prospects for the country's renewables sector are good. According to Wood Mackenzie Power & Renewables, Colombia is forecast to add an average 500MW of solar, and 200MW of wind per year from 2018 to 2023.

Peru pales in comparison

By contrast, the longer-term growth prospects in Peru are less positive, although the market is currently larger than Colombia and is ranked 33 in the RECAI. Four renewable energy auctions since 2009 contributed to 201MW of solar and 244MW of wind by the end of 2017. At the last auction in 2016, wind capacity was successfully bid at US$38/MWh, and solar at US$48/MWh.

However, a lack of financial support for some of the successful bidders meant that, last year, the Peru Government cancelled a planned fifth auction and initiated a review of existing projects.

There is limited potential for new, utility-scale renewables projects in coming years. Peru is a big producer of natural gas, providing large volumes of cheap fuel for gas-fired power plants, supplementing considerable hydroelectric generation. Around 10GW of additional hydro and thermal power capacity is planned or under construction, including 1.2GW large hydro projects by 2021 and a similar level of gas plants. In addition, a proposed crossborder interconnector between southern Peru and Chile would open up the former's market to cheap Chilean renewables generation, making it difficult for new renewables projects in Peru to compete.

In the longer term, the Government would do well to revisit its renewable energy support. According to estimates by BMI Research, electricity consumption in Peru is forecast to grow by 4%–5% each year between 2018 and 2023, driven by growth in the mining sector and an expanding middle class. Renewables would help Peru diversify its power supply from drought-vulnerable hydro and finite, polluting natural gas.

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Sub-Saharan Africa (ex-South Africa)– Country focus

Capacity for growth

Asian investors are increasingly backing subSaharan Africa's grid-based renewables projects, while their Western peers and development banks are branching into off-grid investments. But the region remains a challenging one for clean energy – whether on-or off-grid.

Sub-Saharan Africa has an enormous electrification challenge: according to World Bank figures, its household electrification rate, at 42%, is the lowest in the world. This presents a major barrier to poverty reduction and economic development.

Development finance institutions (DFIs) have long been active in supporting the region's power and utilities sector, but two emerging trends in the region (excluding South Africa, which was covered in its own right by RECAI recently) offer additional potential: growing investment from the Middle East and Asia, particularly China, and accelerating interest in off-grid and micro-grid applications.

The growing participation of Asian and Middle Eastern investors in renewables projects in the region is a natural extension of their existing involvement in infrastructure development in Africa. Chinese groups are particularly active in thermal power generation, while Gulf investors, especially from the United Arab Emirates (UAE), specialise in petrochemicals.

Numerous examples can be found:

• Chinese solar manufacturer Changzhuo Almaden, alongside the UAE's Emirates Fortune, is developing a 400MW solar project in Chad.

• UAE-based Phanes Group is to build 200MW of solar projects in Mozambique, at a cost of US$200m.

• Indian multinational Sterling & Wilson is building 30MWh of battery storage, with solar and diesel generation, in three yet-to-be disclosed locations in West Africa.

• China Jiangxi Corporation has built a 55MW solar plant in Garissa, Kenya.

• China National Electric Engineering Company is to invest US$95m in a 25MW waste-to-energy plant in Ethiopia.

This trend represents a welcome infusion of cash and know-how, but local governments and developers need to go into deals with their eyes open. There is often less transparency around contracting than with Western investors, particularly DFIs. There have also been cases of developers failing to deliver on environmental and social pledges. For example, many African countries have rules requiring local content and employment of local people, to develop domestic supply chains and skills; some developers have not honoured these commitments.

There have also been cases of Middle Eastern investors, in particular, proving reluctant to take local currency risk, saddling local lenders (often governments) with dollar-denominated debt, which could become hard to repay if the local currency depreciates.

Another drawback is that, to date, most development from these investors is in bigger, grid-connected projects – in keeping with the larger-scale infrastructure investments in which they have typically specialised.

It is questionable whether such projects are well suited to African markets, where transmission grids are often inadequate.

For example, power generation from Kenya's 310MW Lake Turkana wind project – funded predominantly by European and South African development banks and private investors – finally began to flow in September, about two years behind schedule, with the construction of its 427km transmission line a particular cause of delays.

However, just as Africa has embraced mobile telecoms, leapfrogging the fixed lines that predominated in the West, off-grid or micro-grid capacity has enormous potential to electrify rural areas and provide a development boost –often at a fraction of the cost of grid extension. Investment in the sector is beginning to take off, and the International Energy Agency predicts that Africa's off-grid capacity will triple in the next three years, to 3GW.

The following are examples of recent projects: • UK-based developer and operator BBOXX has signed a deal with the Government of the Democratic Republic of Congo as part of the country's Énergie Pour Tous initiative, which aims to bring power to 2.5m people by 2020.

• French utility ENGIE is to install eight hybrid solar plants, with 2.2MW of capacity, in Gabon.

• The World Bank has granted a US$350m loan to Nigeria to help fund its 1GW solar rural electrification programme; the loan will be used to build 10,000 solar-powered mini-grids in rural areas by 2023.

• Metka, part of Greek conglomerate Mytilineos, has reached an agreement with the Nigerian Government to develop hybrid micro-grids for nine universities and teaching hospitals.

However, off-grid and micro-grid projects in the region are not without their challenges. These include: the affordability of the electricity they generate for users; a lack of data about potential customers; resistance from utilities and transmission-system operators who want to expand their reach; and regulatory barriers, such as laws restricting electricity sales to the monopoly provider. Financing is a perennial problem, with banks often reluctant to lend against power purchase agreements struck by off-grid developers.

The Power Africa initiative, funded by USAID, is working to address some of these barriers. Its Beyond the Grid scheme is working with investors and developers who have committed to invest more than US$1b in off-grid and small-scale systems. Among other things, it is advising governments on best-practice policies to enable the growth of the off-grid sector.

Individual countries are also making progress. In Tanzania, for example, the World Bank has committed US$200m to a rural electrification programme that aims to bring power to 1.3m households by 2023.

Clearly, sub-Saharan Africa has enormous potential for investors in renewables, as long as supportive regulatory regimes are put in place. In such a diverse region, however, each country has its specific challenges and issues, requiring tailored solutions and on-the-ground advice.

Key development articles

US renewables developers look to state capitals and offshore

US states are pressing ahead with ambitious renewable energy plans, offsetting actions by the Federal Government that are likely to slow clean energy development and boost coal. Activity in the US offshore wind sector, which has long trailed that of Europe, is also accelerating.

In the most dramatic recent development, on 10 September, California Governor Jerry Brown signed into law a bill requiring 100% of the state's power to be generated by renewable sources by 2045 – up from 33% by the end of 2020 under current legislation. California, the world's fifth-largest economy, is only the second US state, after Hawaii, with a 100% target.

Other states are developing renewable energy investment plans. In New York State, for example, Governor Andrew Cuomo announced in April a programme to support up to 10 large-scale renewable energy projects, expected to spur US$1.5b in private sector investment. This will involve the New York State Energy Research and Development Authority buying renewable energy certificates from eligible facilities coming online between 1 January 2015 and 30 November 2020.

Coastal states are also advancing offshore energy plans. In June, Massachusetts and Rhode Island announced they are to procure 1.2GW of offshore wind capacity from developers Vineyard Wind and Deepwater Wind. New York State plans to support 800MW of offshore wind through two bid processes by the end of 2019, as part of its 2030 target of 2.4GW. Projects are also under development off New Jersey, which plans 3.5GW of offshore wind by 2030, and Virginia, which has pencilled 2GW of offshore wind in its 2028 energy plan.

Offshore wind has the backing of the Trump Administration, with Secretary of State of the Interior Ryan Zinke describing it in April as a "God-given resource".

Elsewhere, however, the White House has proved less accommodating to renewables. It has cancelled the Obama Administration's stalled Clean Power Plan, which would have encouraged additional renewables investment by utilities to meet tighter emissions goals. Its proposed replacement, the Affordable Clean Power Rule, is expected to support ageing coal-power infrastructure instead.

In January, the White House also imposed 30% tariffs on the import of solar panels. Nonetheless, a record 8.5GW of utility-scale solar projects were procured in the first half of 2018, according to Wood Mackenzie Power & Renewables, as developers scrambled to secure federal tax credits – which are to be phased down from 2020 – and because of a global glut of cheap panels after China cut its own solar subsidies in June.

No deal Brexit threat to UK renewables sector

Clean energy investment in the UK appears to have slowed ahead of the country's planned departure from the EU next year, with concerns growing that failure to secure a Brexit deal could throw the power sector into crisis.

While financial markets are anticipating agreement between the EU and the UK before March 2019, the volume of initial public offerings (IPOs) in London has fallen compared with the same period last year. Research by EY has also identified concerns around Brexit contributing to a similar dip in corporate appetite for acquisitions.

New investment in renewables has fallen significantly in the past four quarters, compared with the previous 12 months, according to figures from Bloomberg New Energy Finance; investment in the third quarter, at £2.2b (US$2.9b), was 46% lower than the same period last year. The UK's power market is closely linked to those on the EU mainland, and investors in potential renewables projects – as well as operators of existing ones – are concerned that they will be unable to export power to EU markets in the event of a 'no deal' Brexit.

In October, the UK Government warned that the all-Ireland electricity market risks breaking down in such an eventuality, while owners and operators of interconnectors between the UK and the continent would need to have new trading arrangements in place by 29 March if the UK crashes out of the EU.

Meanwhile, the UK Government has scotched hopes for a £1.3b (US$1.7b) tidal lagoon project mooted for Swansea, in South Wales. Developer Tidal Lagoon Power had sought a contract-for-difference subsidy similar to the £92.50/MWh granted to the Hinkley Point C nuclear power plant. However, the Government decided that offshore wind farms could generate the same volume of power over 60 years, for £400m at today's prices.

India's push into solar begins to falter

Good news on India's progress towards its 100GW solar target in the first quarter of 2018 – when it recorded its highest quarterly addition of solar photovoltaics capacity to date – has been eclipsed by a collapse in capacity additions in the following quarter. This was even before the imposition of a 25% tariff on the importation of solar cells from China, Malaysia and developed countries.

In the first quarter, 4.6GW of utility-scale solar was added, bringing the total to 10GW for the 2017–18 financial year. However, just 1.6GW was added from April to the end of June, according to Mercom India Research. The analysis firm attributed the drop to uncertainty around trade cases, module price fluctuations, and renegotiations of power purchase agreements after record low bids.

The Modi Government has made increasing renewables a policy priority, with a goal of 175GW of wind and solar by 2022. Competitive tenders have helped push costs of solar power below that of coal-fired generation and, in 2017, India became the world's third-largest solar market, after China and the US.

The sector faces a range of challenges, however, including a poor grid, low-quality panels and installation, limited land availability, and disputes between developers and state-owned utilities over contract renegotiations. While the imposition of tariffs from 30 July were designed to help support local manufacturers – who have only 10% of the Indian market – they could add to project costs.

Turkish currency crisis casts pall over renewable sector

The slump of the Turkish currency, in response to a weak macroeconomic outlook and a cooling of relations with the United States, has cast a shadow over a hitherto attractive renewables pipeline.

Between January and August, the lira lost 46% of its value against the US dollar, with a political and economic crisis causing international investors, development banks and export credit agencies to hesitate about investing in Turkish projects.

The Government has ambitious renewable energy targets of 20GW of onshore wind and 5GW of solar by 2023. By 2017, Turkey had installed 7GW of wind and 2.6GW of solar. Renewables investors have praised the country's well-developed regulatory regime and the introduction of an auction system for renewables subsidies, which replaces a Feed-in Tariff programme that has been running since 2005. These payments only run for 10 years, but are dollar-denominated, which will cushion existing projects. Nonetheless, higher levels of political risk will probably cause a slowdown in new projects being built, warn funders.

French offshore subsidies

The French Government has negotiated a 40% reduction in lifetime subsidies to be paid to six major offshore wind farms, saving the taxpayer €15b (US$17.4b) and averting fears that tenders might be cancelled or retendered. However, with onshore auctions faltering, industry body WindEurope has warned that the country risks falling behind on wind energy.

The offshore renegotiation covers projects to be operated by EDF, Engie, Enbridge, EDP Renováveis and Iberdrola. They won auctions between 2012 and 2014, for payments of €180/MWh to €230/MWh of power produced. This April, winning bids for 1.6GW of German offshore wind farms averaged €46/MWh.

The national industry body, France Energie Eolienne (FEE), welcomed the renegotiation, noting that the projects will help launch the French offshore wind sector, with the associated local supply chain and employment opportunities. France currently has no offshore wind farms in place.

However, Giles Dickson, CEO of WindEurope, speaking at an FEE conference, said the country needed to be more ambitious on offshore wind, and should be planning for 1GW-2GW of offshore tenders each year over the next five years.

He also described its permitting system for onshore wind as a "stumbling block". In September, France contracted less than a quarter of the 500MW of capacity planned in its latest auction for onshore wind projects. Analysts blamed planning permit delays and regulatory uncertainty, with the future of France's environment agency in limbo. Prices bid were not disclosed.

Germany to miss 2020 carbon targets

Germany is set to fall significantly short of its 2020 emission-reduction targets. Its Government admitted in June that it is only likely to reduce emissions to 32% below 1990 levels, rather than the planned 40%.

A strong economy and population growth have been blamed for increasing energy consumption. The environment ministry also said forecasts had overestimated the reductions that could be delivered by decarbonising the transport sector. This is only expected to deliver 5m–6m tonnes of carbon dioxide reductions by 2020, compared with 174mt–180mt from the energy sector.

However, Germany is pressing ahead with plans to phase out its use of lignite – or 'brown' coal – a particularly carbon-intensive fossil fuel. A special commission was established in June to advise on social and economic policy recommendations to set deadlines for phasing out coal and help coal-producing regions with economic restructuring.

Mainland China steps on renewable

The Chinese Government has moved to slow the growth of its renewables sector, slashing targets for new solar PV installations and trimming subsidies. This has hammered the stocks of solar manufacturers, and promises to create a glut of low-price panels, but analysts see the move as, ultimately, increasing the efficiency of the country's renewables industry.

In May, China's National Energy Administration announced it would replace Feed-in Tariffs (FiTs) for wind power with competitive auctions. The following month, the Government called a halt to all further utility-scale PV plants, and set a cap of 10GW of distributed PV installed in 2018. It also cut FiTs payable to all solar PV projects by between 7% and 10%.

The move is intended to force solar PV towards grid parity more quickly, and ease financial pressure on the country's Renewable Energy Development Fund, which pays renewables subsidies and which has run up a deficit of CNY100b (US$15b) as of 2017.

As a consequence, the China Photovoltaic Industry Association expects new installations this year to come in 30% below its previous projection of 40GW. This is likely to result in manufacturers slashing prices to reduce a probable glut of panels, with Bloomberg New Energy Finance forecasting that prices could fall by as much as 35% by the end of the year.

However, while the moves have hit domestic and internationally listed solar manufacturers – and smaller and/or heavily indebted producers could be vulnerable – China's renewables sector is still considered to be in relatively good financial health.

Taiwan's offshore sector sets sail

Financial close has been reached by the developers of Taiwan's first offshore wind farm, hot on the heels of 3.8GW of contracts being awarded by the Taiwanese Government to build offshore wind.

In June, Australian investment firm Macquarie Capital, Danish energy company Ørsted and local developer Swancor closed Taiwan's first offshore wind project financing, raising TWD18.7b (US$626m) to develop the second phase of the 128MW Formosa 1 project. This involved refinancing the first, 8MW phase, and means construction of the subsequent 120MW of capacity will begin next year.

It follows the announcement, in April, of contracts to develop 12 wind projects off the coast of Taiwan, due to be completed between 2020 and 2024. The winners include Ørsted and Macquarie, Danish investment fund manager Copenhagen Infrastructure Partners, German offshore developer wpd, and Canada's Northland Power, as well as the state-owned Taiwan Power Company (Taipower) and China Steel Corporation.

The successful bidders' schemes will now advance to negotiations for 20-year power purchase agreements with Taipower, which will act as off taker. Under the terms of Taiwan's Energy Act, the tariffs must fall between TWD5,000 and TWD6,000 (US$161– US$194) per MWh.

Philippines project claims region's lowest solar bid

Solar Philippines claims to have won an auction for 50MW of solar photovoltaic capacity with Southeast Asia's lowest bid, of PHP2,340 (US$44) per MWh.

The auctions replace the country's Feed-in Tariff (FiT) programme, which was introduced by the 2008 Renewable Energy Act and which combined FiTs with priority dispatch for clean energy projects.

The tender, awarded in August, was launched by Meralco, the country's power utility, in December 2017, but has faced delays because of the conduct of the competitive selection process.

Last December, Filipino Energy Secretary Alfonso Cusi suspended four out of five commissioners running the Energy Regulatory Commission, for their management of tenders for 5GW of mostly coal-based power purchase agreements. These one-year suspensions, without pay, have led to considerable delays in approvals across the country's power industry.

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