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EDP Renováveis S.A. Equity Research: Pathway towards green

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Abstract

This part of the EDPR equity research report sets the building blocks for the assumptions concerning the projections for the company. It goes from understanding how onshore wind and solar PV costs are expected to evolve and its role feeding in demand. Renewables capacity additions are still, in a big part, backed by government action and stimulus. Understanding the current regulatory environment and energy policies is key to estimate the potential size of the market, while also considering companies that are currently competing for market share, as well as new joiners coming from parallel industries, such as oil & gas.

Keywords

Valuation, EDPR, Energy, Renewables

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This report is part of the EDP Renováveis S.A. Equity Research report (annexed) and should be read has an integral part of it.

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Industry Overview

Green shift towards Renewables

The energy market is changing. Electricity plays a major role in this change as the world moves to a higher electrification environment, despite a lower energy intensity trend. Worldwide installed capacity has grown 4.2% p.a. from 2012 to 2019, and fossil sources still hold a significant share of the mix (*figure 1*).

Technology costs

- Load factor

Onshore wind

Load factors are mainly driven by the quality of the wind resource. Nevertheless, wind turbines had technological developments that resulted in higher load factors. Namely, the installation of higher hub heights allows turbines to operate in areas where the wind resource is generally faster and more consistent (fewer obstacles), operating more time closer to its capacity (*appendix 6.A.*). Although load factors vary by region according to its windiness, other reasons may well influence load factor differences. Land size, population density, and financing also have a say in wind farms' performance (*Boccard 2009*), helping to understand the U.S. and Europe's differences. In fact, countries with bigger land areas and lower population densities registered higher load factors in the past decade (*figure 2*).

Regarding the outlook for wind turbine size, it is expected that rotor diameters continue to increase, followed by higher nameplate capacities (*figure 3*). Our expectation is that hub height will follow this trend, but the pace is uncertain. If the ratio of rotor diameter to hub height is kept constant, by 2025, the weighted average hub height could rise to 96m in the U.S. and 114m in Europe. Moreover, for current rotor sizes, higher hub height would only be preferred economically in moderate wind areas (*NREL*). However, for larger turbines (4.5 MW), there is a preference for higher hub heights, namely, at least 110m and preferably 140m. Hence, we believe in our estimates because Europe generally has a lower wind quality than the U.S., benefiting from increases in hub height.

All of this considered, we expect that load factors to continue to increase, although at a different pace than the last decade (a*ppendix 6.C*).

Solar PV

According to Mark Bolinger[1], there are several factors determining capacity factors for utility-scale solar PV. They are affected by insolation (GHI), modules technology.

In the U.S., considering 377 projects from 2010-2017, Berkley Lab showed that, for the given sample, the capacity factors were explained on average ~66% of the time by GHI levels (*figure 4*). Solar radiance is unstable and is subject to cloudy and rainy days. Nonetheless, it is possible to pinpoint regions where GHI levels are theoretically higher on average (e.g., Chile, Africa) *(appendix 6.B).*

For the forecast of the capacity factors in the relevant regions for EDPR, we mainly divided the

[1] Research Scientist in the Electricity Markets and Policy Department at Lawrence Berkeley National Laboratory

analysis into two major groups. A group of regions where we expect small variations relative to historical values (Europe and the U.S.) and a group where variations would be more considerable (Brazil and Mexico).

In both groups of regions, variations are expected to be driven by increased usage of tracking systems, bifacial modules, and modules' degradation reductions. Note that other cell technologies (e.g., PERC) were understood to impact only the cost per MW, given they do not necessarily mean a larger observable capacity factor. Only an increase in cell efficiency to be able to convert more energy.

The sun-tracking systems have become a common mount type for solar PV projects. It is nothing more than a device that rotates the panel towards the sun. Hence, panels will increase their uptime and, consequently, generation. The power loss by misalignment was studied by Solar Feed, where it can go up to more than 75% (*figure 5*). Regional evidence of the impact of tracking systems on the capacity factor is observable in *figure 4*, highlighting that for same levels of GHI tracking panels tend to have larger capacity factors relative to fixed-tilt panels. Likewise, in *figure 6*, one can extract that despite the decreasing solar radiance of new capacity additions, the capacity factors have been able to hold on to a more or less flat range of values by the contribution of tracking devices.

Bifacial modules are panels able to generate from both sides, which will drive the electricity output upwards. Bifacial modules have been growing significantly in recent years, mainly due to decreased costs (*figure 7*). According to Wood Mackenzie, bifacial modules can increase by tenfold in 2024. The impact over the capacity factor was the subject of study by different authors. According to one of the studies, for an albedo of 0.5, the electricity generated increase can go up to 30% when using bifacial modules (*Sun et al. 2018*).

Considering these technologies, we estimate the main regions' capacity factors where EDPR operates (*appendix 6.D – capacity factor*).

- Costs

Onshore Wind

Capital costs regarding onshore wind mainly relate to wind turbine costs (~69%), system costs (~22%, considers project development, engineering, management, etc.), and financial costs (~9%, insurance, decommissioning, financing, etc.). Wind turbine prices have been decreasing over time (*figure 8)*, which can be explained by multiples drivers: learning by researching[2], learning by development[3], supply chain dynamics[4] , and market dynamics[5](*Elia et al. 2020*). From 2005 to 2017, suppliers & others were the driver of the largest decrease in wind turbine cost (~60%). These are costs related to electricity infrastructure and other services rendered by third parties (e.g., components production). Also, the manufacturing process's efficiency required fewer materials, which combined with employee’s productivity increases sustained the cost drop (~13% and ~11%, respectively).

There is several research on learning rates, which measure the decrease in turbine costs when capacity doubles. However, there are not many results incorporating data from 2010-2019, where installation costs dropped significantly (24.4% vs 7.5% in the previous decade). Our estimate is

[2] Material quantity, R&D costs, Delivery costs (30%)
[3] Delivery costs (50%), Financial and legal, Suppliers & others (50%), Capital depreciation, Employees productivity
[4] Material market price, Energy market price, Salary, Suppliers & Others (25%)
[5] Delivery costs (25%), Suppliers & others (25%), Company profit

based on a range of 4 learning rates obtained in research containing data from the given period (*IRENA*) *(Wiebe and Lutz, 2016) (Grafstrom and Lindman, 2017)*. This range varies between 3.8% to 8.4%, for which we obtained an average of 6.5% and a median of 7.0%, ending with an annualized 0.4% decreasing rate for 2019-2034 (note that we estimate capacity to double by 2034, assuming that capacity continues to increase at 2.7% p.a. after 2030 – Section *Supply Outlook*). We forecast a 0.3% cost decrease p.a. 2019-2030, expecting that turbines remain weighting ~69% of installation costs and that the remaining costs are fixed (*figure 9*). This compares well with the rate of decrease proposed by IEA of 0.4% p.a. (*World Energy Outlook 2020*).

Looking at energy equipment manufacturers gives us confidence in our estimate. The market is now more competitive than at the beginning of the 2010 decade, with new companies gaining market share (*figure 10*). Notwithstanding, the bigger players of the market have ramped up their R&D investments, which are expected to help materialize the expected cost decreases (*figure 11*).

Operation & Maintenance costs were also considered fixed, as new wind turbines are expected to have lower O&M costs, but older wind farms' higher maintenance needs offset this decrease (*IRENA*).

Solar PV

A cross-check between different sources (e.g., IEA, Bloomberg, IRENA, Fraunhofer) points to a cost reduction in solar PV of ~80% from 2010-2019. The lower costs are due to the fall of ~90% in the price of polysilicon, the raw material of most modules PV in the market (*figure 12)*. Note that data of 2019 shows that the module and inverter accounted for ~36% of the capital costs and when combined with the Balance of System (BoS) cost for ~60% (*IRENA*).

Regionally, there are differences between the capital costs, with module prices being lower in European regions (e.g., Spain, Italy, Portugal) and China and relatively higher in the U.S., Canada, and Mexico. Nonetheless, technological improvements considered were considered to affect equally every region. We do not expect any major breakthrough in research in terms of technology, with estimations considering a widespread adoption of current technologies like the Passivated Emitter and Rear Cell (PERC). The increasing adoption of PERC cells (~20% market share in 2017 to ~80% in 2028, *ITRPV)* can increase efficiency cell by 0.8-1%, lower price per MW (*Cherradi 2018*).

In the light of these expectations, we believe capital costs will continue to decline through 2020-2030, but at a smaller rate (~3.3% p.a.) (*figure 13).* Like onshore wind, this declining rate is the combined result of research, technology, and learning curves for solar PV. From different studies (*ITRPV 11th edition, 2020*) (*Kersten and Wawer, 2011*) (*Gorig and Breyer, 2016*), we were able to construct a range of learning rates (16% to 28%) where we have used the median of 17%. We have confidence in the implicit declining rate from this learning rate, given they do not deviate much from the target cost reductions from other sources (IEA – 2.7% p.a. and NREL – 3.4% p.a.).

- Perspectives on LCOE

Considering the expected evolution of both onshore wind and solar PV costs, the LCOE generated from these sources is expected to decrease driven by lower installation costs as capacity increases and processes improvements increase manufacturing efficiency.

For a WACC ranging between 3.0% and 4.0% (section *Discount Rate*), solar PV is expected to have a higher decrease in LCOE than onshore wind due to a higher deployment rate and greater relative cost improvements from experience. Brazil and Portugal are the cheapest regions for solar, driven by GHI exposure and lower installation costs *(appendix 6.B*). In the U.S., the phase-out of current tax benefits schemes leads to increasing solar prices until 2024, and after, lower installation costs are expected to drive down the LCOE.

Onshore wind evolution reflects its maturity relative to solar, as the LCOE decreases, on average, 1.0% p.a. 2019-2030 in Europe. On the other hand, the U.S. LCOE is expected to decrease at, higher than average, 1.8% p.a. 2019-2030, boosted by the load factor expansion (*Figure 14 and 15*).

We highlight that the LCOE metric is subject to our expectations of variables like the WACC and the projects' average life (25-years). Significantly different expectations in these variables and others, such as capacity factors or costs, may lead to very different LCOE.

Demand Outlook

Electricity demand

Not all electricity generated is dispatched to fulfill the demand. In the electricity market, generation is stacked from the lowest to the highest bid. Typically, generation stacks first dispatch electricity from low-cost sources (e.g., wind and solar) followed by the more expensive sources (e.g., natural gas and coal). These last are only dispatched when there is a peak or when the cheapest sources cannot accommodate the whole demand.

Considering electricity demand is greater than the electricity generated by renewable sources, one can question the extent to which demand shocks influence renewable sources. It would be expected that all the electricity these sources can generate will be dispatched and consumed.

In the United States, the electricity demand from all sources for 2000-2019 reveals that demand suffers some shocks that decrease electricity consumption in some years. Nonetheless, *figure 16* displays the resilience of the electricity demand generated by wind and solar. Despite the years of lower electricity demand from all sources, electricity consumption from renewable sources has increased steadily.

The same conclusion is taken when the analysis is shifted to the Euro Union (*figure 17*). Even though this region's demand has been impacted by even more negative shocks than in the U.S., the electricity demand generated by wind and solar increases continuously throughout the period.

In emerging markets like Brazil, the relation is not as clear cut given electricity demand from all sources in these markets displays less downward shocks that can be used to highlight the resilience of electricity consumption from renewable sources (*figure 18)*. Note that emerging markets tend to be in a different development state relative to more mature markets like the U.S. and the EU. In developing economies, the improvement of living conditions enhances electricity access to more people, which is expected to increase electricity demand. The rise in the number of appliances and equipment by household underpins electricity demand growth in emerging markets (*figure 19*). Nonetheless, the resilience and increasing profile of electricity demand generated by renewable sources is also registered in emerging markets.

It can be concluded that the electricity generated by renewable sources is to some extent resilient to demand variations given it is dispatched before the other electricity sources due to lower variable costs or government policies that provide priority in the access to the grid. Therefore, electricity generation from wind and solar is more influenced by the capacity available to generate than the electricity demand.

COVID-19 impact & Top performers

Financial markets have rewarded renewables during 2020 (*figure 20*). This can be observed by comparing stock returns of an equal-weighted portfolio of renewable-focused companies compared to the MSCi world index, an equal-weighted portfolio of big utilities, and the Stoxx 600 Oil & Gas index. Although this evolution was also observed in 2019 (*figure 21*), its magnitude was amplified (renewables had an annualized excess return of 48.5% in 2020 vs. 20.6% in 2019).

Moreover, EDPR displayed signs of resilience during the past crisis (*figure 22*). In 2009 (great recession), despite a significant drop in economic activity (GDP fell 8.6% and 1.8% in Spain and the U.S., respectively), the Company managed to increase its generation 39.7% YoY, where a lower load factor driven by lower wind resource was offset by capacity additions of ~1 000 MW. When it comes to the covid-19 pandemic, although wind generation was down 7.0% YoY in the first 9 months of 2020, that is explained by a sell-down that happened mid-year and a lower wind resource, which translated into a 2 p.p. lower load factor.

We believe that higher resilience and lower exposure to the economic environment result in higher valuations. When it comes to market multiples (e.g., EV/EBITDA), a premium compared to utilities (Section *Relative Valuation*) is registered. This is expected to prevail as long as these continue to be the most cost-competitive source of electricity. Otherwise, if they are not the firsts to fill the demand, exposure o economic activity could increase. Nevertheless, based on our cost analysis, we believe this risk to be residual.

Regulatory Framework

Europe

One instrument that governments use to incentivize renewable energy infrastructures is remuneration schemes (*appendix 7* mentions the key components of schemes in regions of interest for EDPR). In the last four years, we have observed a significant price decrease in tariffs awarded in government auctions (*figure 23*). Moreover, early adopters, such as Portugal and Spain, faced tariff deficits due to providing very high subsidies when technology was too expensive. Note that Spain had in the past, and there are still wind farms under this regime, a remuneration scheme that would guarantee the operator a 300 bps spread to the Spanish 10-year government bond return (7.1%, last updated value) when our estimate for the cost of equity of the company in Europe is 4.1%.

As renewables like onshore wind and solar PV became more competitive compared to other existing sources (gas and hydro), countries have started to decrease the level of subsidies provided to the operators. More capacity is being awarded through competitive tenders, driving the average auction price down. Moreover, countries like France and Poland moved from Feed-in-Premium and Green Certificates schemes, respectively, to Contracts-for-Difference, which offers a more stable and predictable revenue stream. By removing uncertainty regarding the realized market price, awarded tariffs are expected to be lower, given a lower opportunity cost since there is less systemic risk exposure.

Furthermore, early adopter countries also face a problem related to the average asset life of onshore wind existing capacity (12 years in Portugal and Spain has 25% of its capacity with an average life higher than 15 years). For both countries, repowering is not only a need but also a source of growth, as older turbines are often placed in locations with better than country average wind resource, which can benefit from the installation of newer and more efficient turbines. However, regulation is currently short in what concerns these undertakings. Namely, repowering requires new licenses, and countries are yet to announce a remuneration scheme for the new projects, considering that currently, pre-existing projects lose their scheme.

North America

The energy policy and regulatory procedures in the U.S. are particularly debatable and changeable from administration to administration. Political decisions over a swifter decarbonization process and clean-energy transition may impact EDPR in various ways. Current support, investment tax credits (ITC), and production tax credits have been significant drivers of solar and wind growth *(figure 24*).

As far as it concerns EDPR, the most recent change extended the solar ITC until 2023, though a gradual ramp down started in 2020. The 30% ITC for residential, commercial, and utility-scale solar installations will fall to 26% in 2020, and 22% in 2021. After 2021, residential tax credits fall to zero, while commercial and utility-scale projects fall to 10%. The requirement to qualify for the tax credit is construction to begin between 2020 and 2022 and completion before 1st January 2024.

PTCs are eligible for wind projects if construction begins before 2019YE and completion is attainable before 2023YE, meaning projects have four years to be completed since the beginning of construction. Like ITC, a phase-out is scheduled. The most recent change extended PTC for wind facilities for one year, until 2020. Wind projects beginning construction in 2019 will qualify for 40% of the full amount of the PTC ($2.5 cents/kWh), and projects beginning in 2020 will qualify for 60% of the full amount of the PTC.

Both tax credits have been contributing to lower the LCOE of both sources throughout the years. *Figure 25* shows the impact of ITC on solar PV LCOE and the continuation of the stimulus even after the full scheduled phase-out is tied to these sources' cost competitiveness. Based on the competitiveness and increasing demand for renewable electricity by corporations, we believe that the full phase-out of stimulus will not materially affect these sources' cost competitiveness in the U.S.. A caveat when analyzing *figure 25*, this figure used third-party data and was not adjusted by us.

Supply Outlook

Europe

Reaching climate neutrality by 2050 is the goal set by the EU. This configures a favorable perspective for EPDR as regulation and promotion of increased electrification and use of renewable sources are key building blocks to achieve this goal. Initially, the EU set several targets relating to renewables' weight in energy consumption, transports, and electricity generation for 2020 with the EU climate and energy targets, which were further extended and increased for 2030 through the Clean Energy Package 2030 (*figure 26*). As these were legally binding targets for all state members, each one had to submit a National Energy and Climate Plan 2021-2030 (*NEPC*) with measures and policies on how to achieve or surpass the given targets.

Although the targets set by the EU are legally binding, each state still has the flexibility to arrange its mix as it believes it best fits its strategy. This means that they are not required to meet specific technologies capacity targets if, in the end, the binding target is met. While some countries are close or have already met their 2020 targets (Spain, Romania, and Italy), it is still unclear if others will be able to do so (Portugal, France, Poland, and Greece).

Our approach for onshore wind and solar PV additions considers the targets defined by each country in what concerns installed capacity and electricity generated. It can be observed that, generally, all states, except for Poland, are expected to miss their wind capacity targets for 2020, following the most recent available data (2020 Q3, *figure 27*). Our understanding is that solar suffered significant cost reductions during the period, favoring its addition to the mix. All countries under analysis have already met their solar PV targets and often by a significant margin (*figure 27*). Moreover, comparing the implicit capacity factors in the country's projections of capacity and generation for each source and the observed, we concluded that the latter turned out to be lower than the initially projected (*figure 28).* This means that, if these were estimated correctly, capacity targets would be even higher, considering the expected generation.

This led us to analyze each state's capability to meet its 2030 targets to estimate the evolution of installed capacity of wind and solar PV in the relevant regions for EDPR.

First, implicit load factors by capacity and generation estimates are generally lower than both our estimate for future capacity factors (section *Costs*) and the historical average of capacity factors (2013-2020). This means that if countries met the proposed capacity targets while realizing a higher than estimated capacity factor, the share of wind electricity would come out to be higher than expected, which is not likely given the described track record when it comes to meet the established targets. This would mean that in Spain, wind generation would represent 42.4% of total generation (*NEPC* target: 34.5%) and in Portugal, 38.2% (*NEPC* target: 31.0%).

Secondly, when analyzing recently awarded capacity, countries do not seem to be on the right track for wind (*figure 29)*. In Spain, a calendar of auctions was recently presented by the government, which corresponds to a 1.5 GW award rate p.a. until 2025. Other countries such as France also have presented their own at 1.9 GW p.a., but it is still unclear if the countries will follow as auctions scheduled for 2020were delayed due to the covid-19 pandemic. Portugal is on the right pace for solar. When it comes to wind, repowering and overequipement are expected to drive the growth in onshore wind, which is not reflected in the awarded capacity by auctions yet.

Our approach consisted of reflecting the uncertainty regarding capacity additions in two different scenarios. One where capacity targets are achieved and existing capacity is fully repowered. A second one accounts for a 20% miss in onshore wind targets, reflecting the average expected miss for the 2020 capacity targets. Also, existing capacity is not totally repowered due to the uncertainties regarding legislation (*Regulatory Framework*).

North America

In the **United States**, installed capacity was estimated in accordance with U.S. Energy Information Administration (*EIA*). We assessed the reasonability of the estimates by parsing out the drivers steering future capacity. Supporting the growth of wind and solar capacity are the tax credits and their impact on costs, and the increase in renewable portfolio standards (RPS) targets.

Regarding tax credits, investment tax credit (ITC) for solar has recently been extended until 2023, prolonging one of the growth drivers in cumulative solar capacity (*figure 30*). Nonetheless, the extension is followed by a phase-out with projects applying for amounts below the full ITC. Such fact is expected to increase solar cost in the next years (section *Technology Costs).* Hence, solar capacity is expected to continue to grow but slower (12.7% CAGR 2020-2030). As for wind, PTC extension for an additional year is expected to increase the number of projects coming online until 2023. After the stimulus' cease, wind projects' cost increases, lowering the growth pace in wind capacity (5.2% CAGR 2020-2030)

Secluding RPS targets' impact on renewables growth is challenging due to the various layers that impact renewables' growth. Nonetheless, RPS has affected capacity additions in the past years. The assessment of such an impact can be analyzed by identifying the capacity of entities with RPS obligations. According to Berkley Lab, from 2008-2013, ~60% of new additions were linked to RPS targets (*figure 31).* However, that percentage has been decreasing, reaching ~30% in 2018. The recent growth in renewables has spurred additions outside RPS states or not linked to RPS targets, which has driven RPS capacity additions downward. For example, Texas is responsible for part of that growth, but it had already achieved its RPS targets in 2008, 7-years ahead of schedule. Hence, one might question the importance of RPS targets in fostering capacity growth outside the RPS space.

On top of that, states continue to make revisions to RPS policies. More than half of the 29 states with RPS eligibility have raised their targets, with most revisions in recent years. Left to question is the compliance of RPS targets. If compliance is not often achieved, then capacity projections driven by those targets might be unreasonable. Nonetheless, the most recent data available for each of the 29 states shows that generally, targets are met. According to Berkley Lab, except for New York, Washington, and New Mexico, all the remaining states have attained their targets.

This analysis led us to believe that the projections made for wind capacity and solar capacity in the U.S. are reasonable, with a higher possibility of being surpassed if states continue to revise and attain targets upward, rather than being missed.

In **Canada**, the Canada Energy Regulator projects capacity to reach 19 964 MW of wind installed capacity by 2030. In 2019, Canada had 13 413 MW, translating into a 3.7% CAGR for the period. These numbers are supported by the continuation of domestic policies concerning renewables and electricity grids in Canada, like the grid being 95% non-emitting by 2040.

As previously, the achievement of these targets was questioned by looking at the past years. Due to the available information, projected wind capacity additions can only be assessed on a year-by-year analysis from 2017 onwards (*figure 32*). For 2020, based on available data, the analysis point to an estimation error of ~-2% due to construction delays in the region brought by COVID-19.

As a result of this analysis, we cut the future targets by 2.1%, last year's estimations miss. Hence Canada's wind capacity will not surpass 19 278 MW by 2030, growing at 3.3% CAGR 2020-2030 (*figure 33)*.

Brazil

Brazil's renewables capacity has been driven by auctions held by the Brazilian Electricity Regulatory Agency (ANEEL). Due to the current health crisis, the Ministry of Mines and Energy (MME) announced that it would postpone, but not cancel, an A-4 auction expected to 2020 that seeks for solar PV, wind, hydro, and biomass projects (Portaria nº 134, de 28 de Março de 2020).

From 2020 onwards, we considered that the projections of PDE 2030 are also reasonable given it is expected the reintroduction of the A-4 auction postponed and the scheduled auction to award

15-years PPA in 2021. Furthermore, a historical analysis of the capacity projected and the year's effective capacity reveals that PDE projections tend to be surpassed every year (*figure 34*).

Hence, we believe wind capacity in Brazil will reach 39 475 MW in 2030, and 10 622 MW in 2030 for solar PV (*figure 35)*. The region's extensive resource availability is set to continue increasing wind and solar projects' attractiveness supporting capacity additions.

Competitive positioning

The growing awareness of investors about climate change and sustainability will keep pushing companies towards a cleaner asset mix. Furthermore, climate targets will require higher investments in green energy sources from all industries, from utilities to oil and gas companies.

Large utilities

Over the past years, utilities to the likes of Iberdrola, EDP, Nextera, Enel, CEZ Group, RWE, among others, have followed a diversified, integrated business model comprising generation, networks, and commercialization.

EDPR is a power generation company that focuses on renewables, and these large integrated utilities are shifting attention to renewables generation, competing for their market share.

Despite only displaying European utilities, NextEra was also analyzed but not included, given the Company does not provide the amount of CAPEX focused on wind and solar. However, according to their strategic plan, investments of ~$13 billion p.a. are expected. We estimate that ~35% of it is destined for wind and solar, based on the announced targets of capacity by 2022 (*figure 36 and 37*). For regions like Brazil, no significant conclusions were taken from the analysis of Eletrobras and CPFL Energia, with these companies tending more to hydropower than solar and wind.

Considering all, we expect large utilities to continue expanding their share in renewables generation for the foreseeable future, increasing the competition in the renewables power generation industry.

Power producers

A direct competition source comes from the independent power producers (IPP) in the wind and solar industry. The list comprises companies with a similar weight of wind and solar in the mix relative to EDPR.

Under the power generation sector, plants' downtime impacts generations and, therefore, projects' capacity factors. According to *Martini et al.,* 2018, capacity factors can decrease by 1.5% when plant failures exist[6]. As some of the downtimes are not preventable, like the hours at which the energy source is unavailable (e.g., night hours for solar PV power plants), others are. The other primary source of downtime at power plants comes from maintenance activities that can be optimized and managed to minimize forced outages. In this matter, EDPR shows an edge in managing maintenance activities and other *OPEX costs (figure 38).* Note that *Core OPEX* was analyzed per average MW and not per MWh generated to ensure better comparability across companies. It was understood that if otherwise, the ratio would be distorted by wind and solar availabilities (e.g., speeds and GHI), which do not directly impact costs included in the OPEX like personnel costs, for example.

[6] Study considers different scenarios of failures and times of reparations.

From 2014-2019, the gap between EDPR's *Core OPEX per avg. MW* and its peers have been decreasing as more companies keep focusing on cost optimization. EDPR's maintenance plan includes self-perform initiatives that enable segregation and insource of main value-added maintenance activities. Even though these plans have lowered *Core OPEX per MW*, we believe that EDPR's edge has other explanations. The dependency on one single supplier lowers companies' ability to negotiate better terms when using third-party services (e.g., maintenance, engineers). Hence, we analyzed the number of suppliers for EDPR and its peers (*figure 39*) and concluded that the larger number of suppliers of EDPR ensures a better negotiating power and diversification not attainable by its competitors. A caveat for China Longyuan that has eleven suppliers. Nonetheless, all its suppliers are located in Asia, mainly China. In contrast, EDPR's suppliers are scattered across Europe, North and South America, reducing the risk of a shortfall in equipment supply in one of the regions.

A new set of competitors

As mentioned previously, investors' continuing awareness about climate change and sustainability is pushing all types of industries to adjust their business models to a greener and sustainable culture.

Investors' focus on sustainability is stemming oil and gas companies to expand their renewables production capacity. Such increases will be dependent on the returns of renewable projects. Nonetheless, some companies have already started the transition *(figure 40)*. Oil companies' commitment to increasing renewables capacity may reflect higher growth rates of new additions relative to utilities and IPP, but solely because of a lower starting point.

For the next decade, utilities and IPP are expected to continue to dominate the electricity market. However, the entrance of oil companies in the game is expected to be an enduring trend due to the continuing cost attractiveness of renewable sources.

Peers selection

The selection of peers for EDPR combined two analyses based on different sets of companies. Due to the size differences of EDPR to other IPP, we also considered utilities as possible competitors.

We selected three indicators (EBITDA margin and the expected revenue growth) to narrow the group. We concluded that EDPR is significantly more in line with IPP than utilities from the margins' analysis (*figure 41)*. Apart from generation, the services rendered by utilities, like distribution and commercialization, explain the difference in margins. Hence, we selected the group of IPP to analyze.

We disregarded peers within this group with less than five years of returns as their series of returns provided no confidence in future performance (Neoen and Omega Geração).

Moreover, we excluded Voltalia due to the higher expected revenue growth (~44% for 2021). Such revenue growth is sustained by the services segment in which Voltalia provides engineering and maintenance services to third-party clients. In 2019, 52% of the revenue growth came from the services segment[7]. We understand from the Company's strategic plan that this segment will continue to be a significant growth pilar. This segment does not resemble EDPR's operations, therefore we excluded the Company from the peers' list. The final peers' list can be seen in

[7] Revenues of 2018 were restated to exclude the impact of a non-recurrent pricing in Brazil. Otherwise, revenues would have declined in 2019 YoY.

appendix 8.

Corporate Governance

The following section considers the structure of governance implemented by EDPR in the past years. However, the ongoing judicial procedure has forced some changes, with the chairman and CEO being suspended from activity. EDP group has already appointed new interim replacements. For now, we expect the governance model to maintain its current model. Nonetheless, we call the investors' attention to the possibility of further changes in the future. At the date of this report, there is no more information on this matter.

EDPR's BoD is composed of 15 members, of whom 11 are non-executive, including 6 independents. The remuneration policy consists of a fixed plus a variable component (only for executive BoD members) based on the achievement of pre-defined KPIs (*appendix. 13).*

Following the *IPCG Corporate Governance Code*, EDPR sets up three delegate committees (Executive, Audit, and Nominations & Remunerations). EDPR's concentration ownership *(figure 42)* is the major risk that minority shareholders are exposed to. EDP elects' part of the management team of EDPR and controls the approval of any relevant corporate actions (e.g., M&A, increase/reduce capital, bylaws) under a one-share-one-vote scheme (proxy votes allowed).

On top of that, there are three additional risks that minority shareholders are exposed to. The first one concerns the lack of independence of the BoD, with only 40% of independent members in 2019, following a decreasing trend from past years *(figure 43).* Despite this trend, important committees such as the nominations and remunerations remain composed only by independent members.

Secondly, we believe that the executive committee lacks supervision from an independent committee to oversee its performance. A structure like a two-tier rather than the current one (one-tier structure) reduces inefficient decision-making by the management board.

Thirdly, we highlight a perception risk brought by the few skin in the game of the BoD. At 2019YE, only one executive director owned EPDR shares directly, and considering indirect holdings, only the interim CEO, Rui Teixeira, holds EDP shares (figure 44).

Furthermore, investors should be aware of the increasing number of claims of violations of EDPR's code of ethics (+3 in 2019) and with the possibility of a tighter link between the KPIs determining variable remuneration and value creation measures (weight of net income vs. ROIC) *(appendix. 9).*