BRYAN, GARNIER & CO

Utilities & Energy Transition

How to face the intermittency challenge ?

January, 2022

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THEMATICS

As of September 2020, Bryan Garnier & Co's Equity Research is becoming more thematic-focused. This note is specifically addressing and illustrative of the following thematic

Protecting the environment- Tech for good

Given the urgent nature of climate change and in order to meet the various objectives of the energy transition, electricity needs to be produced in a more sustainable and ecological way. In this context, renewables are massively deployed leading to intermittency issues while electricity demand is rising.

How to face the intermittency challenge ?

Given the urgent nature of climate change and in view of the various objectives of the energy transition, the structure of the power grid needs to change. While electricity demand and intermittency issues are rising, several technologies can help to decarbonise the energy mix, as well as improve its resilience despite growing electricity demand.

- As renewables are increasingly contributing to the energy mix, intermittency on the grid is becoming a real challenge and threatens their future growth.
- This comes at the same time as electric vehicles are ramping up and destined to replace the entire fuel engine fleet in coming years, thereby representing a major dilemma in terms of intermittent power production that weakens power grids just as electricity demand (and the associated peaks) is taking off.
- Hardware storage (hydrogen, batteries, thermal storage) and software solutions (vehicle-to-grid, demand response, virtual power plant) are the missing blocks to further accelerate deployment of carbon-free electricity without intermittency issues.
- Growth in new technologies to answer the issues of intermittence and rising power demand is therefore set to involve pioneering companies specialised in this field.
- In this respect, we take advantage of this sector report to initiate coverage of Alfen (Buy, EUR105), Swedish Stirling (Buy, SEK22), Azelio (Neutral, SEK23.4) and HDF (Neutral, EUR24).

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Summary

Résumé

En vue des objectifs de neutralité carbone à horizon 2050, la majorité des gouvernements dans le monde a entamé une transition energétique. Afin d'atteindre les objectifs de neutralité carbone, les energies renouvelables sont perçues comme des énergies d'avenir. Compte tenu de leur déploiement considérable, leur coût a nettement baissé ce qui en fait aujourd'hui l'énergie la plus abordable. Simplement, ces énergies ont un défaut majeur, elles ne sont capables de produire que par intermittence, en fonction notamment des conditions météorologiques. Le réseaux, devant intégrer des moyens de production d'électricité chaque fois plus intermittent, est voué à devenir de plus en plus instable. D'autant plus, qu'en parallèle, se déploient les voiture électriques, censées remplacer la totalité des moteurs à combustion au cours des prochaines années. Nous sommes donc face à un dilèmme majeur, celui d'une production d'électricité intermittente et fragilisant le réseaux à un moment où la demande d'électricité (et les pics associés) ne cesse d'augmenter. Face à cette problématique, plusieurs solutions innovantes apparaissent. D'abord les plus connues, rassemblant les moyens de stockage d'électricité tels que les batteries ou encore le stockage thermique. Ensuite, les plus innovantes, souvent basées sur des technologies logicielles comme le « demand response » (consistant à modifier la demande des consommateurs pour soulager le réseau), le vehicule-to-grid (V2G, imaginant les batteries des futures voitures électriques comme un moyen supplémentaire d'approvisionner le réseau) ou encore, les « virtual power plants », dont l'objectif est d'agréger des capacités de production au travers d'une plateforme virtuelle. L'atteinte des objectifs de lutte contre le réchauffement climatique n'est possible que si le réseau électrique est capable de dépasser les contraintes liées à l'intermittence du renouvelable. Il n'y a pas une mais bien plusieurs solutions. Nous les exposons dans cette note à travers les initiations des sociétés suivantes: Alfen (Achat, EUR105), Swedish Stirling (Achat, SEK22), Azelio (Neutre, SEK23.4) et HDF (Neutre, EUR24).

Executive Summary

In view of carbon neutrality goals for 2050, the majority of world governments have implemented energy transition strategies. As CO2 emissions are an integral part of fossil-fuel combustion (coal, natural gas, oil), other means of producing energy have had to be found. In this backdrop, wind and solar power are increasingly perceived as energies of the future given that they use unlimited resources and require no combustion to action power generating turbines. The various world continents, with western societies leading the pack, are currently rolling out renewable energies on a wide-scale with the aim of making them the main source of power generation over coming decades. This widespread deployment has prompted a clear decline in the cost of renewables, thus making it a more affordable energy source. But renewable energies have one major disadvantage: they can only generate power intermittently, especially if they depend on weather conditions. Power grids must integrate increasingly intermittent power generation sources and are destined to become increasingly unstable. This comes at the same time as electric vehicles are ramping up and destined to replace the entire fuel engine fleet in coming years, thereby representing a major dilemma in terms of intermittent power production that weakens power grids just as electricity demand (and the associated peaks) is taking off. To face this issue, many innovative solutions are emerging. Firstly, the most well-known which combine electricity storage means such as hydroelectricity, batteries and thermal storage, and secondly the most innovative, often based on software technologies such as demand response (consisting of modifying consumer demand to regulate the grid), vehicle-to-grid (V2G, imagining future electric cars as an additional means of supplying the grid), and virtual power plants, the aim of which is to aggregate production capacities through a virtual platform with the aim of being active in the electricity market. Growth in new technologies to answer the issues of intermittence and rising power demand is therefore set to involve pioneering companies specialised in this field. In this respect, we initiate coverage of Alfen (Buy, EUR105), Swedish Stirling (Buy, SEK22), Azelio (Neutral, SEK23.4) and HDF (Neutral, EUR24).

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Energy mix must change to reach 2050 targets

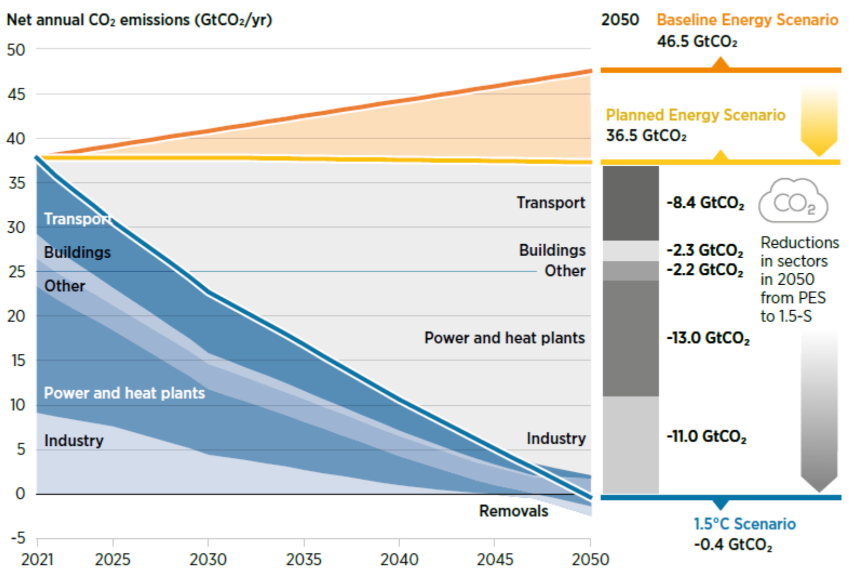
With 195 governments having agreed to the text known as the Paris Agreement (2015), nearly every country in the world is committed to lowering greenhouse gas emissions in a bid to offset the effects of global warming.

The main objective of this international pact is to prevent global temperatures from rising above pre-industrial revolution levels by 2°C and ideally, to limit global warming to 1.5°C by 2100.

Numerous efforts have been made over the past decade with governments and markets resolutely opting for a renewable-based energy network. Over 195 countries have renewable energy targets while innovations related to new types of energy have been intense. However, the energy transition translates into technical and economic challenges (high investments, new ways of living, new regulations etc.).

While the agency acknowledges that efforts have been made to decarbonise our economies (new energy systems emerging and complemented by green hydrogen and modern bioenergy), we are still well far from the 1.5°C target. Indeed, to reach this goal, global CO2 emissions need to fall from 35-40 Gt to 0 within the space of 30 years. Since power and thermal plants are the highest contributors (13 Gt of CO2 per year in 2018), the implication is clearly that power networks need to be rebuilt.

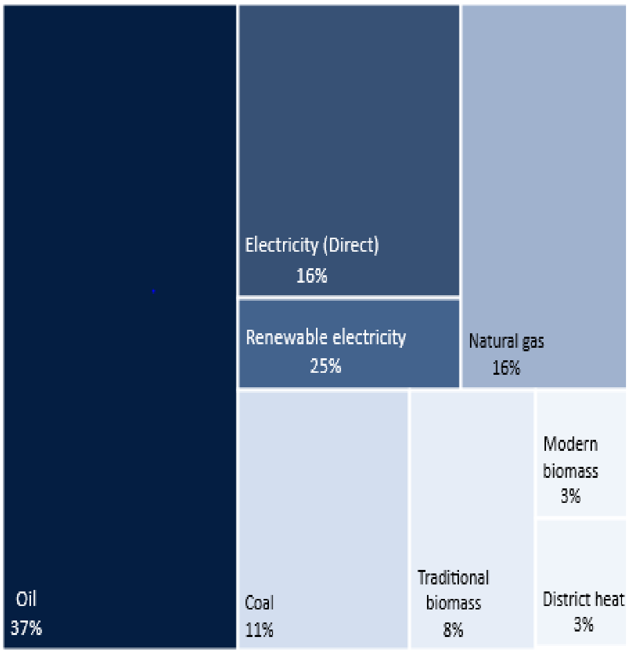
Fig. 1: Global CO2 emissions need to drop to net zero by 2050



Source: IRENA, World energy transmissions outlook, 2021

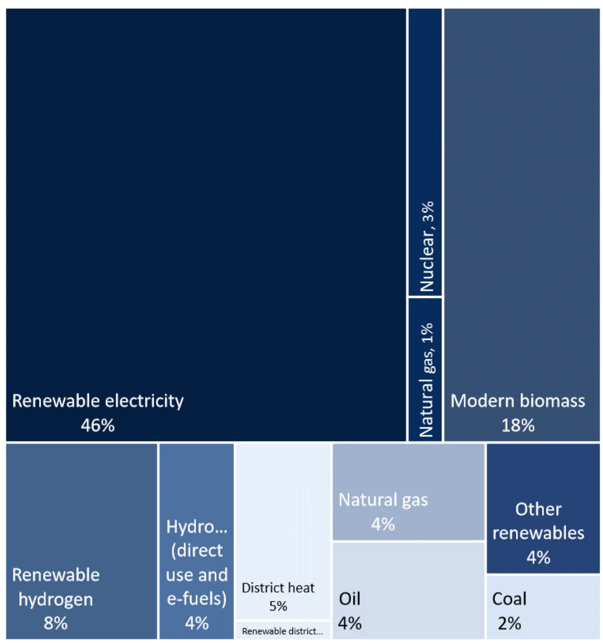
Consequently, the energy consumption mix needs to radically change over coming decades. Electricity and renewables will be on the main stage since electricity is set to rise from 21% to more than 50% of the energy mix. Moreover, whereas only 25% of electricity is generated from renewables today, the IRENA is targeting a share of more than 90% by 2050. In other words, the share of renewables in the energy mix is set to rise from 5% in 2018 to 46% in approximately 30 years.

Fig. 2: Total energy consumption in 2018



Source: IRENA, World energy transmissions outlook, 2021

Fig. 3: 2050 targets



Source: IRENA, World energy transmissions outlook, 2021

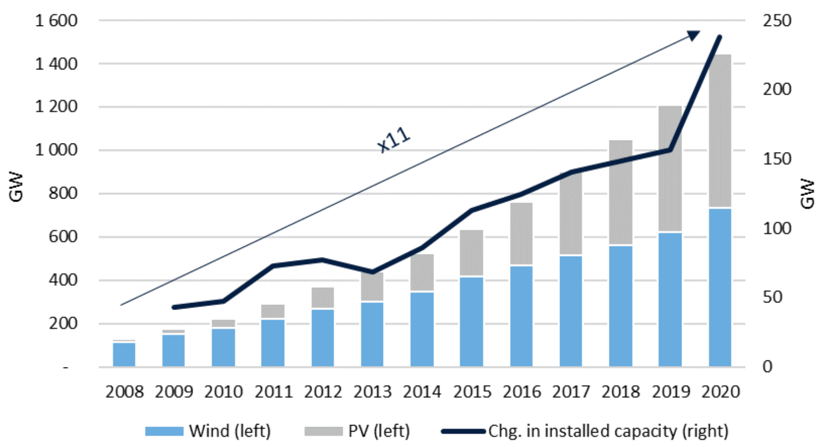
Global increase in wind and PV capacities

Against this backdrop, renewable energy appears as the best solution to face an increasing demand of decarbonized energy. Renewable energy sources are unlimited (continually replenished by nature, i.e. the sun, wind, water etc.) and can be used or transformed to generate energy, most often electricity (but also heat and chemicals).

Over the past few years, the power sector has been undergoing dramatic changes with the massive roll-out of renewables. Global renewable energy capacity additions in 2020 reflect this unprecedented momentum. Despite the economic slowdown caused by Covid-19, the world added more than 260 GW of renewables in 2020, exceeding expansion in 2019 by close to 50%.

In 2020, around 80% of all new electricity capacities were renewables, indicating that it is increasingly the preferred source of power production. Solar and wind in particular have enjoyed exponential growth over recent years, together accounting for more than half of total installed renewables capacity and 90% of new renewable capacities in 2020.

Fig. 4: Global increase in wind and PV capacities

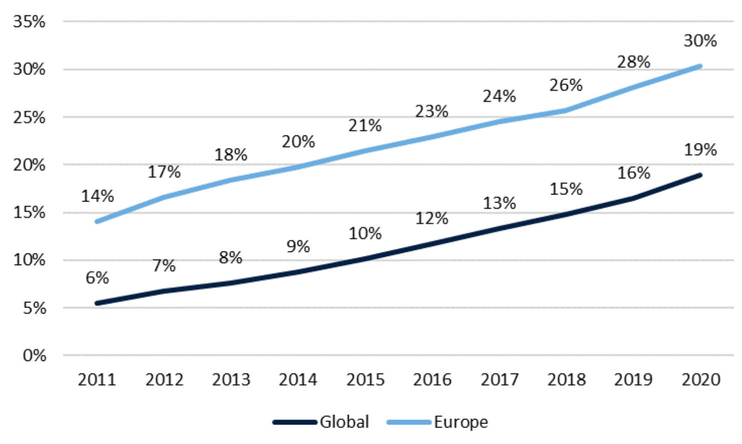


Source: IRENA

Between 2008 and 2020, global installed capacities of wind power increased from less than 115 GW to more than 730 GW, implying a CAGR of 17%. Over the same period, PV installed capacities increased from 15 GW to more than 700 GW, implying a CAGR of 38%.

As a result, wind and PV now represent around 19% of the global installed electricity capacity, up from 6% less than 10 years ago (in 2011). In Europe, the share of wind and solar PV is even more significant, now representing 30% of total installed capacity, vs 14% in 2011.

Fig. 5: Wind and PV share of electricity production capacities

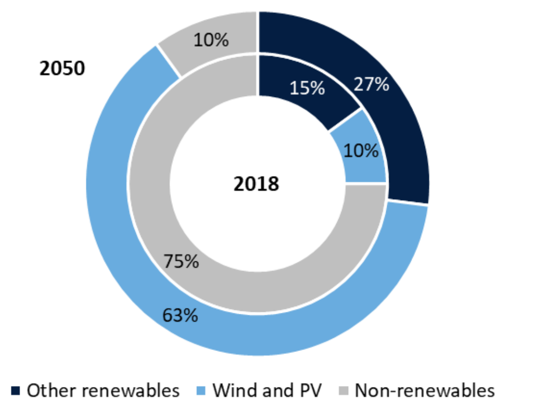


Source: IRENA

Renewables are expected to continue experiencing strong growth over coming decades and to contribute even more significantly to the energy mix. According to IRENA, in order to achieve the Paris Agreement's goal, the share of renewables in electricity capacity must increase from 33% in 2018 to 92% by 2050. Wind and PV will represent the bulk of this capacity, increasing from 15% in 2018 to 74% in 2050.

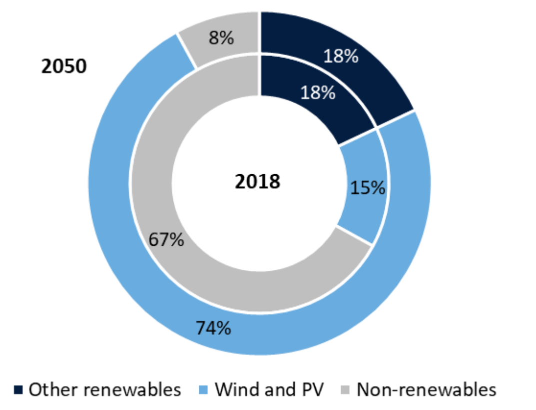
Wind and PV installed capacity are expected to expand from around 1,450 GW today to 22,100 GW in 2050, almost a 20-fold increase! This requires more than 650 GW of capacity addition every year, up from around 240 GW in 2020.

Fig. 6: Global electricity generation mix



Source: IRENA

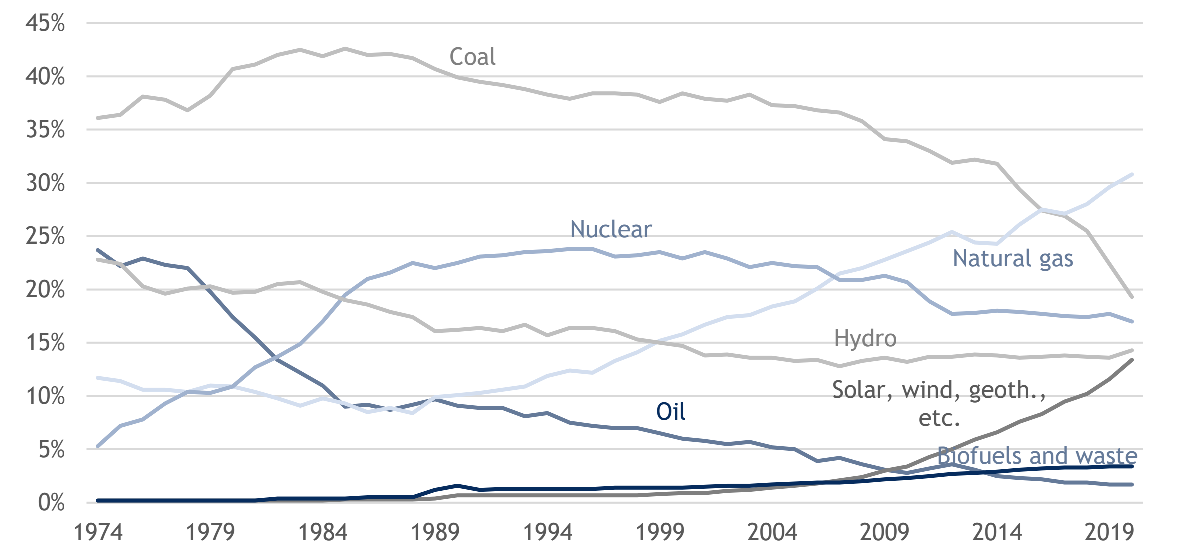
Fig. 7: Global electricity capacity mix



Source: IRENA

The overall renewable growth trend is illustrated in the chart below, showing the share of gross electricity production by source in the OECD countries from 1974 to 2020. Solar, wind, thermal and natural gas tend to strongly increase while coal and oil are experiencing a clear downward trend.

Fig. 8: Share of OECD gross electricity production by source over 1974-2020



Source: IRENA

Renewables are becoming the cheapest source of power

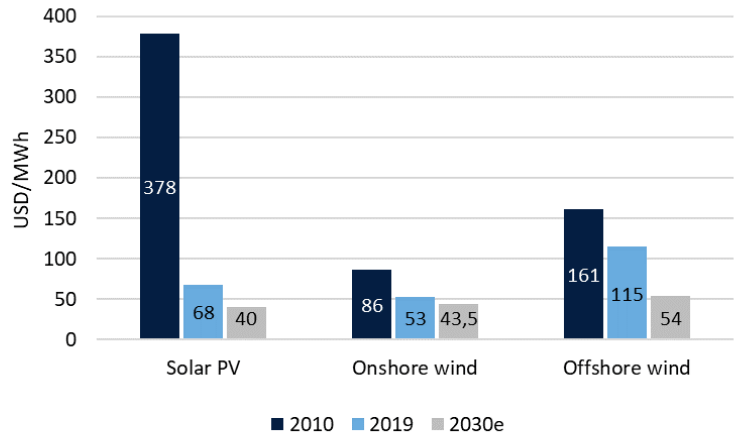
Strong growth in renewables has clearly been driven by the imperative to fight climate change, limit GHG (greenhouse gas) emissions and reduce air pollution. Governments have set up incentivised mechanisms to develop technologies and make them more efficient and affordable. Growing developer experience and increasingly competitive supply chains have also contributed to the competitiveness of renewables.

Between 2010 and 2019, the average LCOE (Levelized Cost Of Electricity) of solar PV decreased by 82%, from USD378/MWh to USD68/MWh and is expected to fall by a further 40% to USD40/MWh by 2030. Note that in 2020, an auction in Portugal set a record low price with a bid of USD13/MWh, beating the previous record of USD13.5/MWh set by JinkoSolar and EDF for a project in Abu Dhabi.

Onshore wind has also seen its LCOE decrease dramatically, from USD86/MWh in 2010 to USD53/MWh in 2019 (-38%). This is expected to reach USD44/MWh by 2030, implying a drop of close to 20%.

Last but not least, offshore wind, which is considered to be one of the most expensive sources of renewable energy, saw its LCOE decrease from USD161/MWh in 2010 to USD115/MWh (-29%) in 2019 and is also expected to plunge by an additional 53% to USD54/MWh by 2030.

Fig. 1: Average LCOE of renewables decreasing sharply

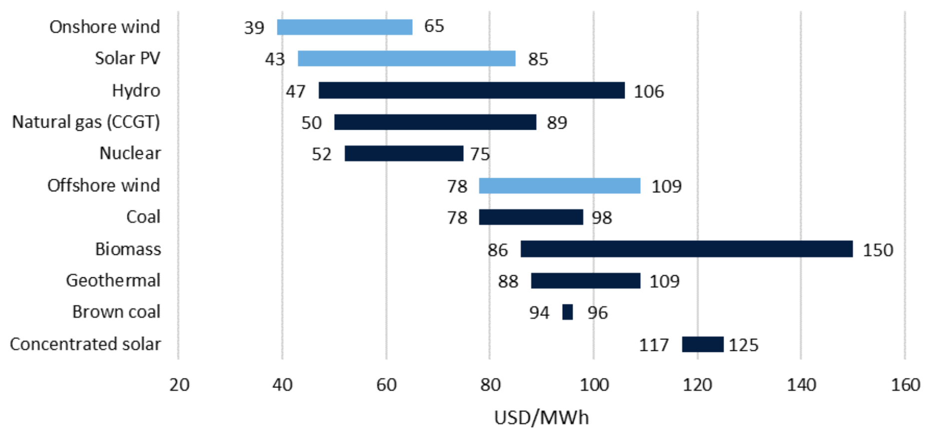


Source: IRENA

As a result, new renewable power projects now increasingly undercut existing fossil-fired plants. According to the IRENA, new PV and onshore wind power cost less than keeping many existing coal plants in operation, and auction results show this trend accelerating. In many regions renewables are now the cheapest source of power.

> " We have reached an important turning point in the energy transition. The case of new and much of the existing coal power generation, is both environmentally and economically unjustifiable. "
>
> Francesco La Camera, Director-General of the IRENA

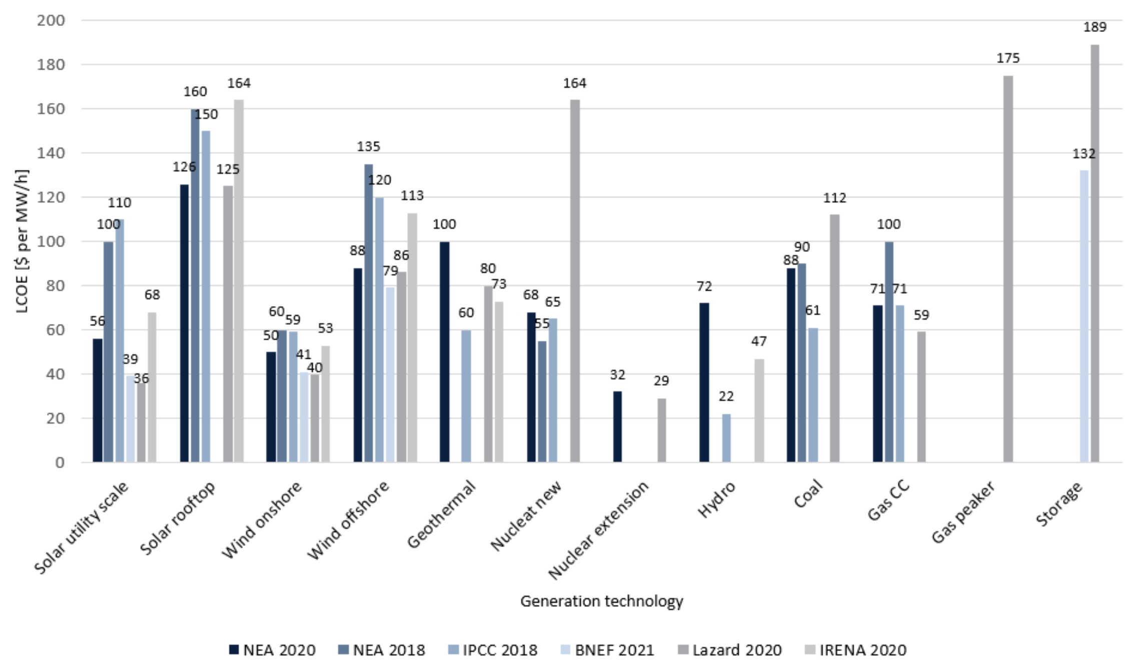
Fig. 2: Comparison of LCOE by fuel type (1st and 3rd quartile)



Source: Lazard

To obtain a broader view of LCOE estimations, we have also compiled cost calculations stemming from several experts over 2018-2021. The ranking reflected in the following chart is the same: solar PV, onshore wind and nuclear extension remain the cheaper energy sources.

Fig. 3: 2018-2021 LCOE estimates by research expert

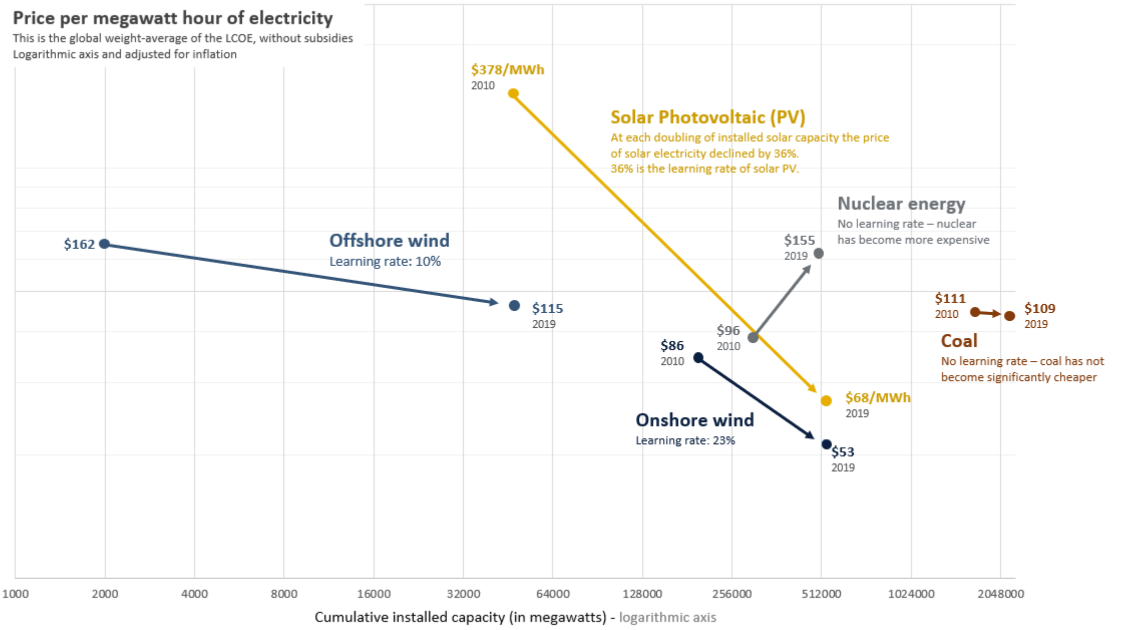


Source: IRENA, NEA, BNEF, Lazard

Another way of looking at LCOE is to look at the learning rate: a price variation is calculated at each doubling in the energy source capacity. The goal is to see the price evolution in relation to the roll-out of capacities.

Although we noticed some discrepancies with Lazardes estimates, notably for offshore wind and nuclear which appear more expensive, this chart shows the learning rate of each different energy source since 2010. As we can see, solar PV and onshore wind boast the biggest price decline.

Fig. 4: Learning rate of solar PV, wind, nuclear and coal



Source: IRENA

Carbon prices are an important tool in the implementation of the energy transition roadmap. The increase in the price of carbon is set to create strong financial incentives for polluters to reduce their emissions and invest in carbon-free technologies.

In 2020, carbon prices in Europe rose by 33% despite the slowdown in economic activity and lower emissions. Prices were driven by the EU's pledge to remove a big chunk of the permit glut annually and the decision to increase its 2030 emissions reduction target from 40% to 55% versus 1990 levels. These elements were strong buy signals for industrials and investors.

Prices are expected to continue to increase as the trading scheme could be expanded to new areas like building emissions, while tightening the market to reflect the tougher targets. Some investors are betting on a carbon price of EUR100/ton as early as this year.

Fig. 5: Carbon price in the EU ETS

Source: Ember

…is causing intermittency issues

Intermittency as a direct consequence

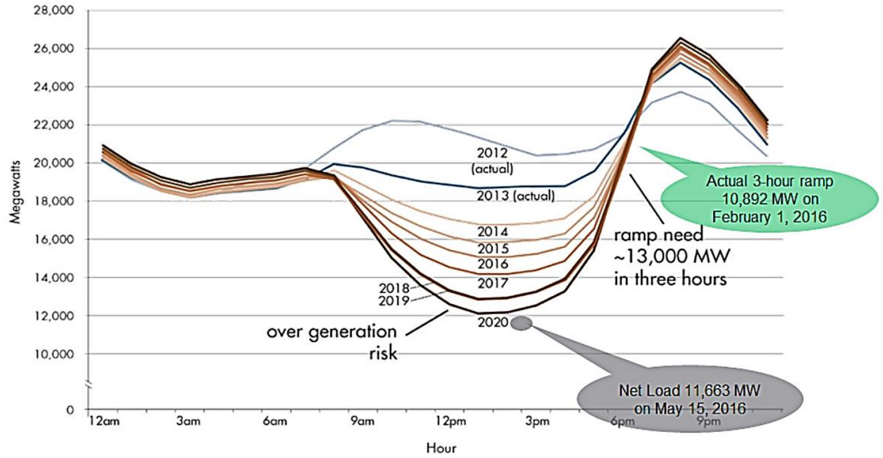
Whereas the rising weight of renewable energies in power generation is necessary to reduce CO2 emissions, this presents new challenges for power generation and the grid. Indeed, renewable energies are for the most part intermittent, contrary to conventional energy sources that are more stable and foreseeable.

Solar PV power is intermittent by nature since it depends on the sun and weather conditions.

Sun levels, like wind levels for wind power can be partly anticipated, thereby allowing for other sources of production to take over. However, forecasts are not perfect and the replacement with other energy sources is not immediate. As such, the higher the share of renewable energy sources, the more complex constraints are for the grid. In addition to having to manage variable demand, the network needs to manage supply that is also increasingly variable.

The challenges in question are highlighted by the "duck curve" drawn up by CASIO (California Independent System Operator), the company that manages the California electricity transmission network. This curve corresponds to electricity demand less PV production, namely the residual demand that needs to be satisified by other energy sources (nuclear, gas, coal etc.).

Fig. 6: The CASIO "duck curve"



Source: California Independent System Operator

The shape of the curve and its change are explained by 1) the gap between electricity consumption and PV generation, and 2) an increasingly high contribution from PV.

The curve shows that at around 4 a.m. net demand picks up slightly as people begin to wake up, while it is still too early for solar to contribute to the energy mix. At around 8 a.m. the sun comes up, PV generation ramps up and energy sources such as gas and coal gradually have to reduce their contribution to the energy mix (in accordance with the merit order principle). Solar PV power continues to gain momentum until around 3 p.m. and then gradually falls off as the sun goes down. Traditional energy sources then return gradually to the mix. At around 8 p.m. household consumption is at a peak, with electrical appliances in use, whereas PV generation is virtually at zero. Power generation is then ensured by conventional energy sources. As of 9 p.m. electricity consumption declines sharply as household and corporate activity falls to a minimum.

The duck curve shows that the more renewable energies the energy mix includes, the more the grid needs to be flexible and react quickly as well as absorb wide variations in the mix.

The 2012 curve is more stable than that for 2020 since the contribution and hence the influence of PV power was lower. The reactiveness necessary for the network to meet changes in the mix is reflected in the slope on the curve. For 2020, the slopes are far steeper, the network needs to absorb the changes more quickly. In 2012, the maximum level of the curve was slightly less than 24,000MW and the minimum 18,000MW, or a difference of less than 6,000MW. In 2020, the minimum level is estimated at 12,000MW and the maximum at more than 26,000MW, or a difference of 14,000 MW, more than double the previous amount. This difference is likely to grow even further in coming years with the ramp-up in solar PV.

These conclusions are not only valid for solar PV but can also be transposed to other sources of intermittant energy. The same exercise for wind power also shows far more erratic variations, less foreseeable and hence increasingly demanding constraints.

Frequency volatility can damage the grid

As we have just seen, one of the main issues related to renewable energies is the strong decorrelation between production and consumption. Solar farms do not produce power at night and wind farms do not generate power on a calm day. Renewable power therefore generates electricity only when climate conditions are met.

While conventional power had to face CO2 emissions and their impact on earth, the main challenge for renewable energies is clearly the ability to produce uninterrupted and stable power to answer energy needs.

According to the Kenan Institute (an American think-tank related to the university of Duke), renewables intermittency has several impacts on grid stability:

The second-minute to minute fluctuations: variations in power intensity occur when sunlight suddenly decreases because of a passing cloud or when the wind calms. Current grid operators are accustomed to constant voltage and frequency, i.e. very small fluctuations.

Normal fluctuations are managed on a second-by-second basis to maintain power quality. These variations are compensated for by adjusting the power generated by on-line plants (virtual centres that coordinate power production). With renewable energies, these power fluctuations increase due to intermittency. On-line plants will have to adapt to the increase in power volatility.

The mismatch between average renewable power generation and average electricity demand on a daily basis: the average demand curve shows that demand first increases in the morning and then falls off in the middle of the day before ramping up again at the end of the afternoon and reaching a peak early evening.

In contrast, a solar farm produces nothing at night, ramps up with demand in the morning but continues to rise and reaches its peak in the middle of the day, before finally declining just when peak consumption is reached at the end of the day.

Consequently, a power grid relying on renewable energy must also manage back-up systems to fill the gaps when renewable power cannot be supplied. This back-up system could involve a power plant operating in part-time mode, on demand, thus making it far from efficient in cost terms of costs.

The ability to match the rise and fall of power demand over the day. Strong differences in the velocity of demand ramps can occur from one day to next. For example, on a very hot day, demand related to air conditioning can surge leading to a sharp increase in power demand. Solar and wind farms can produce what the weather allows them to produce at that time. Consequently, the ability of renewable energy to follow a strong demand ramp-up is limited.

One of the consequences of this mismatch is the generation of surplus solar power during the afternoon peak or the peak in wind at nightime.

If customers do not need the renewable power, other dispatchable power must be cut. This can involve curtailment or shutdowns of fossil fuel or nuclear plants which are expensive actions.

Finally, an important issue resulting from renewables intermittency concerns low capacity factors. Over the year, solar farms can generate about 20-25% of their nameplate capacity. For wind farms, the efficiency ratio can reach 40-45%.

This is well below conventional power plants which stand at close to 85% for combined cycle natural gas and more than 90% for nuclear energy.

The low capacity of renewable energies is explained by their intermittency: solar does not produce anything at night and produces less than the nameplate capacity depending on sun intensity, weather and season.

These low capacity factors as well as variability that is hard to predict (historical statistics show variations from one year to another) put renewable power in a weak position to fit with base load generation needs.

In addition, the more renewable power is added to the grid, the more the grid is challenged since it has to deal with large amounts of surplus power but also large reserves of dispatchable power to compensate for weather and seasonal fluctuations.

Consequently, a power grid mainly working with renewable energies is no possible without additional innovative storage technologies such as batteries, thermal storage or hydrogen.

Shutdowns can occur if nothing is done

According to a report published by the Intergovernmental Panel on Climate Change (IPCC), energy consumption at the end of the current century should be 2.5x higher than it is today. This surge in energy consumption implies a strong ramp-up in renewable energy (40-50% of the energy source by then) to allow a reduction in greenhouse gases.

As such, rising energy demand in coming years will be reflected in global electricity generation. However, the real challenge stems from the difficulty in combining a renewables ramp-up favouring clean energy, with demand for electricity at all times.

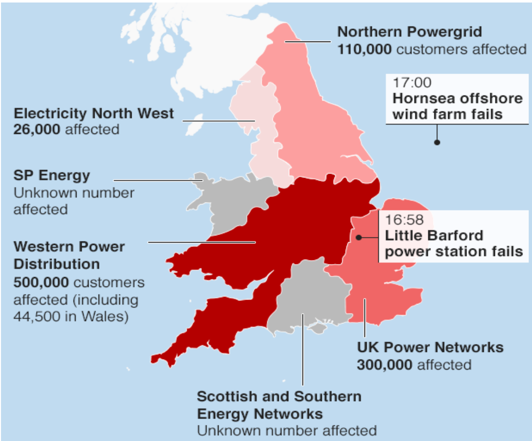
The electricity market is generally based on historical customer behaviour and forecast supply that electricity companies make available to the operator. This expected demand is then adjusted in real time to the true level of consumption during the day thanks to multiple generation resources.

The bulk of the power is still provided by large thermal and nuclear power plants which operate at a constant power level. Adjustments are made by connecting/disconnecting or varying the power of each power generation unit like hydroelectric stations, conventional power plants or renewable power units.

However, with renewable energy sources contributing more and more to our energy mix (37.5% of the German energy mix is made of up wind and solar), challenges for the energy grid are growing since renewable plants do not offer the same adjustment options as conventional units. This is explained by the limited availability of sunlight or wind and also by the difficulty in controlling the level of power injected into the grid. Therefore, important swings due to intense or lacking power production caused by meteorologic events affect the operators' adjustment capacity.

The main risk related to the intermittency of renewables is that of a blackout. This risk is not just theoretical and has already been proven. In August 2019, a blackout affected more than one million homes in the UK. The country's power provider, National Grid said the incident followed a halt of around two minutes at a gas-fired power plant and then at one of the biggest wind farms in the world located in the North Sea. Other significant blackouts took place in the UK in 2003 and 2008. These events unfortunately demonstrate that power grids, even in the most well developed countries, are not yet suited to the future energy mix. The grids need to evolve and innovate to become more resilient.

Fig. 7: Clients affected by the blackout of 9th August 2019



Source: BBC

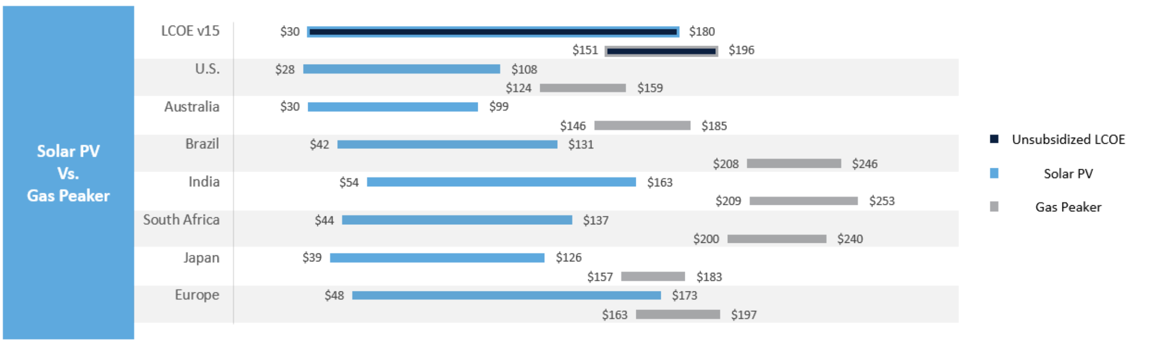
Fig. 8: A blackout of national scope

Source: Channel 4 News

Intermittency also affects the energy cost

Since storage resources have not been fully rolled out in all places using renewable energy sources, back-up power sources are used to provide dispatchable power during peak demand and/or when renewable energies are not working. These back-up power sources are peakers (coming from peaker plants) or combined cycle gas turbine (CCGT).

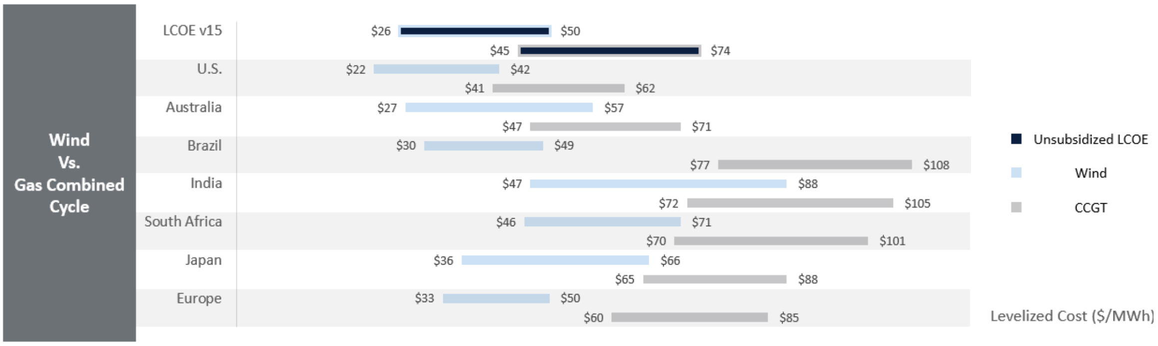
Fig. 9: Comparison between solar PV LCOE per country and CCGT LCOE



Source: California Independent System Operator

These plants are able to start quickly and then to rapidly provide electricity to satisfy high demand while the renewable power source is down. However, these plants have a far higher cost than renewables: according to Lazard and depending on the country, LCOE of peakers or CCGT can range from USD40 to USD253/MWh, thereby raising the overall cost of electricity in a place where renewable are well established.

Fig. 10: Comparison between wind LCOE per country and CCGT LCOE



Source: California Independent System Operator

Current electricity prices in Europe perfectly illustrate the need for alternative electricity production sources to avoid price surges. In 2021, the combination of meteorological conditions (lack of wind and winter season) with huge tension on natural gas sources due to the post-lockdown economic catch-up, notably in Asia, led to a sharp electricity price increase (higher demand, lower supply).

Consequently, in order to liberate current grids from costly and conventional energy based back-ups, alternative solutions should be developed and installed over the coming years.

Roll-out of electric vehicles prompting peak in electricity demand

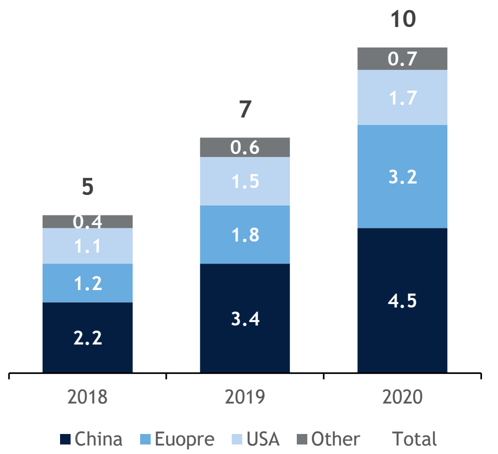
Sharp growth in electric mobility

In addition to facing the intermittency of renewable energies, the power grid also needs to face rising demand for power. Consumption is set to climb further in coming years, not least because of the expansion in electric mobility. While the share of electric vehicles (EV) in the overall vehicle fleet remains low today, it is set to increase in coming years.

In 2020, the global EV fleet exceeded 10m units, up 5m relative to 2018 (+100%). Europe was the main market with almost 1.4m vehicles sold in 2020 and a fleet of 3.2m vehicles, or around 32% of the global total. China had the biggest fleet of approximately 4.5m EV in 2020.

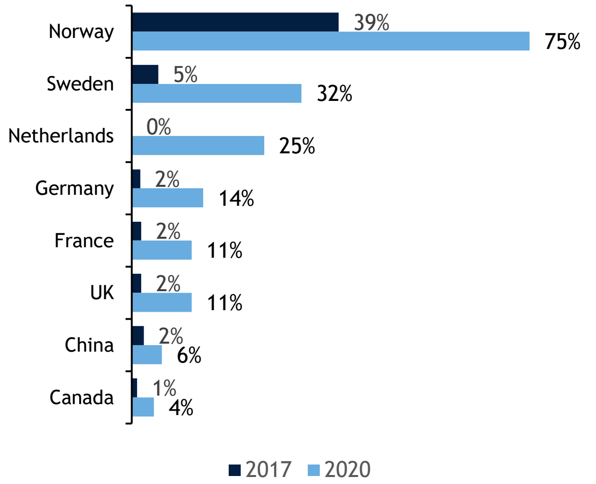
Norway is the most advanced in development of electric mobility: in 2020, EV's represented 75% of sales. Sweden followed with a 32% market share and Netherlands with 25%.

Fig. 11: EV stock by region (m units)



Source: IEA, Bryan, Garnier & Co

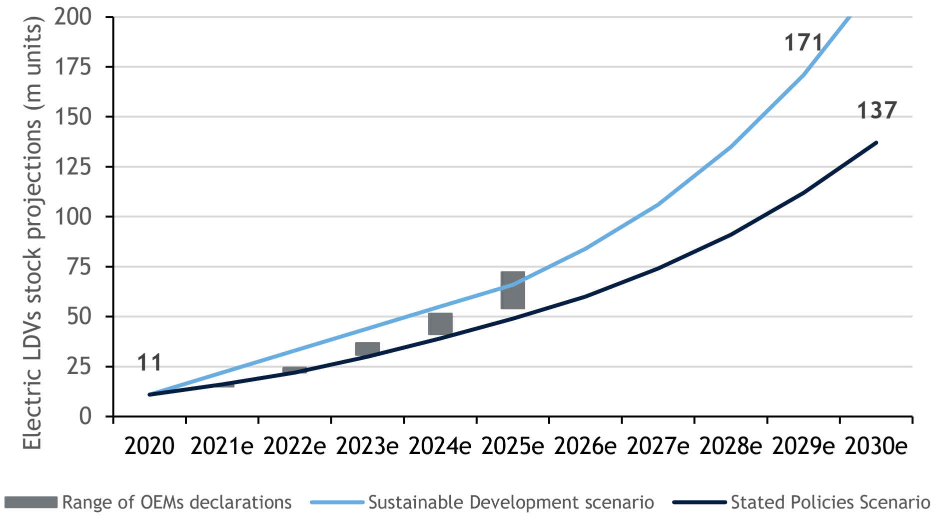
Fig. 12: Market share of EV by country



Source: IEA, Bryan, Garnier & Co

The IEA estimates that growth in the network of EVs should continue at a robust pace of around 30% a year over 2020-2030 according to Stated Policies Scenario (conservative scenario). The global stock of electric vehicles (not including two-wheelers) could be multiplied by more than 4 out to 2025, to reach 50m units, then 137m in 2030. Based on a more aggressive scenario, with a market share in sales of EV of 30% in 2030 (Sustainable Development Scenario), the EV global fleet could reach 220m units in 2030.

Fig. 13: Change in global EV stock



Source: IEA, Bryan, Garnier & Co

Communication by OEMs on their future sales of electric vehicles is now aligned with the most aggressive IEA scenario. Their product ranges are to be adapted to transform all the current segments to electric.

The Volkswagen Group has announced no less than 75 new models by 2025. The roll-out of incentive policies and/or restrictive regulations on thermal vehicles will be also key factors for growth in electric mobility. Norway for example has announced that light vehicles and public buses must be zero-emission by 2025. Other countries such as Israel and Sri Lanka are going even further. Not only will sales of polluting vehicles be banned, but so will those already in circulation.

Target of sales of EV from main OEMs (* European market, ** Chinese and US market)

OEM	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BMW					15-25%					
Daimler					25%					50%
Donfeng Motor		30%								
Ford						100%*				
Honda										40%
Renault-Nissan		20%								
Stellantis						38%* 31%**				70%* 35%**
Volkswagen						20%				70%* 50%**
Volvo						50%				100%*

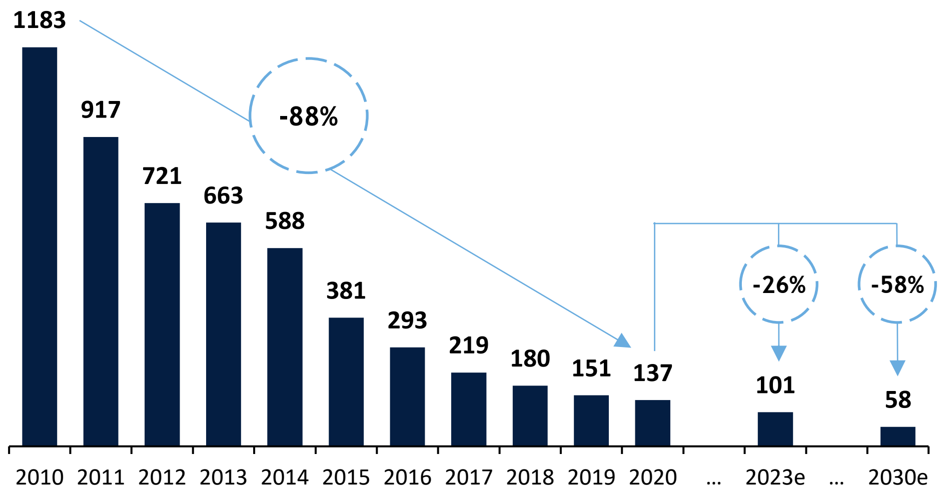
Source: Bryan, Garnier & Co

Growth in the stock of electric vehicles will also be encouraged by technological progress in terms of storage capacity and autonomy. Capacity should continue to rise to reach average autonomy of 350-400km. This implies having batteries of 70-80kWh, vs. around 40-75kWh with an average at 55kWh at present (variable depending on the markets, electric vehicles in the US have batteries with higher capacity).

For example, a Tesla Model 3 has a battery of 75kWh and offers theoretical autonomy of around 500km. A Renault Zoe has a battery of 41kWH and autonomy of around 250km.

The decline in battery production costs is also set to be an important factor for growth in electric vehicles. In 10 years, the lithium-ion battery prices were divided by almost 10, from USD1,183/kWh to less than USD140/kWh (-88%) and the trend is expected to continue. Prices could reach the 100 USD/kWh mark by 2023 (previously forecast for 2024 and already reached for the VW ID3) and reach around USD60/kWh by 2030. Economies of scale ought to participate in the cost reduction. Today, the majority of plants have production capacity of 3-8GWh/year, but some plants exist with capacity of more than 20GWh/year, while others are being built.

Fig. 14: Lithium-ion battery price in USD/KWh over 2010-30e

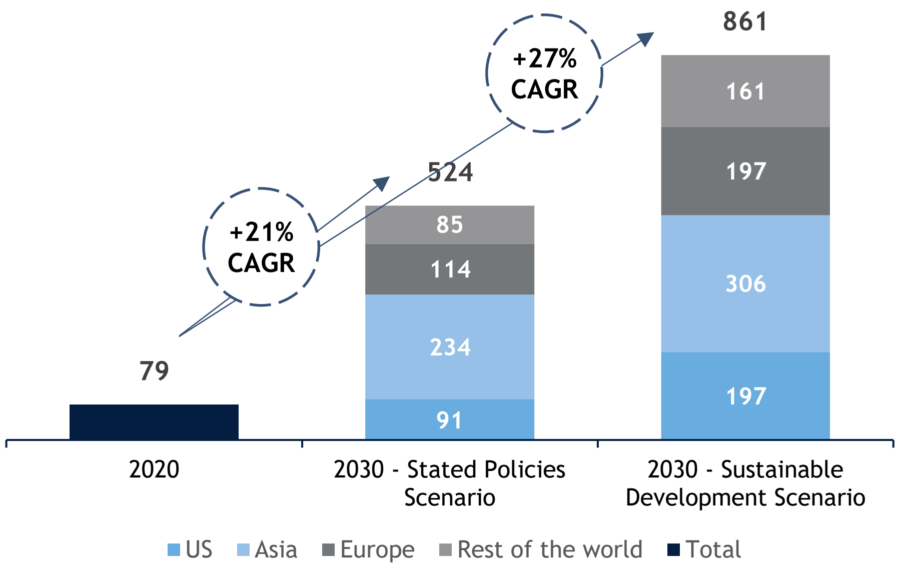


Source: IEA, Statista, Bryan, Garnier & Co

Growth in the fleet of EVs is also logically resulting in a simultaneous rise in electricity demand. In 2020, EV consumption stood at 82.2TWh (+4% compared to 2019), the equivalent of electricity demand for a country such as Belgium. The IEA estimates that, in its most cautious scenario, demand could reach 524TWh in 2030, or the equivalent consumption of Germany in 2019. In a more aggressive scenario, demand could rise to 861TWh in 2030, or the equivalent consumption of Germany and the United Kingdom together in 2019

In addition to rising electricity demand, the development of electric cars poses the problem of balancing supply and demand over one day. Indeed, whereas renewable energy output is highest during the day-time, electric vehicles are mostly recharged in the evenings or overnight when users return home. Expansion in electric mobility therefore adds another constraint for the power grid.

EV power demand by region (TWh)



While the impact on the power grid of expansion in zero-emission mobility is significant, it should be seen in perspective. Indeed, electricity consumption by EVs currently represents less than 0.4% of global consumption in 2020. Even in China, Norway and the Netherlands, where EV penetration is the highest, the percentage is not above 1%.

Assuming global production remains unchanged and EVs grow in line with the IEA's most optimistic scenario (Sustainable Development Scenario), power consumption by electric vehicles would only account for 5% of global demand in 2030.

How does development of autonomous vehicles affect growth in the stock of EVs?

At the same time as vehicles are becoming electric, they are also becoming increasingly autonomous. Today the technology is limited to maintaining vehicles in their lane or adapting speed levels to the vehicle ahead etc. The most advanced models in the field seem to be those of Tesla, whose Autopilot system is capable of determining the best route to take, navigating on roads (even with no ground markings) and moving into complex intersections with traffic lights, stop signs or round-abouts.

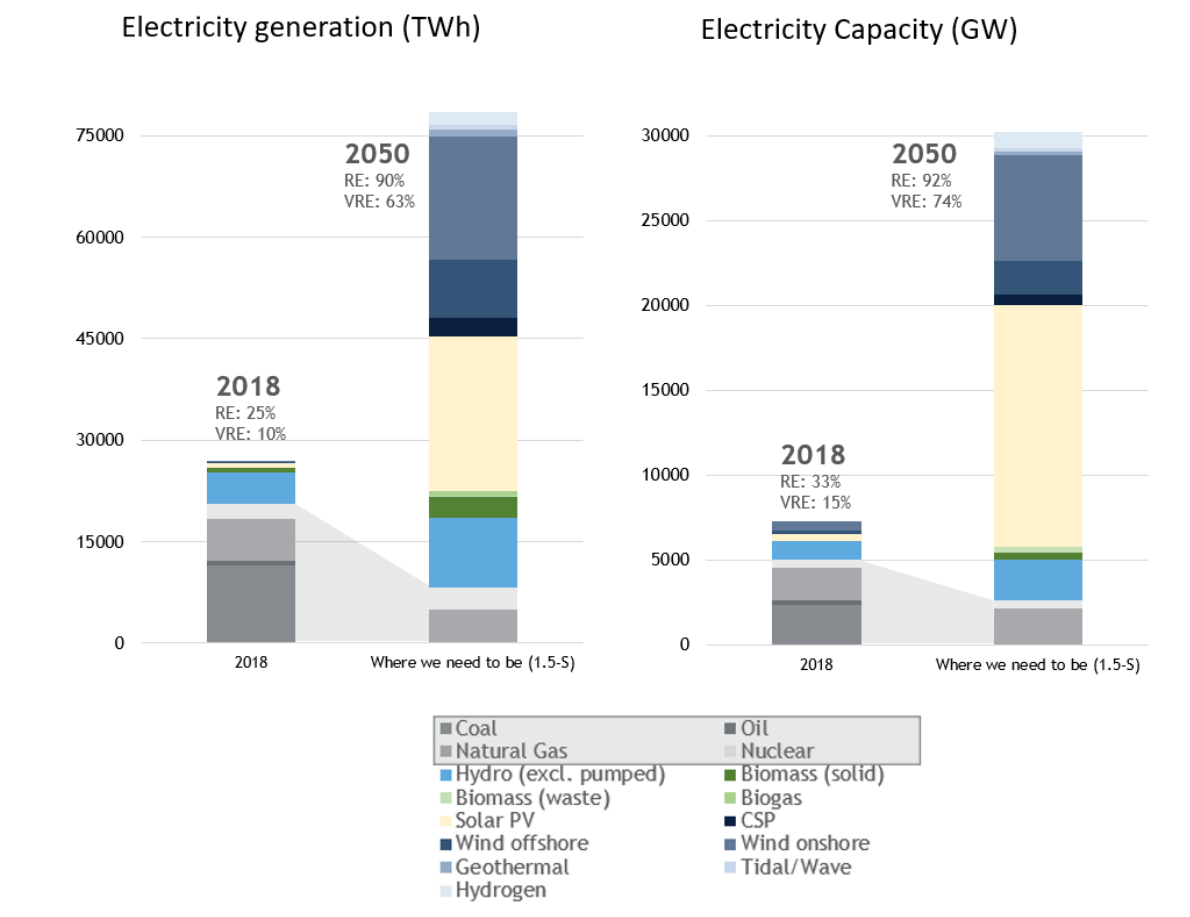
Once the car has become perfectly autonomous, it will become a simple utility vehicle and mere mobility tool. Relations between users and their vehicle will evolve. Cars will no longer be status symbols and driving for pleasure will exist no more. From then on, owning a vehicle will lose its importance. Users will tend to share utility vehicles, especially if they are capable of arriving on order. As such, the generalisation of autonomous vehicles could result in lower growth in the fleet of electric cars than in the scenarios mentioned above.

Peak demand for electricity

Increasing need for electricity

IRENA estimates that by 2050, electricity will become the most important energy carrier: the share of direct electrification in final energy consumption is set to reach c.30% by 2030 and could be above 50% by 2050 (up from 21% today). In all, electricity demand is set to triple compared with current levels and the share of renewables supply should rise to 90% by 2050 (vs 25% in 2018).

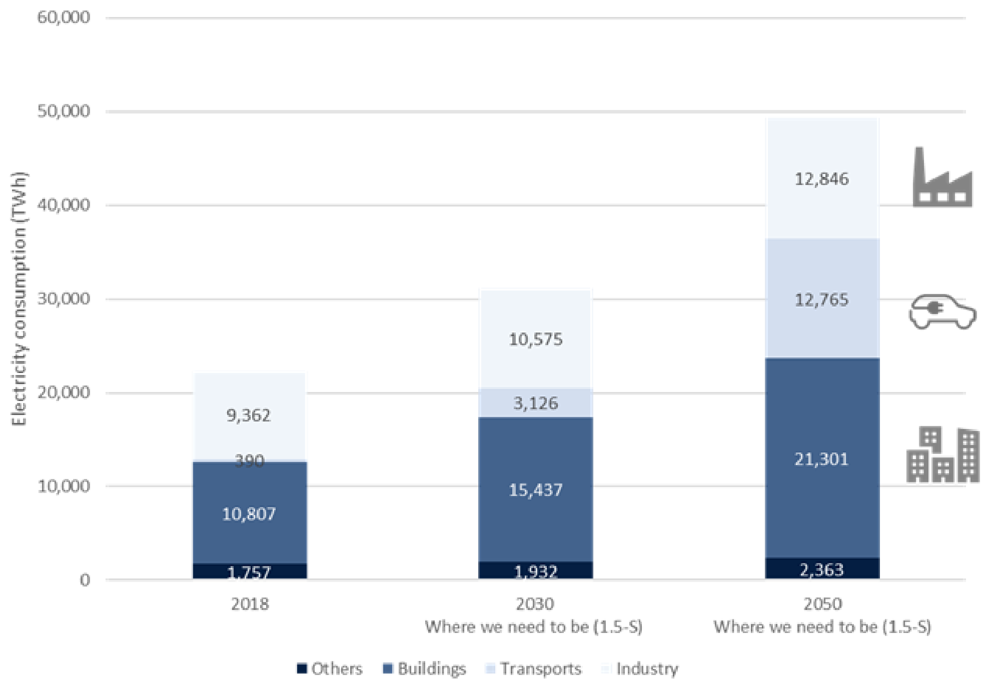
Fig. 1: Electricity capacity to rise almost six-fold by 2050



Source: IRENA, Bryan, Garnier & Co

Electrification of transport is set to accelerate the most in the years to come with the share of electricity reaching c.50% by 2050. According to IRENA, the stock of electric cars should rise from 10 million today to over 380 million by 2030 and 1,780 million by 2050; the stock of electric trucks should reach 28 million in 2050. Other sectors such as building are also set to massively adopt electricity in order to decarbonise.

Fig. 2: Electricity consumption to more than double by 2050



Source: IRENA

As such, since the future smart power system will be largely based on variable renewables such as solar PV and wind, substantial investments in power grids and flexibility (storage included) will be mandatory. IRENA estimates that USD730bn is likely to be needed each year until 2050 (vs USD275bn in 2019) to design new power grids.

Section 02

Storage and power innovative technologies to the rescue

Storage and power innovative technologies to the rescue

From a centralised to a decentralised grid

Structure and businesses destined to change

In addition to intermittency and storage problems, the development of renewable energies goes hand in hand with that of a decentralisation of output. While some renewable energy sources are quite centralised (wind farms for example), others are far more dispersed (solar for example). As such, growth in renewable energies means a decentralisation of production.

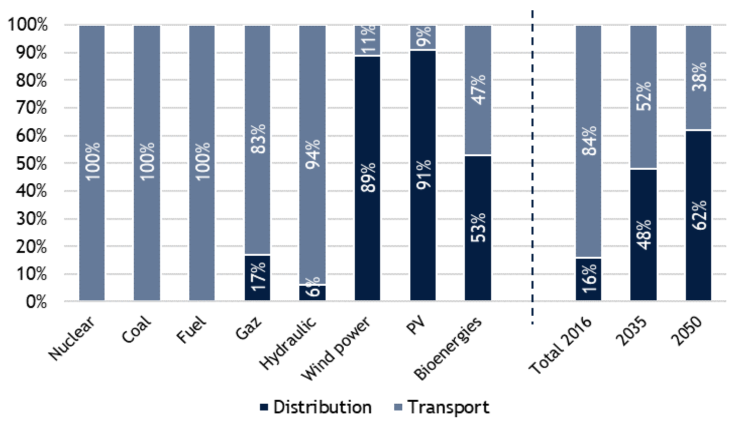
This transformation means the grid as a whole will have to be restructured. Note that the distribution network needs to be distinguished from the transmission network, which carries power production from power plants to consumption zones via high voltage lines (to limit losses during transmission). The distribution network receives electricity from the transmission network and distributes it to consumers through medium and low voltage lines.

In France, high voltage lines are operated, maintained and developed by RTE (Réseau Transport Electricité) whereas average and low tension lines are managed by Enedis (ex ERDF) and to a lesser extent, Electricité de Strasbourg.

Today, 84% of production capacity in France is directly connect to the (high voltage) transmission network and 16% to the distribution network (medium and low voltage). However, the mix is very different depending on the production source. Nuclear and coal are also fully connected to the transmission network whereas solar and wind are mostly connected to the distribution network (89% and 91% respectively). The mounting contribution of these energy sources is automatically set to cause lower use of the transmission network in favour of the distribution network.

According to ENTSOE (European Network of Transmission System Operators for Electricity), by 2030, 40-45% of European production capacity could be connected to the medium and low voltage grid. This figure could even reach 60% in a scenario very beneficial to renewable energies.

Fig. 3: Production capacities connected to the transmission and distribution networks in France

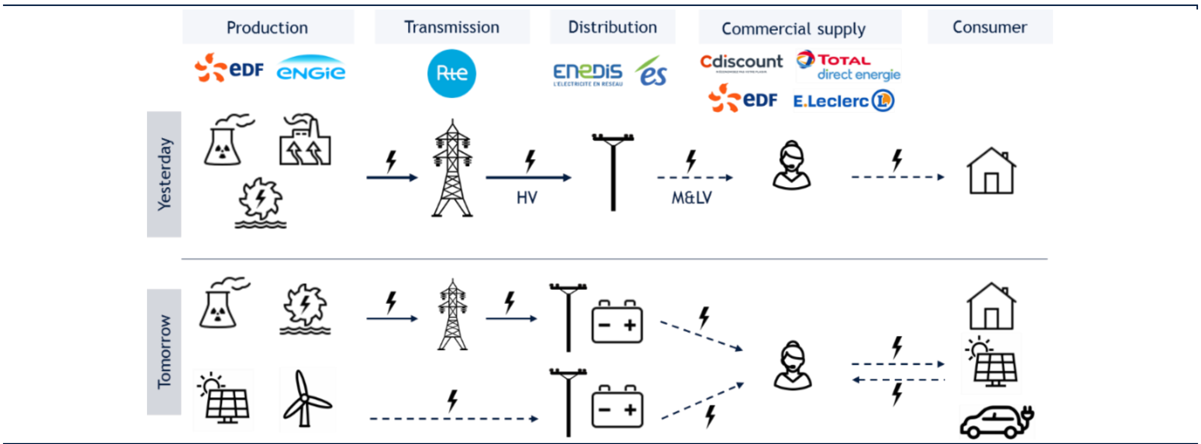


Source: Bryan, Garnier & Co, RTE, Enedis

Elsewhere, the grid needs to integrate the change in status of the various players. Customers are no longer only consumers, they are also power producers (solar panels on their roofs). As such, the historically unidirectional grid needs to become bidirectional.

In this backdrop, the scope of activity is set to gradually change for these players. Rather than simply distribute electricity to consumers, distribution network managers are set to become operators of a local system, taking charge of resource management. Digitalising the sector and rolling out IoT should help them pilot and maintain the network in a more active way.

Fig. 4: Change in electricity distribution and transport network



Source: Bryan, Garnier & Co

Microgrid and self-consumption trends

Growth in renewable energies and the decentralisation of production is seeing a simultaneous development of self-consumption and microgrids.

Microgrids are small-sized distribution networks, based on local production methods, often solar and wind. These ensure the supply of one or more sites such as ecodistricts, campuses, industrial estates, islands etc. Microgrids can function entirely autonomously or be connected to a wider distribution system.

The US is currently the leading market in microgrids (80% market share) given the lower quality of the power grid relative to Europe. These are primarily installed for supply safety reasons or to supply critical installations (hospitals, military bases).

In the future, the application scope for microgrids could be extended and exceed these niche applications. This development is set to be driven by an improvement in renewable energy performances and the progress made in battery capacity.

In this backdrop, Engie announced in early September 2019, the acquisition of Mobisol, specialised in off-grid installations in Africa. The aim of the operation is to extend the group's offer in decentralised power in Africa. Engie already had a subsidiary in this field, Fenix International, acquired in 2017 (300,000 households equipped with its photovoltaic panels solution). In addition, Engie is building and operating microgrids in Tanzania via Engie PowerCorner.

In French Polynesia, Engie EDT (Électricité de Tahiti) has deployed a hybrid power solution on the scale of the island including solar panels, batteries and diesel generators. This system helps supply up to 70% of the island's requirements and reduces the cost of supply for residents.

EDF is also positioned in these markets. In 2016, the group acquired Global Ressources Options (known as groSolar), a US company specialied in the installation and sale of small-sized PV plants. In 2018, EDF took a 50% stake in EnterSolar, which is specialised in the decentralised production of solar power for industrial clients. The logic behind the two operations was to be able to offer an entire range of solutions for decentralised power production.

Reflecting the genuine interest in microgrids, and the aim of players to go beyond the off-grid segment, between 2012 and 2016, EDF carried out an experiment in the Carros district of Nice. The five-year project was based on the roll-out of Linky smart meters (2,350 units). The main results of this experiment were the following:

- Disconnection from the network was possible for an extended period (five hours), with no blackout and no impact on customer consumption. The microgrid can therefore isolate itself from the rest of the grid thereby relieving it if necessary;

- Smart water heaters enabled a shift of 56% of consumption during "solar hours". The system was piloted remotely through the Linky meters;

- Reduction in winter consumption peaks thanks to the piloting of electric heating and a 20% decline in average consumption for individuals.

The development of microgrids is accompanied by a parallel increase in self-consumption, which is ultimately also a microgrid made up of a single producer who is also the consumer. This development is already prompting historical players to change their offers. Indeed, Engie has joined forces with German company Sonnen specialised in residential batteries to round out its solar self-consumption range. The Sonnen offer is particularly innovative since it handles the customer's electricity consumption in return for a fixed monthly rental fee following the purchase of a solar panel+batteries system.

Sonnen values the customer's storage capacity as a primary reserve. This valuation is carried out through grid operators under the framework of the grid's short-term equilibrium mechanism and the offer can be assimilated to energy performance contracts that consist of guaranteeing a service in exchange for a fixed rental fee. Note nevertheless that this type of offer requires a commitment by the consumer over time. French regulations do not currently allow this type of contract for residential consumers.

Another example is the Engie subsidiary in Australia, Simply Energy which markets an energy offer combining self-consumption (installation of solar panels) and storage (Tesla PowerWall batteries) since 2016.

Further out, the development of microgrids could challenge business at distribution network managers for whom they represent both an opportunity and a threat. They are an opportunity in the sense that they are systems for which new services can be offered, but at the same time, they are a threat since they are set to prompt a decline in use of the centralised network.

The Energy Regulation Commission (Commission de Régulation de l’Energie - CRE) estimates that 20 years from now, self-consumption could remove 15% of power from the distribution network. In transmission, the decline could reach 25-30%.

New storage solutions can fill the gap

The current mix is dominated by hydrostorage

Energy storage technologies absorb energy and store it before releasing it to supply or power services. Energy storage has been used for decades. Batteries were created in the 1800s and the first pumped storage systems were implemented in the early 1900s. However, the energy storage sector has witnessed strong momentum since the Paris Agreement given that it is one of the few solutions capable of filling the gap between renewable energy production and baseload generation.

Storage technologies have been ramping-up alongside the use of portable electronics and electrification of the transport sector, but have become crucial with the implementation of renewables in the power grid. By improving flexibility and filling the gap caused by the mismatch between production and consumption of energy, storage technologies are considerably easing the expansion of renewable energies and consequently, the decline in CO_2 emissions. In buildings and industry for example, thermal energy facilitates temporal shifts in renewable electricity or thermal energy supply to satisfy heating and cooling needs.

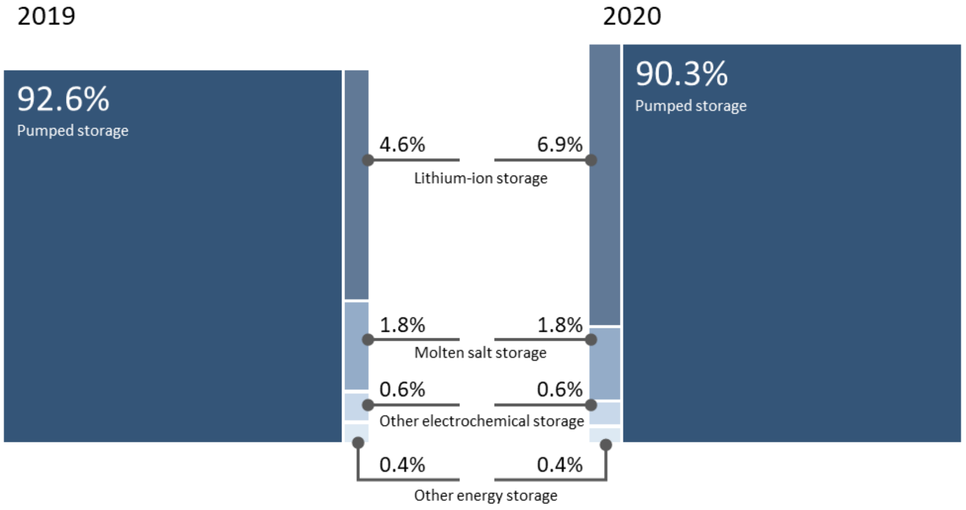
Key technologies allowing energy storage include mechanical (pumped storage, flywheels), electrochemicals (batteries including lithium-ion and lead-acid), chemical (hydrogen) and thermal energy storage. Depending on the type of technology, the duration of storage can vary considerably, from less than 10 hours (small batteries) to seasonal storage (pumped storage). Energy storage technologies can also be distinguished by their stationary (storage connected to a fixed point on the network) or mobile nature (on-board storage in electric vehicles). Among the many ways to store energy, batteries are used especially since they are easy to deploy and benefit from cost reduction trends. Hydrogen used as a storage energy technology is also starting to benefit from higher visibility and lower costs.

In terms of market, the Covid-19 pandemic delayed the implementation of energy storage systems in 2020 since supply chains were troubled and travel possibilities (to visit sites) restricted. Nevertheless, according to REN21, new electrochemical energy storage projects reached 4.73 GW in 2020, up 62% compared with 2019 when only 2.9 GW of capacity was added to electricity systems. Note that the storage market has benefited from stimulus packages aiming to encourage corporates to reach carbon neutrality goals.

In all, global operational energy storage capacity reached 191.1 GW in 2020, pointing to 3.4% yoy growth. In terms of geographic mix, China represented c.19% of worldwide capacities (35.6 GW, up by 4.9% compared with 2019).

The US had 23.2 GW in 2020 while the European market grew by 54% adding 1.7 GWh of storage capacity (for a total of 5.4 GWh).

Fig. 5: Share of global energy storage installed capacity by technology (2019 and 2020)



Source: REN21, global status report

Pumped storage still accounts for the majority of installed capacity (more than 90% energy storage capacity). However, batteries are continuing their uptrend since global battery storage capacity increased c.2% in 2020 despite the health crisis. Battery storage now represents 7.5% (or 14.2 GW) of total storage capacity. Lithium-ion unsurprisingly represents the majority of batteries (92%), the rest being split between sodium-sulphur (NAS) batteries (3.6%) and lead-acid batteries (3.4%). Finally, thermal energy storage, mainly in the form of molten salts, represented 1.5% of worldwide energy storage capacity in 2020 (c.2.9GW). Molten salt storage is usually deployed in concentrating solar thermal power (CSP) plants.

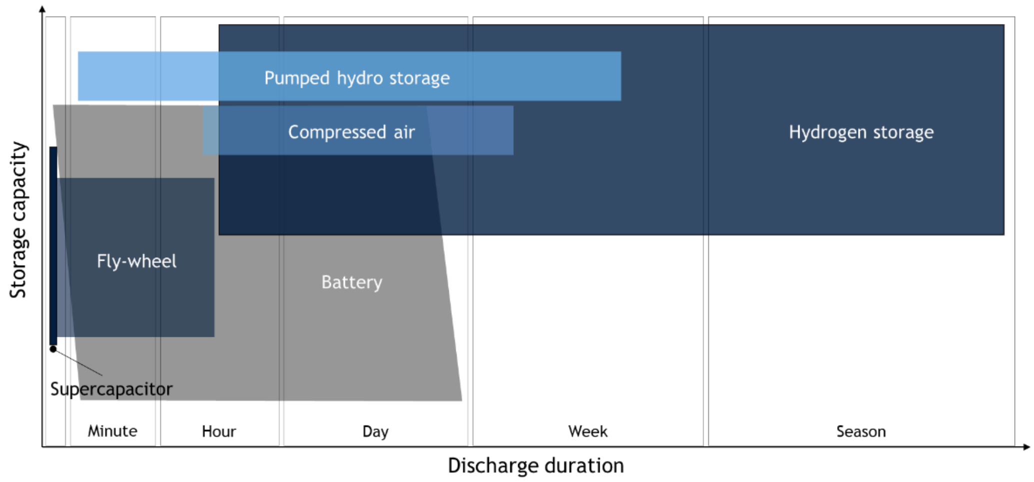
Consequently, the storage energy mix is clearly dominated by pumped storage (hydropower) and batteries. However, storage technologies like hydrogen, representing only 0.05% of total installed capacities, are very promising. Renewable hydrogen is produced using renewable electricity to power an electrolyser that splits the hydrogen from water molecules. Interest in renewable hydrogen increased in 2020 on the back of renewable energy expansion and the lower cost of electrolysis equipment leading to a decline in production costs. This combination prompted the consolidation of hydrogen energy frameworks all over the world (Chile, Norway, Russia, Australia, EU etc.).

As seen in the previous section, this transition towards a clean energy mix is bringing major structural changes to electricity systems around the world. The energy mix is shifting from centralised systems to a large number of relatively small production units, many of which use intermittent renewable resources (wind and PV).

To deal with the rising intermittency of the energy mix, the grid must integrate a growing number of balancing solutions. Several electricity storage solutions exist but they all have their own features and are not always relevant, depending on storage capacity and discharge duration constraints.

Batteries are well suited for relatively small storage capacities over a limited period of time. However, when large-scale storage and/or long-term storage is required, hydrogen is more relevant.

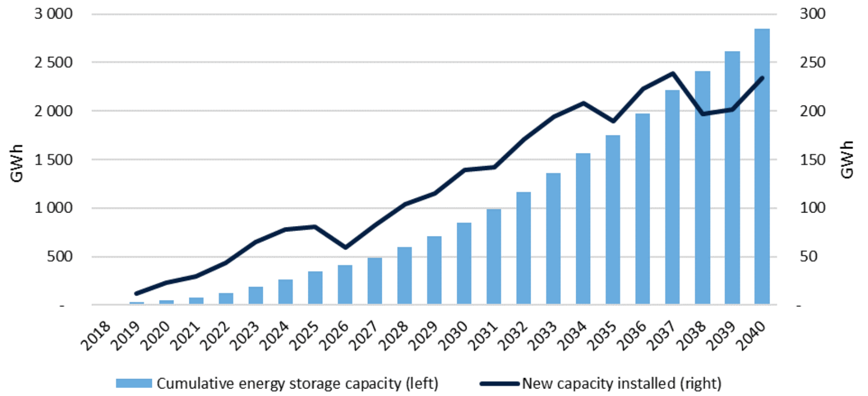
Fig. 6: Different storage technics



Source: Bryan, Garnier & Co

According to BNEF, the global energy storage market is estimated to grow from 52 GWh in 2020 to 2,850 GWh by 2040, attracting USD660bn of investment. The projected cumulative energy storage capacity is expected to grow at a CAGR above 20%.

Fig. 7: Projected energy storage capacities



Source: BNEF

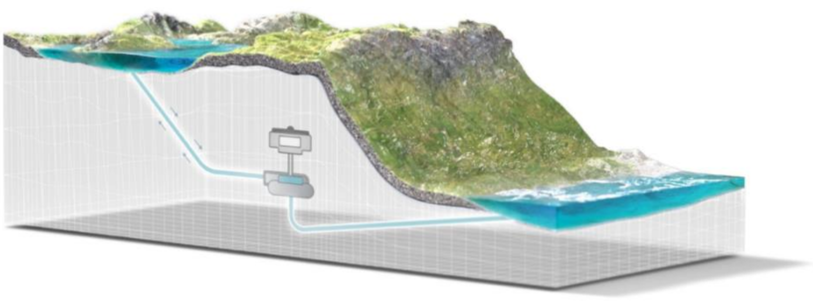
Large-scale deployment of renewables is required to comply with environmental commitments and reach a 100% renewable energy mix. However, the intermittency of renewables is probably the main hurdle to their own deployment. Indeed, the wider the deployment of renewables the more intermittent the grid becomes and hence the more crucial deployment of storage capacities is.

Pumped hydrostorage is by far the most used storage technology today. It is also one of the most mature and largest capacity storage technologies available in view of its low cost. Pumped hydrostorage (PHS) is made up of two reservoirs connected by an underground shaft and a powerhouse containing a turbine-generator. It is a two-step process. Firstly, energy is stored by pumping water to the highest tank. Then, when energy is required, the water is released and passes through the turbine that operates the generator to produce electric power. PHS is usually chosen for delivering long duration storage services. It also benefits from numerous advantages:

- Gravitational energy stored in the upper reservoir can stay for longer periods of time without any energy loss.
- Pumped storage can react quickly when electricity is needed.
- It can be integrated into the electric system but also in specific projects where it can be combined with other renewables.

Nevertheless, despite some innovations, no growth is anticipated due to the lack of suitable locations. PHS indeed suffers from hard geographical and societal constraints.

Fig. 8: Hydropower technology



Source: https://voith.com/uk-en/industry-solutions/hydropower/pumped-storage-plants.html

Suitable geological locations vary from country to country and are usually found in remote locations like mountains. PHS also faces long development processes limited by environmental impact concerns such as:

- Blocking important migration routes for fish leading to a decline in the fish population.

- Upstream/downstream flooding destroys wildlife populations.

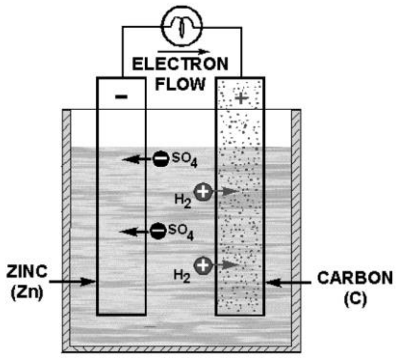
Consequently, while PHS is currently the main energy storage technology, it is set to decline as growth in other segments rises (such as batteries), as progress is made in technology and costs are reduced.

Is battery storage the solution to intermittency ?

Batteries are the most common technology for storing electrical energy. There are various types of batteries ranging from button cells in watches providing just a few watts to megawatt-sized installations providing important load services. Alessandro Volta built the first battery in around 1800. It was made of a disc of copper and zinc separated by cardboard with a brine solution acting as an electrolyte. After several innovations (Daniell's cell, Leclanché's cell) carbon replaced the copper for the cathode.

A battery consists of a number of cells assembled in a common container and connected together in order to generate power. A cell is a device that transforms chemical energy into electrical energy: it includes a piece of carbon and a piece of zinc suspended in a jar containing a solution of water and sulfuric acid called the electrolyte.

Fig. 9: Battery structure (cell)

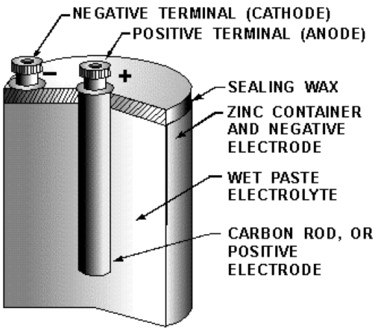


Source: introduction to batteries, engineering.com

In every battery, there are two electrodes: conductors by which the current leaves or returns to the electrolyte. In the simple cell, electrodes are the carbon (usually carbon + manganese dioxide) and the zinc placed in the electrolyte (water + sulfuric acid but can also be a saline or an alkaline solution). The electrodes can be distinguished according to their properties and their role in the electrochemical process.

If a device that consumes electrical power is connected externally to the electrodes of a cell, electrons will flow thanks to the chemical reaction of the electrodes, with the anode (positive electrode) on one side and the cathode (negative electrode) on the other. By being in contact with the electrolyte, the anode sends electrons to the cathode. When all the electrons have flowed from the anode to the cathode, the battery no longer produces electricity. The electrolyte can be liquid or solid. When solid, the battery is known as a "dry cell". In some cells, the container acts as one of the electrodes and in this case, a carbon rod is placed in an electrolyte paste.

Fig. 10: Dry cell structure



Source: introduction to batteries, engineering.com

There are two types of batteries:

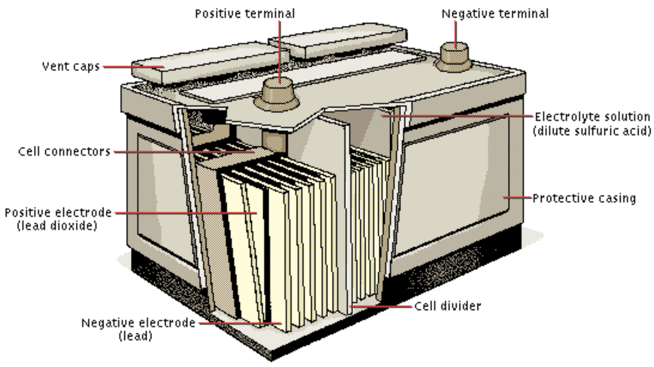
- Primary: in this case, the chemical action eats away one of the electrodes. When this happens, the electrode must be replaced or the cell must be changed: in other words, primary cells are not rechargeable: the alkaline cells for example (using alkaline electrolytes and manganese oxide for the cathode, invented in 1949).
- Secondary: these are rechargeable and can be used to store energy repetitively. In this case, electrodes and the electrolyte are altered by the chemical action but the cell can be restored to its initial condition by forcing an electric current through them in the opposite direction to that of discharge (electrons return to the anode).

In the case of the renewable energy transition and the various storage technologies, secondary batteries are the most interesting. There are several types of secondary batteries with lead acid, nickel-cadmium, lithium-ion, NaS and flow batteries the main technologies used today.

Lead acid batteries

The lead-acid battery is the most widely used secondary cell: it produces electricity by electrochemical action. It works with a lead dioxide anode, a sponge lead cathode and the electrolyte is also composed by sulfuric acid and water.

Fig. 11: Schematic of lead acid battery



Source: http://sustainableskies.org/ill-take-manhattan/lead-acid-battery/

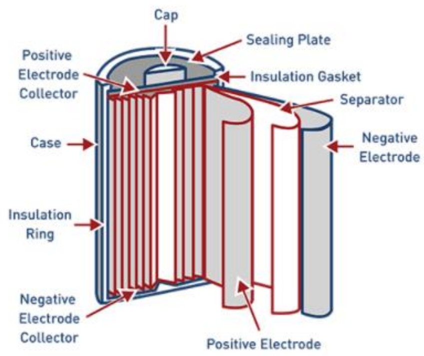
These batteries are low-cost, reliable, heavy-weighted and large. They are mostly used in sedentary applications due to their weight and size. We usually see them in solar-panel energy storage, vehicle starters, lights, back-up power and power generation.

Nickel electrode batteries

The nickel-cadmium cell uses cadmium hydroxide as the cathode and nickel hydroxide as the anode while the electrolyte is made of potassium hydroxide and water.

These batteries are relatively cheap but made of toxic materials and suffer from a high self-discharge rate. However, they benefit from a higher number of charging/discharging cycles than lead acid batteries. Energy density is also better and they fit with more locations since they are smaller and available in different sizes. They are generally used in low-cost devices like toys, solar light or cordless phones.

Fig. 12: The nickel-cadmium cell

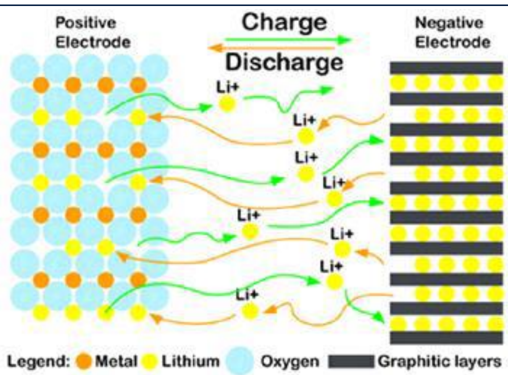


Source: https://clearpath.org/tech-101/intro-to-energy-storage/

Lithium-ion batteries

Lithium-ion batteries usually work with lithium cobalt oxide used as cathode and graphite for the anode. The electrochemical process is the same as for other batteries, namely the lithium ions move from the anode, go through the electrolyte until they reach the cathode where they recombine with their electrons and electrically neutralise.

Fig. 13: Schematic of a lithium-ion battery



Source: introduction to batteries, engineering.com

Lithium-ion batteries have numerous advantages compared with other battery technologies. They have one of the highest energy densities of all the battery technologies (three times higher than nickel cadmium batteries for example) and they can deliver large amounts of current for high-power applications. They do not need regular maintenance and do not have a memory effect (a detrimental process where repeated partial discharge/charge cycles can cause a battery to remember a lower capacity like for nickel-cadmium batteries for example). Finally, they do not have a high self-discharge rate and they do not contain toxic cadmium which makes them easier to dispose than the nickel cadmium batteries.

Lithium-ion batteries can also be called solid state batteries when they use a solid electrolyte instead of liquid or polymer gel electrolytes. These batteries can provide multiple solutions for problems encountered with liquid li-ion batteries like flammability and limited voltage. They could therefore potentially be safer with a higher energy density but also much more expensive. Solid state batteries (or solid state electrolyte, SSEs) are mainly used in electric vehicles. Toyota for example, announced in September, that its new hybrid electric vehicles will be equipped with solid state batteries.

Given all their advantages, lithium-ion batteries are dominating the market. They have indeed replaced the nickel-cadmium batteries in portable electric devices (smartphones, laptops). They are also used to power electrical systems for aerospace (Boeing 787) and for cars (battery-powered cars like the Nissan leaf or the Tesla model S).

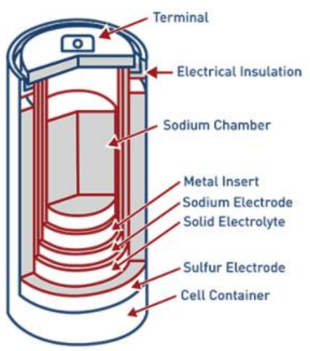
However, lithium-ion batteries also have some drawbacks, notably regarding safety: they have a tendency to overheat which, in some cases, can lead to combustion (like in the Boeing 787). Plus, their cost is high, almost 40% higher than nickel-cadmium batteries.

NaS batteries

In this battery, molten sodium and molten sulphur are used as negative and positive electrodes while solid ceramic sodium alumina acts as electrolyte.

The technological advantage of the sodium battery is its high power density and long battery lifetime (c. 10 years). However, the sodium sulphur battery is a high temperature battery. It needs to operate at 300-350°C to liquefy the sodium. This constraint increases the difficulty of using these kind of batteries and also contributes to high production costs. Another drawback is that the sodium battery is very dangerous if the liquid sodium comes into contact with water.

Fig. 14: Schematic of an NaS battery

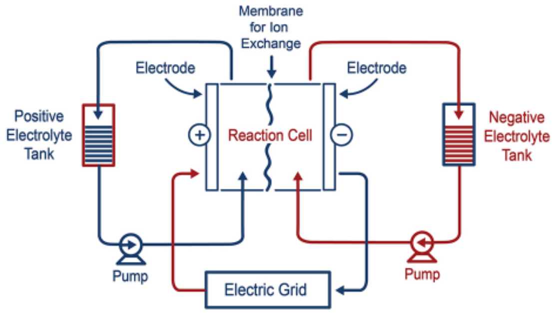


Source: https://clearpath.org/tech-101/intro-to-energy-storage/

Flow batteries

Flow batteries, also called redox batteries (for reduction-oxidation), are made up of two electrolytes separated by a proton membrane. Energy is stored in the electrolytes by increasing the potential difference between the two liquids (i.e. by oxidising one and reducing the other). Electricity can also be created by reversing the process. The oxidation and reduction process is achieved thanks to the membrane.

Fig. 15: Schematic of a flow battery



Source: https://clearpath.org/tech-101/intro-to-energy-storage/

The main advantages of this technology are easy scalability (capacity proportional to tank size), no detrimental effect of discharge, very low self-discharge, long cycle life and low cost production. However, the energy power is quite low and the system is complex since it requires pumps and plumbing to make the electrolyte circulate correctly through the membrane. Consequently, this technology is mainly used for large scale applications.

Fig. 16: Battery comparison

Type of battery	Type of use	Advantages	Drawbacks
Lead acid	• Sedentary applications • Back-up power generation	✓ Low cost ✓ Reliable	▪ Heavy ▪ Large
Nickel	• low-cost devices like toys • solar light • cordless phones	✓ Cheaper ✓ Higher number of cycles than lead acid ✓ Smaller ✓ Modular size ✓ High energy density	▪ Use of toxic materials ▪ High self discharge rate
Lithium ion	• Electric vehicles • Planes • phones	✓ Very high energy density: 3x Nickel ✓ Deliver large amounts of power ✓ No maintenance ✓ Do not contain toxic material	▪ Tendency to overheat ▪ Expensive: 40% higher than Nickel batteries
NaS	• Energy storage • power stabilization for wind farms • Solar PV systems	✓ high power density ✓ Long battery lifetime (i.e. 10 years)	▪ Working conditions: 300-350°C to work ▪ High production cost ▪ Dangerous materials: Sodium
Flow	• Large scale applications	✓ Scalability ✓ No detrimental effect of discharge ✓ Low-self discharge ✓ Long cycle life ✓ Low cost production	▪ Low energy power ▪ Complex system with pumps and plumbing

Source: Bryan, Garnier & Co

Thermal storage is emerging

Different categories of thermal storage

Thermal energy storage refers to the concept of storing energy in heating or cooling systems, enabling its use later for heating, cooling or power generation. Applications can store heat on an intra-day, weekly or even seasonal basis. Thermal storage is still a relatively small niche market, but the technology is benefiting from strong momentum thanks to the expansion of renewable energy and the aim to decarbonise heat. Thermal energy can solve numerous issues related to variations in supply and demand at different scales and can be implemented to power and heat industrial sites or households.

Thermal energy storage can be divided into three categories:

Sensible heat storage: an increase or decrease in storage material temperature. The most commercial heat medium is water but the storage material can be air, oil, concrete etc. This involves several techniques and early stage/mature technologies like molten-salt technology, heat storage in tanks/caverns, hot silicon technology, molten aluminium and heat storage in hot rocks.

Latent heat storage or phase change material: this relies on the phase transformation of the storage materials (phase change materials, from example from solid to liquid and vice versa).

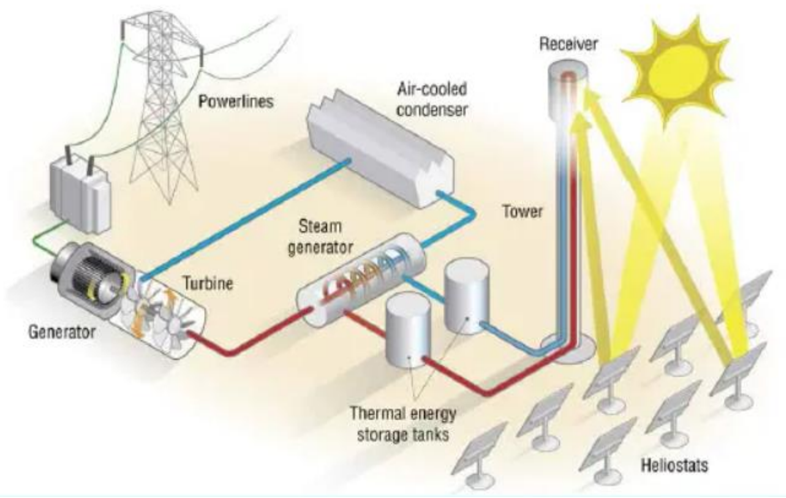
Thermochemical storage: this less mature technology refers to the use of reversible chemical reactions to store large quantities of heat in a compact volume.

Current R&D efforts cover storage materials, containers, thermal insulation and target an improvement in the efficiency of these processes. Phase change materials and thermochemical storage should be the first segment to witness cost reductions since meaningful R&D milestones have been reached.

While thermal storage is still a niche market, these technologies should expand due to the increasing demand of cooling services and electrification of heating combined with renewable energy penetration. Thermal energy storage applications involve district heating and cooling networks.

Thermal storage systems generally store heat in the form of hot water in tanks enabling additional flexibility in the heat supply-demand balance. In a concentrated solar power plant, this helps address intermittency issues. Finally, thermal energy storage also supports the use of waste heat from industry, allowing efficiency gains in the industrial process and helping corporate to reduce their CO_2 emissions.

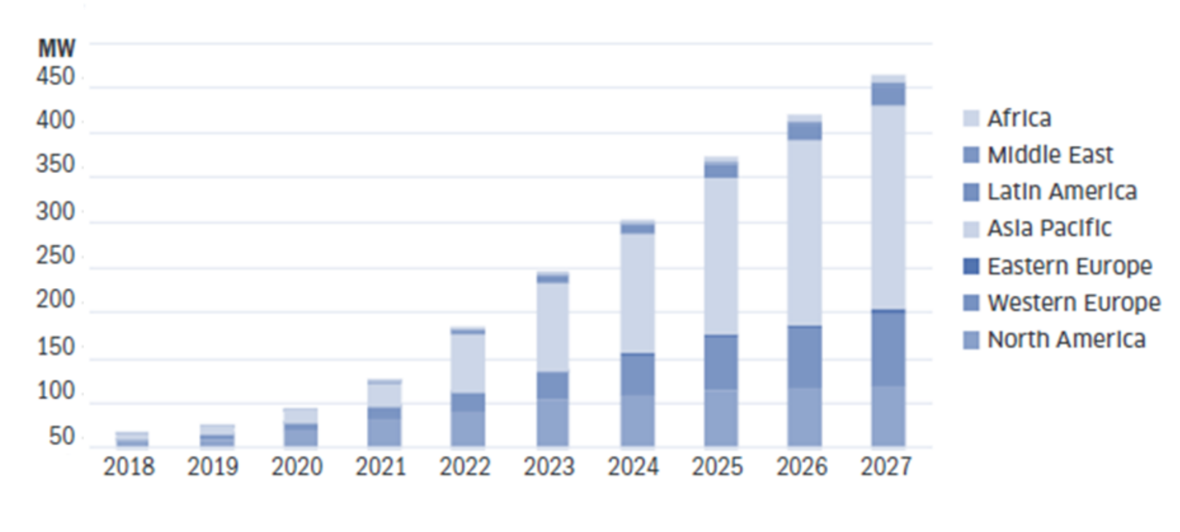
Fig. 17: Schematic of a thermal energy storage system with a heliostats park



Source: https://hivepower.tech/the-future-of-grid-energy-storage/

Asia-Pacific is by far the most dynamic geography in terms of TES. Annual power capacity deployments in this region are expected to increase from 5.1MW in 2018 to 226.2MW in 2027 (>50% CAGR).

Fig. 18: TES power capacity (in MW) forecast by region (2018-2027)



Source: Global market analysis and forecast, TES, Engie

TES technologies could ease the expansion of renewable energies since distributed storage can compensate for the variability of renewables and stabilise the local system on the demand side.

Overview companies and transactions in the sector

In terms of companies, we have identified several innovative players devoted to a specific vertical:

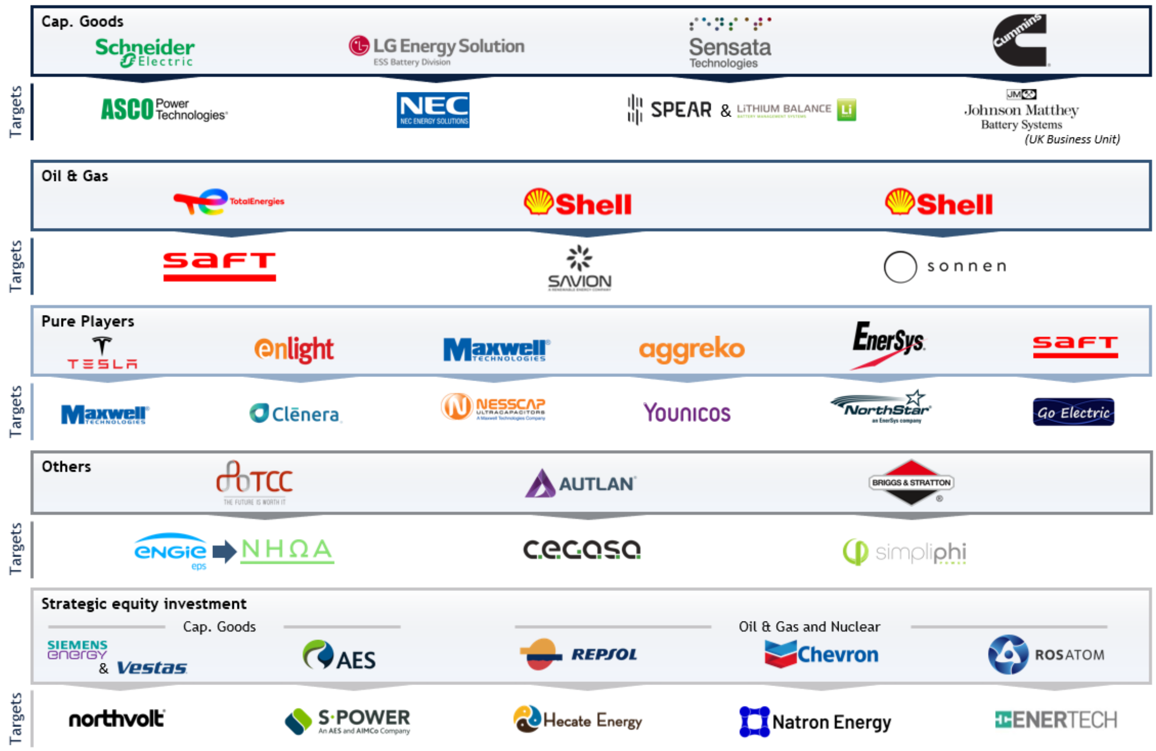
Fig. 19: The most innovative players in energy storage

Source: Bryan, Garnier & Co

We have focused on pure players in order to highlight the most active companies in each vertical.

We have also identified the main transactions in the battery sector, which has been by far one of the most dynamic over the past four years. There have been several types of transaction: 1) capital goods companies like Schneider Electric, Sensata and Siemens Energy have been strengthening their positions in the storage market through acquisitions or partnerships with pure battery players; 2) oil & gas players are also entering this market with large transactions such as Total Energies taking over Saft in 2016 for EUR950m; 3) pure players are also active but not for diversification purposes. Indeed, their aim is to gain critical mass to maintain or increase their market share in light of growing competition.

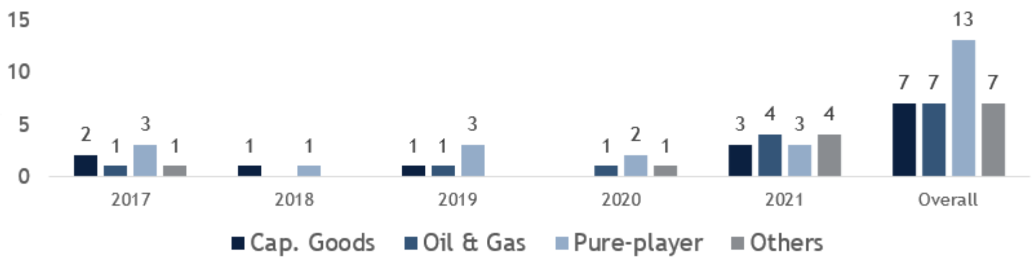
Fig. 20: Relevant transactions by type of acquirer



Source: Bryan, Garnier & Co

A look at the number of deals shows that meaningful transactions have tripled compared with 2019 (we skip 2020 because of Covid-19), thereby reflecting the sector consolidation.

Fig. 21: Number of deals per type of acquirer



Source: Bryan, Garnier & Co, Merger market

Hydrogen will also help change the grid

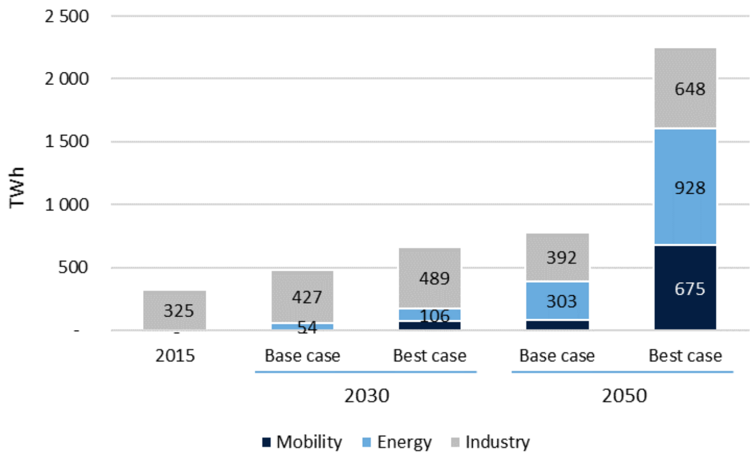
Hydrogen is set to contribute significantly to the global energy mix and power production

Thanks to its growing competitiveness, green H_2 is set to play an increasingly important role in the energy transition. In its last Energy Outlook, BP stressed that hydrogen could account for 7-16% of total final energy consumption. Above all, this hydrogen will be mostly green, hence produced through water electrolysis which requires renewable electricity. BP expects green hydrogen to represent around a third of hydrogen production in 2035 and more than 50% by 2050 (vs 1% today).

> "Hydrogen could account for 20% of worldwide energy consumption by 2050. It will be a USD2,500bn market, which will create millions of jobs."
>
> Benoît Potier, CEO of Air Liquide

These estimates are broadly in line with those of the FCH JU (Fuel Cells and Hydrogen Joint Undertaking). Depending on the scenario, hydrogen could represent between 8 and 24% of total energy demand in Europe, or up to 2,250 TWh by 2050. Energy applications, including power generation and buffering, could represent up to 16% of European demand for hydrogen by 2030 and 41% by 2050.

Fig. 22: Hydrogen demand in Europe by application



Source: IRENA

How much will hydrogen-based power cost ?

Obviously, electricity from green hydrogen is still a nascent and hence relatively expensive technology. Based on a simplified model, we estimate the cost of hydrogen power to be around USD450/MWh. We estimate that electricity (from solar PV) represents the majority of the cost, at around USD250/MWh. We then add the capital cost of the fuel cell and the electrolyser for around USD160/MWh and USD35/MWh, respectively.

Thanks to the expected decrease in the cost of renewables, the cost of green hydrogen production should fall significantly as should the cost of the electricity generated at the end of the process.

The capital cost of both the fuel cell and the electrolyser is also set to drop sharply over the next few years on the back of the increased lifetime of the products and their better efficiency. We have detailed our calculation in the table below.

We estimate that by 2030, the cost of hydrogen-based power could decrease by around 60% to USD170/MWh. Electricity (from solar PV) could represent around USD140/MWh (40%), the fuel cell USD12/MWh (-90%) and the electrolyser USD15/MWh (-60%).

Fig. 23: Estimated cost of hydrogen power

	2019	2030e	
Solar PV - global average LCOE	68	40	USD/MWh
Electrolyser power consumption	4,5	4,5	kWh/Nm3 of H2 produced
Electricity required to produce 1kg of H2	50	50	kWh
H2 production cost	3,4	2,0	USD/kg
H2 required to produce 1 kWh	0,8	0,8	Nm3
H2 required to produce 1 kWh	0,07	0,07	kg
Cost of electricity (excluding FC and ELY cost)	**246**	**144**	**USD/MWh**
Fuel cell cost	3 300 000	500 000	USD/MW
Fuel cell lifetime	20 000	42 500	hours
Power production during its lifetime	20 000	42 500	MWh (1MW FC)
Fuel cell capital cost	**165**	**12**	**USD/MWh**
Electrolyser cost	700 000	300 000	USD/MW
Electrolyser lifetime (alkaline)	80 000	80 000	hours
H2 production for a 1 MW electrolyser	200	200	Nm3/hour
H2 production over lifetime	16 000 000	16 000 000	Nm3
H2 production over lifetime	1 438 080	1 438 080	kg
H2 needed to produce 1 MWh	72	72	kg
--> over its lifetime, a 1 MW ELY produces enough H2 to generate	20 000	20 000	MWh
Electrolyser capital cost	**35**	**15**	**USD/MWh**
Total cost of production	**446**	**171**	**USD/MWh**

Source: Bryan, Garnier & Co, Ballard, McPhy, IRENA, Air Liquide

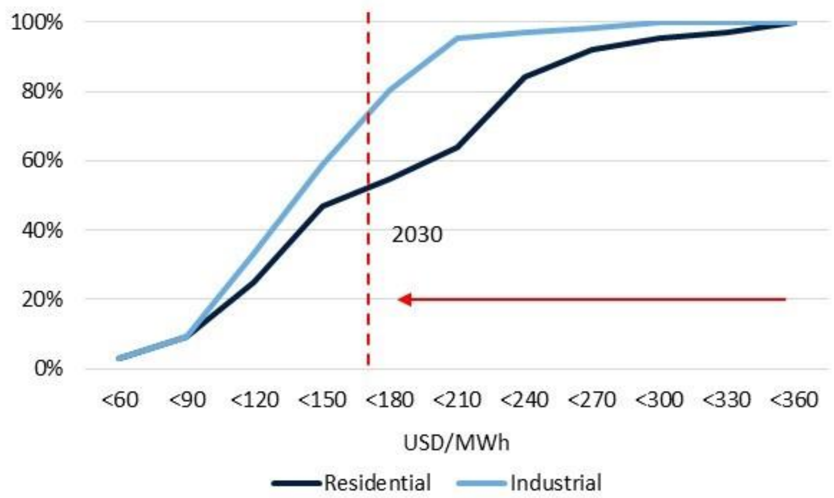
Where is power from green hydrogen competitive?

Today, power production from hydrogen is still expensive and therefore not competitive in most markets. However, we observe a significant standard deviation between geographies, depending on the energy mix and the level of grid development.

According to the IEA, the global average electricity price for residential consumers stands at USD134/MWh and USD97/MWh for industrial clients, well below the cost of hydrogen power.

However, we have identified some markets with significantly higher electricity prices. For example, in Cyprus or Cap-Vert, the average power cost stands at around USD250/MWh.

Fig. 24: Global distribution of electricity prices for residential and industrial consumers



Source: Bryan, Garnier & Co

Admittedly, there is only a very limited number of geographies where power generation from hydrogen could be competitive. However, this only reflects the cost of electricity in well-developed and interconnected grids, not the price of electricity for off-grid locations, which is significantly higher. In this context, hydrogen power can be competitive.

Moreover, we believe that hydrogen power systems could be installed in geographies where its price is not yet competitive. Indeed, today, diesel generators are usually used in these off-grid systems but are a very polluting solution. While challenging to measure, air pollution has a huge social and financial cost that can be avoided thanks to hydrogen. Cost-competitiveness is not always the sole criteria.

French Guiana is a good example of these (almost) off-grid locations where HDF can provide competitive solutions. HDF is working on a project named CEOG to supply green electricity to the city of St-Laurent du Maroni. The city is already connected to the grid but the connection is not strong enough to support the needs of a fast growing population.

According to the CRE (French Energy Regulation Commission), in 2015, thermal power production plants in French Guiana had production costs ranging from EUR425 to EUR600/MWh. Even solar PV, which is usually the cheapest source of power, presented production costs as high as EUR450/MWh on average (tropical conditions require adapted products, increased maintenance and reduce the load factor for PV panels). At these prices, power production from hydrogen is competitive. Multiple locations with equivalent prices exist all around the world and are attractive for HDF.

Replacement of diesel generators is the first target

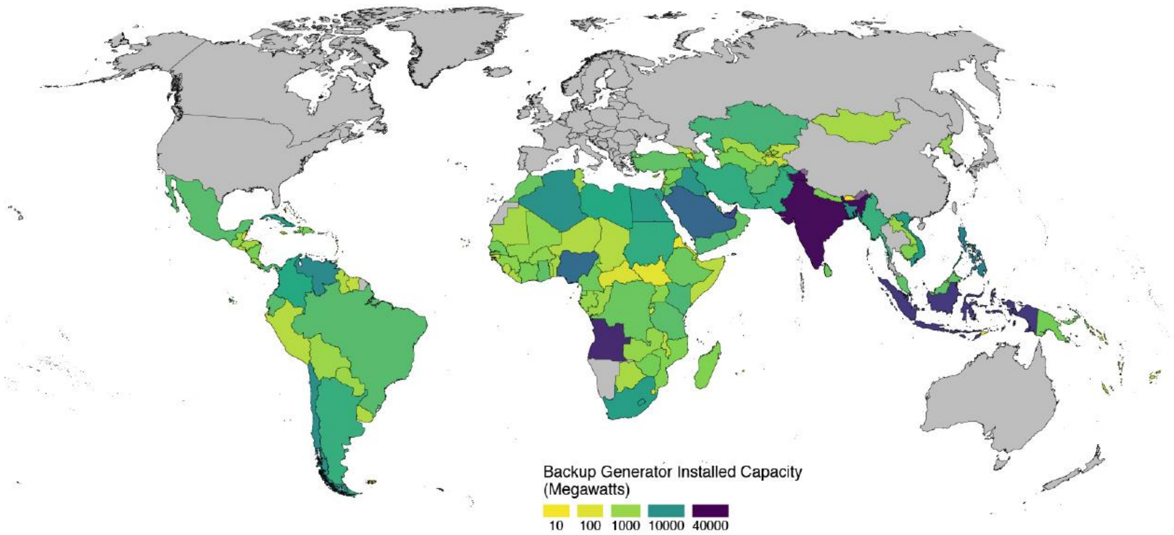
Diesel generators are not only used for back-up power in off-grid locations but also for baseload, 24/7 power generation. In western Africa, diesel generators account for over 40% of the electricity consumed annually!

According to the World Bank, there are around 25,000,000 diesel gensets in developing countries, representing installed capacity of 350 to 700 GW, equivalent to 700-1,000 large coal power stations.

This fleet is dominated in numbers by small gasoline and diesel generating units that provide service for loads less than 60kW and are not relevant targets for HDF as it is too complex to install a system integrating PV panels, an electrolyser, a hydrogen storage tank, a fuel cell and batteries for such a low power generation capacity. Unfortunately, these units will continue to run until a reliable grid is deployed.

Large sized diesel generators (>300kW) account for only 2% of the global fleet (0.5 million units) but around half of the power generation capacity (≈ 220 GW). HDF estimates its addressable market for Renewstable projects is a fraction of this market at around 18 GW of fuel cells and 277 GW of solar PV, which is still a huge opportunity.

Fig. 25: **Installed capacity of back-up generators in emerging countries**



Source: IFC "The dirty footprint of the broken grid"

While diesel generators are clearly convenient, they are a highly polluting solution, and are also very expensive, with an LCOE estimated at around EUR225/MWh, depending on the cost of fuel and logistics. In off-grid locations, the cost of transporting fuel can be prohibitive and volumes limited by the lack of infrastructure.

It is not all about hardware

Demand response

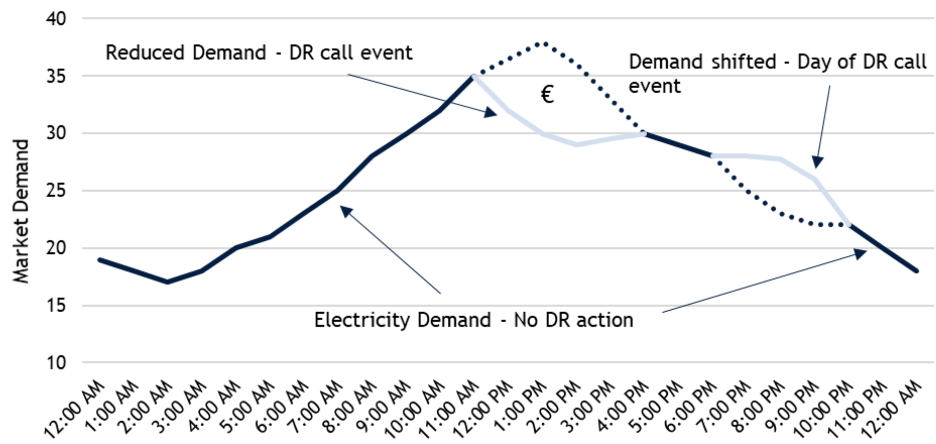
The solution for balancing supply and demand is generally found on the supply side. Traditional power sources can easily and more or less rapidly be increased or decreased and thereby ensure the balance. In contrast, renewable energies are far more flexible and intermittent.

Green energies have priority access to the grid and traditional energy sources round out the supply. However, use of fossil fuels should not remain the only solution given their environmental impact and financial cost. Green energy can be stored in batteries in the form of hydrogen or compressed air, but storage capacity is (very) limited.

As such, if the supply is no longer capable of ensuring the balance, then demand needs to become the adjustment variable.

Demand response (DR) is an answer to this issue by offering end-consumers payment in return for changes in their consumption. In concrete terms, in the event of a power consumption spike, consumers can shut down their demand to help avoid a supply/demand mismatch. Their consumption can resume later on when the peak has ended. For customers not to be penalised, they can establish with their power provider the time frames and shutdown capacity they would like to make available.

Fig. 26: Principle of demand response and impact on demand



Source: Bryan, Garnier & Co

DR is not new; it has existed for some time but until recently was only applicable to a small range of industrial clients. The technology was not sufficiently well advanced to be genuinely profitable. The aim was above all to reduce use of air conditioning and water heating, which consume huge amounts of energy. Progress made in digitalisation, automation and development of IoT now means the application scope can be extended and real forecasts made.

Demand flexibility has a very clear economic interest in terms of industrial withdrawal. Its value lies primarily in reducing requirements so that production means can meet spikes. In other words, paying industrial groups for their availability works out cheaper than creating additional production means to meet demand peaks (means that may only be used very temporarily). Value also lies in the costs avoided to strengthen the network and redispatch energy. Note nevertheless that for the benefit to be tangible, the availability of industrial groups must be absolute and rapidly mobilisable.

Withdrawal in demand by the services sector and individuals could also present an economic interest but this is less certain. We estimate the roll-out of the IoT in smart home and the deployment of smart meters will help implement suitable solutions.

We could imagine the prospect of an individual receiving proposals via their smartphone such as: "Would you like to reduce your electric heating today between 8 and 8.30 p.m.? The potential seems genuine, especially if it is presented in the form of a game with a points system that could then be used to reduce electricity bills.

As an example, to face consumption spikes during the summer period, New York utility group ConEdison set up an auction system enabling certain consumers to withdraw from a part of the grid. The solution was considered more profitable than strengthening the network by creating a new source station (system helping to reduce voltage and adapt it to consumer needs).

Overview of the sector in terms of companies and transactions

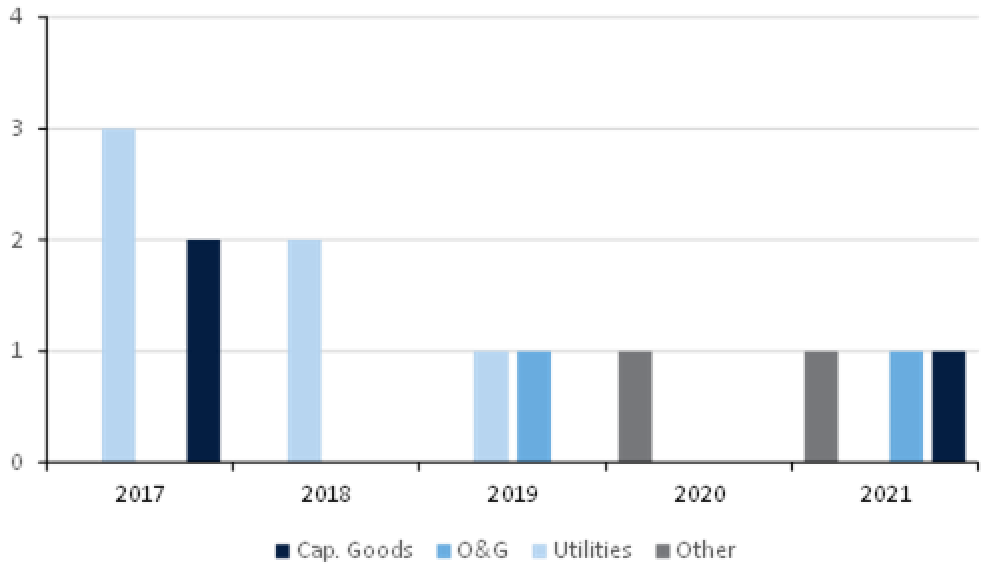
We have identified several moves in the sector which show that major players are interested in this business model/technology. Our research demonstrates that capital goods companies focused on energy (hardware) like Mitsubishi Electric, oil & gas players like BP or Shell, and utilities companies (Enel, Itron) are the main type of acquirers. The rationale for capital goods companies is to combine the software part with hardware equipment to sell a fully-integrated solution. For oil & gas groups, demand response acquisitions fit with their global strategy to diversify their business towards energy transition technologies (batteries, demand response, VPP etc). Finally, utilities like Enel are also investing in demand response in order to maintain their position in the energy sector thanks to new offers, solutions leading to a change in the investment programme since paying incentives to clients who agree to modify their consumption is more interesting than handling high capex for construction of a new plant.

Fig. 27: Most innovative demand response players

Source: Bryan, Garnier & Co

In terms of deals over the past three years, the number of consolidation moves was higher in 2017 and 2018. However, since 2020 and 2021 were affected by the Covid-19 pandemic, another wave of acquisitions cannot be ruled out over the next five years.

Fig. 28: Most innovative demand response players



Source: Bryan, Garnier & Co

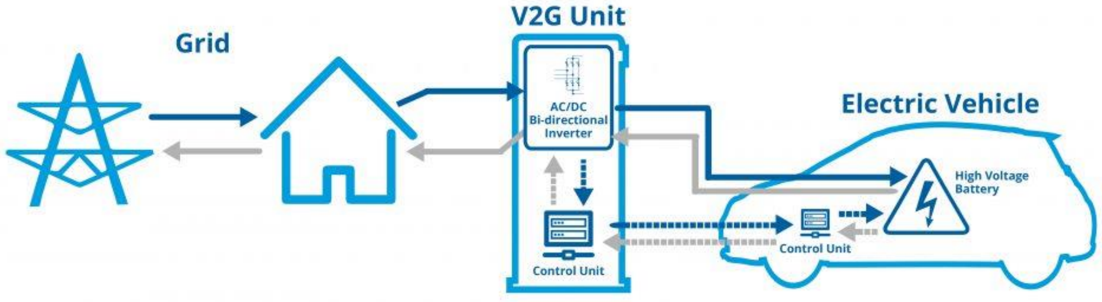
The slowdown in deal activity can also be explained by a decrease in the number of pure players in the market.

Principles and prospects of V2G

As seen in the previous parts of this report, the main answer to intermittency of renewable energies and the gap between power output and consumption lies in storage. In concrete terms, the aim is to accumulate electricity when supply is higher than demand and then recover it when supply is lower. There are several solutions for this: batteries, hydrogen, compressed air etc. While the principles of these technologies are well-known, their performances still need to be optimised to gain in competitiveness.

Rather than see the development of electric mobility as a challenge to the network's stability, V2G aims to exploit it and make it a support factor. The idea behind V2G (vehicle-to-grid) is to make electric vehicle batteries available to stabilise the grid if needed. Given that a vehicle is mostly stationary, a significant amount of battery capacity can be made available. EDF estimates that 50% of vehicles are parked permanently at home and that 69% of those in circulation are parked for around six hours a day on average in a reserved parking slot. National Grid estimates that electric vehicles could store up to 20% of solar production in the UK.

Fig. 29: Principles of vehicle-to-grid (V2G)

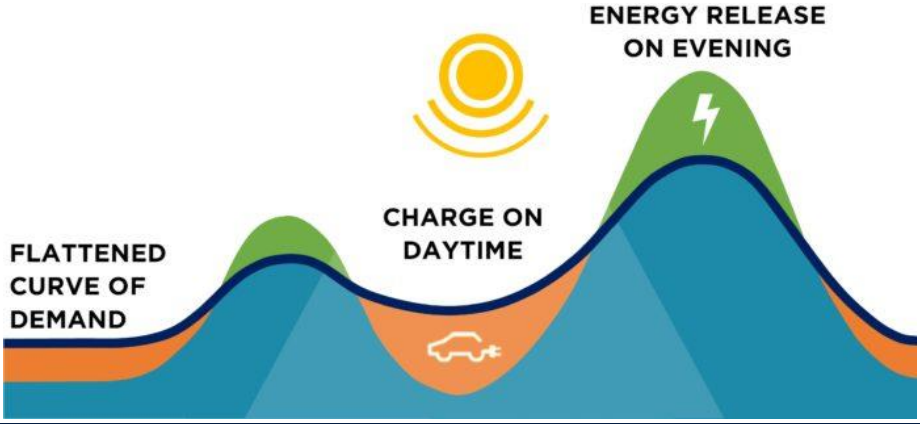


Source: Bryan, Garnier & Co

For the grid, V2G aims to flatten the demand curve by charging batteries when consumption is low and then to relase this energy into the network when demand is high. By avoiding peaks and troughs in consumption, the grid is less sollicited and its flexibility less tested.

V2G system projects have existed for several years already, including one in Los Angeles. The project initially arose from the need to provide greater stability to the network. Indeed, between 2000 and 2001, California witnessed a surge in electricity prices and recurring power cuts. Since then, California has reviewed its regulation system and has looked into a variety of solutions, including V2G, to secure supply.

Fig. 30: Impact of V2G electricity demand curve



Source: Bryan, Garnier & Co

Expansion in electric mobility depends to a large extent on the availability of charging stations, which are lacking in number today. This places a brake on development especially in view of fears over vehicle autonomy. At present, grid operators have no real interest in developing a network of charging stations themselves, and electric car carmakers such as Tesla are setting up the network to underpin growth in the fleet of electric cars.

Once companies such as EDF and CASIO start seeing vehicles as a tool necessary for stability in the grid, and not as challenge or a cost, the issues and the outlook should change radically.

At this stage, providing credible figures for the V2G market is not possible since development of the technology and the market is still in the very early stages. We can nevertheless consider that growth should be high and will follow a similar trajectory to that of the network of electric vehicles. Certain countries such as the Netherlands and Norway have a network that is already well developed and penetration of V2G should therefore be faster and deeper.

National Grid estimates that by 2050, 61-78% of electric vehicles in the UK will use smart charging and 10-14% will use V2G. Smart charging is a less well developed version of V2G whereby the aim is simply to optimise the timing and intensity of the recharge. Furthermore, the energy flow is unidirectional (grid → vehicle), contrary to V2G which is bidirectional (grid ←→ vehicle).

The first commercial offers are emerging

In this context of renewable energies growth and the search for solutions to strengthen the electricity network, EDF created Dreev, a joint venture with Californian start-up Nuvve, specialised in V2G. The solution is to be marketed through different channels, especially Izivia, an EDF subsidiary specialised in recharge infrastructure. For the moment, the solution is only offered to companies and local authorities but ought to be available for individuals by 2022.

Fig. 31: V2G most innovative players

Source: Bryan, Garnier & Co

Although the advantage of V2G for EDF is clear, customers also need to see an advantage for it to take off on a wide scale. To encourage electric vehicle owners to take part in the network, EDF will therefore pay them. Depending on the vehicles' usage and time frames, power consumption for a V2G connected vehicle could be reduced massively, down to zero anord even enabling users to earn money.

Dreev has installed one of the first charging stations in a company near Bordeaux. In exchange for making storage capacity available, the company is to be paid EUR20 a month per vehicle, or EUR720 a year in this example (three cars). Dreev has also launched an experiment with Renault on Reunion island with 150 vehicles. EDF aims to develop the offer with four major historical markets (France, the UK, Italy and Belgium). Dreev is aiming to roll out several hundred charging stations as of 2019.

In September 2019, EDF announced the acquisition of US start-up PowerFlex Systems, specialised in smart charging. The company develops systems to optimise vehicle charging depending on user demand or on-site power generation.

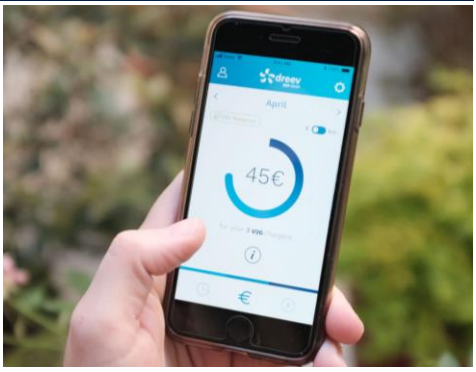
Renault and EDF are not the only ones to have ambitions in V2G. Since 2015, Nissan has been working with Enel on V2G experiments throughout Europe. Under this framework, a test was launched in Denmark that proved to be entirely satisfactory since the network gained in stability.

Beyond the financial/remuneration aspects, for a potential customer to agree to participate, they must be certain that making their power available is not disadvantageous for them. In other words, they need to be sure that their battery remains sufficiently well charged to allow them to use their vehicle when they want to.

This is achieved through a mobile app that enables the definition of charging and discharging moments and cycles to optimise the overal cost of the system. In an emergency, the charging station enables a rapid recharge.

Fig. 32: Dreev charging station | **Fig. 33: Dreev application**

Source: Agence APPA



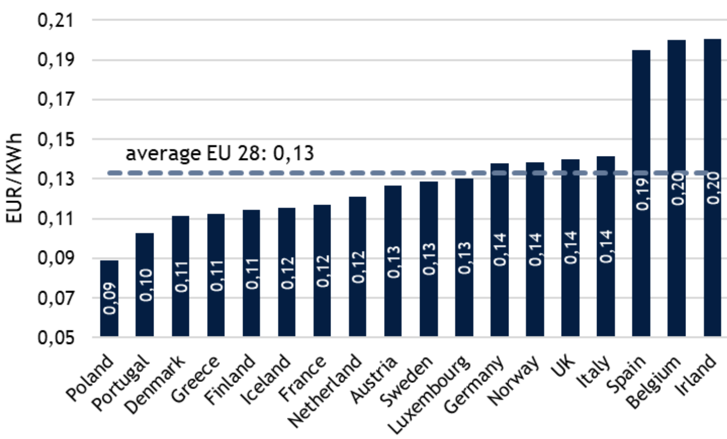
Source: Dreev

Other concerns could rise regarding the battery's lifespan, given the high number of charge/discharge cycles they are subject to. This fear should be eased by the fact that carmakers generally propose battery rental offers and their replacement if the battery loses more than a certain percentage of its initial capacity. The batteries replaced can then be reused by carmakers for power storage stations. Elsewhere, algorithms can be used to optimise battery use and extend their lifespan. The algorithm only provides access to the battery if its use has no negative effect on its duration. Research to better understand the causes and mechanisms of deterioration in batteries will nevertheless be necessary. In general, questions over the end of life cost of batteries remain fully intact.

The application scope of bidirectional charging goes well beyond V2G. The same principle can be applied to power in the home, which is then known as Vehicle-to-Home (V2H). In Japan and some European countries, Mitsubishi proposes a Dendo Drive House (solar panels + domestic battery + bi-directional charger). Total investment is estimated at EUR20-25K, amortisable over a few years depending on electricity prices.

Note that the deployment of these various solutions depends widely on the investment needed and the time to amortise it. The lower the purchase price of electricity for operators, the more complicated it is to make the system profitable. As such, we believe that V2G and V2H should easily penetrate the Spanish and Belgian markets where electricity prices are high. In contrast, it will be more complicated to penetrate the French and Portuguese markets where prices are low. The price differential between the countries probably explains why Mitsubishi's Dendo Drive House will be offered in Germany but not in France (electricity prices are 18% higher in Germany than in France).

Electricity prices in Europe (residential clients)



Sources: Eurostat, Bryan, Garnier & Co

Virtual power plant is the perfect example of a software based solution

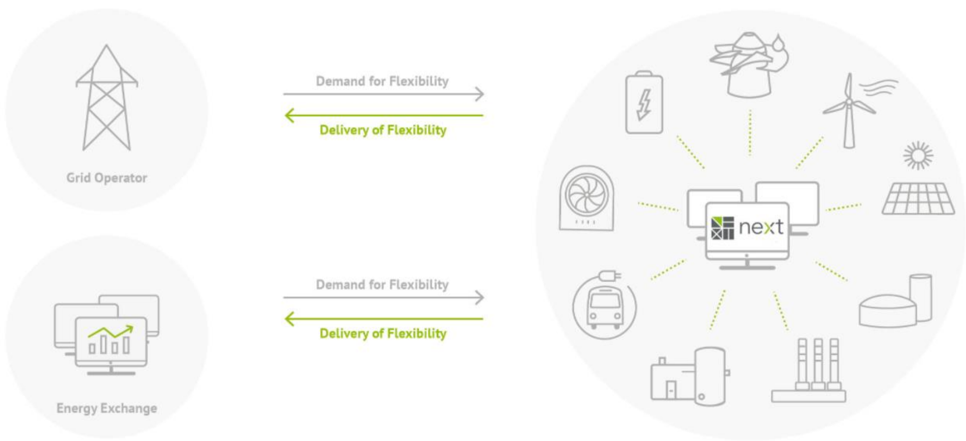
New activities are emerging, especially the development of aggregation and flexibility (modulating consumption). In concrete terms, the aim is to roll out virtual power plants (VPP) to optimise a large number of resources.

Virtual power plant (VPP) as a concept started to emerge in the 90's but really took off 10 years ago. According to Next Kraftwerke, one of the first companies active in this segment, a modern VPP is a "network of decentralised, medium-scale power generating units such as wind farms, solar parks and combined heat and power units, as well as flexible power consumers and storage systems".

In other words, a virtual power plant works remotely to combine a number of independent energy resources from disparate locations into a network able to provide reliable power 24/7.

Concretely, the plants work thanks to software based technologies (smart grid) which utilise planning, scheduling and bidding of distributed energy resources to create a network that provides power.

Fig. 34: Virtual power plant process



Source: https://www.next-kraftwerke.com/vpp/virtual-power-plant

The main goal is to build a network of distributed energy resources in order to monitor, forecast and to trade their power. Therefore, the fluctuations related to renewable power generation can be handled by balancing power. What can make VPP very useful is that they can aggregate flexible capacity to address electricity peak demand. Consequently, they can replace back-up stations (turbo gas stations for example) to help address distribution network bottlenecks.

VPP are different from demand response, microgrid or hardware solution like batteries. Indeed, while microgrids are usually off-grid and restricted to a specific location, VPP are integrated into the grid and can gather several power sources connected at any part of the grid. Regarding demand response, VPP can also act as a demand response aggregator but today, we observe that it's more and more a supply-side initiative.

Finally, technology is one of the main ingredients of VPP: the whole supply process relies on software platforms able to monitor and control customer needs.

Since 2017, this mechanism obliges power producers to sell their electricity on the market and no longer directly to EDF. Selling electricity on the market is a very different activity to developing and operating production units and implies intermediaries known as aggregators. Their role is precisely to facilitate access to the market and even to carry the risk of the trading business.

Schematically, the VPP business model consists of buying electricity at a guaranteed price from producers and selling it on at the market price. Their earnings depend on their capacity to anticipate production and price curves to optimise their trading.

Therefore, a VPP needs an innovative software platform to aggregate all the capacities, a trading floor to be able to buy/sell electricity quickly and a large network of electricity producers to source electricity.

Overview of the sector in terms of companies and transactions

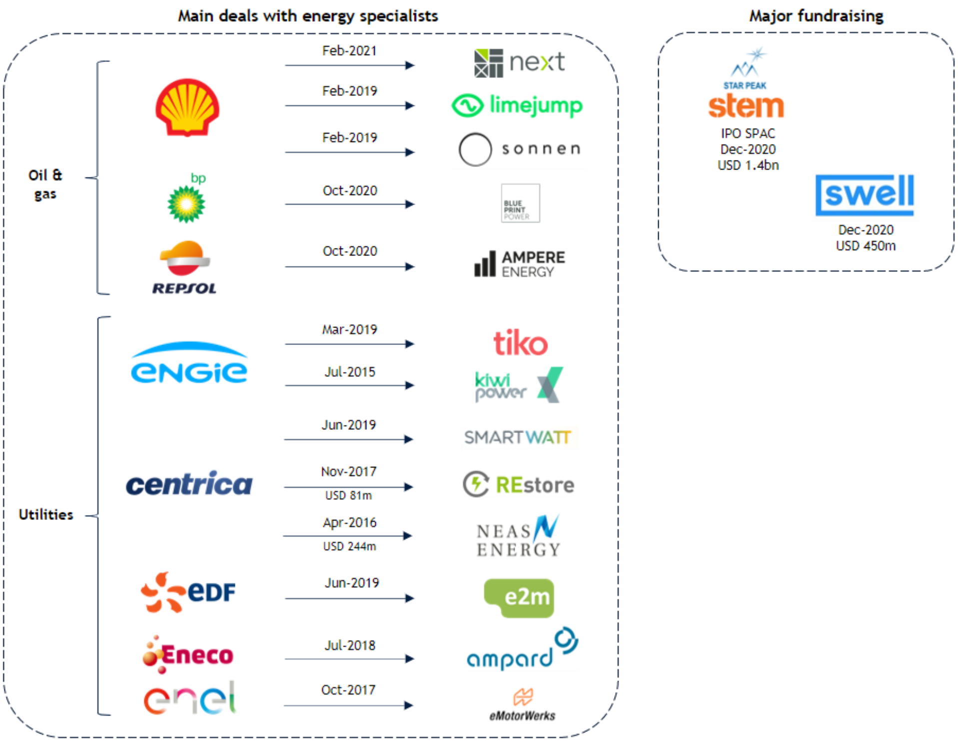
In terms of deals, we note the following:

- Enel purchased Demand Energy, EnerNOC and eMotorWerks to strengthen the foundations of its VPP offering.
- Engie bought a stake in Kiwi Power (UK) in 2018 and Tiko (Switzerland) in 2019.
- Shell bought Sonnen, a German home battery maker, which is developing VPPs in Australia, Germany and the US in 2019.
- Generac Power Systems bought Enbala Power Networks for an undisclosed sum in 2020.
- Spain’s largest oil & gas company, Repsol, last year invested an unspecified amount in Ampere.
- Shell acquired Next Kraftwerk in August 2021.

Regarding business newsflow:

- Germany’s Next Kraftwerke is bidding electric vehicle battery capacity in the Dutch secondary reserve market, and start-up Tibber is doing the same in Germany.
- Residential solar Sunrun has established solar-plus-storage-based VPPs in the US.
- Centrica has assembled a VPP in Cornwall (UK) in association with Sonnen, the software firm N-Side, Western Power Distribution and National Grid.
- GreenCom Networks is assembling "energy communities" in Germany with software that can provide VPP services.

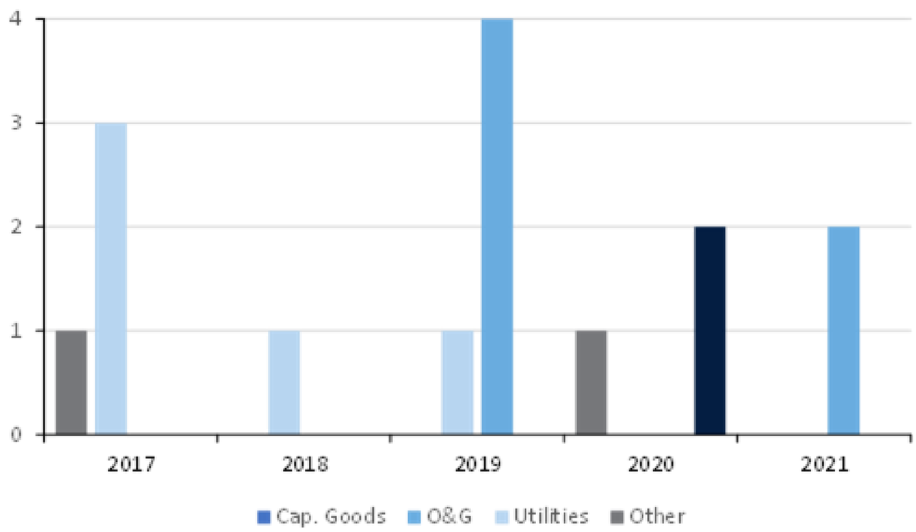
Fig. 35: Main virtual power plant deals



Source: https://www.next-kraftwerke.com/vpp/virtual-power-plant

As mentioned in the previous paragraph, a VPP needs to combine a powerful software platform, a commodity trading expertise to buy/sell electricity and an important customer portfolio to be able to aggregate enough capacities. In this context, we observe that mainly two types of groups are making acquisitions, utilities and oil & gas players. These groups usually have the commodity trading expertise and the customer portfolio but are missing an appropriated software platform. This can explain why the bulk of deals focus on software companies.

Fig. 36: Virtual power plant players



Source: Bryan, Garnier & Co

In terms of the number of deals, 2019 was particularly dynamic mainly thanks to interest in VPP from the oil & gas industry (Shell was one of the most active players). VPP is indeed an excellent way of penetrating the electricity/renewable energies market without paying the huge amounts of CAPEX related to traditional plants. Other companies active in VPP are set out in the following chart:

Fig. 37: Other virtual power plant players

Source: Bryan, Garnier & Co

Whereas hardware is over-represented today in terms of solutions for intermittency, software capacities should not be forgotten, especially regarding grid stability. In this backdrop, we would highlight **Smart Wires** (not covered), a US-based company listed in Sweden.

Fig. 38: Example of software based solutions to improve grid stability

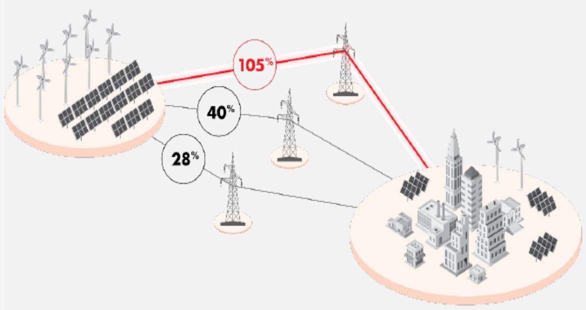
Reimagine the grid with Smart Wires

Today's grid consists of legacy technologies (steel and copper) which have been around for decades with limited innovation. This system is both inefficient and not flexible enough to support the increasing contribution of renewables. Hence, infrastructure is becoming a limiting factor to the energy transition. Modernisation of the grid is now critical to achieve this transition and add new renewable capacities.

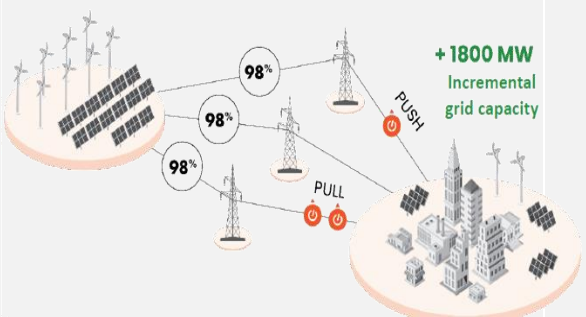
Grid congestion and curtailment prevent the connection and flow of new clean energy sources that are cheaper than existing generation. According to Berkley Lab, over the last nince months of 2020, UK consumers paid over USD1bn in congestion costs when the grid could not transport available and cheap renewable energy.

New transmission lines and traditional improvements are considered slow, costly and complex to implement. To solve this, Smart Wires has developed a modular power flow control solution. Its technology controls and efficiently directs power flow on high voltage electric transmission systems. Basically, the controllers eliminate potential line overloads by redirecting power to other lines, reducing congestion. By doing so, the power grid can be optimised and used at its full capacity which allows for increased contribution of renewable energy while postponing the need for additional transmission lines.

Before Smart Wires



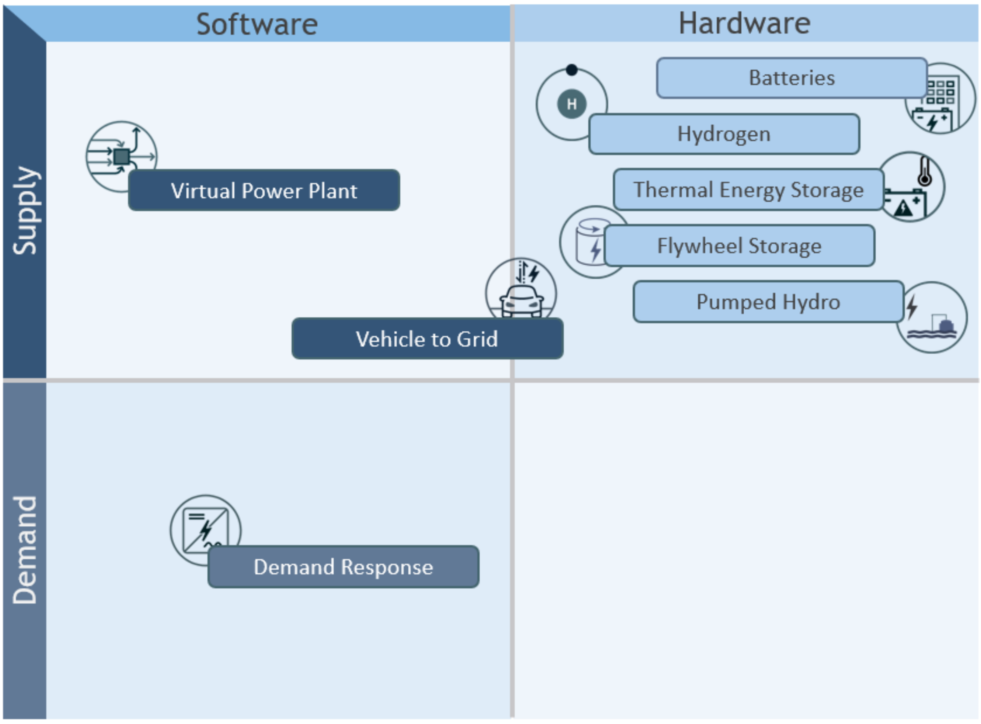
After Smart Wires



Source: Bryan, Garnier & Co

To sum-up, we have organised the different technologies in a chart demonstrate whether they are active on the demand/supply side, and whether they work with hardware/software techniques.

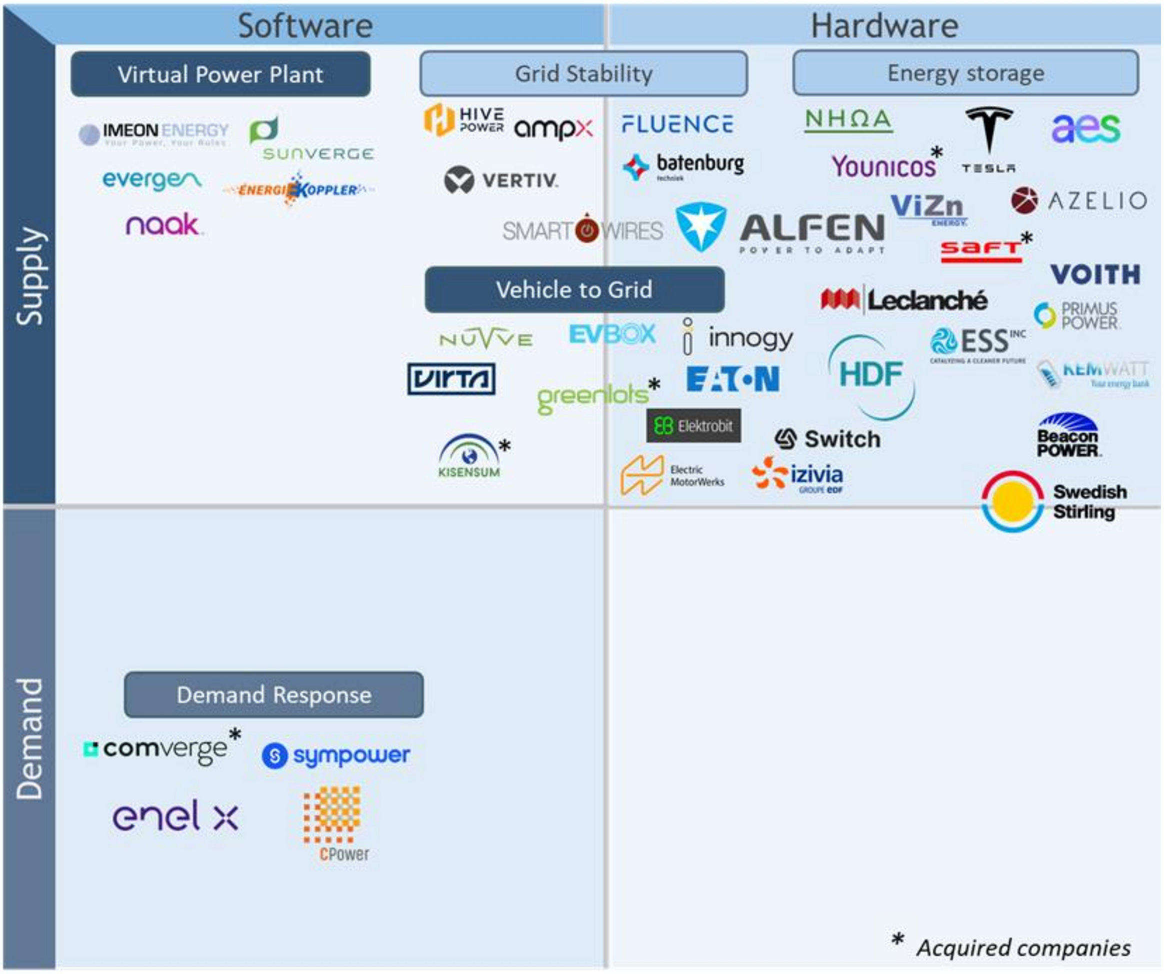
Fig. 39: Nature of current solutions to face intermittency and produce clean power



Source: Bryan, Garnier & Co

Keeping the technologies and adding the main players into each vertical also provides an interesting view of the sector.

Fig. 40: Current companies to face intermittency and produce clean power



Source: Bryan, Garnier & Co

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Section 03

Alfen

Market Data:

ALFEN

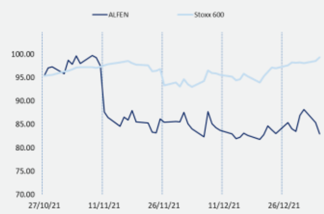
BUY Coverage Initiated

TP EUR105

Bloomberg / Reuters	ALFEN NA/ALFEN.AS
Share price	EUR85.4
Market Cap.	EUR1,708m
E.V.	EUR1,707m
12m high / low	EUR102.4 / 55.9
Free Float	86.5%
Ytd Perf.	3.4%

Shareholders

Capital research & management	6.4%
Free Float	86.5%



Paul de Froment
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Fiscal year end 31/12	2019	2020	2021e	2022e	2023e
Financial Summary					
EPS	-	-	0.88	1.40	1.96
Restated EPS	-	-	0.88	1.40	1.96
% change	-	-	-	57.9%	40.2%
BVPS	-	-	4.30	5.69	7.65
Operating cash flows	-	-	1.24	2.36	3.32
FCF	-	-	0.31	1.05	1.56
Net dividend	-	-	0.00	0.00	0.00
Average yearly Price	-	-	-	-	-
Avg. Number of shares, diluted (k)	-	-	21.750	21.750	21.750
Valuation (x)					
EV/Sales	-	-	NS	NS	NS
EV/EBITDA	-	-	NS	NS	NS
EV/EBIT	-	-	NS	NS	NS
P/E	-	-	96.63x	61.19x	43.65x
FCF yield (%)	-	-	0.37%	1.23%	1.83%
Net dividend yield (%)	-	-	NM	NM	NM
Profit & Loss Account (EURk)					
Revenues	143	189	250	330	428
Change (%)	-	32.1%	32.1%	32.2%	29.5%
Adjusted EBITDA	14	24	35	53	73
EBIT (current)	9	17	27	43	60
Change (%)	-	100.7%	58.3%	56.3%	39.5%
Financial results	-1	-1	-1	-1	-1
Pre-Tax profits	8	17	27	42	59
Tax	-2	-5	-7	-12	-17
Net profit	6	12	19	30	43
Restated net profit	6	12	19	30	43
Change (%)	-	113.1%	60.4%	57.9%	40.2%
Cash Flow Statement (EURm)					
Operating cash flows	15	22	27	51	72
Change in working capital	-2	0	8	2	1
Capex, net	7	10	12	17	21
Free Cash flow	7	9	7	23	34
Dividends	0	0	0	0	0
Capital increase	0	49	0	0	0
Net debt	16	-32	-39	-61	-94
Balance Sheet (EURm)					
Tangible fixed assets	16	24	27	30	34
Intangibles assets	11	14	16	19	24
Cash & equivalents	0	52	59	81	114
current assets	49	56	80	102	128
Other assets	0	0	0	0	0
Total assets	77	147	181	233	301
L & ST Debt	19	20	20	20	20
Provisions	0	0	0	0	0
Others liabilities	44	52	68	89	114
Shareholders' funds	13	74	93	124	166
Total Liabilities	77	147	181	233	301
Capital employed	28	93	112	142	185
Ratios					
Operating margin	6.0%	9.2%	11.0%	13.0%	14.0%
Tax rate	28.1%	27.7%	28.0%	28.0%	28.0%
Net margin	3.9%	6.3%	7.7%	9.2%	9.9%
ROE (after tax)	84.8%	29.8%	37.6%	44.4%	46.1%
ROCE (after tax)	40.0%	23.9%	31.4%	38.6%	41.5%
Gearing	123%	-44%	-41%	-49%	-57%
Pay out ratio	0.0%	0.0%	0.0%	0.0%	0.0%

Source: Company Data; Bryan, Garnier & Co ests.

Alfen

Company snapshot

Founded in 1937 as the J. van Alfen factory dedicated to high and low voltage equipment in the Netherlands, Alfen became an international organisation focused on products and projects closely involved with electric energy. In the early years, the company mainly manufactured switching equipment but over the course of decades, Alfen grew to become an international and diversified player commercialising smart grid solutions (hardware and software), energy storage (based on batteries) and charge points for electric vehicles (EV).

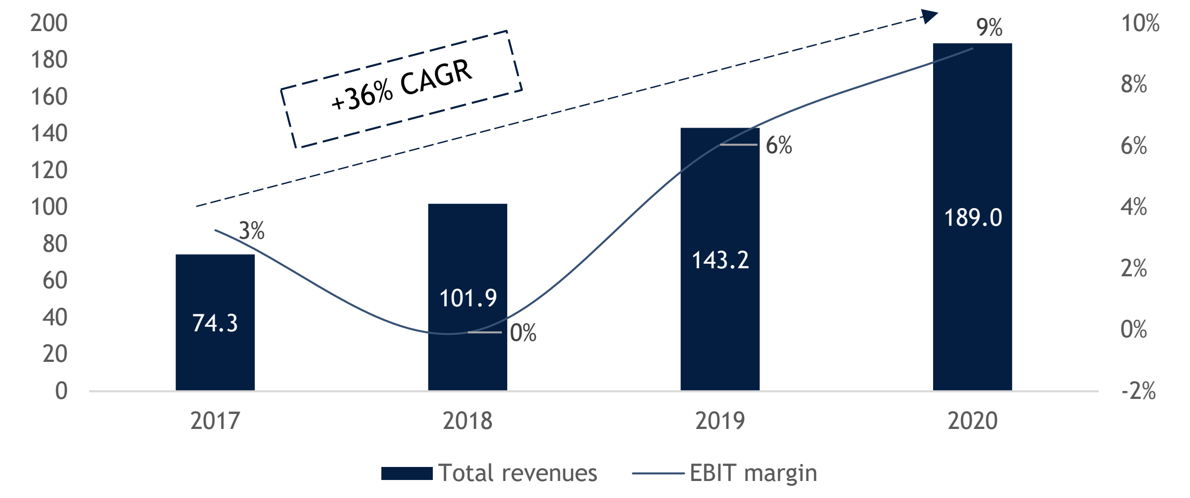
Fig. 41: Main events in Alfen's history

1937	*Founded as 'J. van Alfen's Hoog- en Laagspanningapparaten' in Hilversum. Initial focus on manufacturing high- and low voltage switching equipment*
1968	*Product range expanded with secondary transformer substations*
1971	*Acquired by TBI Techniek B.V. (not the right partner for internationalization, as it turned out)*
1976	*The first compact concrete station is delivered*
1978	*Delivery of the 1,000th transformer substation*
1983	*HQ moved to Almere*
2000	*Product range expanded with smart grid solutions*
2002	*Delivery of the 10,000th transformer substation*
2007	*Name change to Alfen and opening of offices in Belgium*
2008	*Product range expanded with EV charging equipment*
2011	*Product range expanded with energy storage systems*
2014	*Expansion of sales forces to the UK and Germany. Infestos acquires c. 70% of Alfen's shares. Alfen delivers its 25,000th transformer substation*
2015	*Product range expanded with grid automation solutions. Infestos acquires the remaining c. 30% in Alfen*
2016	*Expansion of Almere production facilities*
2018	*Announce IPO and listing on Euronext Amsterdam*
2019	*Infestos completed a private sale of share while remaining major shareholder.*
2020	*Issuance of new ordinary shares for EUR51m and appoints Eline Oudenbroek and Willem Ackermans as members of the supervisory board*

Source: Alfen, Bryan, Garnier and Co

After entering the EV charging equipment business (2008) and energy storage (2011), the group witnessed sharp growth and margin expansion with a better product mix and strong operational leverage.

Fig. 42: Alfen's top line and EBIT margin since 2017



Source: Alfen, Bryan, Garnier and Co

Alfen is structured into three segments:

- Smart grids, which houses the transformer substation business and the grid project connection/automation segment (started in 2015).
- Energy storage, which is dedicated to lithium-ion batteries.
- EV destination charging equipment, which focuses on the delivery of charging stations in public, semi public and private spaces.

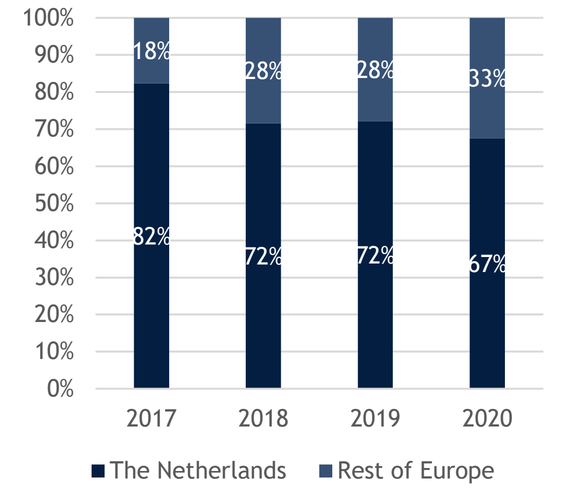
Fig. 43: Alfen core activities

Source: Alfen, Bryan, Garnier and Co

Alfen is the only player present in these three segments. The historical transformer substation business provides Alfen clear visibility (8-10 years contracts) combined with a solid client portfolio (70-80% market share in the Netherlands). This division (including the grid project sub segment) represented 63% of total revenue in 2020.

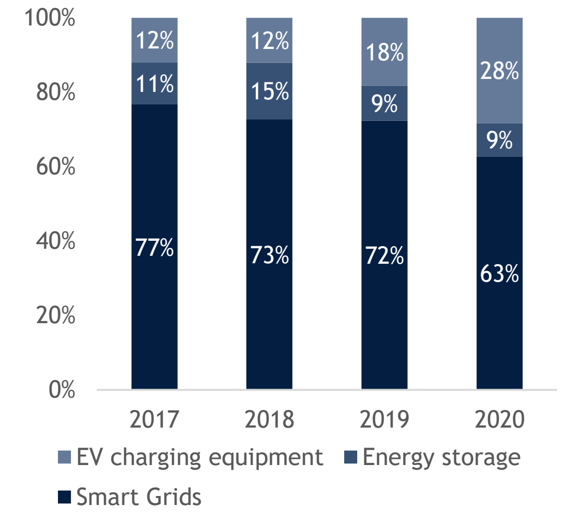
However, as we can see in the business split since 2017, the highest-growing divisions are energy storage and EV charging stations .

Fig. 44: Sales split in terms of countries



Source: Alfen, Bryan, Garnier and Co

Fig. 45: Sales splits in terms of division



Source: Alfen, Bryan, Garnier and Co

Since Alfen is very well established with its smart grids business in the Netherlands, we assume that forthcoming growth will stem from the energy storage and EV charging station businesses notably thanks to their international expansion.

In this context, Alfen has set various medium term goals:

- 50% of international sales by strengthening and expanding the international sales force, leveraging the existing international footprint and foreign customers (focus on Europe).
- +40% top-line CAGR (strong focus on cross selling and new products).
- 15-20% of EBITDA margin (scale-up, leverage of cost base).
- 2-3% of CAPEX to sales ratio (improving the asset-light business model, mostly assembly plants and some manufacturing sites)

Unique positioning in the energy sector

Smart grids, the historical business

As mentioned in the sector part of this report, the energy market is massively impacted by a strong shift from conventional fossil fuels to renewable energy sources. This involves massive changes for grid operators since they have to deal with:

- The intense roll-out of renewable equipment to produce electricity and EVs.
- Intermittency caused by natural sources of power like sun and wind on top of fluctuating electricity flows.
- Decentralisation: contrary to fossil fuel production, which needs a strong industrial set-up, renewable energy installations, especially solar panels, can be rolled out on a local site, far from the rest of the grid.
- Peak demand caused by a growing dependence on electricity by corporates and individuals, notably because of the ramp-up in electric vehicles.

Since the current grid is not able to handle all these changes (power fluctuations, bi-directional flows, numerous EV charging stations used at the same time, micro grids), current infrastructure therefore needs to be upgraded.

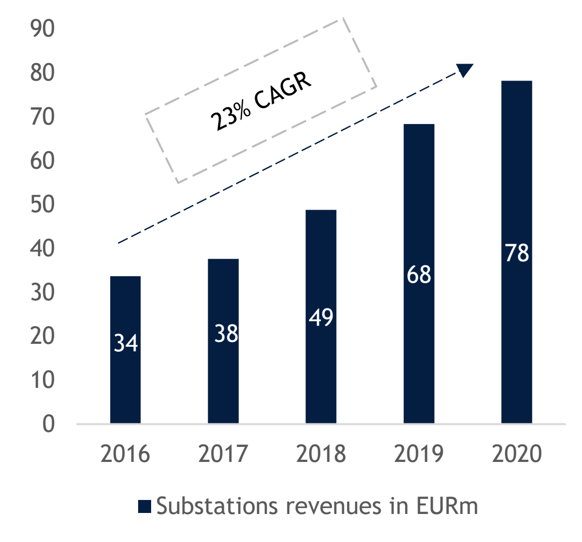
Alfen's historical and largest sub-segment, the smart grid division, is mainly focused on the design, assembly and sale of transformer substation. These stations are key in a grid infrastructure since they allow a correct dispatch of electricity from production source to the end user.

Indeed, to easily transport electricity long distances, the voltage needs to be very high. As it gets closer to the end-user, the voltage must be lowered to fit with household electricity consumption. In this context, transformer substations need to be set in different parts of the grid to convert the electricity frequency.

Consequently, distribution system operators (DSOs, operating managers and sometimes owners of the energy distribution networks) order on a regular basis to manage/expand/modify the grid. Representing approximately two thirds of the smart grid division, transformer substations are Alfen's historical business.

The first transformer substation was installed by Alfen in 1968 and since then, we estimate that c. 30,000 units have been sold. Since different sizes (and complexity) and even custom-built models are available, pricing varies considerably, ranging from EUR20k to >EUR100k approximately. Thanks to its long history and robust know-how, Alfen has managed to build reliable long-term agreements with the main Dutch DSOs.

Fig. 46: Estimated 2016-2020 transformer substations revenue in EURm



Source: Bryan, Garnier and Co

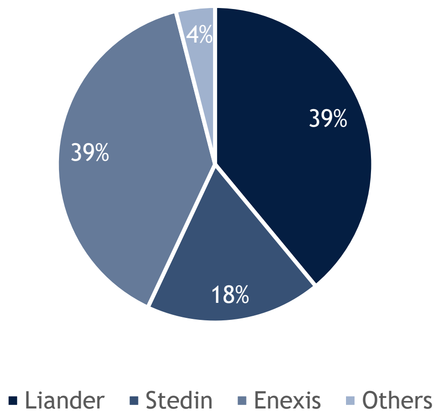
Fig. 47: Transformer substation in the Netherlands

Source: Alfen, Bryan, Garnier and Co

The DSO market in the Netherlands is particularly concentrated with the main three DSOs (Stedin and Enduris are the same company) totalling 96% of the distribution network market in terms of number of substations.

We understand that Alfen benefits from long-term agreements with at least two of the three largest DSOs ensuring strong positions with market share close to 70-80% in the Netherlands.

Fig. 48: Dutch market in terms of substation per DSO



Source: Alfen, Bryan, Garnier and Co

Moreover, since the Dutch regulation obliges DSOs to publish their forthcoming substation capacity programmes every two years for the following two years, we have clear visibility on the business.

Fig. 49: Main DSO capex over 2015-20 and 2021-22 in number of units

In number of stations	2015	2016	2017	2018	2019	2020	2021	2022
Substation CAPEX	1020	1104	995	1147	1266	1708	1671	1712
growth	NS	8%	-10%	15%	10%	35%	-2%	2%

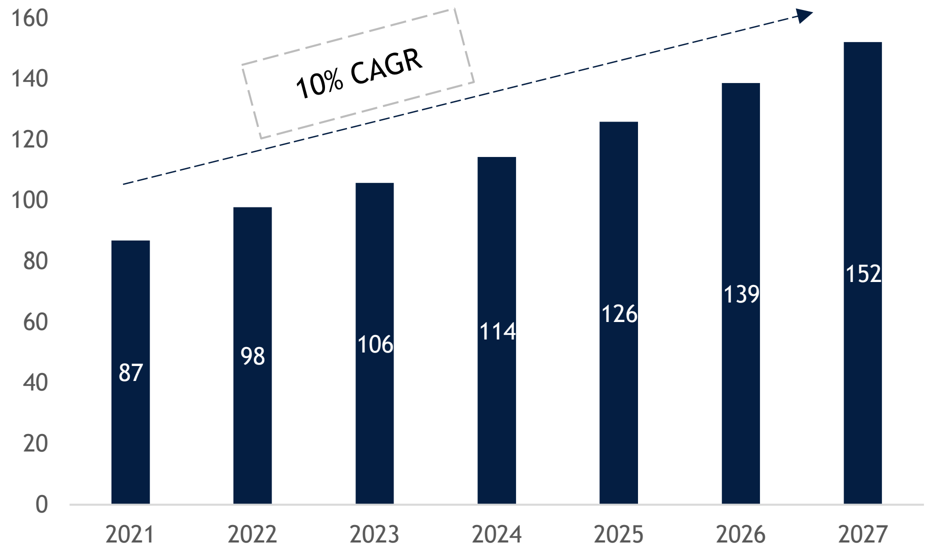
Source: Bryan, Garnier and Co

To establish forecasts for this division, we have chosen to stick to the 2021 and 2022 expectations published by the DSOs and to apply a 130% PoS (historical data shows that DSOs invest well above their targets) taking into account a stable market share of 80%. Indeed, all investment estimates provided by the DSOs have been inaccurate in the past since real CAPEX was always higher than expected.

We have based our forecasts on the price range related to transformer substations (EUR20->100,000 per unit) leading us to expect 2021 revenue of EUR87m.

For our LT estimates, we have applied a sales CAGR of 7.5% combined with yearly inflation of 2%. Our sales CAGR relies on historical data (21% CAGR over 2015-20) and forthcoming challenges for the DSO (renewable ramp-up, intermittency, electricity peak demand) involving a regular increase in capex.

Fig. 50: Substation business forecast in EURm over 2021-27



Source: Bryan, Garnier and Co

Smart grid projects, the growth contributor

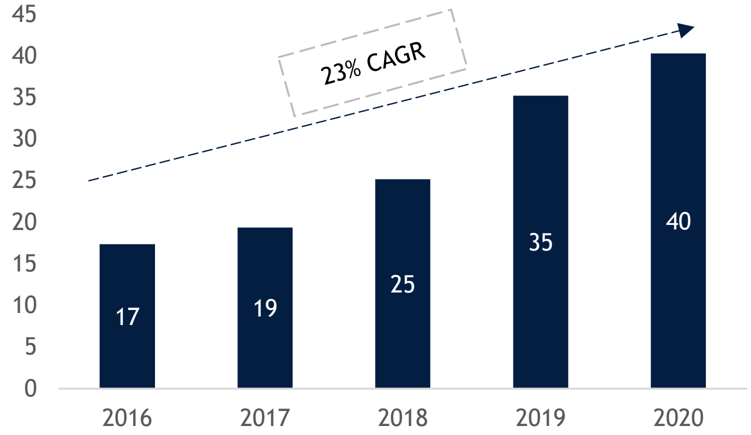
In smart grid projects, Alfen connects and integrates renewable energy sources to local grids but also allows cutting-edge monitoring of the microgrid infrastructure.

The microgrid subsegment is focused on providing grid solutions including grid connections for large energy producers and/or consumers that need their own energy infrastructure (solar, greenhouses, industrials etc).

Grid automation is both software (digitalisation of the grid) and hardware. Alfen's product "Alfen connect" allows the visualisation of real-time substation data, temperature, lighting, electricity consumption etc. Customers can therefore monitor their grid infrastructure according to their specific needs.

Alfen's competitive advantage relies on strong know-how of medium voltage infrastructure, an integrated offer bundling software monitoring and hardware connection, strong relations with DSOs at least in the Netherlands, and finally, a satisfying track record reflected in the more than EUR130m of sales cumulated since 2016.

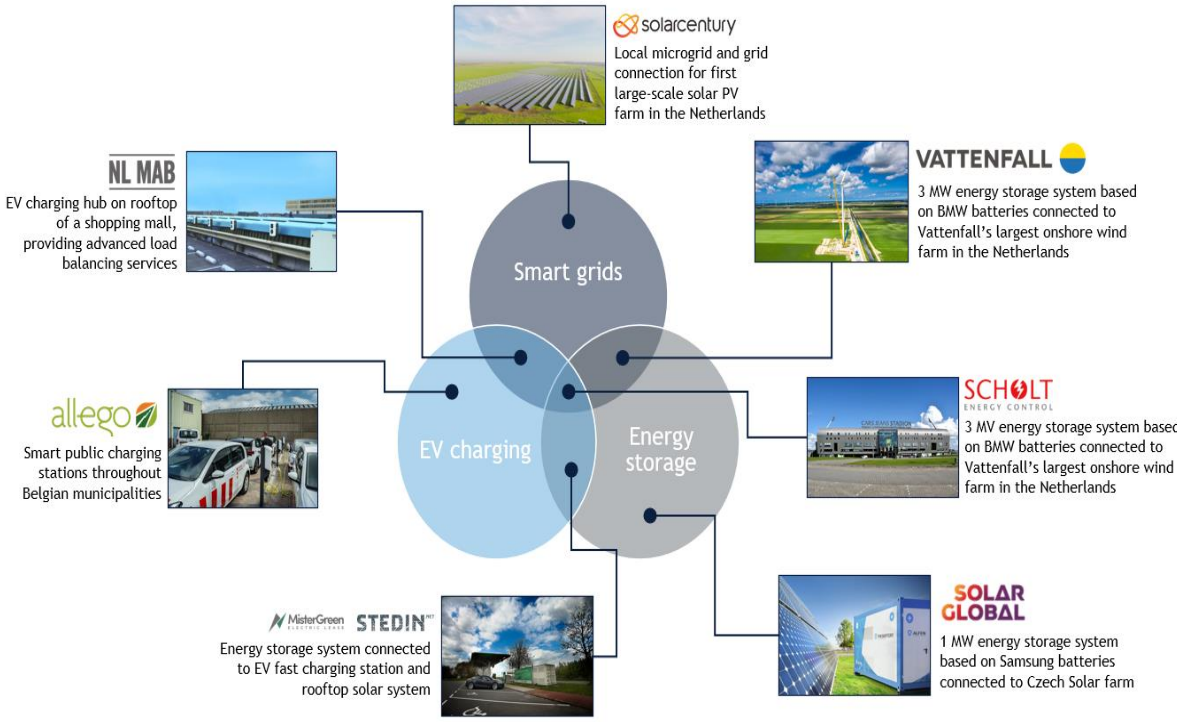
Fig. 51: Historical grid projects CAGR



Source: Bryan, Garnier and Co

In terms of customers, Alfen targets large decentralised energy consumers like the horticulture industry for example. However, one of Alfen's main goals is to respond to projects that comprise all of the company products, highlighting its cross-selling ability and integrated offer. This is the case of the Cars Jeans stadium in The Hague (solar panels combined with TheBattery), for which Alfen supplies the entire stadium including 20 EV chargers in the car park. Alfen also provided the local grid solution which resulted in a fully integrated project.

Fig. 52: Cross selling examples



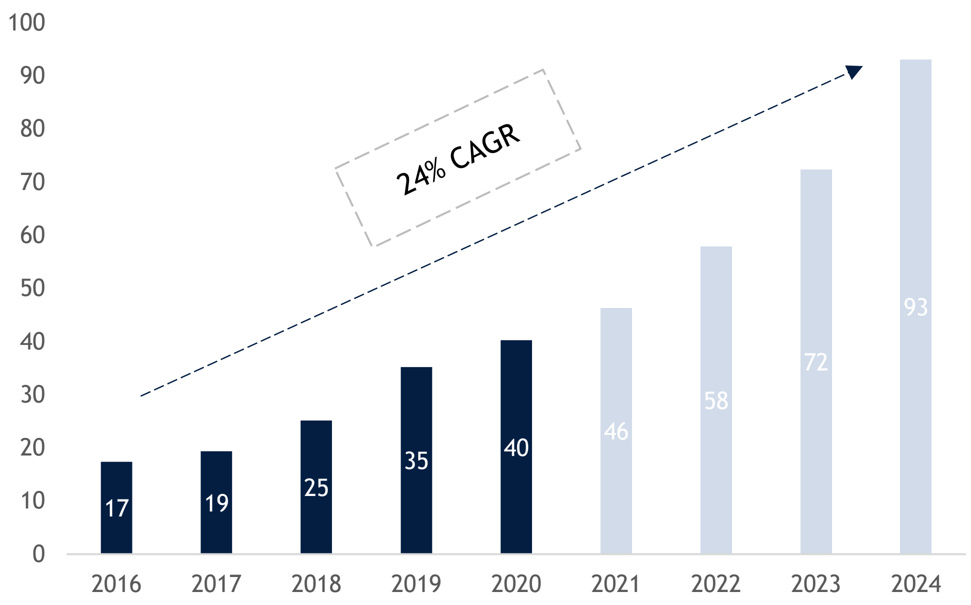
Source: Alfen, Bryan, Garnier and Co

Alfen's grid project subdivision should easily benefit from the ramp-up in microgrid projects in Europe since the group is well established in this market. Moreover, Alfen should also benefit from additional revenues related to its installed base, since it is also responsible for maintenance (this is not the case for transformer substations). As such, Alfen should gradually increase profitability in the division in line with the mounting number of projects.

Nevertheless, market visibility is poor and precise projects are difficult to forecast. Given Alfen's position in this market, it is bound to benefit from the increase in the microgrid market.

According to several sources (Navigant research, Global market insights), the solar microgrid market should continue to grow at a CAGR of 27% from 2021 to 2027, reaching USD33.4bn in 2027 (vs USD6.7bn in 2020) made up of c.70% microgrid and 30% off-grid projects.

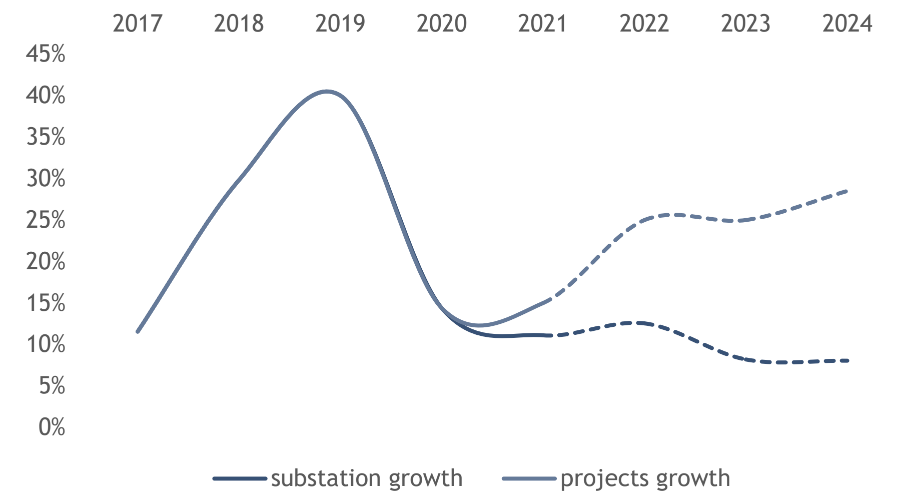
Fig. 53: Grid projects CAGR over 2016-24



Source: Bryan, Garnier and Co

A look at the combined top line of grid projects and transformer substations shows that forthcoming growth is set to be driven more by grid projects (+15% CAGR out to 2031) than transformer substations (+7%).

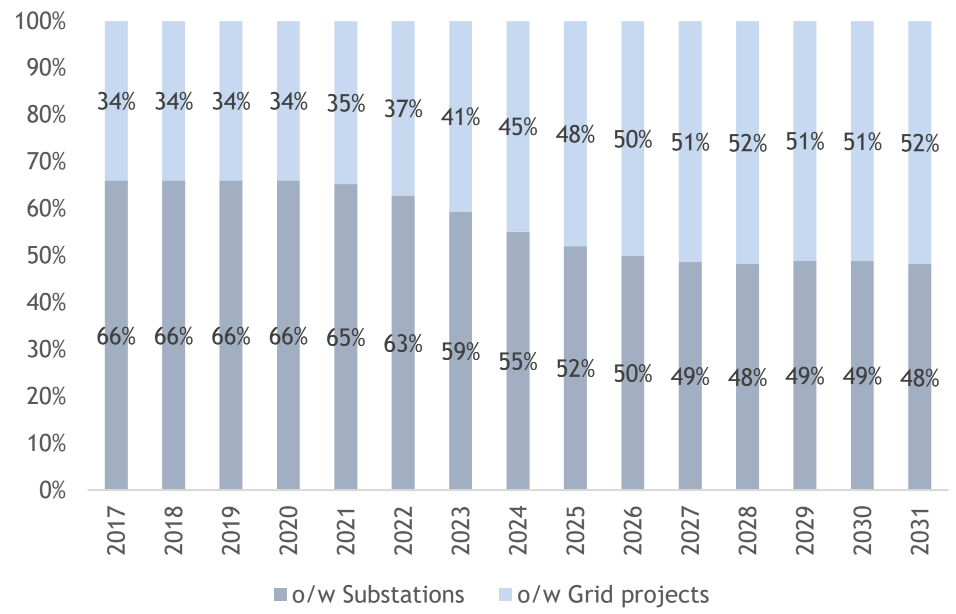
Fig. 54: Forthcoming growth related to substations and grid projects



Source: Bryan, Garnier and Co

Therefore, grid projects should become more important in the sales split of the smart grid division and account for almost half of the division's top line as of 2026.

Fig. 55: Smart grid top line split over 2017/2031

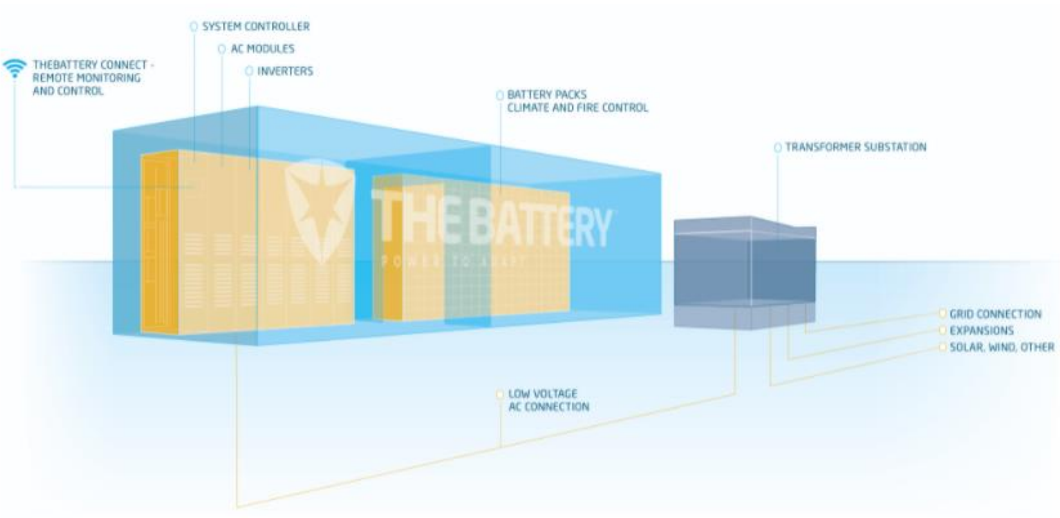


Source: Bryan, Garnier and Co

Energy storage, a fast growing business

Alfen is also positioned in the energy storage market with its product launched in 2011, TheBattery, a lithium-ion modular plug-and-play standardised unit that can be remotely monitored and controlled for different kinds of applications like frequency control and peak shaving. Alfen's goal is indeed to provide turnkey and integrated solution including project management, substations, grid connection, remote monitoring and on-site services for utilities, industrial players and large corporates.

Fig. 56: TheBattery



Source: Alfen, Bryan, Garnier and Co

Alfen's energy storage solutions are flexible and can be designed in different sizes:

1. TheBattery HighDense: an industrial design for >2MW energy storage solutions with an integrated transformer for MV connection. TheBattery HighDense has high energy density as it allows for up to 3.3 MWh in one 40-foot. container. The system is often used for grid services or for blackstart and back-up functionalities. The system is often supplied in a multi-container configuration for which Alfen provides an end-to-end solution including medium-voltage switchgear and grid connection.

2. TheBattery Mobile: Alfen's green alternative for diesel generators. This consists of a moveable 10-foot. container. The compact design allows up to 422 kWh of energy. This system is often used at sites where a temporary power supply is required, such as, festivals, construction sites and grid takeovers.

Regarding the competitive landscape, Alfen mainly competes with Fluence and Wärtsilä.

Fig. 57: Competitive landscape in energy storage

	Component suppliers	ALFEN and competitors	Customers
Energy storage	• Developers of batteries and/or ancillary components • Some battery manufacturers also offer integrated storage solutions on a project basis o In these case storage solutions are based on these companies' own batteries o Typically relatively inflexible to cater to clients' requests for certain specifications • A number of large international players offer storage solutions based on externally sourced battery cells o Limited competition from these players in small- or mid-sized projects requiring flexibility and system integration capabilities	• Early stage market, Alfen active since 2011 resulting in a first mover advantage • Direct competition arises from smaller pure-play storage (and microgrid) players (e.g. EPS and Leclanché) • Several companies focused on energy storage were recently acquired: o EPS in the process of being acquired by French utility Engie (2018) o Belectric was recently acquired by German utility Innogy (2017) o Younicos by generator rental company Aggreko (2017) o Greensmith by Finish marine energy equipement company Wartsila (2017) • US-Based players (e.g. Greensmith and Younicos) are increasingly expanding into Europe	• Customers for storage solutions include: o Utilities o Grid operators o Energy traders o Renewables developers o Large energy users
	SAMSUNG, socomec, SIEMENS, TESLA, LG, Danfoss, BMW i.	NHOA, Leclanché, TESLA, FLUENCE, Younicos	VATTENFALL, SOLAR GLOBAL, SCHOLT, eandis, Eneco, ENGIE, STEDIN

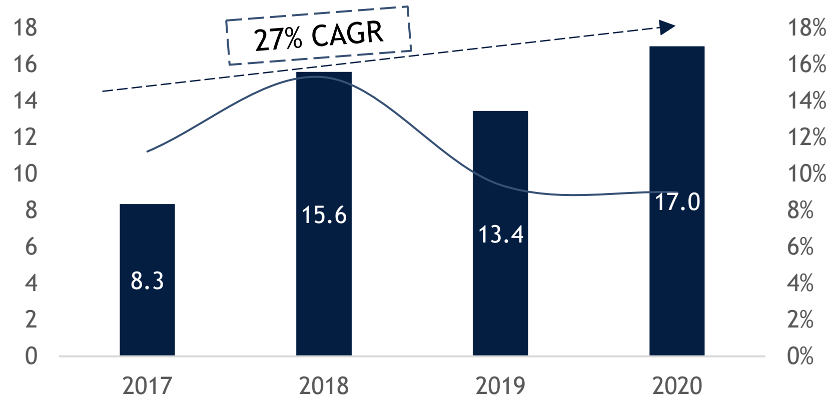
Source: Alfen, Bryan, Garnier and Co

Demand for battery storage is rising

Energy storage is becoming increasingly important as renewable energy sources are being rolled-out. In this context, batteries are among the most adopted technologies to face intermittency issues (back-up power sources). They are also a clean alternative to diesel generators in off-grid systems which can then help to stabilise the grid during peak demand moments (set to become more frequent with the EV ramp-up).

All these drivers explain the strong demand related to battery products. Since Alfen is already very close to battery consumers (DSOs, large energy consumers, C/I market rather than residential already targeted by Tesla), it has managed to rapidly develop its top line.

Fig. 58: Energy storage top line in EURm and % of total sales



Source: Alfen, Bryan, Garnier and Co

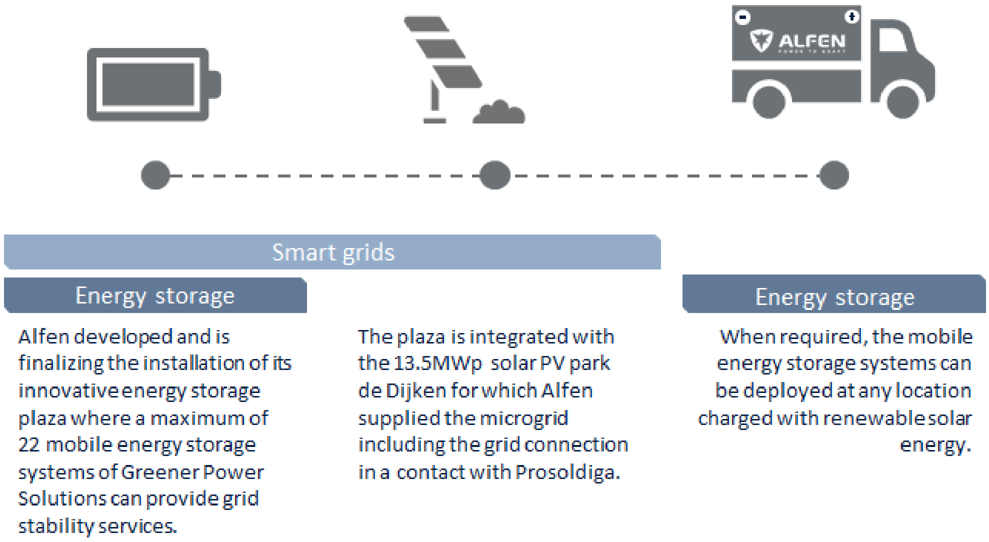
Numerous competitive advantages

On top of a premium quality reputation for its products, the group has started to stand out from its competitors for its cross-selling capacities.

By offering a turnkey solution combined with its expertise in grid connection and its strong partnership network with DSOs, Alfen is perfectly positioned to expand a cross-selling strategy.

TheBattery can be deployed as a back-up power source in a microgrid project connected by Alfen to the national grid for example. An EV station with several charging points installed by Alfen could also host batteries that could be useful to handle peak demand. Finally, TheBattery is technology-agnostic meaning that it can work with different technologies and suppliers (Samsung, BMW are examples) to meet client requests.

Fig. 59: Integrated project example

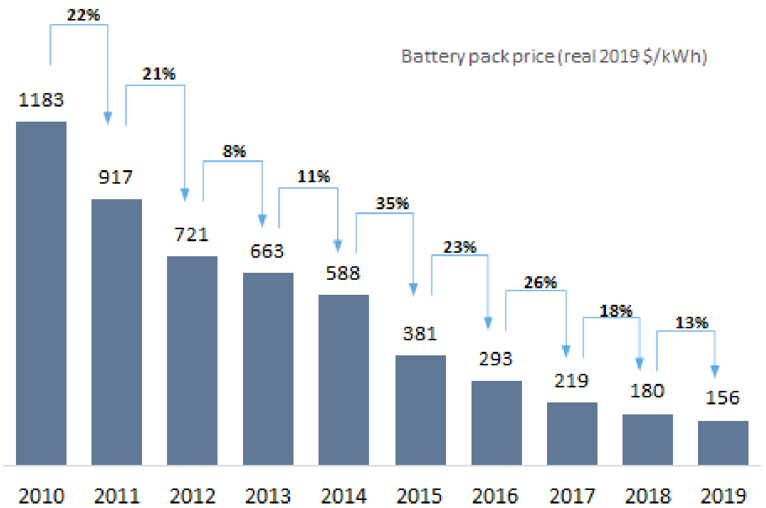


Source: Alfen, Bryan, Garnier and Co

Market and forecasts

The energy storage market is still a very young market dominated by innovation and cost reduction. The price of lithium-ion batteries has been divided by 10 in less than 10 years mainly because of scale up effects. According to Bloomberg New Energy Finance (BNEF), the price of lithium-ion batteries should continue to decline by an average of 8% per year over the next five years. In term of storage capacities, BNEF expects an overall installed capacity of 2.2GW by 2025 reflecting an average CAGR of 45%.

Fig. 60: Lithium-ion battery price in USD/KWh over 2010-19



Source: https://clearpath.org/tech-101/intro-to-energy-storage/

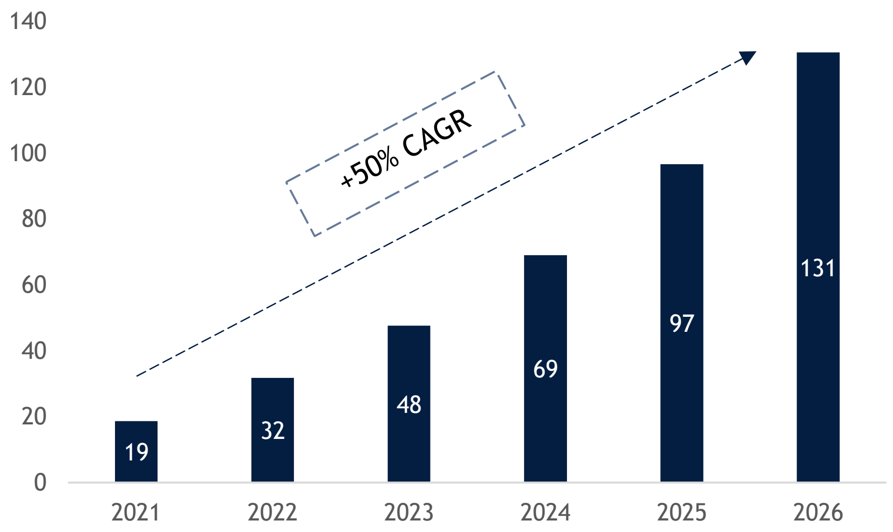
Given that there is no clear data since the market is a very recent market, Alfen does not provide any information related to pricing, installed capacity or market share. Consequently, we have forecast Alfen's energy storage business mainly thanks to market data.

Lithium-ion battery prices fell from USD1183/KWh in 2010 to USD156/KWh in 2019 in view of massive scale up and optimisation. Whereas we could forecast further price declines of 6-8% a year for the next 10 years and derive a top-line estimate for the energy storage division we do not have the number of KWh per year sold by Alfen. Indeed, the company has two models (TheBattery Highdense and TheBattery Mobile), which are modular systems meaning that capacity can change from one customer to another. On top of that, lithium-ion is not the only component in a battery pack, which also include inverters, the container and the switch etc. Finally, Alfen's offer also relies on a specific software dedicated to monitoring/control of TheBattery, which also tends to absorb the lithium-ion price decline. Therefore, bottom-up forecasts would be too inaccurate.

According to several market research sources (BNEF, Engie, GMI), the European energy storage market (mainly composed of batteries) should grow by 35-45% a year over the next 10 years.

Since we believe Alfen will be able to gain additional market share over the next five years thanks to its numerous competitive advantages and its leading positions, we forecast a sustained top-line increase of 50% a year on average until 2026. Since the market's guidance for revenue CAGR lies in the 40-50% range since 2020, we think that our sales forecasts are realistic.

Fig. 61: Energy storage top line forecast in EURm

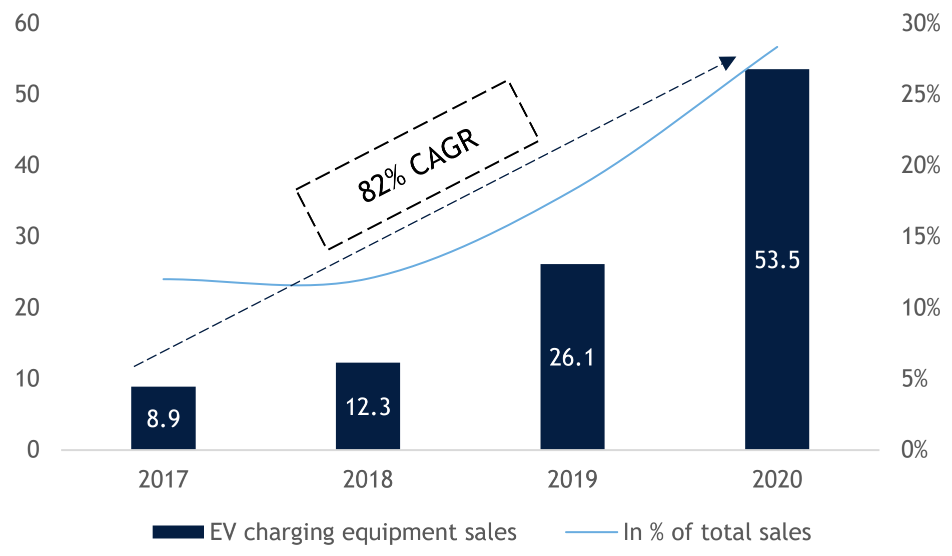


Source: Bryan, Garnier & Co

EV charging stations, the most promising division

Alfen entered the electric vehicle market in 2008 with the manufacturing and the distribution of EV charging stations. The company started with its domestic market before expanding to the rest of Europe. Thanks to strong reseller and customer relationships, Alfen managed to boost this segment with sales increasing by 82% a year on average over the last four years.

Fig. 62: EV equipment top line in EURm and % of total sales



Source: Alfen, Bryan, Garnier and Co

While the high growth of EV car adoption is still underpinned by public subsidies, the limited availability of charging equipment represents a massive opportunity for companies like Alfen.

Since there is no European standard for EV charging stations, each country has to respect a specific regulation.

As a result, Alfen has designed several charging stations respecting the different regulations in Europe, thereby enabling it to rapidly expand its international footprint.

The difference between the equipment types also lies in the power capacities: from 3.7kW for the Eve single s-line to 22kW for the Twin model. Since the European commission considers that a “normal power charger” goes up to 22kW, Alfen’s products are not seen as fast charging equipment.

Fig. 63: Alfen product range

Source: Alfen, Bryan, Garnier and Co

In terms of positioning, Alfen targets :

- the private, public and semi public destinations (home, offices, supermarket)
- the AC segment (slow charging equipment)

Fig. 64: Alfen EV charging stations characteristics

	Eve Single Pro-line	Eve Double Pro-line	Twin	Eve Double PG-line
Description	Compact Walbox	Robust charging station with glasfiber enforced casing	Highly robust and solid charging station especially designed for public locations	Highly robust and solid charging station especially designed for grid specifications in Germany
Use	Home, workspace	Workspace, public, parking garage	Public	Public
Outlets	Single socket or tethered cable type 1 or 2	Dual type 2 sockets	Dual type 2 sockets	Dual type 2 sockets
Charging capacity (per socket)	3.7kW, 7.4kW, 11kW, 22kW	3.7kW, 7.4kW, 11kW, 22kW	11kW, 22kW	11kW, 22kW
Purpose	On the wall or on an optional mounting pole	Mounting pole	Solid metal casing	Solid metal casing
Further Information	✓ Fully equipped with functionalities for financial transactions and smart charging ✓ Competitively priced and offers unrivaled value for money	✓ Modern design that fits perfectly within every environment, renewed in 2017 ✓ Charging station comprises of a special composite material (strengthened with fiber glass) making it water-resistant and durable	✓ Specially designed for applications in public and semi-public areas ✓ Alfen redesigned the Twin in 2017 and improved its interior with enhanced charging technology	✓ Offers same benefits of the Twin but has been modified to comply with German grid specifications (smart meter gateway communication requirements) ✓ Alfen amongst the first to implement the new chargers requirement

Source: Alfen, Bryan, Garnier and Co

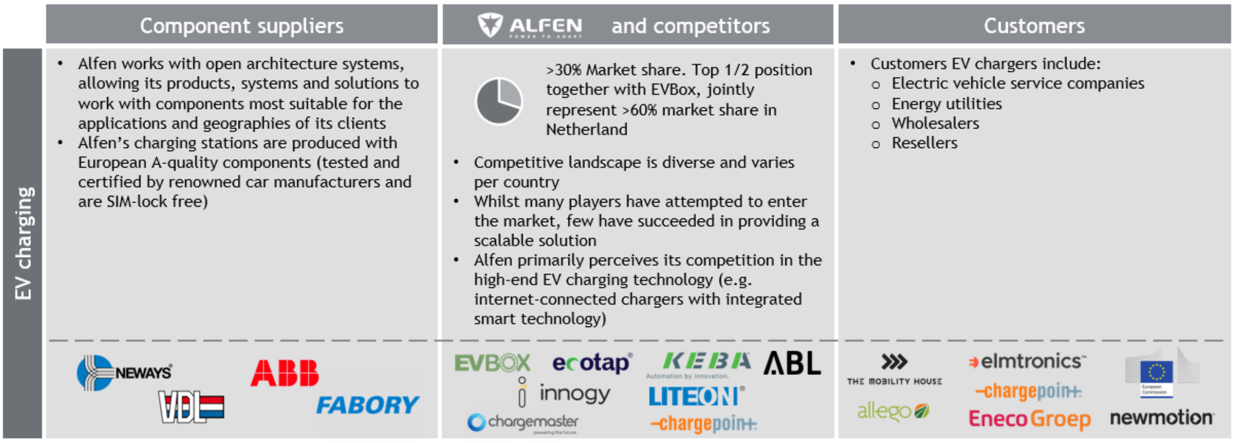
While the DC segment (fast charging stations) is experiencing a fast ramp-up, Alfen is not positioned in this segment and, from what we understand, does not plan to target it. The reasons for this are numerous but the most significant one is that the bulk of the market (more than 95% of EV charging stations according to Navigant Research) concerns slow-charging stations.

This split should not change since growth in EV charging stations is driven by individuals and corporates involving the installation of charging equipment in homes and offices in the city centres. DC charging stations can only be installed on highways and on the outskirts of cities for two reasons:

- The need for fast charging occurs for long distance driving.
- Power consumption is so high that it needs a specific connection to the grid, thereby making it unsuitable for individuals.

Finally, Alfen does note compete with Tesla, which is focused on fast-charging equipment and this helps ease the competitive landscape.

Fig. 65: Alfen EV charging competitive landscape



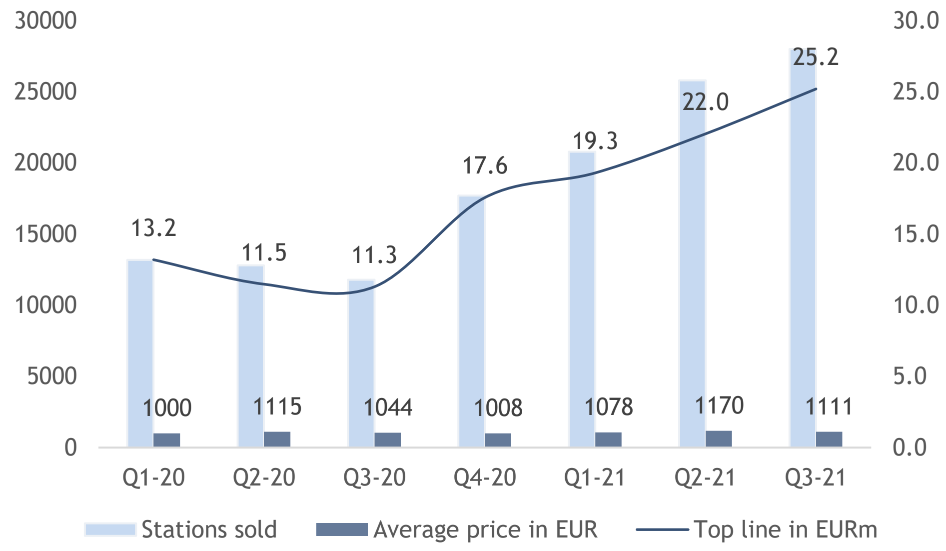
Source: Alfen, Bryan, Garnier and Co

Market and forecasts

As with the energy storage division, Alfen provides no information related to pricing per charging station, the pipeline, or precise targets in terms of the amount of charging equipment.

Nevertheless, the company provides quarterly updates in terms of charging stations sold, enabling us to derive an average unit price of EUR1,000 per station.

Fig. 66: Quarterly number of stations sold and average price

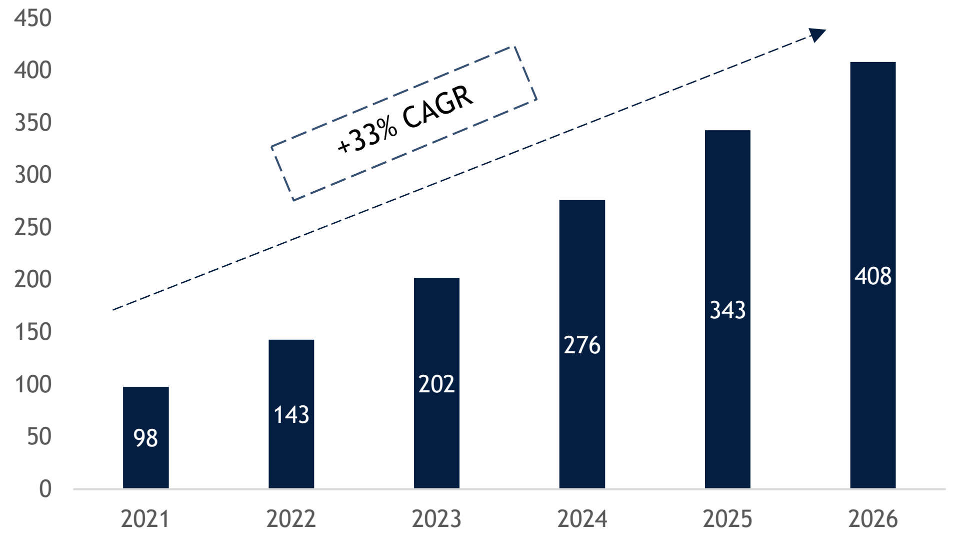


Source: Bryan, Garnier and Co

We combine this assumption with the data projections from BNEF stating that approximately 1.2m EV charging stations were installed in Europe and that this number should grow at a 17% CAGR over the next nine years.

Assuming a market share of 6% in 2021 in Europe, which could rise to 12% in 2026 given the company's strong positioning and cross-selling advantages, we have derived top-line expectations resulting in a 33% sales CAGR for the next five years.

Fig. 67: EV equipment top-line forecast in EURm over 2021-26



Source: Bryan, Garnier and Co

V2G could contribute to maintain a significative growth level in a few year's time

We assume a 30% top line growth per year in average for the EV charging business but our estimates could be below the real potential of this division. Indeed, while the whole EV market is asking for a massive ramp-up of EV charging stations, other catalyst like the V2G (vehicle-to-grid, described above in the report) could boost Alfen's top line.

First, to be possible, V2G needs bi-directional flows equipment (in order to receive/send back electricity to the grid). Since this technology is very early stage (business model is not clearly defined), current EV charging stations do not allow bi-directional flows, from an hardware perspective. Consequently, an overall adoption of V2G could involve the replacement of older charging stations, which induces more top line.

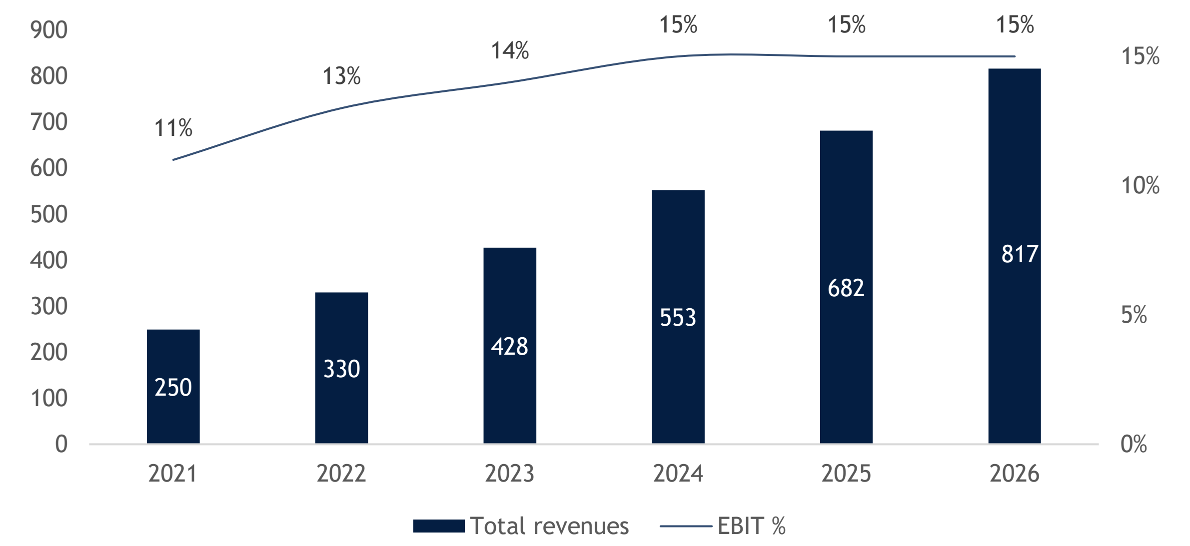
Assuming a very gradual replacement of the installed base of Alfen charging units as of 2025 (from 1% to 10% of the installed base), we identify a EUR1.3bn of (potential) additional sales over 2025-2031 which are not taken into account in our current valuation.

Initiating coverage with a Buy rating, EUR105TP

Still a fast growing company

Consequently, after taking into account the three divisions top-line development, we have derived sales assumptions highlighting a sustained 27% CAGR out to 2026.

Fig. 68: Top line and EBIT margin forecast over 2021-2026 in EURm



Source: Bryan, Garnier & Co

In terms of margins, we assume a gradual improvement related to cost reductions, scale-up effects, on-going innovation (new products, software updates, growing maintenance revenues depending on the installed base) and little price erosion. Operational leverage will consequently help margins widen from 11% in 2021 to 15% in 2025.

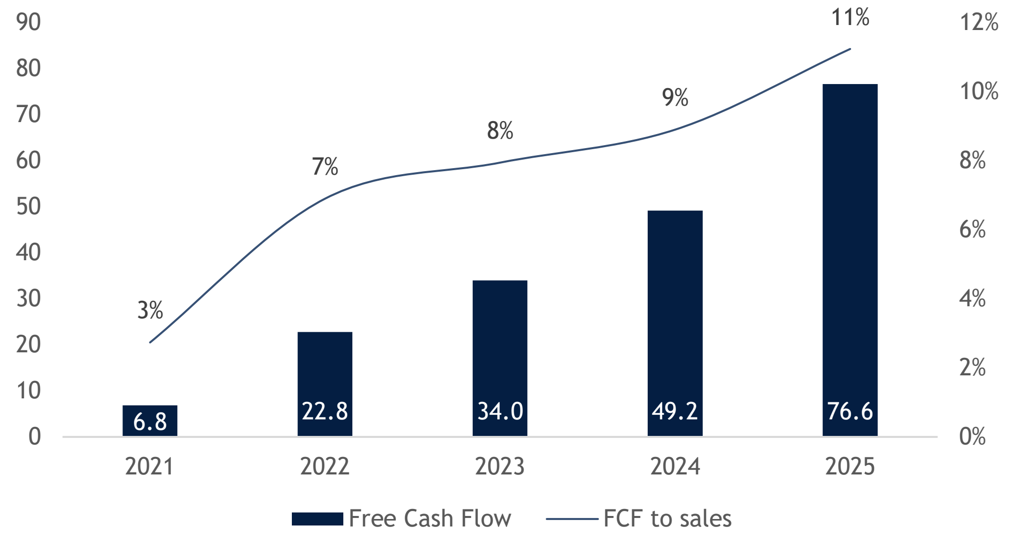
Improving FCF generation

We forecast relatively low capex for Alfen (from 5% in 2021 to 3% in 2025) since the company relies on an asset-light business model. Alfen plants are focused on assembly and not manufacturing, thereby implying that production lines are not expensive and easy to add. Moreover, from what we understand, Alfen has room for further capacity production with limited additional capex for multiple years.

Regarding working capital, Alfen takes advantage of its leading positions and strong customer relationships in all these markets to adopt strict discipline for its WCR. Although the company indicated it was facing supply chain issues (albeit with a limited impact so far), we have raised the level of inventories in 2021 resulting in an overall WCR of 6% (vs 4% in 2020). However, we forecast a quick decline to 2% in 2025 and in our LT assumptions.

The combination of rising revenue and margins with a gradual capex and WCR decline should result in strong cash generation improvement over coming years.

Fig. 69: FCF forecast in EURm over 2021-25



Source: Bryan, Garnier & Co

Share price analysis

Alfen's share price has experienced intense momentum since 2019, jumping from less than EUR20 in October 2019 to approximately EUR100 two years later on the back of strong revenue and margin expansion (+40-50% in some quarters).

The company also took advantage of supportive market trends to achieve a capital increase of EUR50m in order to strengthen its balance sheet.

Since the company provides little information on its division pipeline or the updated installed base per quarter or year, investors mainly react to quarterly revenues.

Fig. 70: Stock price since 2019

Source: Thomson reuters, Alfen

Main DCF assumptions

In our view, a DCF is the most appropriate approach for valuing Alfen, as it best captures the company's prospective long-term profitability and thus cash flows and value creation.

We run our nine-year DCF (2022-31) with the following assumptions (based on the current scope, meaning we factor in no acquisitions to calculate the free cash flow stream):

- Our 2022-26 top-line growth estimates, which we detailed in the previous section.
- 2026-31e: a slower revenue growth rate, gradually falling from 20% to 2%.
- We expect capex/D&A of around 1x as of 2025 (around 3% of sales, same level for our LT assumption).
- EBIT margin: gradually rising until 2025 to reach 15% of sales on a LT basis.
- A 28% tax rate, based on historical data.
- WCR: gradually falling from 6% in 2021 to 2% in 2025 and on a LT basis.

In this model, the top line is driven solely by the company's organic expansion and we expect a gradual improvement in EBIT margin thanks to operational leverage.

In line with general Bryan, Garnier & Co research assumptions, we assume a risk-free rate of 0.6% and an equity risk premium of 7.9%.

Our cost of equity stands at 9% and our post-tax cost of debt at 1.4%. Overall, given the structure of the balance sheet (85% funding with equity, 15% with debt), our calculation yields a WACC of 8%.

Therefore, our assumptions are:

- A WACC of 8% based on a 0.6% risk-free rate, 7.9% market premium, and beta of 1.1.
- A 2% terminal growth rate.

Fig. 71: WACC parameters

Beta	1.1
Risk Premium	8%
Risk Free rate	1%
Cost of Equity	9%
Equity funding (%EV)	85%
Debt funding (%EV)	15%
Cost of debt	2%
Taxes	28%
WACC	8.0%

Source: Bryan, Garnier and Co

Fig. 72: Equity bridge

SUM of DCFC	911
Terminal Value	1330
Entreprise Value	2241
(-) Net debt end-2021E	-39
Other	0
Implied Equity value	2280
Number of shares (fully diluted)	21.8
Equity value per share	105

Source: Bryan, Garnier and Co

From this DCF model, we derive an implied equity value of EUR2, 280m leading to TP of EUR105/share highlighting an upside of 20% and justifying a Buy rating.

Comparable analysis

We took Alfen’s main competitors (mentioned above in the report) to define an appropriate peer group. However, the diversified business model of Alfen and some of its competitors (capital goods companies like Schneider very active in the energy sector) tend to make comparison of multiples less relevant.

In addition, significant differences in profitability levels (in the EV charging segment for example), earnings or cash generation can also hamper the comparison.

Consequently, in our case, the comparison of peer group multiples serves more as a reference than as a means of deriving a Fair Value. Depending on the level of maturity, whenever possible, we have used classical ratios such as EV/EBIT and EV/Sales, or only the latter if the company is not profitable.

Fig. 73: Sector multiples by segment

Smart Grids

Name	Market Cap. (m)	Currency	Sales CAGR 2019-21E	EBIT Margin 21E	EV/Sales 2022E	EV/Sales 2023E	EV/Sales 2024E	EV/EBIT 2022E	EV/EBIT 2023E	EV/EBIT 2024E
Schneider Electric	95,024	EUR	2.7%	15.4%	3.5x	3.3x	3.2x	21.5x	19.4x	18.2x
ABB	70,094	CHF	1.8%	15.0%	2.6x	2.5x	2.3x	18.2x	16.7x	14.8x
EATON	65,797	USD	N/A	15.0%	3.6x	3.5x	3.3x	21.4x	19.6x	18.2x
NHOA	388	EUR	40.7%	N/A	3.5x	2.6x	-	22.2x	15.6x	-
				Median	3.5x	3.0x	3.2x	21.4x	18.0x	18.2x
				Average	3.3x	3.0x	2.9x	20.8x	17.8x	17.1x

Energy storage

Name	Market Cap. (m)	Currency	Sales CAGR 2019-21E	EBIT Margin 21E	EV/Sales 2022E	EV/Sales 2023E	EV/Sales 2024E	EV/EBIT 2022E	EV/EBIT 2023E	EV/EBIT 2024E
Tesla	936,547	USD	44.3%	15.0%	13.1x	10.9x	9.5x	80.5x	61.3x	46.4x
AES Corporation	16,061	USD	1.9%	23.2%	3.6x	3.5x	-	15.2x	14.0x	14.2x
Fluence Energy	8,680	EUR	N/A	2.0%	1.0x	0.9x	0.8x	26.4x	21.1x	18.0x
NHOA	388	EUR	40.7%	N/A	3.5x	2.6x	-	22.2x	15.6x	-
				Median	3.6x	3.1x	5.2x	24.3x	18.4x	18.0x
				Average	5.3x	4.5x	5.2x	36.1x	28.0x	26.2x

EV charging

Name	Market Cap. (m)	Currency	Sales CAGR 2019-21E	EBIT Margin 21E	EV/Sales 2022E	EV/Sales 2023E	EV/Sales 2024E	EV/EBIT 2022E	EV/EBIT 2023E	EV/EBIT 2024E
ChargePoint	6,299	USD	-	N/A	15.7x	9.6x	6.3x	N/A	N/A	N/A
EVgo	2,786	USD	-	N/A	69.6x	25.1x	11.7x	N/A	N/A	406.4x
Volta	1,346	USD	48.1%	N/A	11.8x	5.5x	3.1x	N/A	N/A	N/A
Blink Charging	1,190	USD	159.2%	N/A	30.5x	16.3x	8.7x	N/A	N/A	N/A
Fastned	839	EUR	38.5%	N/A	25.4x	12.5x	7.5x	N/A	152.8x	19.7x
				Median	25.4x	12.5x	7.5x	N/A	152.8x	213.1x
				Average	30.6x	13.8x	7.5x	N/A	152.8x	213.1x

	EV/Sales 2022E	EV/Sales 2023E	EV/Sales 2024E	EV/EBIT 2022E	EV/EBIT 2023E	EV/EBIT 2024E
Total Median	3.6x	3.5x	4.8x	21.8x	19.4x	18.2x
Total Average	14.4x	7.6x	5.7x	28.4x	37.4x	69.5x

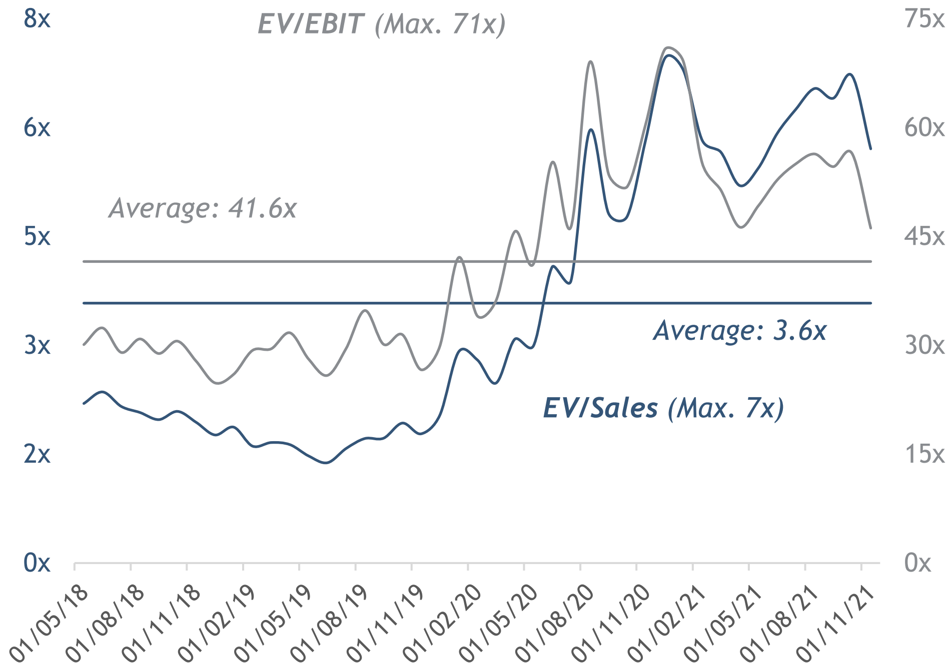
Source: Thomson reuters, Bryan, Garnier & Co

Comparing Alfen's multiple with those of the sector provides an interesting view of the company's current valuation. Our DCF-based valuation implies 2023 and 2024 EV/sales and EV/EBIT multiples of 5.2x, 4.1x and 37x, 27x respectively, which places our valuation in line with the sector in terms of EV/sales (2023 and 2024 EV/Sales average of 7.6x and 5.7x for the sector) and EV/EBIT (2023 and 2024 EV/EBIT of 37.4x and 69.5x respectively for the sector).

However, as we see in the table above, regarding EV charging and energy storage, the multiples are not really useful since either the companies are not profitable (EV charging mainly), or they just reach breakeven (EV charging and energy storage) thereby prompting very high numbers and inflating the whole sample.

The only acceptable multiple metric we obtain comes from the smart grids segment which is more mature. Nevertheless, we could argue that these companies are not pure players, which also tends to make the comparison with Alfen's business unmeaningful.

Fig. 74: Alfen historical EV/sales and EV/EBIT (NTM) multiples



Source: Thomson reuters, Bryan, Garnier & Co

In terms of historical multiples (both EV/sales and EV/EBIT), we note that Alfen shares always benefit from a high premium compared with the average of smart grid or energy storage peers. We think this premium is justified by its integrated and complementary business model, which fully answers the challenge arising from the energy transition. Consequently, we consider that our valuation which implies 2023 EV/sales and EV/EBIT multiples of 5x and 36x respectively is not too aggressive.

Bryan, Garnier & Co vs the consensus

Fig. 75: Alfen historical EV/sales and EV/EBIT (NTM) multiples

	2021			2022			2023		
in EURm	Consensus	Bryan, Garnier & Co	change	Consensus	Bryan, Garnier & Co	change	Consensus	Bryan, Garnier & Co	change
Sales	244.4	250	2%	326.8	330	1%	422.6	428	1%
EBITDA	34.6	35.0	1%	51.3	52.8	3%	71.2	72.7	2%
EBIT	25.9	27.5	6%	40.8	42.9	5%	58.5	59.9	2%
Net Income	18.7	19.2	3%	29.6	30.4	2%	42.3	42.6	1%

Source: Thomson reuters, Bryan, Garnier & Co

Comparing our estimates with the consensus shows that we are slightly above all the key metrics (sales, EBITDA, EBIT, net income) which also explains why our TP is at the upper-end of the consensus range.

Sensitivity analysis

Below, we set out our sensitivity analysis, which uses different WACC and terminal growth assumptions, providing a relatively wide valuation range .

Fig. 76: TP sensitivity to LT growth

	104.8	WACC 6%	7%	8%	9%	10%
LT Growth	0%	116	99	88	79	73
	1%	133	110	95	84	76
	2%	160	126	105	91	81
	3%	208	150	119	100	87
	4%	320	194	142	113	96

Source: Bryan, Garnier and Co

Fig. 77: TP sensitivity to LT EBIT % estimate

	104.8	WACC 6%	7%	8%	9%	10%
LT EBIT %	13.5%	144	114	96	84	75
	14.5%	152	120	100	87	78
	15.5%	160	126	105	91	81
	16.5%	167	131	109	94	84
	17.5%	175	137	114	98	87

Source: Bryan, Garnier and Co

However, using different assumptions for the EBIT margin and WACC provide an idea of the company's valuation if it managed to reach EBIT margin of close to 15-17%. Above is our sensitivity analysis, using different WACC and long-term EBIT assumptions.

Investment case conclusion

In our view, Alfen is an appealing growth company benefiting from numerous positive aspects .

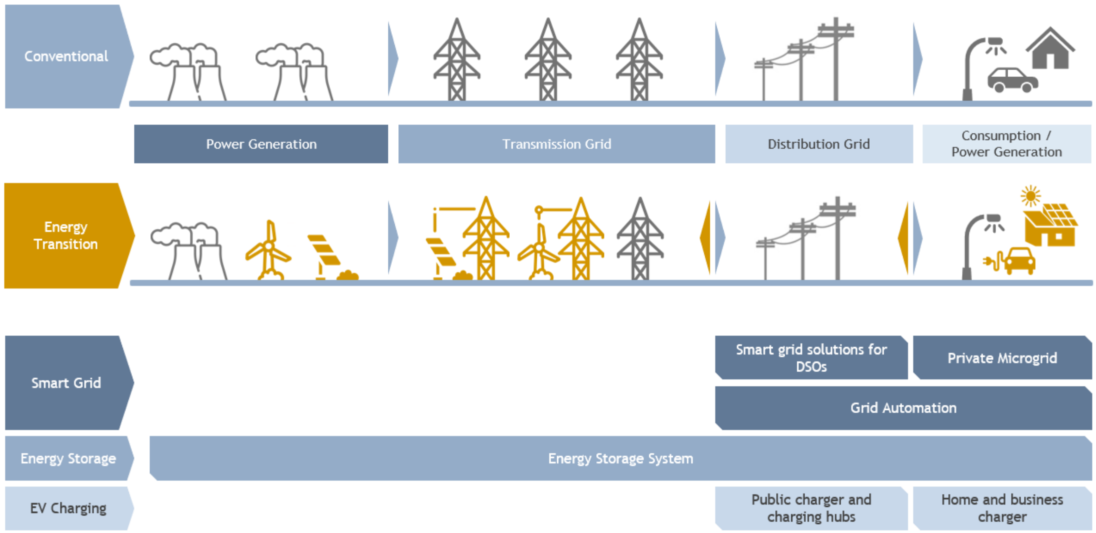
Unique positioning

Alfen is the only player in the energy sector that is positioned simultaneously in the substation, microgrid, energy storage and EV charging station businesses. This positioning provide the group a defensive profile since the smart grid business (+7% CAGR over the next 10 years) enjoys clear visibility thanks to an oligopolistic position in the Netherlands) mixed with strong top-line and profitability growth opportunities arising from the promising energy storage (+32% CAGR over the same period) and EV charging station segments (+22 %CAGR). This unique positioning also contributes to market share gains since every single contract can lead to cross-selling opportunities and cost synergies.

Promising trends

Thanks to its diversified profile, Alfen should benefit in full from the fast-growing penetration of renewable energies and the EV ramp-up in Europe. Visibility on these markets ensures a high level of growth for at least 10 years from now.

Fig. 78: Alfen's positioning regarding the energy transition



Source: Alfen, Bryan, Garnier & Co

A very well managed company

Finally, we see Alfen as a very well-managed company. Thanks to its asset-light business model, the company can deliver high volumes without being penalised by high levels of stocks and capex. Consequently, WCR and CAPEX to sales ratios are quite low (under 4%) and prompt substantial and growing FCF (FCF/sales moving from 3% in 2021 to 11% in 2025)..

EUR100TP is achievable, EUR120 in our best case scenario

Our DCF based valuation highligths a TP of EUR105, implying high 2023 EV/Sales and EV/EBIT multiples (5x and 37x respectively) but consistent with Alfen's historical numbers (4x and 42x). Adding the EUR1.3bn of potential sales related to a gradual replacement of a small part of the installed base of charging stations (from 1% to 10% over 2025-2031) in light of an expansion of the V2G technology boosts our TP by EUR20. Including this scenario in our valuation would lead to a EUR125 TP inducing an upside of more than 40%.

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Section 04

Swedish Stirling

Market Data:

Swedish Stirling

BUY Coverage Initiated

TP SEK22

Bloomberg / Reuters	STRLNG SS/ STRLNG.ST
Share price	SEK15.78
Market Cap.	SEK2,026
E.V.	SEK2,026
12m high / low	SEK26.6 / 13.2
Free Float	60%
Ytd Perf.	18.3%

Shareholders	
Sven Sahle	22%
AC cleantech growth fund	10%
East guardian SPC	8%
Free Float	60%

Fiscal year end 31/12	2019	2020	2021e	2022e	2023e
Financial Summary					
EPS	-	-	-1.13	-0.87	-0.23
Restated EPS	-	-	-1.03	-0.79	-0.21
% change	-	-	-	-23.2%	-73.1%
BVPS	-	-	3.15	16580.77	-
Operating cash flows	-	-	-0.73	-4386.95	-
FCF	-	-	-0.93	-4465.05	-
Net dividend	-	-	0.00	0.00	-
Average yearly Price	-	-	-	-	-
Avg. Number of shares, diluted (k)	-	-	141	141	141
Valuation (x)					
EV/Sales	-	-	NS	NS	NS
EV/EBITDA	-	-	NM	NM	NS
EV/EBIT	-	-	NM	NM	NM
P/E	-	-	NM	NM	NM
FCF yield (%)	-	-	NM	NM	-
Net dividend yield (%)	-	-	NM	NM	-
Profit & Loss Account (SEKm)					
Revenues	45	53	3	16	58
Change (%)	-	18.2%	-94.0%	415.0%	255.8%
Adjusted EBITDA	-23	-20	-78	-74	1
EBIT (current)	-101	-23	-126	-94	-12
Change (%)	-	-77.3%	-449.7%	-25.7%	-87.2%
Financial results	-25	-48	-20	-18	-18
Pre-Tax profits	-126	-71	-146	-112	-30
Tax	-1	-1	0	0	0
Net profit	-127	-73	-146	-112	-30
Restated net profit	-127	-73	-146	-112	-30
Change (%)	-	-42.6%	-99.9%	-23.2%	-73.1%
Cash Flow Statement (SEKm)					
Operating cash flows	-87	-45	-102	-88	-19
Change in working capital	30	-40	5	-4	1
Capex, net	-47	-57	-48	-20	-13
Free Cash flow	-87	-45	-131	-89	-13
Dividends	0	0	0	0	0
Capital increase	0	107	209	0	0
Net debt	87	66	-71	37	68
Balance Sheet (SEKm)					
Tangible fixed assets	3	5	5	5	5
Intangibles assets	250	347	356	356	356
Cash & equivalents	37	142	200	93	61
current assets	56	20	26	19	33
Other assets	0	0	0	0	0
Total assets	346	513	587	473	455
L & ST Debt	120	72	122	122	122
Provisions	0	0	0	0	0
Others liabilities	0	0	0	0	0
Shareholders' funds	216	293	443	332	302
Total Liabilities	131	220	143	141	154
Capital employed	335	367	566	455	425
Ratios					
Operating margin	-223.5%	-43.0%	-3960.7%	-571.5%	-20.5%
Tax rate	0.0%	0.0%	-	-	-
Net margin	-281.2%	-136.5%	-4572.8%	-682.0%	-51.5%
ROE (after tax)	-46.8%	-7.8%	-28.4%	-28.3%	-4.0%
ROCE (after tax)	-30.1%	-6.3%	-22.3%	-20.6%	-2.8%
Gearing	40%	23%	-16%	11%	23%
Pay out ratio	0.0%	0.0%	0.0%	0.0%	0.0%

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Source: Company Data; Bryan, Garnier & Co ests.

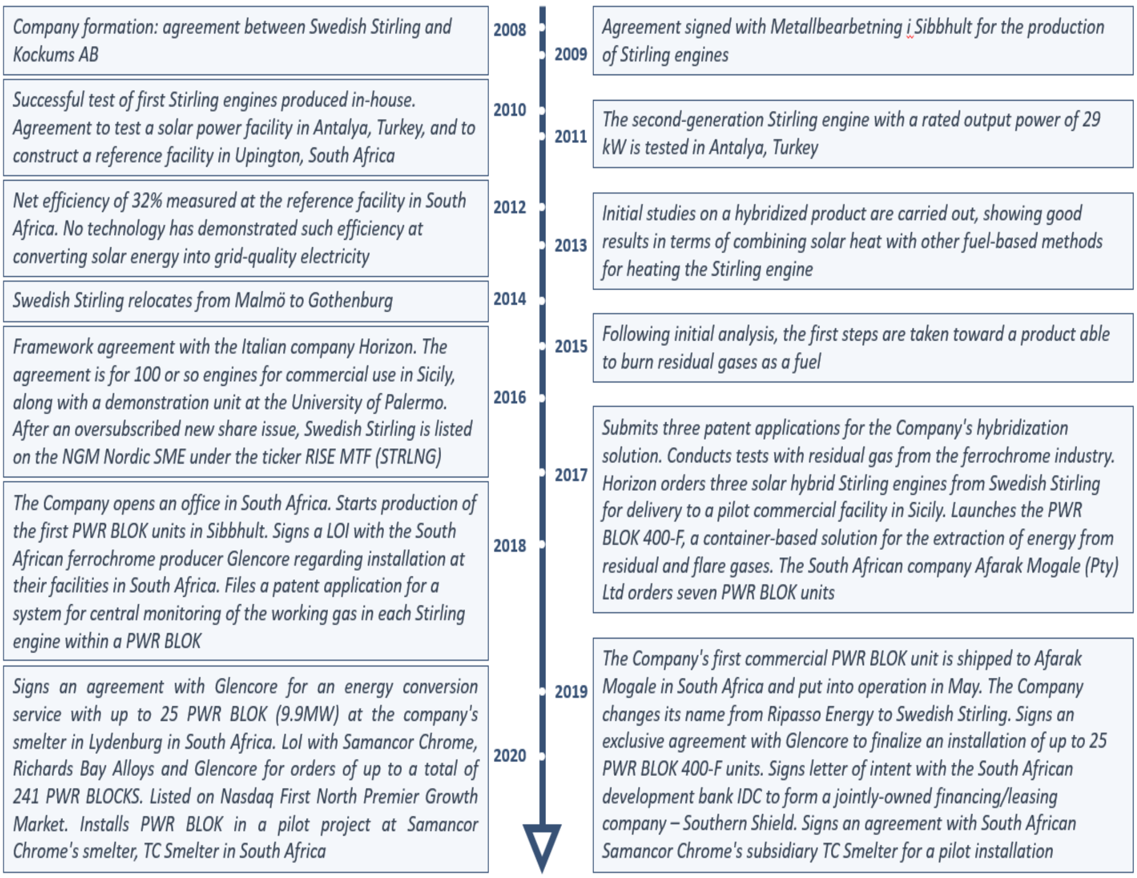
Swedish Stirling

A pioneer of thermal energy conversion

Founded in 2008, listed in 2016 and based in Gothenburg (since 2014), Swedish Stirling (formerly known as Ripasso Energy) is a Swedish cleantech founded by Gunnar Larsson, previously CEO of Kockums AB. The company was founded with the mission to further refine the Stirling technology to convert thermal energy to electricity, and initially the focus was on a Solar based solution. Over the years, the company has successfully developed a unique Stirling engine based solution, PWR BLOK 400-F, to convert thermal electricity from industrial residual gases at high capacity and with great efficiency.

PWR BLOK was introduced for the first time to the ferrochrome industry in South Africa in late 2017 as a solution that could harness the energy from residual and flare gases and convert it to electricity. The global ferro alloy industry in general, known for massively generating residual gases on top of consuming important amounts of electricity, have for decades, without success, searched and tried different solution to recycle the energy in these gases. Swedish Stirling mechanically targeted the South African ferrochrome industry first since the company had a presence in the region since 2012, the market price of electricity in South Africa is high and the country makes up a third of the world production of ferrochrome. Swedish Stirling have managed to sign promising contracts with major South African ferrochrome players such as Samancor and Glencore.

Fig. 79: Main events of Swedish Stirling's history

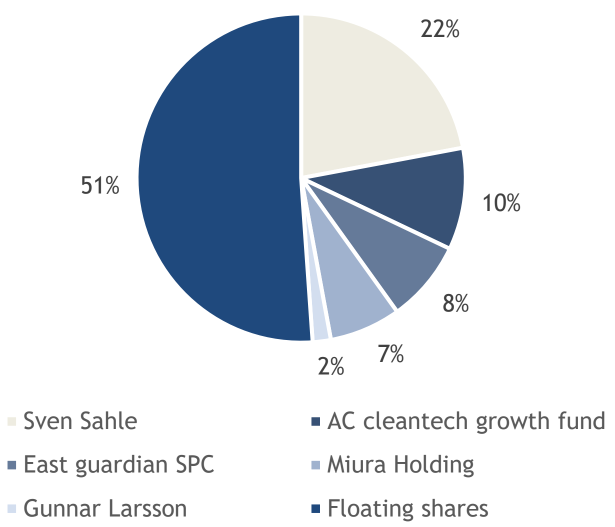


Source: Swedish Stirling, Bryan, Garnier and Co

With 60 employees and consultants in 2021 (mainly engineers, technicians and sales) (compared with eight in 2017), the group is ready to expand its business in Africa and Europe. Swedish Stirling also strengthened its entire management team with the hiring/appointment of a new CEO (Dennis Andersson), new CFO (Dan Hillén) and a new CTO (Christian Nilsson) in 2021.

The company has also managed to raise funds and to attract several investors through multiple capital increases (SEK214.5m and SEK225m in 2020 and 2021 respectively).

Fig. 80: Shareholding structure in 2021



Source: Swedish Stirling

While the company achieved its pre-commercial expansion by raising capital, strengthening its management team, opening an office in South Africa and signing several key contracts, Swedish Stirling is now at a turning point, as it moves from an appealing and innovative concept to a growing industrial energy conversion player.

A unique waste-to-energy solution

From the Stirling technology…

Invented in 1816 by Robert Stirling in Scotland, the Stirling engine is a gas pressure engine. Its practical applications have been limited compared with the internal combustion engine for example and as such has never had a major commercial breakthrough.

However, the Stirling engine boasts numerous characteristics that make it particularly well-suited to climate change issues, more specifically :

- ✓ The Stirling engine can work with any heat source
- ✓ The combustion that drives the engine takes place externally (outside of the engine itself), making the engine insensitive to variations in gas quality
- ✓ It is quiet and generates almost no vibration

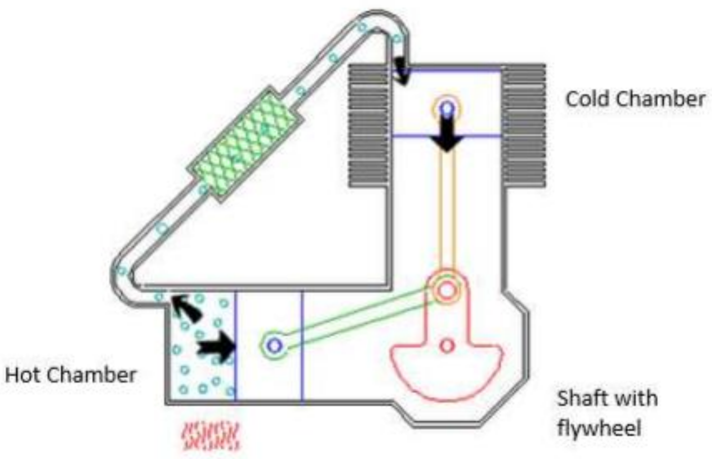
Basically, the Stirling engine is a closed system with an expansion cylinder and a compression cylinder filled with a working gas (most often helium or hydrogen). The pistons are linked by a connecting rod.

When the working gas is heated, pressure increases. This depresses the piston and thus perform works. Part of the force is used to push the hot working gas from the expansion cylinder into the compression cylinder.

In the two cylinder Stirling engine, one cylinder is kept hot while the other is kept cool. In the chart below, the lower left-cylinder is heated by burning fuel and the other cylinder is kept cool by air circulating in a sink. The Stirling engine works following four steps :

- Expansion: most of the gas in the system is driven into the hot cylinder. The gas heats and expands driving both pistons inward.
- Transfer: the gas has expanded but most of it is still located in the hot cylinder. The flywheel contributes to transferring the bulk of the gas to the cold cylinder.
- Contraction: the majority of the expanded gas has shifted to the cold cylinder. Consequently, it cools, pressure decreases, the gas contracts and drives both pistons outward.
- Transfer: the contracted gas is still located in the cold cylinder. The flywheel transfers the gas to the hot cylinder and cycle starts again.

Fig. 81: Stirling engine example



Source: http://animatedengines.com/vstirling.html

The Stirling cycle is famous for being the most efficient thermodynamic cycle for the transformation of heat into mechanical energy. The efficiency of a Stirling engine increases at high temperature differentials between the hot side and the cold side. Since there is no internal waste due to combustion, the pistons, bearings and seals have a very long service life.

…to the PWR BLOK 400-F, an innovative gas recycling solution…

Before launching the PWR BLOCK 400-F, Swedish Stirling spent several years adapting the Stirling technology for several uses. The main technology behind Swedish Stirling is under licence from Kockums (where Gunnar Larsson was CEO). Kockums and Swedish Stirling signed an agreement in 2008 giving Swedish Stirling a perpetual worldwide licence to develop, market, sell and manufacture Stirling engines (with the exception of Defence applications). License fees are based on delivery volumes.

Consequently, Swedish Stirling was able to optimise the Stirling engine and adapt it to energy conversion. The company optimised the engine by improving its efficiency with solar applications (32% rate of conversion from solar energy to electricity). The new design also allowed the same engine to run on several heat sources.

In principle, any heat source, liquid or gaseous fuel can be used such as natural gas, biogas, ethanol etc. Usually, the main disadvantage of the Stirling engine is its high production cost. One of the main challenges for Swedish Stirling was therefore been to adapt the engine for mass production and to lower maintenance costs.

All these developments served to create Swedish Stirling's main asset, the PWR BLOK 400-F, devoted to converting flare gases into electricity.

The PWR BLOK 400-F is a container based solution in which the Stirling engines are used to extract energy from residual and flare gases in industrial applications. Indeed, many industrial applications especially in the ferrochrome sector produce residual industrial gases that are currently burned off. These gases are generally of low quality and internal combustion engine struggle to handle them. However, thanks its external combustion design and its indifference to any type of gas burned and quality, the Stirling engine can recycle these gases as fuel to generate electricity.

The PWR BLOK 400-F is a container based solution in which the Stirling engines are used to extract energy from residual and flare gases in industrial applications. Indeed, many industrial applications especially in the ferrochrome sector produce residual industrial gases that are currently burned off. These gases are generally of low quality and internal combustion engine struggle to handle them. However, thanks to its external combustion design and its indifference to any type of gas burned and quality, the Stirling engine can recycle theses gases as fuel to generate electricity.

Fig. 82: The PWR BLOK 400-F can use residual gas to generate electricity

Source: Swedish Stirling

…that provides numerous advantages

Each PWR BLOK 400-F contains 14 Stirling engines in a container (see picture above) and delivers a total net output of 400 kW. The PWR BLOK is deployed in industrial applications and facilities where residual gas combustion occurs allowing the engine to generate electricity at high efficiency.

A recycling technology

More precisely, the PWR BLOK uses the flare gas rejected in the air as source of heat to make work the Stirling engines inside the PWR BLOK.

Thanks to the temperature difference, the engine can create kinetic energy of the heat and generators attached to the engines transform this kinetic energy into electricity that is delivered back to the smelter. In this context, we can say that the flare gas is recycled into electricity.

Lower electricity cost

The other important point is that the PRW BLOK produces cheaper power than conventional energy sources, especially in South Africa where the electricity is at 87% generated from coal.

The levelized cost of energy (LCOE) calculated by Swedish Stirling (and checked by an independent expert) in 2019 showed that the cost of generating electricity from residual gases using the PWR BLOK is near to USD22.5/MWh. This level is one of the lowest compared with conventional energy types (coal, natural gas) and renewables (wind, solar).

More independence from the grid thanks to self-consumption

The PWR BLOK strengthens the independence of its owner regarding grid electricity. By producing itself a part of the electricity it needs at a predictable cost, the company does not fully rely on the electricity coming from the gird (which is a true benefit in countries where grid electricity is unstable like in South Africa).

Less CO2

Finally, the PWR BLOK lowers the CO_2 emissions as less electricity from the grid is needed. In South Africa, 87% of all electricity is generated from fossil fuels, mainly coal. The recycling of residual gas into electricity made possible by Swedish Stirling's technology reduces the smelters consumption of coal-based grid electricity. According to Swedish Stirling calculations, in South Africa, the technology results in an annual 3,500 tonnes reduction in carbon dioxide emissions per PWR BLOK installed, and the technology yields greater CO_2 savings per USD invested than any other type of energy source (certified by independent expert in 2019).

Fig. 83: In door PWR BLOK 400-F

Source: Swedish Stirling AR 2020, Bryan, Garnier & Co

Fig. 84: Installed PWR BLOK 400-F

Source: Swedish Stirling AR 2020, Bryan, Garnier & Co

To sum-up, the main competitive advantages of the PWR BLOK are:

- ✓ A cheaper energy source enabling the users to lower their electricity bills;
- ✓ A waste-to-energy solution that through recycling lowers CO_2 emissions by reducing grid electricity consumption;

- ✓ Long economical life-time and low maintenance cost due to external combustion;
- ✓ A specific design suited to industrial applications;

A consistent and efficient commercial strategy

First contracts related to the South African ferrochrome industry

Swedish Stirling decided to target the ferrochrome industry in South Africa, which accounts for 30% of the world production and which is well known to issue large amount of flare gases, to illustrate the benefits of its PWR BLOK.

Electricity cost account for a third of the industry’s total production costs. According to Swedish Stirling, the average annual price for the ferrochrome industry in South Africa is USD57.60/MWh.

During ferrochrome production, 50% of the energy used in the process is converted to residual gas. The PWR BLOK 400-F has an efficiency of approximately 30% meaning that the energy recovered from the residual gas lowers the company’s need for purchase grid electricity by up to 15%. With a economical life-time of 25 years, the PWR BLOK is highly attractive for industrial customers.

Since the PWR BLOK 400-F is able to convert heat coming from industrial gases into climate-friendly electricity, the group needed to target electricity-intensive customers with high flare gas generation. In this context, the ferrochrome industry in South Africa ticks all the boxes since:

- 87% of grid electricity is generated through fossil fuels
- The ferrochrome industry issues large amounts of gases : during ferrochrome production, 50% of the energy used in the process is converted to residual gas
- South Africa concentrates 30% of the world ferrochrome production
- Electricity accounts for a third of total production costs in the ferrochrome industry

As such, Swedish Stirling naturally targeted the South African segment and has signed multiple contracts :

- In December 2017, three months after the launch of the PWR BLOK, Swedish Stirling sold its first seven PWR BLOK units to South African ferrochrome producer Afarak Mogale. However, tough market conditions for Afarak Mogale led the companies to terminate the contract in March 2020
- In December 2019, Swedish Stirling signed an agreement with another South African ferrochrome manufacturer, **Samancor Chrome** for its subsidiary **TC Smelter** involving a pilot installation of an energy conversion service with one PWR BLOK. The unit was commissioned in November 2020.
- In February 2020, the company signed an agreement with **Glencore** for an energy conversion service of up to 25 PWR BLOK (10MW capacity) at the company's smelter in **Lydenburg,** also in South Africa.
- In July 2020, Swedish Stirling and **Richards Bay Alloys** (RBA, privately owned ferrochrome smelter facility in Richards Bay, South Africa) signed a letter of intent related to the installation and sales of 18 PWR BLOK units (7.2 MW capacity) for USD18m.
- In July 2020, Swedish Stirling signed a MoU with **Samancor** regarding the installation of up to 135 PWR BLOK (54MW capacity at Samancor Chrome’s **TC Smelter, Ferrometals and Tubatse Alloys smelters** (45 PWR BLOK / smelter corresponding to 18 MW capacity / smelter)
- In August 2020, Swedish Stirling and Glencore signed a letter of intent related to an installation of up to 88 PWR BLOK (35 MW capacity) at Glencore's Lion Smelter.

- In March 2021, Swedish Stirling signed an agreement with **SMS Group** (14 000 employees, EUR2.9bn sales) regarding the use of the PWR BLOK technology for pilot energy recovery project in **Europe** within the ferroalloy industry.
- In April 2021, the company signed an energy conversion service agreement with **Glencore** (second contract with this group) involving the installation of 25 PWR BLOCK 400-F (10MW capacity) at the **Lion Smelter** (the term of the agreement is eight years with an option to extend for another seven years). The letter of intent signed in August 2020 involved the installation of 88 PWR BLOK at the Lion Smelter.

Four years after the PWR BLOK launch, Swedish Stirling therefore works closely with major players in the ferrochrome industry. Indeed, Samancor and Glencore for example represent over 90% of ferrochrome production in South Africa.

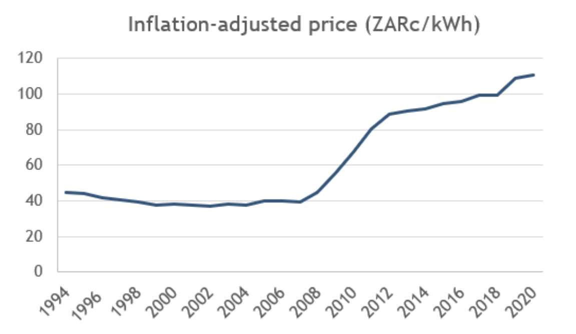
A huge market opportunity

First, South Africa

A long-standing electricity crisis in South Africa

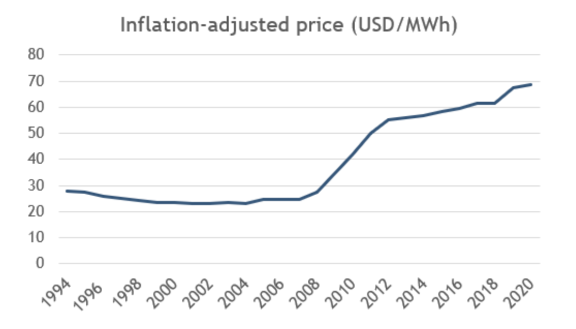
Ferrochrome is an alloy of chromium and iron produced through a heavy industrial process (carbothermic reduction operation at high temperatures obtained from an electric arc). Consequently, the ferrochrome industry houses the largest electricity consumers in South Africa. According to Statista, the industry sector (o/w the ferrochrome industry) was the largest electricity consumer in South Africa in 2019 (56% of total consumption). Looking closer at the energy consumption mix, we note that energy demand from the iron and steel industry is focused on electricity generated by coal and gas. Given recent changes in coal and gas prices and the tax related to CO2 emissions, these two energy sources are clearly unlikely to help optimise the cost structure and competitiveness of South African ferrochrome industry players. Regarding electricity, the country has been facing serious issues related to grid stability over the last 15 years reflected by on-going price increases.

Fig. 85: Electricity prices in South Africa



Source: Bryan, Garnier & Co

Fig. 86: Same prices in USD/MWh

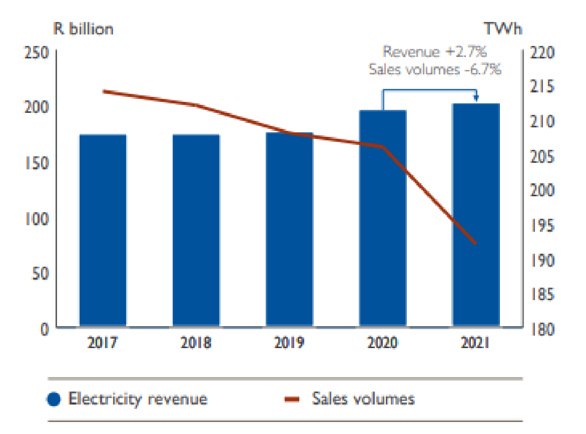


Source: Bryan, Garnier & Co

South Africa has indeed been experiencing a deep energy crisis since 2007 with rolling blackouts due to insufficient power supply leading to grid destabilisation. According to the government-owned national power utility and primary power generator, Eskom, the reserve margin is estimated at 8% or below. However, since infrastructures are too old (average plant age is 40 years), around 35% is taken off-line due to maintenance/breakdown issues resulting in a 20GW lack of power production in an already very stretched network (load shedding issues led to 40 to 50 power cuts per year over recent years). Several press articles also point to corruption and mismanagement difficulties as additional key factors in the ongoing power supply problems at Eskom.

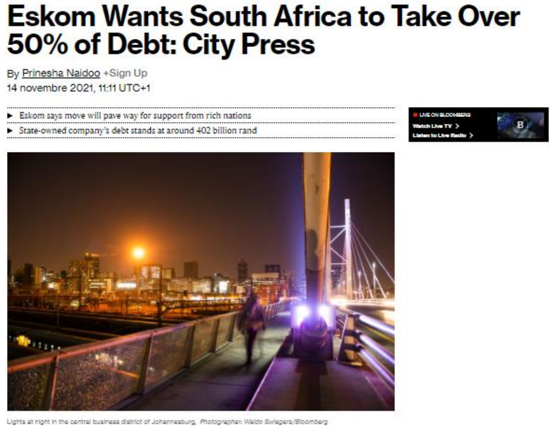
Suffering from decreasing sales and profitability over recent years combined with massive financing costs (R34bn in 2020-2021) related to its huge debt (R402bn in 2021), Eskom's cashflow (R4bn in 2020/21) is not high enough to refurbish the existing infrastructure (even with government support) and add capacities given current electricity prices in South Africa.

Fig. 87: Decline in Eskom volumes



Source: Eskom annual report 2020/21

Fig. 88: Eskom's high debt



Source: Bloomberg

In this context, the CFO acknowledged that "*the reality is that cash generated from operations is simply inadequate to support an asset-intensive business with a highly leveraged capital structure like ours*" before adding that "*this shortfall can only be corrected through cost-reflective tariffs*".

Against this backdrop, Eskom announced on December that it will apply a 20.5% electricity tariff increase for 2022. The Energy regulator Nersa, which usually does not grant Eskom the full amount it applies for, accepted the increase given the emergency related to power generation in South Africa. Eskom cited the rise in the coal and carbon tax as the main reason to justify this increase.

Fig. 89: Press article on electricity price increase

Source: Reuters

South African prices to rise but power grid infrastructure to keep deteriorating

However, Eskom recently admitted that interruptions are likely to persist for several years even if CAPEX rises, mainly because of delays in setting up new power plants. On top of ageing plants, breakdowns and maintenance related to a large part of the power generation, the country also lacks lower voltage lines (325,000Km of lines that distribute electricity to homes, corporates etc vs 150,000Km for New Zealand for a tenth of South Africa’s population). To avoid shutting down the entire the grid, frequency has to stay balanced. When demand exceeds supply, the frequency of the grid starts to fall (below 50 Hz) and the power plants start to disconnect since supply cannot meet demand.

To prevent the grid collapsing, Eskom has implemented strict demand management for situations in which demand is higher than supply: load shedding consists of planning power cuts in some areas to keep frequency at a sustained level on the grid. If the situation is very bad, Stage 4 is triggered meaning that approximately 4GW of total demand is cut (around four hours without electricity in some regions).

Fig. 90: Press article mentioning blackouts


Why South Africa’s electricity blackouts are set to continue for the next five years

30 mars 2021, 15:26 CEST

For now, only those who can afford it will be able to escape the power cuts. Shutterstock/ Arnold Petersen

Source: The conversation

Fig. 91: South African president on Eskom issues


Load shedding in South Africa is inevitable: Ramaphosa

Staff Writer 25 November 2021

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President Cyril Ramaphosa says that load shedding in South Africa is an inevitability due to a combination of factors.

Source: Reuters

South African president Cyril Ramaphosa announced that the country could add 11,800 MW in total made up of 6,800 MW of wind and solar, 3,000MW of gas and diesel and 1,500 MW of new coal power while current shortages point to between 4,000MW and 6,000MW in lacking power capacities (current total capacity if c.58GW of which 44GW handled by Eskom, with 38GW from coal). However, since new renewable energy capacities are set to be installed annually, the impact is unlikely to be meaningful for at least five years according to experts. Moreover, renewables will still account for less than 10% of the energy supply. New coal capacities are set to suffer from high costs while nuclear plant construction could take several years on top of being very expensive. Finally, gas could be considered a solution but like other conventional energies, it is expensive and envisaged as a back-up for emergency situations. In this context, small and medium scale solutions like domestic installations could be the best options to avoid power cuts.

An urgent need for ferrochrome players

For large energy consumers in South Africa like Samancor, Glencore and Richard Bay Alloys, the current situation is very unsatisfactory since they are not protected against load shedding while their energy bill is increasing substantially.

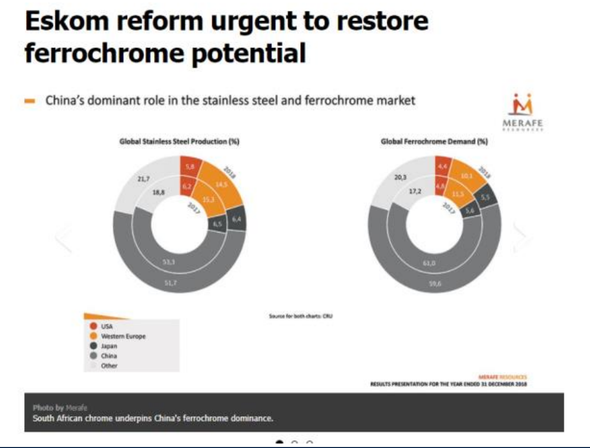
This combination makes South African ferrochrome more expensive for its main client, China, which instead of buying South African ferrochrome, has recently preferred to directly import chrome ore (79% of it came from South Africa in 2019) to create ferrochrome in Chinese plants.

This solution is increasingly attractive for China mainly because of the rising cost of South African ferrochrome directly linked to Eskom prices. One solution could be to apply taxes on South African chrome ore exports but this would affect local miners.

Fig. 92: Market share loss because of energy prices

Source: Mining weekly

Fig. 93: Competitivity loss for ferrochrome players



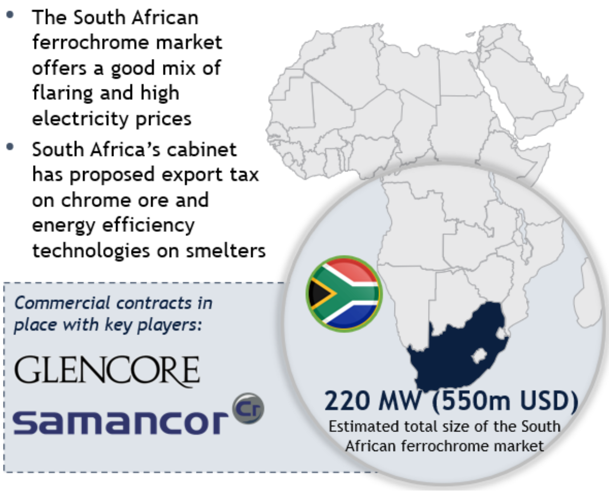
Source: Mining weekly

According to Mining Weekly, the South African ferrochrome industry has lost market share in China because of the on-going rising in electricity prices. Consequently, the main ferrochrome industry players are seeking cheaper energy alternatives like renewables or cogeneration. However, despite some progress, the industry leader declared that the current challenges are a "threat to the viability of its smelters". In the past two years, nearly 40% of South Africa's ferrochrome production has either been closed or mothballed putting at risk several thousand jobs and suppliers. Mining Weekly mentions that the South African ferrochrome industry plans to generate up to 750 MW of its own electricity comprising wind, solar and cogenerated power by 2024.

The PWR-BLOK 400-F brings a durable solution to ferrochrome industry players and for the South African grid

In this very tense atmosphere related to the competitiveness of ferrochrome players and electricity shutdowns in South Africa, the PWR BLOK 400-F brings a durable solution to the industry.

Fig. 94: Initiatl target market – the South Africa ferrochrome industry



Source: Bryan, Garnier & Co, Swedish Stirling

From Eskom's perspective, Swedish Stirling's solution clearly contributes to debottlenecking grid demand and hence limiting load-shedding risk. And for ferrochrome producers, the PWR BLOK 400-F meets several needs by providing:

- A back-up power generation source when the grid is exposed to load-shedding risk (which can deeply impact ferrochrome production) leading to increasing independence from Eskom.
- A cheaper electricity source (USD22.5/MWh vs USD57.60/MWh before 25% price increase) resulting in lower production costs and better competitiveness.
- A cleaner way of producing electricity since the PWR BLOK takes flare gases as input instead of coal-based electricity.

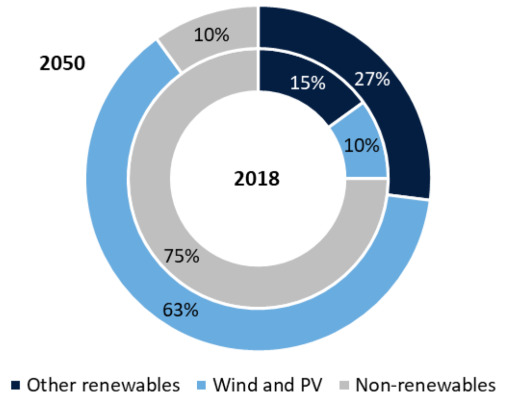
Then, the rest of the world

The PWR block will also benefit from the rise of renewables…

Renewables are expected to continue experiencing strong growth over coming decades and to contribute even more significantly to the energy mix. According to IRENA, in order to achieve the Paris Agreement's goal, the share of renewables in electricity capacity must increase from 33% in 2018 to 92% by 2050. Wind and PV will represent the bulk of this capacity, increasing from 15% in 2018 to 74% in 2050.

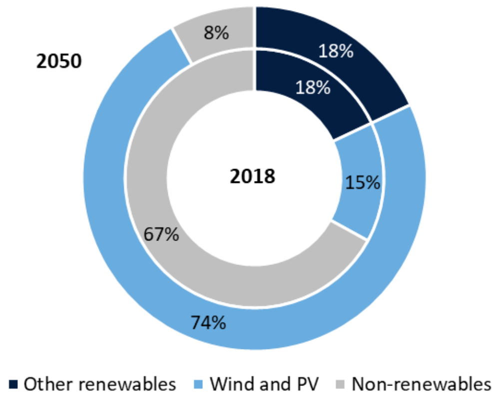
Wind and PV installed capacity are expected to expand from around 1,450 GW today to 22,100 GW in 2050, almost a 20-fold increase! This requires more than 650 GW of capacity addition every year, up from around 240 GW in 2020.

Fig. 95: Global electricity generation mix



Source: IRENA

Fig. 96: Global electricity capacity mix



Source: IRENA

Whereas the rising weight of renewable energies in power generation is necessary to reduce CO2 emissions, this presents new challenges for power generation and the grid. Indeed, renewable energies are for the most part intermittent, contrary to conventional energy sources that are more stable and foreseeable.

Solar PV power is intermittent by nature since it depends on the sun and weather conditions. Sun levels, like wind levels for wind power can be partly anticipated, thereby allowing for other sources of production to take over.

However, forecasts are not perfect and the replacement with other energy sources is not immediate. As such, the higher the share of renewable energy sources, the more complex constraints are for the grid. In addition to having to manage variable demand, the network needs to manage supply that is also increasingly variable.

While conventional power had to face with CO2 emissions and their impact on earth, renewable energy's main challenge is clearly the ability to produce uninterrompted and stable power to answer to energy needs.

…and of decentralised power generation

The development of renewable energies goes hand in hand with that of a decentralisation of output. While some renewable energy sources are quite centralised (wind farms for example), others are far more dispersed (solar for example). As such, growth in renewable energies means a decentralisation of production.

This transformation means the grid as a whole will have to be restructured. Note that the distribution network needs to be distinguished from the transmission network, which carries power production from power plants to consumption zones via high voltage lines (to limit losses during transmission).

According to ENTSOE (European Network of Transmission System Operators for Electricity), by 2030, 40-45% of European production capacity could be connected to the medium and low voltage grid. This figure could even reach 60% in a scenario very beneficial to renewable energies.

Growth in renewable energies and the decentralisation of production is seeing a simultaneous development of self-consumption and microgrids.

Microgrids are small-sized distribution networks, based on local production methods, often solar and wind. These ensure the supply of one or more sites such as ecodistricts, campuses, industrial estates, islands etc. Microgrids can function entirely autonomously or be connected to a wider distribution system.

The US is currently the leading market in microgrids (80% market share) given the lower quality of the power grid relative to Europe. These are primarily installed for supply safety reasons or to supply critical installations (hospitals, military bases).

In the future, the application scope for microgrids could be extended and exceed these niche applications. This development is set to be driven by an improvement in renewable energy performances and the progress made in battery capacity.

Since the PWR-BLOK 400-F provides a durable solution for intermittency issues, it can target almost every industry everywhere

One of the main reasons for equipping ferrochrome players with a PWR BLOK 400-F is its ability to prevent blackouts due to a mismatch between demand and supply of electricity. With the massive ramp-up of renewables, intermittency issues are set to increase, not only in South Africa but all over Asia, Europe, Latin America and the US. In this context, the PWR BLOK 400-F fits perfectly with the rising demand for energy independence from several industries, currently reflected by the increase in micro grids.

Fig. 97: Real market potential of Swedish Stirling

Source: Bryan, Garnier & Co

Smart and flexible business model

In terms of business model, several options could be set up. Indeed, a first possibility would rely on direct sales ; Swedish Stirling manufactures and sells a specific quantity of PWR BLOK to its client following a price / unit. This price could be adjusted according to the client and the size of the contract (a discount could be applied for a new customer or for a huge order for example) but would have to move within in a narrow price range.

Another option is the renting business model: Swedish Stirling takes care of the installation but remains the sole owner of the PWR BLOK. Its client pays a monthly fee (energy conversion service) given the number of MWh generated / month.

Both options are well balanced in terms of advantages/drawbacks. In the direct sale business model, WCR is optimised and yearly cash inflow is higher due to possible upfront payments.

However, if we think in terms of carbon credits, the renting business model is better. Cash inflow is lower in a ramp-up phase but once the carbon credit is monetised, Swedish Stirling will considerably increase its profitability.

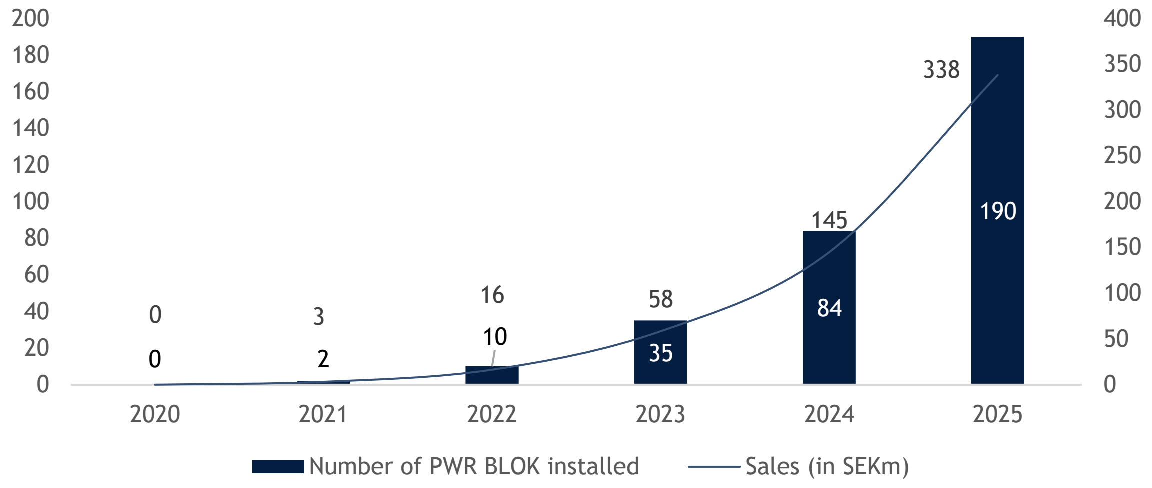
Given that carbon credits belong to the owner of the equipment, if Swedish Stirling directly sells these, the company would never generate inflows related to carbon credits.

From the information we found in the Swedish Stirling's annual report, the short term strategy is to implement a renting business model relying on an energy conversion service. On a LT basis, i.e. once the company enjoys a meaningful market share, Swedish Stirling could switch to a direct sale business model and increase the price / PWR BLOK by adding a premium related to carbon credits.

In order to fit with the group's strategy, we have applied a renting business model leading to a yearly payment based on MWh generation per PWR BLOK. Our sales expectations therefore rely on the following assumptions:

- 3200 MWh / year / PWR BLOK
- USD55 / MWh
- 3% inflation per year
- 190 PWR BLOK installed by 2025 relying on current contracts
- 30% sales CAGR from 2025 to 2030 assuming new services agreements
- A 14% sales CAGR as of 2030 until 2040
- 2% long term growth

Fig. 98: Sales forecasts in SEKm over 2020-25



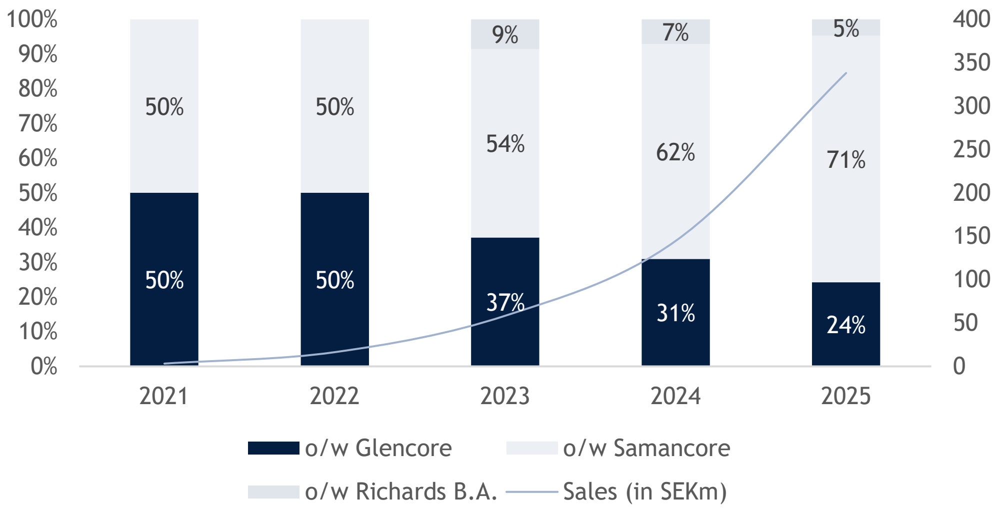
Source: Bryan, Garnier & Co

Our revenue forecast over the next four/five years solely relies on the current contracts assuming:

- 100 PWR BLOK installed over 2022-2027 at Glencore Smelters
- 135 PWR BLOK installed over 2021-2025 at Samancore smelters
- 118 PWR BLOK installed over 2023-2028 at Richards Bay Alloy smelter

The sales mix is therefore set to be dominated by Glencore and Samancor deliveries over the next four years :

Fig. 99: Customer mix over 2021-25

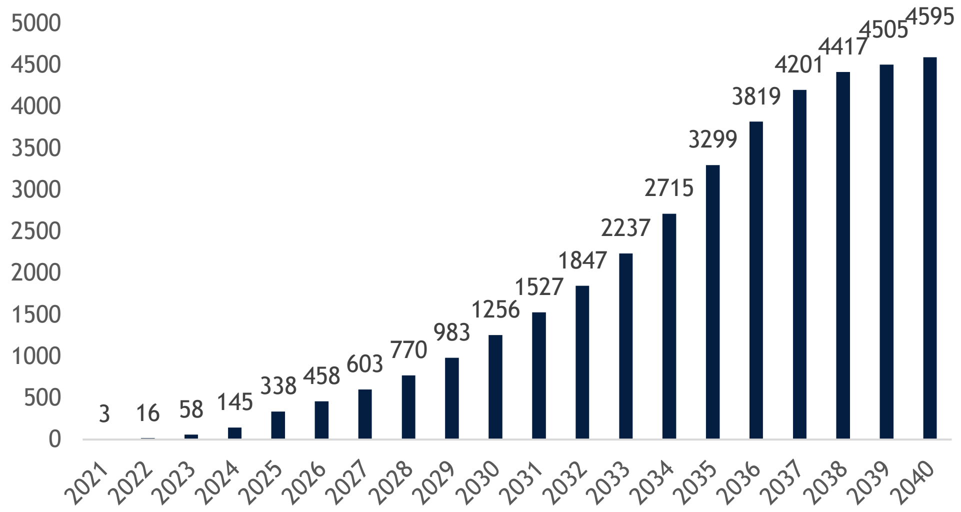


Source: Bryan, Garnier & Co

We forecast a sustained 30% top-line CAGR over 2025-30 since we think that Swedish Stirling should gain more contracts based on its track record with key players of the ferrochrome industry. As of 2030, we normalise our sales growth expectations with a double digit sales CAGR gradually falling to 2% on a LT basis.

Indeed, we think that Swedish Stirling, once the track record is built in South Africa, will easily export its PWR BLOK to the rest of world, beginning by important electricity consumers in the European industry.

Fig. 100: Sales forecast in SEKm over 2021-2040

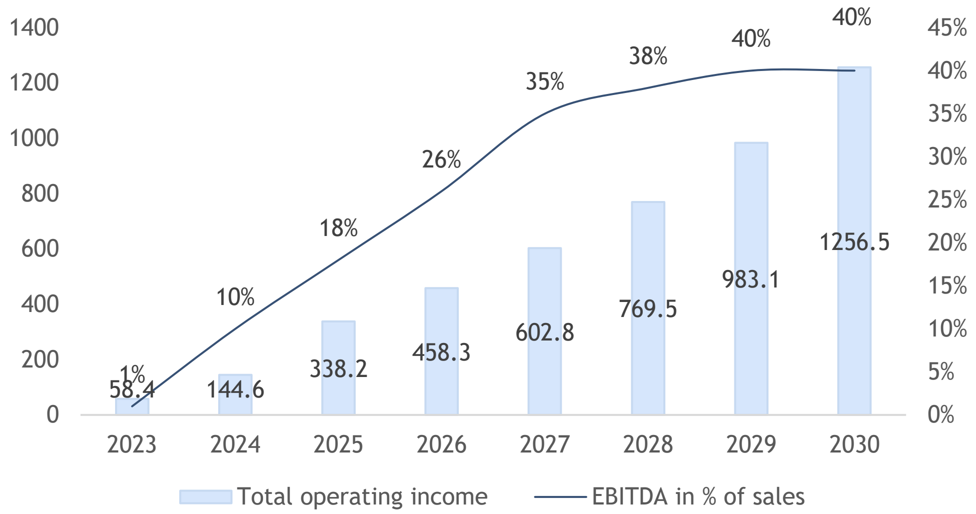


Source: Bryan, Garnier & Co

In terms of margins, we expect the EBITDA to reach the breakeven point in 2023 after the ramp-up of the Glencore and Samancor contracts. Our EBITDA margin expectations then gradually switch from 10% in 2024 to 40% in 2029 and 35% on a LT basis on the back of :

- Sustained top line growth and operational leverage
- Cost reduction thanks to production synergies and engine optimisation (new design leading to lower production cost)
- Better pricing thanks to a better track record and electricity price increase in South Africa

Fig. 101: EBITDA margin forecast over 2023-2030

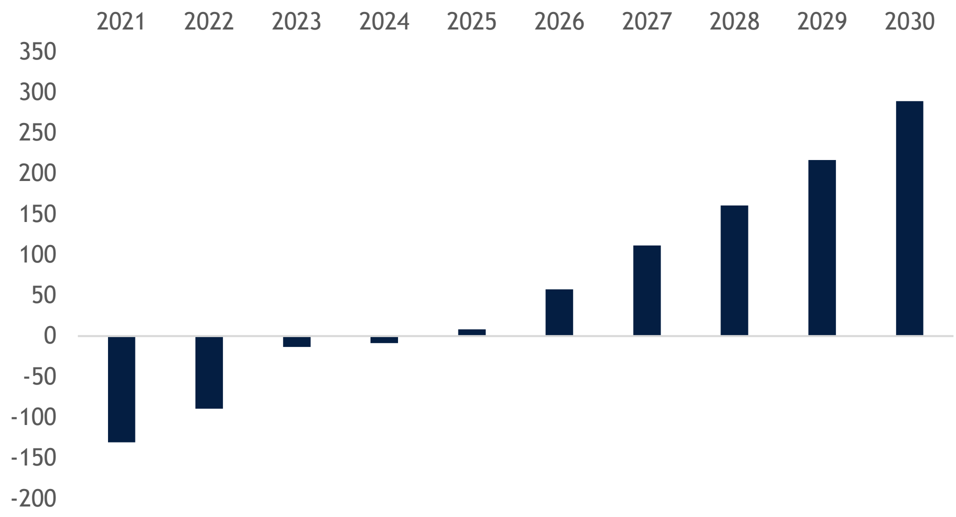


Source: Bryan, Garnier & Co

Promising FCF generation

We forecast CAPEX of around SEK40-50m/year, in line with 2020, out to 2027 and then we set our assumption at 6-4% / year on a LT basis. CAPEX will be equally expensed between tangible (plant extension, new machines, hardware) and IT systems (enterprise resource planning, manufacturing execution system etc). On the WCR side, we gradually set a WCR at 10% of sales as of 2026. Our FCF generation figures therefore start to be positive as of 2025 since we forecast strong top line growth resulting in a high cash consumption related to WCR along significant CAPEX as a percentage of sales between now and 2025.

Fig. 102: FCF generation in SEKm



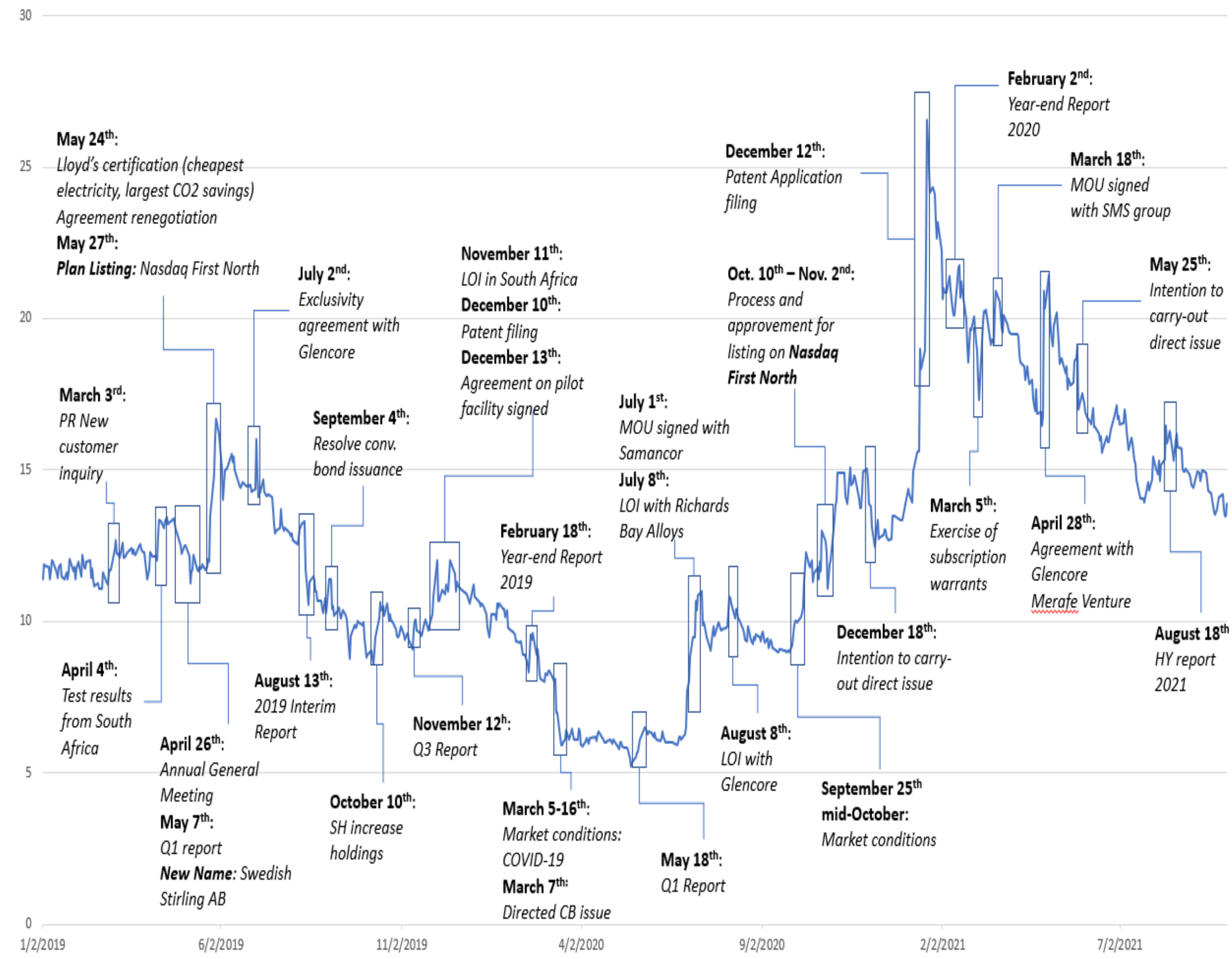
Source: Bryan, Garnier & Co

Initiating coverage with a Buy rating, SEK22TP

Equity story

Swedish Stirling's shares obviously strongly and positively reacted to the announcements of promising MoUs like Samancore, Glencore and Richards Bay Alloys. We think that other signatures could boost the shares but it will not be enough to create a durable momentum. Investors are clearly waiting for top line growth deriving from the contract signed in 2020. With a growing installed base of PWR BLOK, the visibility on the company will be considerably strengthened: FCF will be easily predictable thanks to a multiple year renting business model and will make Swedish Stirling more appealing for investors.

Fig. 103: Swedish Stirling share price since January 2019



Source: Bryan, Garnier & Co, Reuters

Main assumptions

In our view, a DCF is the most relevant approach for valuing Swedish Stirling, as it best captures the company's expected long-term profitability and thus cash flows and value creation.

We run our 18 year (2022-40) DCF with the following assumptions (based on the current scope, meaning we have factored in no acquisitions to calculate the free cash flow stream:

- Our 2022-30 top line growth estimates, set out in the previous section.
- 2030-40e: a slower revenue growth rate, gradually falling from 28% to 2%.
- We expect capex/D&A of around 1x as of 2030 (around 5-6% of sales, the same level as our LT assumption).
- EBIT margin: breakeven in 2025, gradually rising out to 2030 to reach 35% of sales and 30% on a LT basis.
- A 28% tax rate as of 2025 (EBIT breakeven), based on the South African corporate tax.
- WCR: stable at 11.6% of sales as of 2025 and 10-7% on a long-term basis.

In this model, the top line is driven only by the company's organic expansion, and we expect a gradual improvement in EBIT margin thanks to operational leverage.

From this DCF model, we derive an implied equity value of SEK 3, 094m.

Our assumptions are:

- A 11.6% WACC based on a 0.6% risk-free rate, 8.4% market premium, and 2.2 beta (adjusted beta over the past 10 years).
- A 2% terminal growth rate.

In line with general Bryan, Garnier & Co research assumptions, we assume a risk-free rate of 0.6% and an equity risk premium of 7.9%.

Swedish Stirling estimated WACC

Beta	2.2
Risk Premium	8%
Risk Free rate	1%
Cost of Equity	18%
Equity funding (%EV)	60%
Debt funding (%EV)	40%
Cost of debt	3%
Taxes	28%
Discount rate	11.6%

Source: Bryan, Garnier & Co

Our equity bridge is summarised in the table below:

Fig. 104: Swedish Stirling equity bridge

SUM of DCFC	1731.0
Terminal Value	1292.0
Entreprise Value	3023.0
(-) Net debt end-2021E	-70.8
others	0.0
Implied Equity value	3093.8
Number of shares (fully diluted)	140.9
Equity value per share	22.0

Source: Bryan, Garnier & Co

Sensitivity analysis

Below, we set out our sensitivity analysis, which uses different WACC and terminal growth assumptions, providing a relatively large valuation range.

Fig. 105: TP sensitivity to LT growth

		WACC				
	21.96	9.63%	10.63%	12%	12.63%	13.63%
LT growth	0.0%	29.0	24.1	20.2	17.2	14.7
	1.0%	30.6	25.2	21.0	17.7	15.1
	2.0%	32.6	26.6	22.0	18.4	15.5
	3.0%	35.3	28.3	23.1	19.2	16.1
	4.0%	38.8	30.5	24.6	20.2	16.8

Source: Bryan, Garnier and Co

Fig. 106: TP sensitivity to LT EBIT % estimate

		WACC				
	21.96	9.63%	10.63%	12%	12.63%	13.63%
LT EBIT %	28.0%	31.4	25.7	21.3	17.9	15.1
	29.0%	32.0	26.1	21.6	18.1	15.3
	30.0%	32.6	26.6	22.0	18.4	15.5
	31.0%	33.2	27.0	22.3	18.6	15.7
	32.0%	33.8	27.4	22.6	18.9	15.9

Source: Bryan, Garnier and Co

However, using different EBIT margin and WACC assumptions provides an idea of the company's value if it managed to reach an EBIT margin of close to 30%. Above is our sensitivity analysis, using different WACC and long-term EBIT assumptions.

Investment case summary

We view Swedish Stirling as an attractive growth company just about to switch from the concept to the top line phase. The company indeed ticks all the boxes:

- It benefits from a unique technology, able to convert heat generated by industrial gases into clean electricity.
- The commercial strategy is well in place with two customers housing 50% of the ferrochrome market on top of a growing penetration of the South African market.
- The business model (energy conversion agreement) is profitable and provides clear visibility on the top-line ramp-up while keeping an option on the carbon credits.
- The whole management team has been expanded (new CTO, CFO, CEO) in order to focus exclusively on top-line growth (new CEO is the former head of sales).
- The market potential is huge when it comes to see the PWR BLOK as a solution for grid stability.

After factoring in all the contracts set to generate promising top-line growth, our DCF-based model leads us to a Target Price of SEK22 resulting in a Buy rating.

Section 05

Azelio

Market Data:

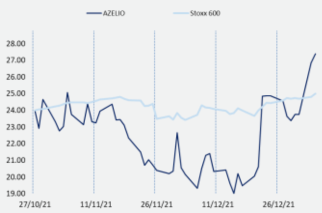
AZELIO

NEUTRAL coverage initiated

TP SEK23.4

Bloomberg / Reuters	AZELIO SS AZELIO.ST
Share price	SEK26.56
Market Cap.	SEK3,110m
E.V.	SEK3.110m
12m high / low	SEK73.2 / 19.0
Free Float	75%
Ytd Perf.	-48.6%

Shareholders	
Blue Marlin	15%
Capital group	5%
Avanza Pension	5%
Free Float	75%



Fiscal year end 31/12	2019	2020	2021e	2022e	2023e
Financial Summary					
EPS	-	-	-2.73	-1.02	0.14
Restated EPS	-	-	-2.57	-0.96	0.13
% change	-	-	-	-62.7%	-
BVPS	-	-	8.70	7.75	7.88
Operating cash flows	-	-	-2.03	-0.15	0.95
FCF	-	-	-3.07	-1.43	-0.28
Net dividend	-	-	0.00	0.00	0.00
Average yearly Price	-	-	17.01	-	-
Avg. Number of shares, diluted (k)	-	-	123	123	123
Valuation (x)					
EV/Sales	-	-	NS	NS	NS
EV/EBITDA	-	-	NM	NM	NS
EV/EBIT	-	-	NM	NM	NS
P/E	-	-	NM	NM	NS
FCF yield (%)	-	-	NM	NM	NM
Net dividend yield (%)	-	-	NM	NM	NM
Profit & Loss Account (SEKm)					
Revenues	133	136	30	382	772
Change (%)	-	1.8%	-77.8%	1168.0%	102.3%
Adjusted EBITDA	-118	-178	-248	-18	121
EBIT (current)	-161	-192	-315	-117	21
Change (%)	-	-19.6%	-63.9%	-62.8%	-
Financial results	0	-1	-1	-1	-1
Pre-Tax profits	-161	-193	-315	-118	20
Tax	0	0	0	0	-4
Net profit	-161	-193	-315	-118	16
Restated net profit	-161	-193	-315	-118	16
Change (%)	-	-19.7%	-63.7%	-62.7%	-
Cash Flow Statement (SEKm)					
Operating cash flows	-119	-179	-249	-18	117
Change in working capital	29	-38	-48	-51	-55
Capex, net	-139	-129	-90	-111	-100
Free Cash flow	-266	-296	-377	-176	-34
Dividends	0	0	0	0	0
Capital increase	0	560	612	0	0
Net debt	-31	-283	-544	-368	-333
Balance Sheet (SEKm)					
Tangible fixed assets	19	24	24	24	24
Intangibles assets	749	519	543	554	554
Cash & equivalents	56	332	567	390	356
current assets	19	23	22	154	307
Other assets	22	24	24	24	24
Total assets	866	922	1,180	1,147	1,264
L & ST Debt	-9	-259	-521	-344	-310
Provisions	0	0	0	0	0
Others liabilities	-546	-363	-438	-412	-362
Shareholders' funds	710	772	1,069	951	968
Total Liabilities	155	150	111	195	297
Capital employed	747	809	1,106	989	1,005
Ratios					
Operating margin	-120.5%	-141.5%	-1044.6%	-30.6%	2.7%
Tax rate	0.0%	0.0%	0.0%	0.0%	0.0%
Net margin	-120.8%	-142.0%	-1046.7%	-30.8%	2.1%
ROE (after tax)	-22.6%	-24.9%	-29.4%	-12.3%	2.2%
ROCE (after tax)	-21.5%	-23.7%	-28.4%	-11.8%	2.1%
Gearing	-4%	-37%	-51%	-39%	-34%
Pay out ratio	0.0%	0.0%	0.0%	0.0%	0.0%

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Source: Company Data; Bryan, Garnier & Co ests.

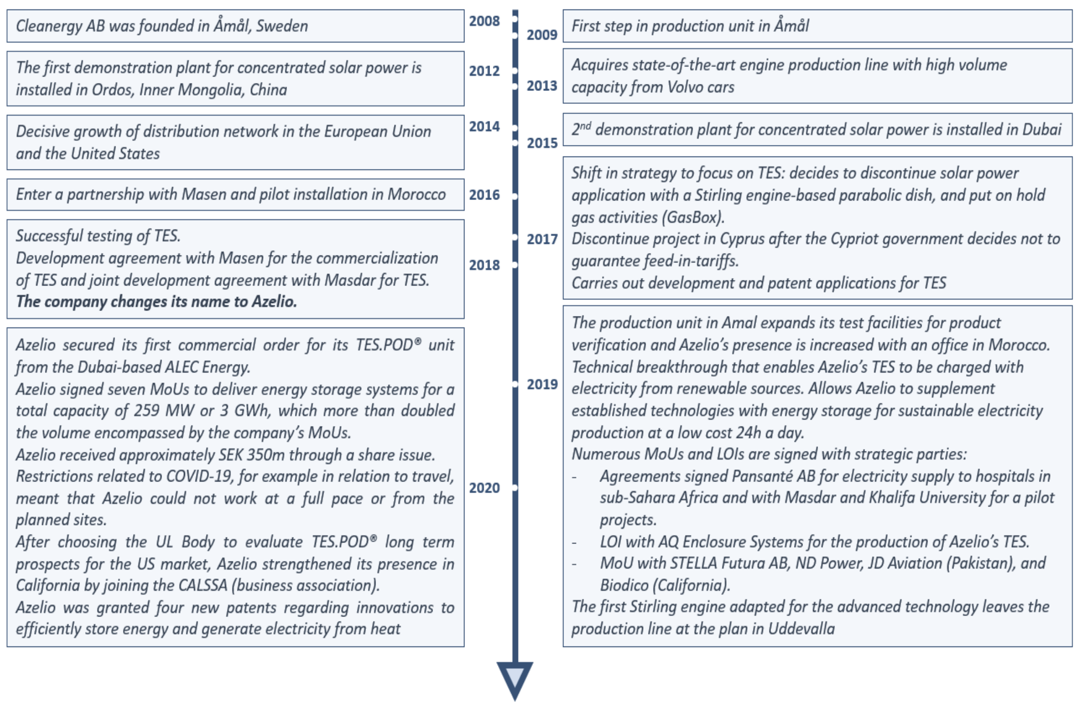
Azelio

A pure player in thermal storage..

Listed in 2018 but founded in 2008 in Sweden as Cleanergy by four entrepreneurs who bought rights from a German firm focused on the Stirling engine, Azelio (new name in June 2018) manufactures, develops and sells its Stirling-based energy storage system named the TES.POD.

In contrast to Swedish Stirling, Azelio is more focused on thermal storage and renewable systems. The primary goal of Azelio is indeed to fill the gap caused by the intermittency of renewable energies, in particular solar and wind, with a 13-18h thermal storage system. Consequently, the group mainly targets off-grid locations, mini-grid and renewable baseload systems.

Fig. 107: Main events in Azelio's history



Source: Azelio, Bryan, Garnier and Co

With 170 employees in 2021 (mainly engineers, technicians vs 70 in 2017), the group is ready to expand its business in Africa, the Middle East, in Australia and the US. Azelio has also strengthened its manufacturing organisation by creating two plants, one in Åmål (sub-assembly of the Stirling cylinder kits, demonstrator system) and another in Uddevalla (final assembly of the TES.POD, able to produce 45,000 units/year).

Azelio also managed to raise funds to finance its development through multiple capital increases. Since 2018, the company has managed to raise more than SEK1bn (PP, IPO, capital increase).

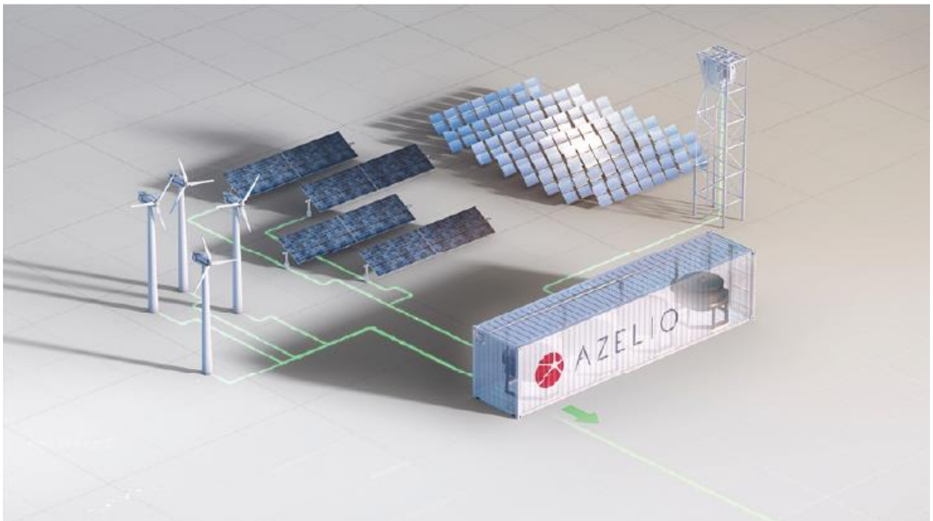
While the company has signed several Memorandum of Understandings (MoU) over recent years (which could translate into sales of USD2bn by 2025 according to Azelio), it is now about to convert these agreements into orders.

Like Swedish Stirling, the main challenge concerns the ability to produce and deliver an increasing amount of TES.POD as of 2022.

…benefiting from its unique technology

Azelio's system relies on Stirling based electricity production combined with a thermal energy storage technology. Like Swedish Stirling, the company spent several years developing its own Stirling engine to combine it with a thermal storage process. Since May 2019 (more than 10 years after the group's foundation), Azelio has been able to convert electricity from photovoltaics and wind power into stored thermal energy.

Fig. 108: TES.POD first version with concentrated solar energy (heliostat and PV)



Source: Azelio 2019 prospectus, Bryan, Garnier and Co

How does it work ?

The TES.POD's standard configuration consists of a Stirling engine (POD) as power conversion unit and a thermal energy storage (TES), to provide clean power from renewables despite intermittency.

1. TES (thermal energy storage, before 2019)

   - A sun-feathered filed of mirrors (fig.42) captures the sun's rays concentrating them at a specific point mounted on top of a tower where a receiver is located.
   - The receiver (the TES part of the TES.POD) absorbs the heat and uses it to melt an aluminum alloy that is part of a special thermal storage solution.
   - The molten aluminum is then able to harness the heat for a longer period of time.
   - Then, the TES.POD can provide full power for 13 hours. On 50% of the nominal power level the system can provide power for 26 hours. If no power is used the system can save the energy within the system for weeks.

Consequently, the TES part consists of heating aluminum alloy until it is fully molten in order to provide completely charged storage.

Azelio has made slight changes to the TES part since 2019. The receiver is no longer heated directly with concentrated solar rays but instead with electricity produced by solar/wind energy during the day in order to gain efficiency. The Stirling engine is also very important since it highly contributes to generate electricity from heat.

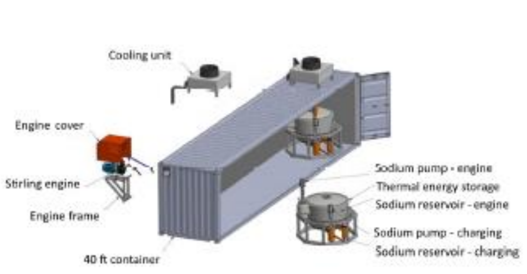
2. POD (power on demand)

A pump then starts pumping liquid sodium in order to transfer the hot sodium to the Stirling engine located in the container

- Inside the Stirling engine, a working gas is heated up and cooled down.
- When the gas is heated up, it expands (pressure increases) and pushes down the piston.
- Momentum/motion is created.
- The compression piston on the other side is pushed up.
- Gas passes through the cooler (pressure decreases).
- The piston goes back.
- Then gas is then heated up again and another cycle starts.
- The motion is used through a crankshaft (directly connected to a generator) to move the turbine of the generator which creates electricity.

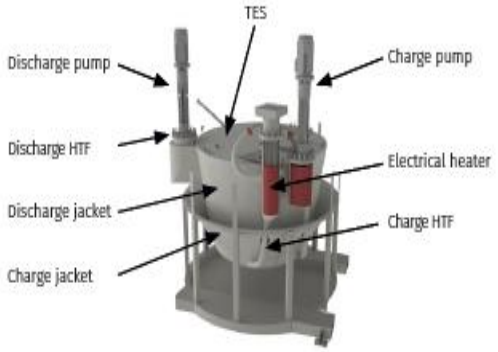
Azelio's Stirling engine generates about 25 cycles/second with a temperature spread of more than 500°C (600°C for the hot side and 55-60°C for the cold side)

Fig. 109: 12m container for Azelio's TES.POD



Source: Azelio, Bryan, Garnier and Co

Fig. 110: Heat pump

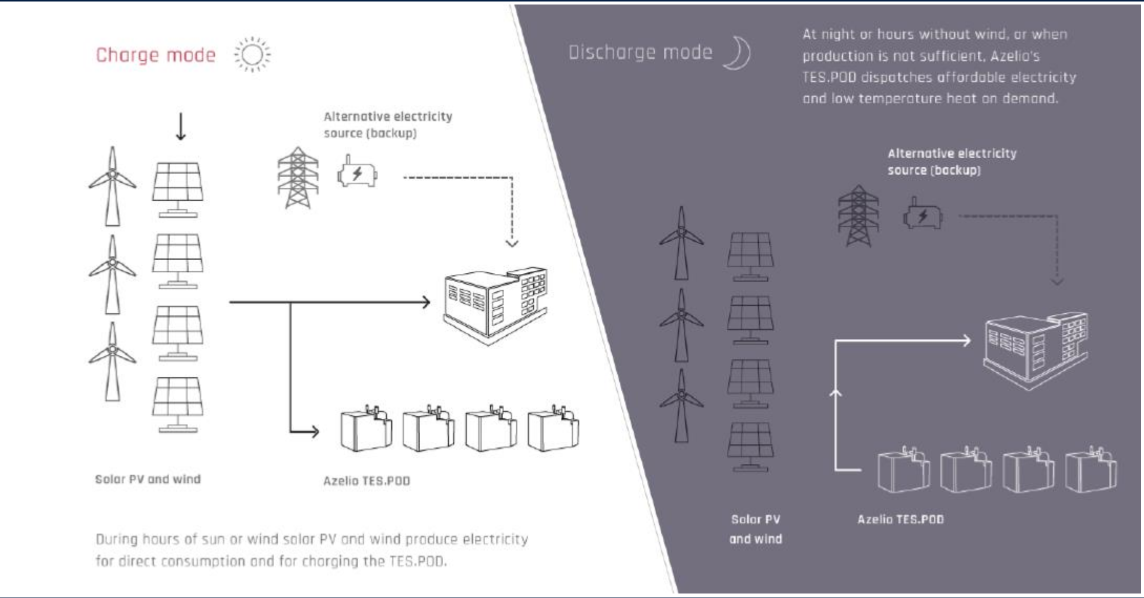


Source: Azelio, Bryan, Garnier and Co

In other words, electricity is generated according to the phase change material (PCM) process:

- Storing electricity is expensive and inefficient but storing heat has significant benefits. That is why Azelio converts the thermal energy to electricity after storage instead of before. Thermal Energy Storage (TES) is the obvious and optimal choice for electricity on-demand all hours of the day.
- A PCM is heated up to just above 600°C (the PCM temperature is 577°C but the system is heated above 600°C) and liquefied in the container. During discharge, heat is transferred from the PCM through a heat transfer fluid (HTF) to the Stirling engine. A working gas is heated and cooled off by ambient air, and thereby runs the engine.
- The Thermal Energy Storage (TES) part is the heart of Azelio's innovation. Since the greatest energy recovery is obtained during the conversion phase, Azelio chose an aluminum alloy for its specific phase changing characteristics.

Fig. 111: Azelio's system concentrated with solar energy (heliostat and PV) and wind

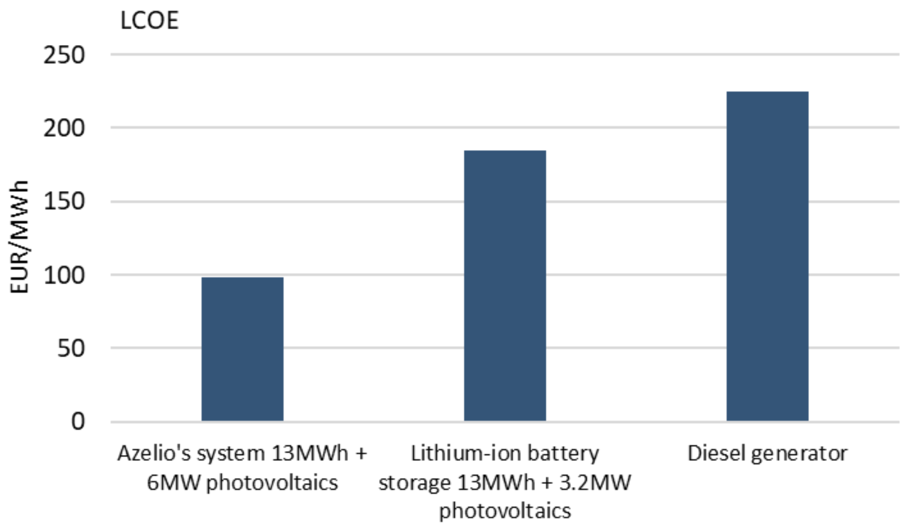


Source: Azelio 2021 investor presentation, Bryan, Garnier and Co

Numerous competitive advantages

- Cost effective: according to Azelio, once volume production is reached (as of 2022-23), Azelio's sytem combined with photovoltaics will have an LCOE of EUR93/MWh for around the clock production using the following assumptions : 30 year lifetime, 4.5% discount rate. With the production ramp-up, Azelio expects the LCOE to fall to EUR64/MWh (n+4 after the launch). This calculation does not include potential carbon credits. LCOE for the TES.POD combined with photovoltaics in 2021 can be compared with fossil fuels (diesel) which has an LCOE of around EUR200/MWh. Photovoltaic with 13h of storage in batteries will provide an LCOE of EUR135 MWh in 2021 according to the national renewable energy laboratory, Lazard and Azelio's internal calculations.

Fig. 112: LCOE comparison with batteries and diesel



Source: Azelio, Bryan, Garnier and Co

Azelio has provided a breakdown of the LCOE of its installation (combination of the TES.POD with photovoltaic) and a comparison between 2021 and 2025 which shows the decline in costs linked to the production ramp-up and the overall roll out of renewable solar energy. Azelio then forecasts an LCOE failing from EUR93/MWh in 2021 to EUR64/MWh in 2025.

Fig. 113: 2021 LCOE

2021 LCOE	SEK/MWh	EUR/MWh
Levelised capital cost Azelio's system	431	40
Levelised capital cost photovoltaics	350	33
Fixed operation and maintenance costs	214	20
Spare parts incl. service materials	*88*	*8*
Insurance, permits, and other	*39*	*4*
Operating costs (personnel, electricity, etc.)	*13*	*1*
Operation and maintenance costs photovoltaics	*74*	*7*
Total	**995**	**93**

Source: Azelio 2019 prospectus, Bryan, Garnier and Co

Fig. 114: 2025 LCOE

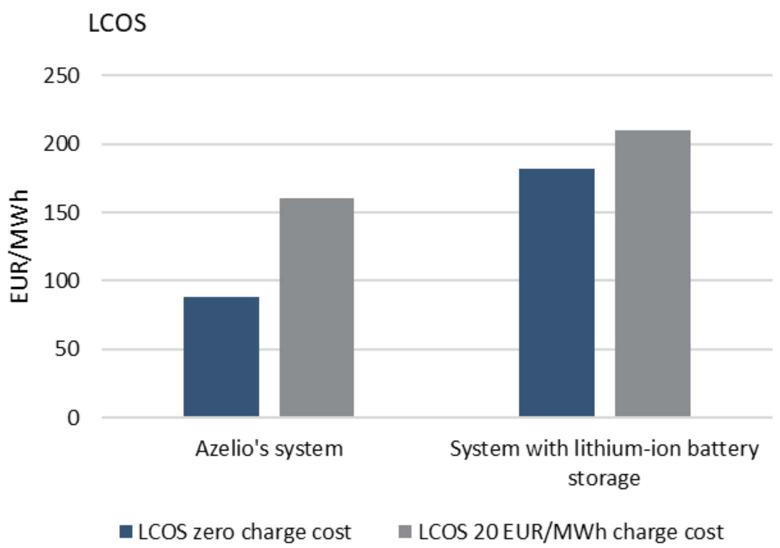
2021 LCOE	SEK/MWh	EUR/MWh
Levelised capital cost Azelio's system	304	27
Levelised capital cost photovoltaics	253	24
Fixed operation and maintenance costs	142	13
Spare parts incl. service materials	*48*	*4*
Insurance, permits, and other	*30*	*3*
Operating costs (personnel, electricity, etc.)	*9*	*1*
Operation and maintenance costs photovoltaics	*55*	*5*
Total	**699**	**64**

Source: Azelio 2019 prospectus, Bryan, Garnier and Co

LCOS (i.e. the cost per produced energy unit for energy storage) also highlights gradually declining costs. When an energy storage system is not generating electricity and depends on other generating technology, it is referred to as LCOS instead of LCOE.

Azelio uses LCOS to assess the cost related to storage of energy ; Azelio’s pricing strategy is based on LCOS. Like the LCOE, Azelio projects a decline in the TES.POD’s LCOS.

Fig. 115: Azelio’s system concentrated with solar energy (heliostat and PV) and wind



Source: Azelio, Bryan, Garnier and Co

- Industrial scalability: the modular design of the TES.POD facilitates projects of various size and different capacities (from 0.1 to 100MW). Installation is quick and incremental expansion is easy.
- Suitable for different sources of energy: the TES.POD works with different renewable energies like photovoltaic installations or wind but also off-grid or mini-grid systems allowing a smooth transition from traditional baseload generation to renewable systems.
- Durability: according to Azelio, the TES.POD has a 30 year lifetime and does not deteriorate over time.

- Storage capacity: the TES.POD can provide full power for 13 hours. On 50% of the nominal power level the system can provide power for 26 hours. If no power is used the system can save the energy within the system for weeks.
- Lower maintenance needed: since there is no combustion inside the Stirling engine, there is no combustion waste damaging the pipes. Consequently, the TES.POD can operate 6, 000 hours between maintenance sessions.
- Sustainability: no CO2 emissions, recycled aluminium, fits perfectly with renewables systems.

Diversified client portfolio

Several revenue models could apply to Azelio's project. Like Swedish Stirling we could imagine a renting business model based on the number of MWh produced or in terms of capacity depending of the size of the installation and the number of MW needed.

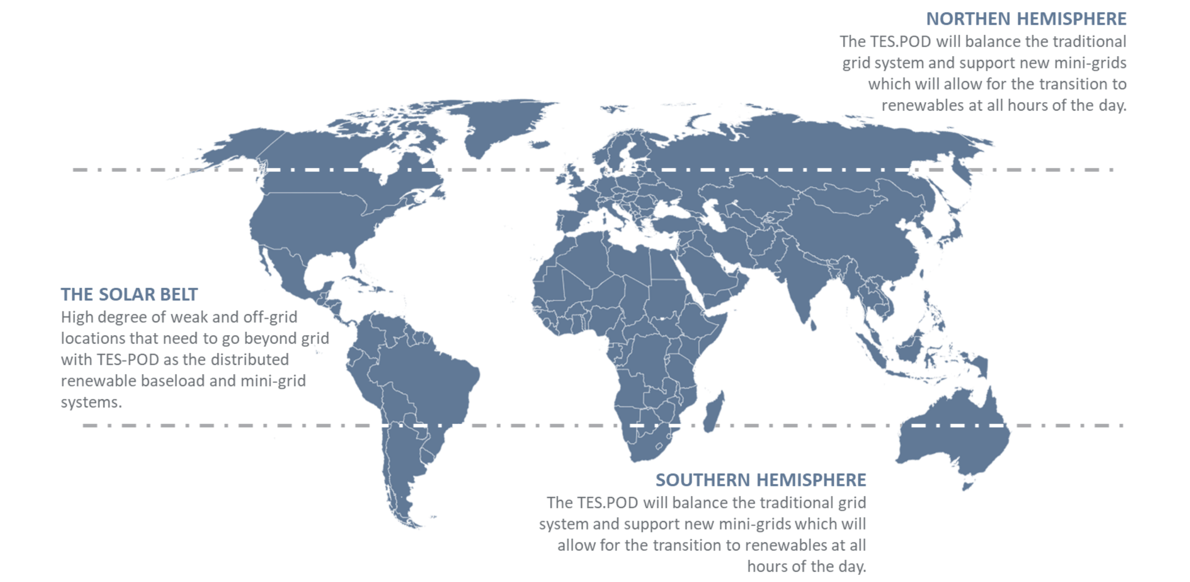
However, in the case of Azelio, the company intends to sell directly its TES.POD based on 15% payment on order, 40% on delivery followed by 30% on commissioning of the system and 15% over the next two years.

In the aftermarket, the company intends to apply a revenue model taking the form of a consultancy fee linked to hardware upgrades, new software features and maintenance.

Portfolio overview

Azelio's main challenge will be to roll out its promising product. Since the TES.POD mainly works with solar applications (even thought it could be combined with other renewable systems), the company primarily targets sunny places, i.e. locations mainly in the solar belt (but not only).

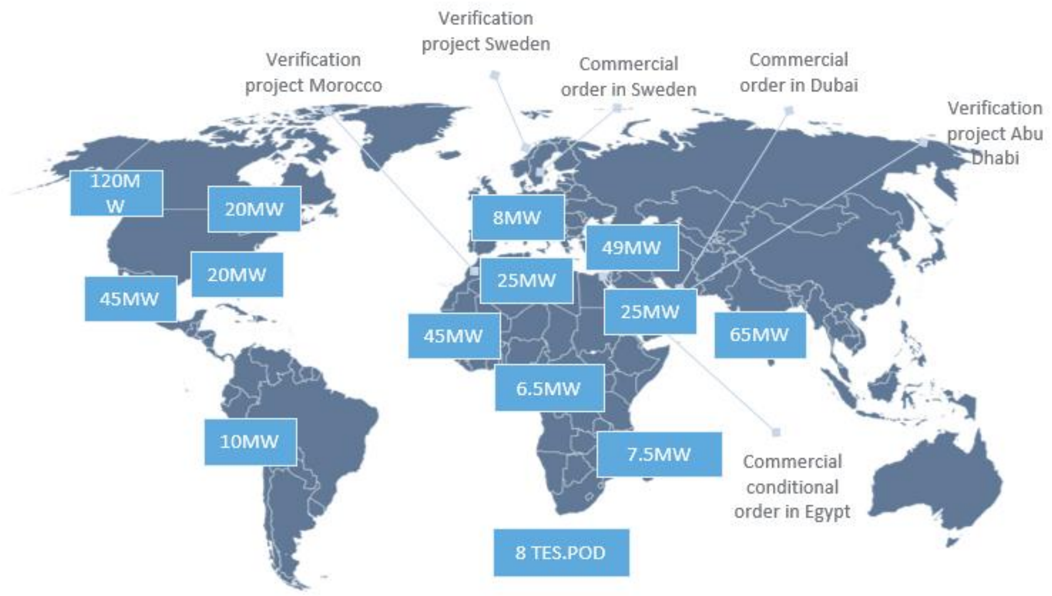
Fig. 116: Azelio's addressable target in terms of geography



Source: Azelio, Bryan, Garnier and Co

Nevertheless, since the TES.POD can be coupled with mini-grids, off-grid or traditional grid systems, Azelio can also address a larger market. The TES.POD can also be installed outside of the solar belt (good solar conditions are enough to make the TES.POD work) and on-grid applications can be achievable in a context of high energy prices). Azelio started to sign contracts as of 2019, once the TES.POD and the internal organisation (patents, plant, headcounts) were ready for commercial ramp-up.

Fig. 117: Azelio's customer portfolio



Source: Azelio 2021 investor presentation

The following is an overview of the main Memorandum of Understanding (MoU) and orders signed:

<u>**MoU**</u>

Biodico (US), announced in November 2019, 120 MW

- MoU with the US company BIODICO INC (Biodico) for a project in Atascadero, California. The MoU frameworks a collaboration for a capacity of about 120 MW of Azelio's energy storage technology in the US market until 2024
- Ramp-up: 13 kW in 2021 (Atascadero project), 15 MW in 2022, 35 MW in 2023 and 70 MW in 2024. Fully installed, the capacity corresponds to approximately 9,000 units of Azelio's system.
- Customer description: Biodiesel producer in the US founded in 1993. The name change from Biodiesel Industries to Biodico came about as the company expanded its focus from biodiesel production alone to the integration of other types of renewable energy solutions.

Atria Power (India), announced in September 2020, 65MW

- MoU to collaborate on installing over 65 MW capacity of Azelio's energy storage out to 2025 in India.
- Ramp-up : collaboration over 65 MW until 2025, starting with small scale commercial installations of 100 kW in 2021, followed by larger scale installations with an expected total of 12 MW in 2023, 18 MW in 2024 and 35 MW in 2025.

- Customer description: Atria Power is an integrated energy solutions provider, evaluating energy efficiency, energy consumption and energy purchasing for its customers.

  By combining investments in technology with tailor-made service offerings, Atria Power offers services beyond those of a commodity supplier of renewable energy.

ALEC energy (Dubai), announced in December 2020, 49 MW

- MoU, covering a collaboration over 49 MW of installed capacity of Azelio's energy storage until 2025.

- No ramp-up schedule communicated.

- Customer description: ALEC Engineering and Contracting L.LC. (ALEC) is a large construction company with related businesses operating in the GCC with a presence in Africa. The company builds and provides construction solutions in the Middle East and in Africa.

Trimark Associates (US), announced in June 2020, 45 MW

- MoU with US-based company Trimark Associates Inc. (Trimark) which covers a collaboration over 45 MW capacity of Azelio's energy storage until 2025 in the North American market, where Trimark will be the system integrator. In addition to this MoU, the parties anticipate an extended project pipeline once the first projects are initiated.

- Ramp-up: the first projects are targeting 150 kW in 2021, followed by 3 MW in 2022, 6 MW in 2023, 12 MW in 2024, and 24 MW in 2025.

- Customer presentation : Trimark is based in California, and offers a fully integrated portfolio of services, ranging from hardware and software products to field installation, integration, testing, and ongoing maintenance of power plants. The company contributes to "greening the grid", and supports the reduction of greenhouse gas emissions.

Jet Energy (Morocco), announced in October 2020, 45 MW

- MoU with Morocco based Jet Energy to explore energy storage projects with Azelio's TES.POD in French-speaking Africa. The collaboration targets approximately 45 MW capacity of the TES.POD out to 2025, with JET ENERGY as project developer.

- Ramp-up: the first project targets 50 kWe in 2021, followed by installations of larger scale projects with an expected total of 5 MWe in 2022, 10 MWe in 2023, 15 MWe in 2024 and 15 MWe in 2025.

- Customer presentation: Jet Energy is an EPC (engineering, procurement and construction) contractor specialised in construction, operation and maintenance of photovoltaic power plants.

Hussein Atieh (Jordan), announced in January 2019, 25 MW

- MoU with Jordanian company Hussein Atieh & Sons Co. (HAE), to work together on setting up a small-scale project in Jordan. The project paves the way for a commercial collaboration of about 25 MW of Azelio's energy storage technology in the Jordanian market until 2023.

- Ramp-up: this capacity is forecast along the following timeline: 50 kW in 2020, 3 MW in 2021, 7 MW in 2022 and 15 MW in 2023.

- Customer presentation: HAE is a privately owned general contracting firm which has successfully executed several projects of varied and complex disciplines throughout Jordan over the past six decades (since 1961).

  HAE is certified as a first-class general contractor in Jordan covering several disciplines in electromechanical works and infrastructure projects.

Al MAshani (Oman), announced in December 2019, 25 MW

- MoU to jointly work on establishing a small-scale project in Oman. The goal of the installation is to demonstrate Azelio's system in a realistic commercial setting and start a broader implementation of Azelio's technology in the country together with Al Mashani, for an aggregated project pipeline of about 25 MW between 2021 and 2024.

- Ramp-up: this capacity is forecast along the following timeline: 50 kW in 2021, 5 MW in 2022, 7 MW in 2023, and 13 MW in 2024.

- Customer description: Founded in 1976, Al-Mashani Trading Contracting & Importing Company is a well-known family business in Oman. The group started it's diversifying investments in 2014 entering different business categories in the Sultanate such as Converting Industries, Real Estate development, Tourism, Mining & Importing.

Citrus (Mexico), announced in June 2020, 20 MW

- MoU with Citrus to assess energy storage for food & beverage, agricultural, mining, and the oil & gas industry as well as the tourism sector with hotels and resorts in Mexico, North and Central America. The MoU frameworks a collaboration for 20 MW in capacity of Azelio's energy storage until 2024.

- Ramp-up: the first projects are planned to be small scale, aiming for 150 kW in 2021, followed by 3 MW in 2022, 6 MW in 2023, and 11 MW in 2024.

- Customer presentation : CITRUS, based in Mexico, is an industrial equipment supplier and a turn-key energy project developer. The company contributes to the sustainability of industrial process lines and providing high-tech integrated renewable energy solutions to its customers for both heat and power.

VOGT (Chile), announced in April 2020, 10 MW

- MoU with the Chilean company Industria Mecánica VOGT S.A. (VOGT) to assess energy storage projects for the mining industry in Latin America. The MoU frameworks a collaboration for a 10 MW capacity of Azelio's energy storage from 2021 until 2024. The parties expect to trigger further projects after this initial agreement.

- Ramp-up: the first projects aiming for 50 kW in Q1, 2021 and 100 kW in Q3, 2021, followed by an additional 2 MW in 2022, 3 MW in 2023, and 5 MW in 2024.

- Customer presentation : VOGT is a leading regional supplier of pumping systems for the mining industry, with clients including some of the biggest metallic and non-metallic mining companies operating in Latin America. The pumping systems require electricity 24/7, currently provided by diesel generators in off-grid locations.

Svea Solar (Sweden), announced in January 2021, 8 MW

- MoU to develop projects using Azelio's long-duration energy storage, TES.POD, coupled to PV systems. A total of 8 MW of installed power and more than 100 MWh in equivalent storage capacity.
- Ramp-up: the collaboration will span at least three projects in 2021, five in 2022, and 10 in 2023.
- Svea Solar is Sweden's largest solar PV installer. In support of expanding its business offerings into the energy storage segment in Sweden in particular and Europe in general, a collaboration is initiated with Azelio, as a developer of long-duration energy storage.

Stella Futura (Sweden), announced in October 2019, 6.5 MW

- MoU with the Swedish sustainable energy solutions company Stella Futura, to work together on setting up a small-scale commercial project in Sub-Saharan Africa. Stella Futura has several projects in the pipeline between 2021 and 2023 where Azelio's technology can be used. The forecast power of these projects is 6.5 MW.
- Ramp-up: the first project will demonstrate Azelio's solution by distributing renewable power around the clock to off-grid communities, storing energy from solar power and dispatching it on demand. Two potential sites are under evaluation for the project, one in Ghana and one in Togo.
- Customer presentation : Stella Futura is an independent energy solution provider that partners with state-of-the-art storage technology solution providers to design, source and install complete reliable and safe solar powered energy solutions (on- or off-grid) for their customer pipeline in Sub-Saharan Africa.

<u>**Orders**</u>

Engazaat Development (Egypt), announced in August 2021, 20 TES.POD

- Azelio has received a conditional order from Engazaat Development for 20 of Azelio's TES.POD renewable energy storage units. The order is valued at approximately USD1.5m and delivery is estimated to take place in December 2021.
- The TES.POD units are intended to be financed, installed, and operated through a project company jointly owned by Azelio and Engazaat, and be used in the SAVE sustainable agriculture project in Egypt. The 20 TES.POD units have a combined storage capacity of 3.3 MWh of electricity production and will be part of a mini-grid system to supply farmers with renewable energy.
- Customer description: Egypt-based Engazaat company specialises in development, implementation and management of infrastructure systems in the water, technology, and renewable energy sectors. In its sustainable agro-village and entrepreneurship platform project SAVE, at the Moghra Oasis in Egypt, a mini-grid system is planned to supply farmers with 85% of their energy from renewable sources.

Wee Bee limited (South Africa), announced in November 2021, 8 TES.POD

- Azelio won an order for eight units of TES.POD with 1.3MWh clean electricity supply from South African-based farming company Wee Bee Ltd.

- The order has a value of approximately USD1.2m over 15 years including expected price increases. The system is planned for delivery by end of 2021 and the installation start up and commissioning will be carried out by Azelio in collaboration with its partner ALEC Energy.

- Wee Bee Ltd. is a mixed farming company with annual energy consumption of around 1.9 GWh. With an energy demand for day and night operations, reliable and cost-effective energy supply is of great importance.

Potentially strong sales ramp up

In terms of business model, we have assumed a direct sales model. In our forecast, Azelio manufactures and sells the TES.POD directly to its clients. Our key assumptions are based on the information we have gathered from annual reports, various press releases related to on-going contracts, corporates websites and financial data rooms.

We have chosen to stick to the main contract terms of each MoU (launch date, number of units, timeframe etc.) but have applied a specific PoS/contract given the numerous risks related either to execution (transport, delivery, installation), or a lack of visibility on the business reliability of customers (the bulk of whom are relatively small/medium sized businesses), or geopolitical stability in the country where the TES.POD will be located.

We have managed to compile useful information allowing us to assess the credibility or the quality of the contract based on consistency between the size of the order and the estimated resources of the counterparty.

Our probabilities of success range from 5% to 50% and are based on several criteria such as the top line, the number of employees at the client and the size of the order. In this context, we consider that a company such as Biodico, with between five and 10 employees and almost no sales, will not be able to spend SEK4.9bn on a TES.POD installation over the next four years. We have applied the same rationale to Atria Power (10%) and all the Azelio contracts in order to derive realistic top-line forecasts.

Fig. 118: Azelio's selected customer portfolio

Customer	Contract size	Top line (USDm)	# of employees	PoS %
BIODICO	120 MW	0.5	5	5%
Atria Power	65 MW	n.c	72	10%
ALEC Energy	49 MW	6.0	12000	50%
Trimark Associates, Inc.	45 MW	9.6	85	10%
Jet Energy	45 MW	n.c	50+	50%
Hussein Atieh & Sons Co.	25 MW	22.0	375	15%
Al Mashani Trading & Importing Co	25 MW	n.c	25	10%
Citrus	20 MW	n.c	8	5%
Vogt	10 MW	9.0	200	30%
Svea Solar	8 MW	55.2	333	30%
stella	6.5 MW	n.c	15	10%
engazaat	260 kW	n.s	n.c	50%
Wee Bee Ltd.	108 kW	n.c	n.c	50%

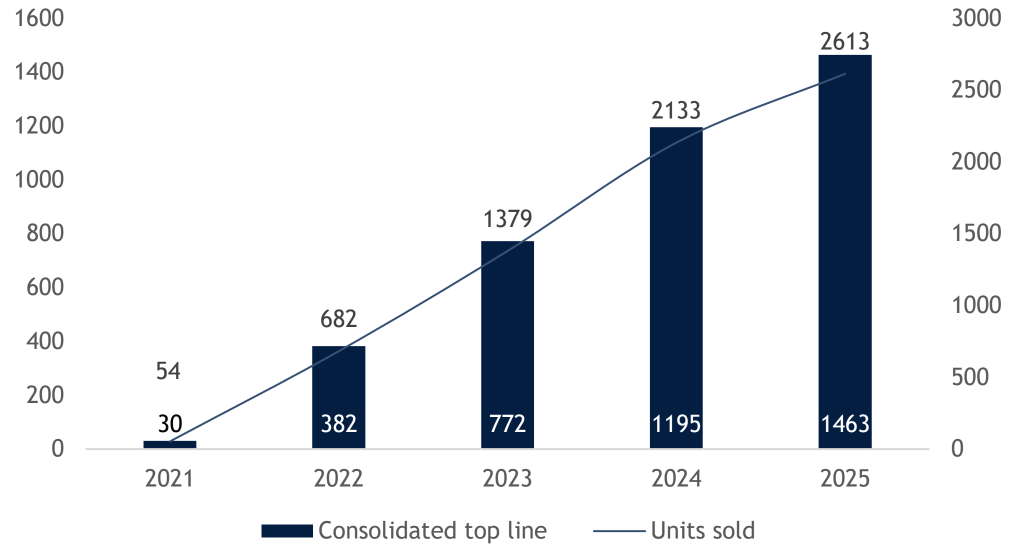
Source: Azelio, Bryan, Garnier and Co

Our estimates rely on the following metrics:

- 0.0130MW nominal capacity per TES.POD
- A selling price of SEK0.56m per TES.POD
- 2600 units sold in 2025 after application of our PoS estimates
- 10% sales CAGR over 2025-2030 assuming new contracts
- A gradual growth decline from 2030 to 2040 (4% sales CAGR over the period)
- 3% long term growth

After taking into account all the contracts and applying the respective PoS, we reach the following ramp-up over 2021-2025:

Fig. 119: Top line estimates in SEKm and units sold



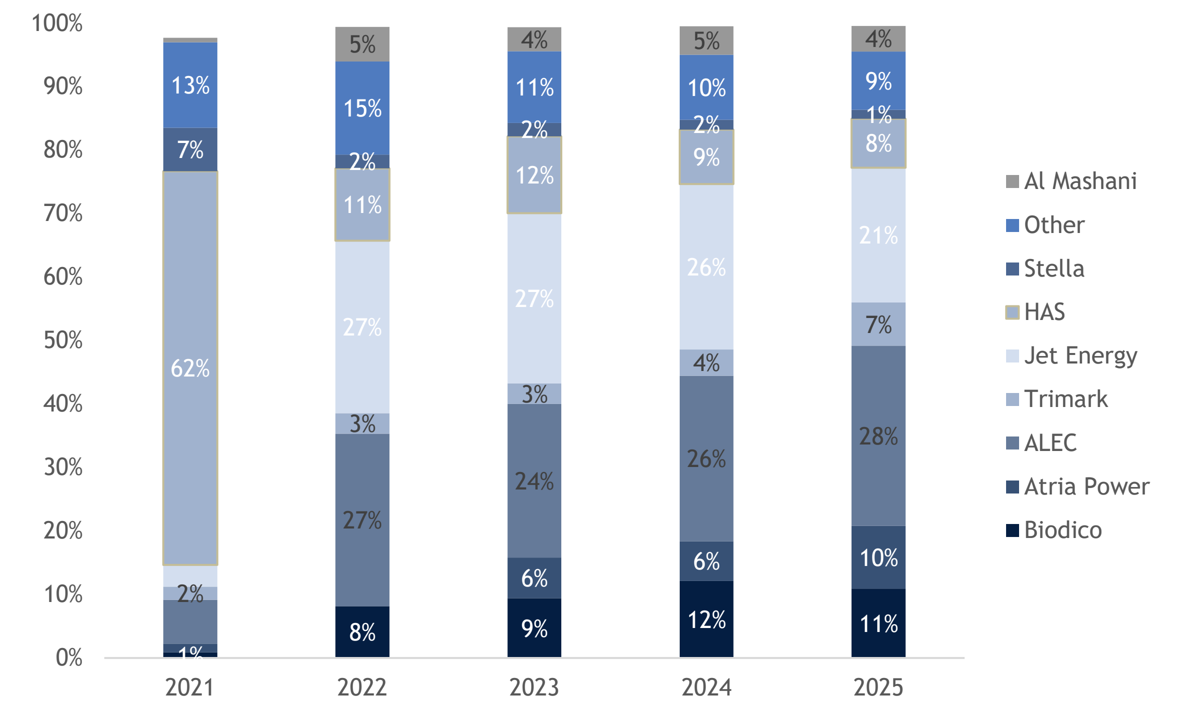
Source: Bryan, Garnier & Co

Our revenue forecast over the next four-five years solely rely on the current contracts assuming (without PoS applied):

- Biodico, mainly starting in 2022 and involving around 445 units sold by 2024
- Atria Power, mainly starting in 2023 and involving 480 units sold by 2025
- ALEC Energy mainly starting in 2022 and involving c. 1818 units sold by 2025
- Trimark associate starting in 2021 and involving c. 334 units sold by 2025
- Jet Energy, mainly starting in 2022 and involving c. 1668 units sold by 2025
- Hussein Atieh and sons, mainly starting in 2021 and involving c.278 units sold by 2023
- Al Mashani mainly starting in 2022 and involving c. 186 units sold by 2024
- Citrus JMK mainly starting in 2022 and involving c. 75 units sold by 2024
- VOGT, mainly starting in 2022 and involving c. 226 units sold by 2024
- SVEA Solar, mainly starting in 2022 and involving c.181 units sold by 2024
- Stella futura starting in 2021 and involving c. 80 units sold by 2023
- Engazaat Development starting in 2021 and involving c. 20 units sold by 2023
- Wee Bee starting in 2021 and involving eight units sold within 15 years

As such, the sales mix over the next 5 years seems to be well balanced between large contracts and small top line contributors.

Fig. 120: Customer mix over 2021-2025 in % of top line

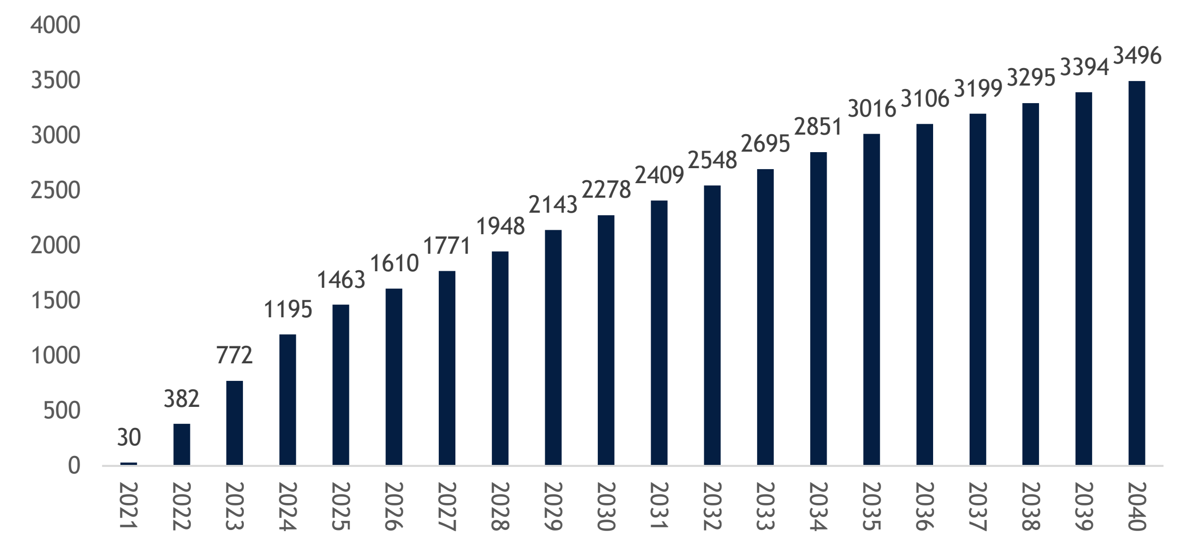


Source: Bryan, Garnier & Co

Total top line forecasts point to significant TES.POD rollout

Consequently, after taking into account all the contracts and applying their respective PoS, we derive a top-line forecast that implies a significant ramp-up starting with SEK30m sales in 2021 and reaching more than SEK3.4bn in 2040.

Fig. 121: Top line forecast over 2021-2040 in SEKm



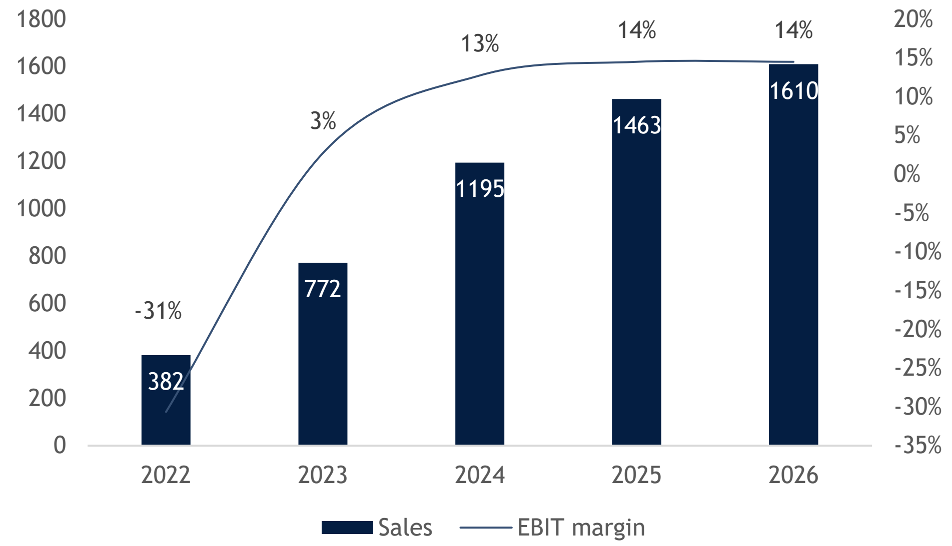
Source: Bryan, Garnier & Co

In term of units, we forecast c.680, 1380, 2100 and 2600 units sold in 2022, 2023, 2024 and 2025 respectively.

In terms of sales and margin, our forecast rely on a strong top-line ramp-up leading to EBIT margin expansion (from 3% in 2023 to 15-16% in 2030) thanks to operational leverage, cost synergies related to engine optimisation (new versions, software updates etc.) and better pricing following a better track record.

Azelio should be able to post a 15%+ EBIT margin as of 2030, which is in line with the sector average.

Fig. 122: Sales and EBIT margin forecast in SEKm over 2025-30



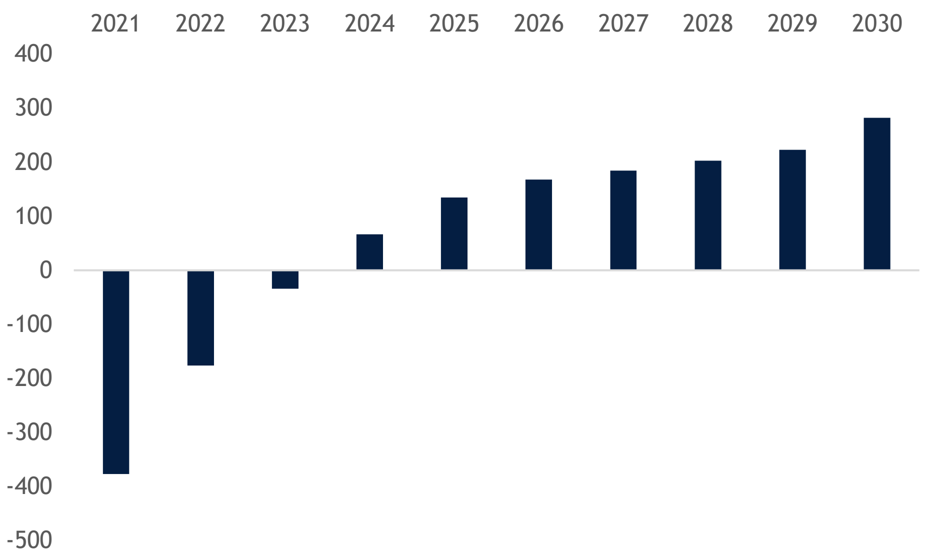
Source: Bryan, Garnier & Co

FCF generation set to improve

We project CAPEX around SEK90-140m/year out to 2027, in line with 2019-2020, before gradually setting our assumption at 6% / year on a LT basis. CAPEX should be equally expensed between tangible (plant extension, new machines, hardware) and IT systems (enterprise resource planning, manufacturing execution system, softwares upgrades etc). In terms of WCR, we set a level at 13% of sales as of 2025 and on a LT basis.

FCF generation should therefore start to become positive as of 2024 since we forecast strong top-line growth momentum resulting in high consumption of cash related to WCR change along important CAPEX as a percentage of sales between now and 2024.

Fig. 123: FCF forecast in SEKm over 2021-30



Source: Bryan, Garnier & Co

Strong balance sheet

However, Azelio nevertheless boasts a strong balance sheet (SEK612m capital increase in 2021) with at least two years of financial visibility based on the cash burn level seen in 2020.

Initiating with a Neutral rating, SEK23.4TP

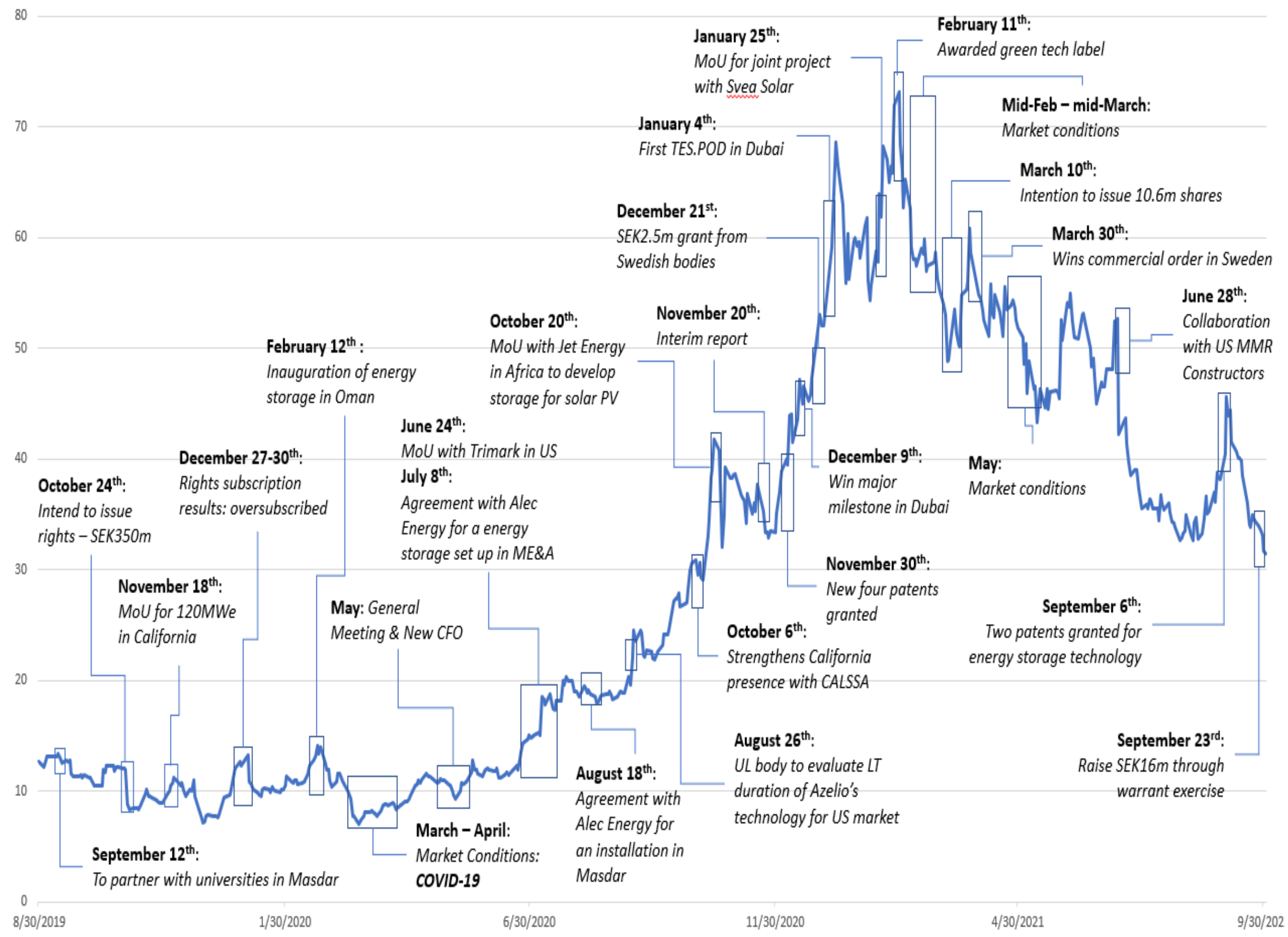
Share price analysis

Azelio's share price moved from SEK10/share to SEK75/share over 2019-20 on the back of very positive newsflow involving several MoU announcements (six MoUs signed in one year) and cash inflows obtained from rights issues and grants enabling clear financial visibility. However, since February 2021, Azelio shares have suffered from the combination of demanding valuation and decreasing trust in its ability to transform the MoUs into tangible revenue.

Several articles in specialised Swedish press have clearly stated that Azelio's pipeline was probably not as promising as expected. Since it is at a turning point and just about to sell its TES.POD, Azelio seems confident it can generate significative growth over coming quarters. In the meantime, we believe new MoU announcements will probably not have the same positive effect as in the past since the market is clearly waiting for top-line generation.

In this context, quarterly publications will be the main catalyst for the Azelio share price as of 2022. Investor will indeed closely monitor sales growth, margins and cash inflows as well as the number of units sold resulting from current MoUs.

Fig. 124: Azelio's customer portfolio



Source: Azelio 2021 investor presentation

DCF-based TP of SEK23.4/share leading to a Hold rating

In our view, a DCF is the most appropriate approach for valuing Azelio, as it best captures the company's expected long-term profitability and thus cash flows and value creation.

We have established a 18 year (2022-40) DCF with the following assumptions (based on the current scope, meaning that we have factored in no acquisitions to calculate the free cash flow stream:

- Our 2022-30 top line growth estimates, which we set out in the previous section.
- 2030-40e: a slower revenue growth rate, gradually falling from 10% to 3%.
- We expect capex/D&A of around 1x as of 2030 (around 5-6% of sales, same level for our LT assumption).
- EBIT margin: breakeven in 2023, gradually rising out to 2030 to reach 20% of sales on a LT basis.
- A 20% tax rate as of 2023 (net profit breakeven), based on the Swedish corporate tax.
- WCR: Stable at 13% of sales as of 2022 and on a long-term basis.

In this model, the top line is driven only by the company's organic expansion, and we expect a gradual improvement in the EBIT margin thanks to operational leverage.

From this DCF model, we derive an implied equity value of SEK2, 870m.

Our assumptions are:

- A 11% WACC based on a 0.6% risk-free rate, 8% market premium, and beta of 2.0.
- A 3% terminal growth rate.

In line with general Bryan, Garnier & Co research assumptions, we assume a risk-free rate of 0.6% and an equity risk premium of 7.9%.

Fig. 125: Azelio estimated WACC

Beta	2.0
Risk Premium	8%
Risk Free rate	0.6%
Cost of Equity	17%
Equity funding (%EV)	60%
Debt funding (%EV)	40%
Cost of debt	3%
Taxes	20%
WACC	**11.0%**

Source: Bryan, Garnier & Co

Our equity bridge is summarised in the table below:

Fig. 126: Azelio equity bridge

SUM of DCFC	1380
Terminal Value	968
Entreprise Value	2348
(-) Net debt end-2021E	-521
Others	0
Implied Equity value	2869
Number of shares (fd)	123
Equity value per share	23.4

Source: Bryan, Garnier & Co

Sensitivity analysis

Below, we set out our sensitivity analysis, which uses different WACC and terminal growth assumptions providing a relatively wide valuation range.

Fig. 127: TP sensitivity to LT growth

		WACC				
	23.4	9.0%	10.0%	11.0%	12.0%	13.0%
LT growth	1.0%	29.2	25.0	21.7	19.0	16.9
	2.0%	30.9	26.1	22.4	19.6	17.3
	3.0%	33.1	27.5	23.4	20.2	17.8
	4.0%	36.3	29.4	24.6	21.0	18.3
	5.0%	41.0	32.1	26.2	22.0	19.0

Source: Bryan, Garnier and Co

Fig. 128: TP sensitivity to LT EBIT % estimate

		WACC				
	23.4	9.0%	10.0%	11.0%	12.0%	13.0%
LT EBIT %	18%	31.5	26.3	22.5	19.6	17.3
	19%	32.3	26.9	22.9	19.9	17.5
	20%	33.1	27.5	23.4	20.2	17.8
	21%	33.9	28.1	23.8	20.5	18.0
	22%	34.8	28.7	24.2	20.9	18.3

Source: Bryan, Garnier and Co

However, using different assumptions for EBIT margin and WACC provides an idea of what the company's value could look like if it managed to reach EBIT margin of close to

20-22%. Below is our sensitivity analysis, using different WACC and long-term EBIT assumptions.

Investment case conclusion

In our view, Azelio is very well positioned in the thermal energy storage market thanks to its promising TES.POD technology, which is a perfect fit with photovoltaic installations and which could be easily adapted to wind. With its 13-18h electricity generation, Azelio's TES.POD clearly allows its customers to fill the gap resulting from renewable intermittency.

The company also benefits from the mounting worldwide aim to try and decrease/erase CO2 emissions by 2050, thereby placing Azelio in a good position to sell its technology.

This combination has allowed the group to easily raise money over recent years, notably in 2021. With a net cash position of SEK520m expected at end-2021, Azelio has at least two years of financial visibility and a strong balance sheet.

However, we believe the customer portfolio is not strong enough to ensure a clear top-line ramp-up as of 2022. Some contracts are not consistent with the company placing the order and visibility is quite weak on their ability to order important MW capacities.

Consequently, after adjusting sales expectations for probabilities that take into account the quality of the client portfolio, our DCF model points to a valuation of SEK23.4TP/share. As such, we initiate coverage of Azelio with a Hold rating.

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Section 06

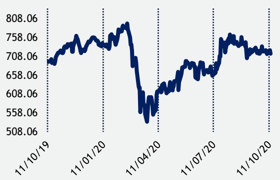
Hydrogen de France A pioneer in hydrogen power

Market Data:

HDF

NEUTRAL Coverage Initiated
TP EUR27.5

Bloomberg / Reuters	HDF FP/HDF.PA
Share price	EUR27.5
Market Cap.	EUR377m
E.V.	EUR378m
12m high / low	EUR32.8 / EUR25.5
Free Float	16.8%
Ytd Perf.	-11.4%



Fiscal year end 31/12	2019	2020	2021e	2022e	2023e
Financial Summary					
EPS (EUR)	0.04	0.03	0.08	0.11	0.24
Restated EPS (EUR)	0.04	0.03	0.08	0.11	0.24
% change	27.7%	-34.0%	165.3%	42.0%	114.8%
FCF (EUR)	-0.25	-0.07	0.31	-0.75	-0.76
Net dividend (EUR)	0.00	0.00	0.00	0.00	0.00
Average yearly Price	-	-	-	-	0.00
Avg. Number of shares, diluted (m)	13.711	13.711	13.711	13.711	13.711
Historical Entreprise value (EURm)	-	-	-	-	-
Valuation (x)					
EV/Sales	-	-	83.78x	38.67x	6.73x
EV/EBITDA	-	-	NS	NS	20.33x
EV/EBIT	-	-	NS	NS	61.33x
P/E	-	-	NS	NS	NS
FCF yield (%)	-	-	1.11%	NM	NM
Net dividend yield (%)	-	-	NM	NM	NM
Profit & Loss Account (GBPm)					
Revenues	2.4	1.9	3.0	6.8	39.8
Change (%)	154.3%	-19.7%	55.0%	125.7%	487.8%
Organic change (%)	154.3%	-19.7%	55.0%	125.7%	487.8%
Adjusted EBITDA	0.5	0.7	1.7	2.1	13.2
Adjusted EBIT	0.9	0.6	1.5	2.0	4.4
Change (%)	28.5%	-34.5%	167.8%	32.5%	120.7%
Financial results	0.0	0.0	0.0	0.1	0.1
Pre-Tax profits	0.9	0.6	1.5	2.1	4.5
Tax	-0.2	-0.1	-0.4	-0.5	-1.2
Net profit	0.6	0.4	1.1	1.5	3.3
Restated net profit	0.6	0.4	1.1	1.5	3.3
Change (%)	27.7%	-34.0%	165.3%	42.0%	114.8%
Cash Flow Statement (GBPm)					
Operating cash flows	-1.5	-0.1	2.3	0.9	6.8
Change in working capital	-2.0	-0.4	2.0	-0.8	-5.3
Capex, net	0.0	-0.5	-0.2	-10.3	-12.0
Free Cash flow	-3.5	-1.0	4.2	-10.3	-10.5
Financial investments, net	0.8	-0.5	-1.0	-1.0	-1.0
Dividends	0.0	0.0	0.0	0.0	0.0
Capital increase	0.0	0.0	125.4	0.0	0.0
Other	2.0	0.4	-2.0	0.8	5.3
Change in net debt	0.7	1.1	-126.6	10.5	6.2
Net debt (+)/cash (-)	-0.3	0.8	-125.7	-115.3	-109.1
Balance Sheet (GBPm)					
Tangible fixed assets	0.5	0.6	0.5	10.7	13.9
Intangibles assets	0.7	2.4	3.4	4.4	5.4
Cash & equivalents	0.6	0.0	126.6	116.1	109.9
current assets	2.7	5.1	3.5	4.1	10.1
Other assets	0.0	0.0	0.0	0.5	2.8
Total assets	4.5	8.1	133.9	135.8	142.0
L & ST Debt	0.3	0.9	0.9	0.9	0.9
Provisions	0.0	0.0	0.0	0.0	0.0
Others liabilities	1.4	4.0	3.4	3.7	6.7
Shareholders' funds	2.8	3.2	129.7	131.2	134.5
Total Liabilities	4.5	8.1	133.9	135.8	142.0
Ratios					
Gross margin	-	-	-	41%	45%
EBITDA margin	20%	35%	58%	32%	33%
Operating margin	35%	29%	50%	29%	11%
Tax rate	27%	26%	27%	27%	27%
Net margin	26%	22%	36%	22%	8%
ROE	25%	14%	2%	1%	2%
ROCE	25%	15%	34%	20%	21%
Gearing	-9%	26%	-97%	-88%	-81%
FCF/EBIT	-408%	-177%	280%	-518%	-240%
Dividend payout	0%	0%	0%	0%	0%

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Source: Company Data; Bryan, Garnier & Co ests.

Hydrogen de France A pioneer in hydrogen power

A dual profile

HDF is a pioneer in green hydrogen power, with an innovative dual profile. The company is both:

- An electricity producer, developer and owner of hydrogen power projects,
- A technology provider of multi-MW fuel cells.

Firstly, we see HDF as a sort of Orsted, Voltalia or Neoen 2.0. Their business profiles and areas of expertise are broadly the same name, namely HDF will manage the feasibility study, the permitting process, the financial structuring (SPV – Special Purpose Vehicle), pick contractors, supervise construction and commissioning, and maintain the system. HDF is a sort of conductor. Then, for some projects, those with the best expected IRR, HDF can decide to maintain or invest equity in the project and become an IPP (Independent Power Producer). These projects will be backed by PPA (Power Purchase Agreement), providing HDF recurring revenues and good financial visibility.

Note that HDF will benefit from the experience of its management team in the development of “conventional” renewable projects. Before engaging in hydrogen power projects, the company was named Immosun Solutions and was specialised in engineering consulting for solar projects including battery-based storage.

However, HDF is not “just” a project developer and power producer. Contrary to pure players in the renewables sector, HDF is also a technology provider. The company provides the PEM fuel cell used to produce electricity from hydrogen. In other words, HDF masters the key technology implemented in the project. This would be similar to Voltalia or Neoen manufacturing their own wind turbines, PV panels or batteries. Integrating part of the supply chain allows HDF to capture additional value and improve its competitiveness.

Fig. 129: HDF’s unique business model

Source : Bryan, Garnier & Co

HDF is a unique opportunity for investors to replay and invest in the renewable energy sector, as they did at the beginning of its acceleration, 10 years ago. The story is broadly the same with the same drivers, but pushed one step further with renewable power now being non-intermittent and produced from green hydrogen. Back to the Future.

Leveraging a partnership ecosystem to de-risk execution and accelerate market penetration

HDF has developed an extensive network of strategic, commercial and industrial partnerships. This has several benefits as it:

- Significantly reduces execution risks by leveraging the experience of some of the world's leading players,
- Improves the commercialisation timeline and penetration of markets by using existing products and the sales/service footprint,
- Provides a long-term competitive advantage thanks to access to engineering support and the ability to capture purchasing savings.

HDF's main strategic partnership is with Ballard, the world's leading provider of PEM fuel cells. Ballard's strategy is to focus on transport applications (low to medium power) and the group has therefore decided to give HDF a worldwide exclusive license for power generation applications. The license is for seven years ending in 2026.

HDF's second main strategic agreement is with Rubis, which is also its second biggest shareholder with c. 18.5% of the capital. Rubis benefits, for a period of five years, from a priority to invest in projects that HDF Energy plans to develop in Africa/Indian Ocean, in the Caribbean and in Europe, allowing Rubis to position itself as a majority direct investor in renewable electricity production projects.

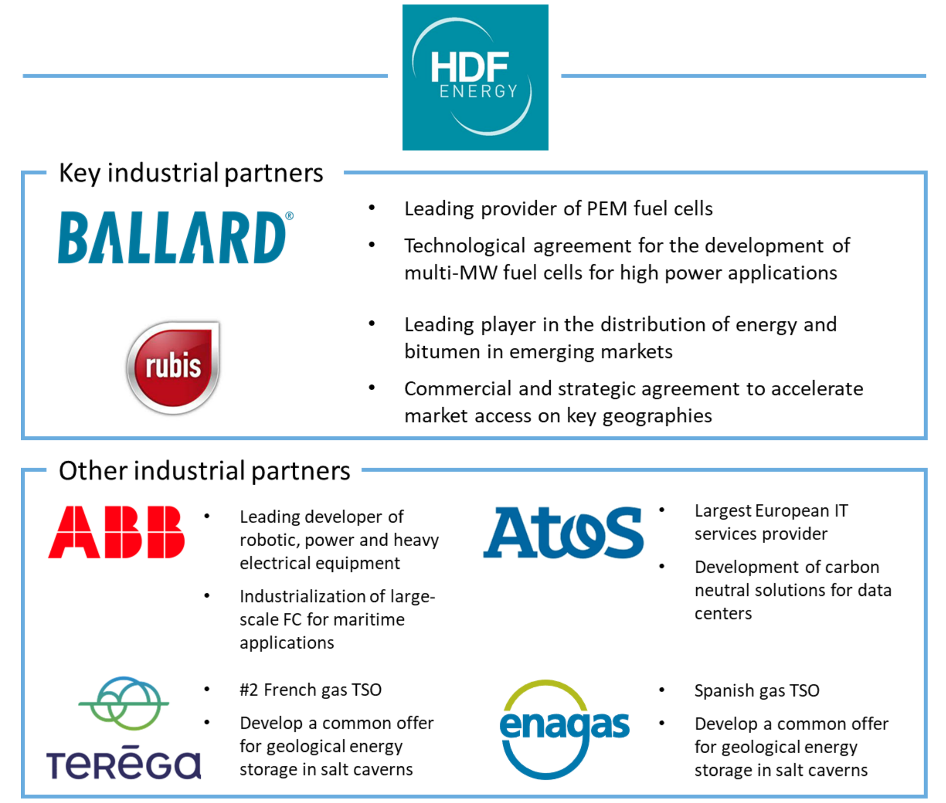
In addition to this, outside of these areas, Rubis will have the option to invest in such a project without requiring a majority stake. Rubis will provide HDF with local knowledge and technical, logistical, administrative, and legal support for the projects developed in the countries where Rubis is present and in which it has invested.

Last but not least, Rubis gets a seat at the Board of Directors of HDF and a position of censor.

HDF also signed partnerships with ABB and Atos for the co-development and industrialisation of carbon-neutral solutions for maritime transport and data centres respectively.

Last but not least, HDF signed partnerships with two leading TSOs (Transmission System Operator), Teréga and Enagas. Their ambition is to develop a common offer for geological energy storage in salt caverns.

Fig. 130: Structuring the green hydrogen ecosystem through partnerships



Source : Bryan, Garnier & Co

The next gen project developer and IPP

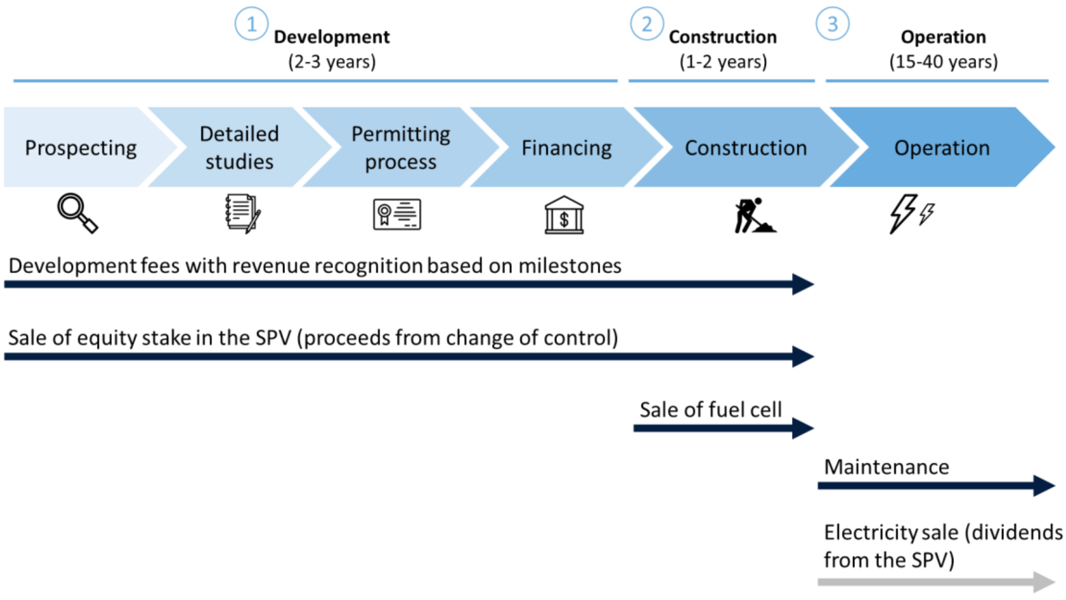
Integrated business model covering the full asset lifecycle

HDF is an electricity producer, developer and owner of hydrogen power projects. The company operates across the entire value chain from project origination to commissioning and maintenance.

Projects in renewables are long-term with multiple steps over several years, each step leading to payment/revenue streams. We have identified three major phases:

- Development: usually lasting two/three years, depending on the complexity and size of the project. In the early stages of the project, HDF manages the prospection, land acquisition negotiations, plant design and permitting process. Once validated, HDF negotiates the PPA or the auction participation as well as financing of the project (structuring of the SPV). During the development phase, HDF sells investors all or part of its stake in the SPV.
- Construction: usually lasting one/two years depending on the size of the project. HDF does not build the plant itself but selects the building contractor, oversees construction and selects the technology providers.
- Operation: once commissioned, the plant can operate between 15 and 40 years and generate revenues from electricity sales, whether under PPA or not. Income resulting from the sale of electricity will flow to HDF in the form of dividends paid by the SPV. HDF is in charge of supervising project maintenance and receives recuring revenue from fuel cell maintenance.

Fig. 131: Project and revenue development timeline



Source : Bryan, Garnier & Co

Revenue generation for HDF can have two different profiles, depending on the project. HDF is always involved in the first and second phases presented above. However, for the third phase (operation), HDF's involvement and future revenue profile will depend on each project.

1/ For best-in class projects, those with the most interesting conditions, HDF will have a significant but minority equity stake in the SPV, hence becoming an electricity producer, generating recurring revenues through electricity sales.

2/ For other projects, those with more limited potential, HDF will limit its involvement to project development and then sell or significantly reduce its equity stake.

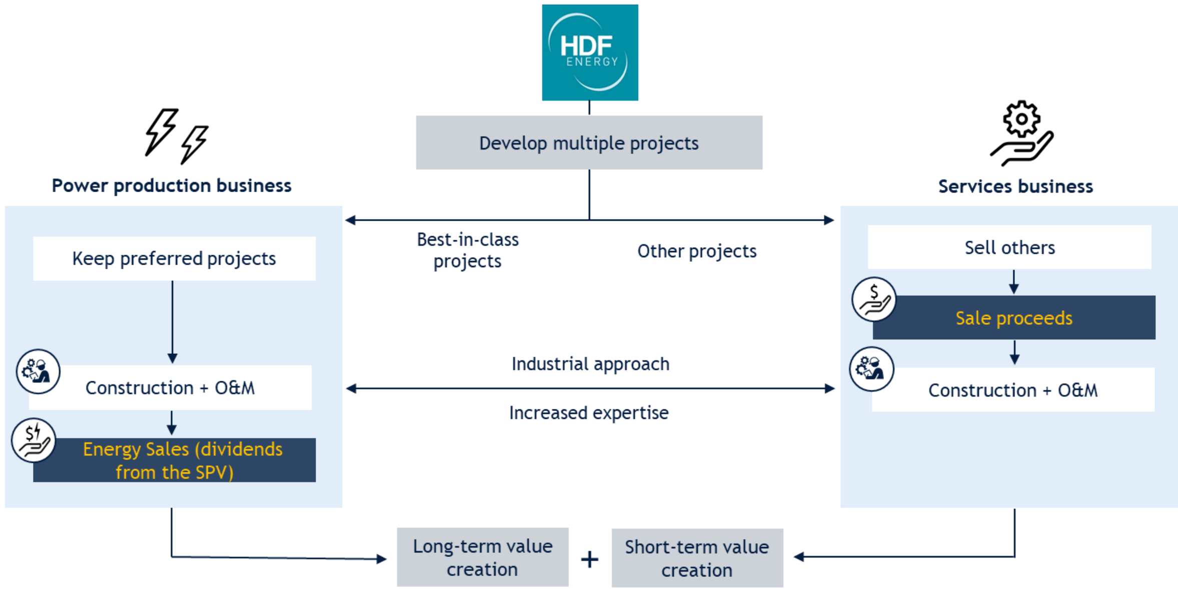
In any case, HDF will be in charge of maintenance, providing additional recuring revenues.

This strategy lowers the capex effort and allows the group to develop more projects with the same "equity firepower". By doing so, HDF mitigates the risk of each project and benefits from industrialisation and scale effects (EPC, O&M, energy management etc.). Moreover, by selling all or part of its equity stake in projects, HDF front loads value creation (sell-down margin).

This strategy is very similar to that of many conventional IPPs (Engie's DBpSO strategy for example). However, we see HDF's positioning in the asset lifecycle as more comprehensive since it also provides the fuel cell, bringing unique integration know-how which is not yet mastered by other IPPs.

We believe that thanks to this business model, HDF will generate both long and short-term value creation for its shareholders.

Fig. 132: Revenue generation model



Source : Bryan, Garnier & Co

Chasing higher return projects

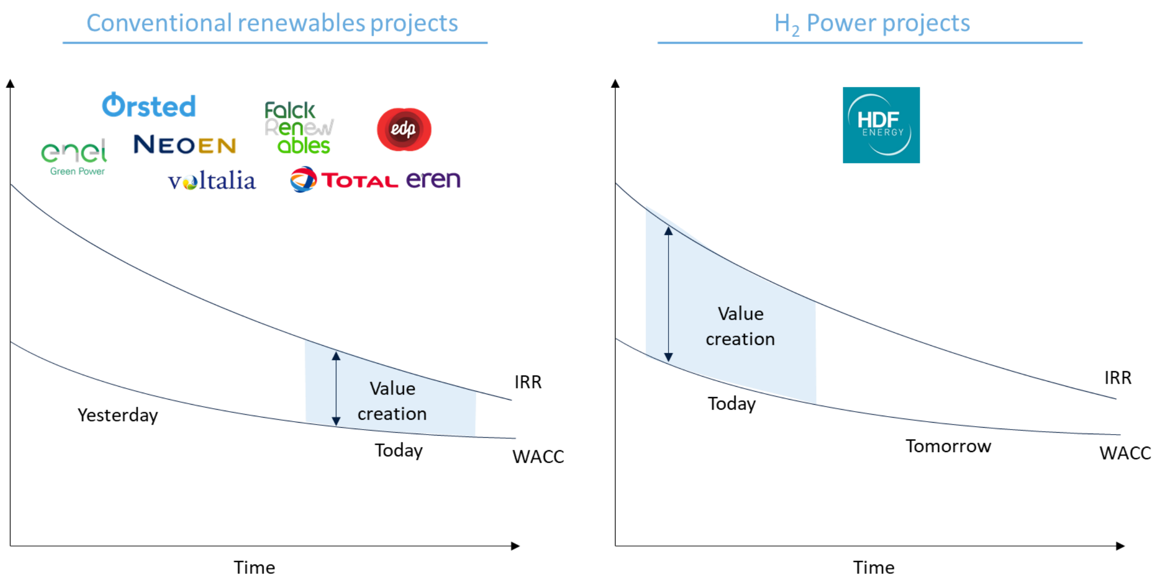
The rapid development of renewables over the past few years has attracted numerous investors and increased competition for new projects, which *in fine* has led to lower returns. This was favoured by the low-risk, bond-like profile of these projects, often backed by PPA, which has attracted investors with low return expectations (pension funds, insurance companies etc.). As a result, renewables are increasingly commoditised and projects now generate limited returns.

In a competitive auction, returns for a conventional project in renewables start at around 5-6% on an equity basis, which is obviously below the cost of equity hence not acceptable. By leveraging the project, its return can be boosted to 8-10%, which is above the WACC hence acceptable but still relatively low.

In contrast, power production from hydrogen is a nascent market, still left behind by conventional IPP. Being the first one to be positioned in hydrogen power projects, HDF operates in an environment with limited competition, hence higher returns. We estimate that HDF is able to achieve a double digit ROE.

Admittedly, hydrogen power projects are less mature and therefore probably deserve a higher WACC (higher risk premium). However, we believe that the spread between IRR and WACC is more attractive for hydrogen power projects than it is for conventional renewable projects, leading to greater value creation.

Fig. 133: HDF is chasing higher return projects



H2 Power projects have the potential to generate higher returns despite higher WACC

Source: Bryan, Garnier & Co

A multi-MW fuel cell technology provider

Unique positioning in the fuel cell ecosystem

HDF is not “just” a project developer and renewable electricity producer. HDF is also a multi-MW fuel cell technology provider.

There are several types of fuel cell technologies available: PEM, alkaline, phosphoric acid, direct methanol, solid oxide and molten carbonate. All these technologies have their preferred application but PEM is the most relevant for transport applications.

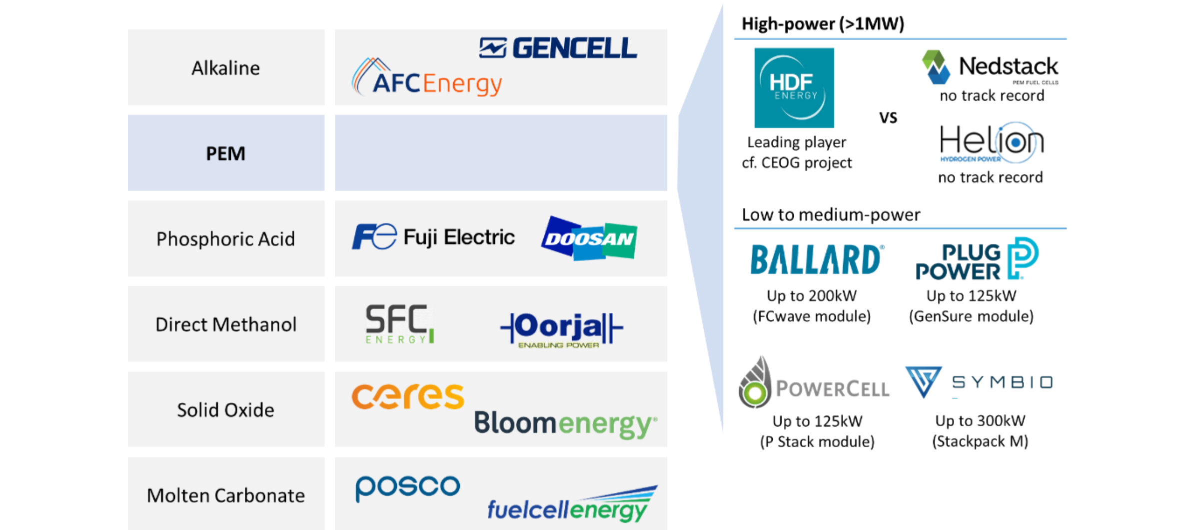
Fig. 134: Different fuel cell technologies

Technology	Advantages	Weaknesses	Application
Alkaline	- Quick start - Low parts and operating costs	- Sensitive to impurities	- Aerospace - Military
PEM	- Quick start - High energy density - Operating life	- Sensitive to impurities - Complex heat and water control	- Transport
Direct Methanol	- Easy fuel storage - Compact design	- Slow response - Low energy efficiency	- Portable
Solid Oxide	- Fuel flexible - High energy efficiency	- High heat causes corrosion affecting the lifespan - Long pre-heat time	- CHP - Power generation
Phosphoric Acid	- Insensitive to CO2	- Low energy efficiency - Long pre-heat time	- CHP - Power generation
Molten Carbonate	- Fuel flexible - High energy efficiency	- High heat causes corrosion affecting the lifespan	- CHP - Power generation

Source : Bryan, Garnier & Co

HDF's positioning is quite unique. The company is developing high-power (>1MW) PEM fuel cells while most players are positioned in low to medium-power fuel cells (≈ 100-150kW). We have identified Nedstack and Helion (Alstom) as two potential competitors in multi-MW PEM FC but their credibility is limited as they have no real track record.

Fig. 135: Fuel cell ecosystem



Source : Bryan, Garnier & Co

Leveraging the expertise of the automotive industry

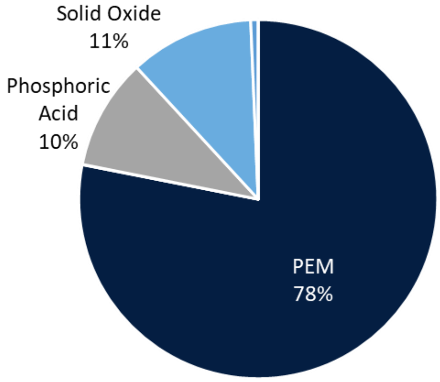
As already mentioned, HDF is positioned in the PEM technology, which is better suited to transport applications. Admittedly, power generation for the grid is all but a mobility application. So why use PEM instead of solid oxide for example?

Today, PEM is the dominant fuel cell technology thanks to its:

- good energy efficiency,
- quick start (no pre-heat time),
- high energy density/compact design, and
- long operating life.

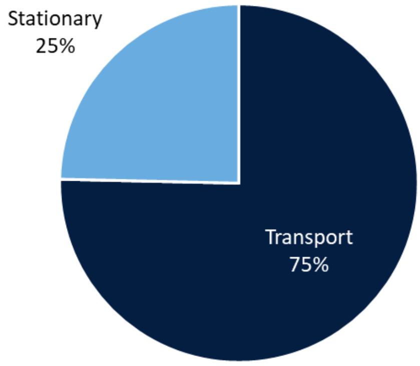
In 2020, PEM fuel cells represented almost 80% of the market in terms of MW and 75% in terms of units.

Fig. 136: Market by technology (MW)



Source: E4tech "The fuel cell industry review", 2020

Fig. 137: Market by application (MW)



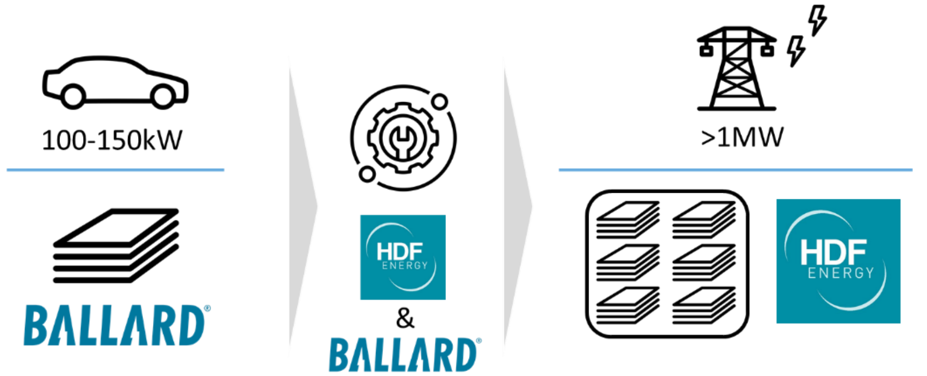
Source: E4tech "The fuel cell industry review", 2020

Since PEM is the preferred technology for transport applications, which are the most developed today, it is benefiting from all R&D efforts made by the automotive industry. However, automotive applications require fuel cells with relatively limited power, around 100 kW, while stationary applications require powers above 1 MW.

Since no PEM stacks exist with enough power for stationary applications, HDF as decided to use existing automotive stacks as a building block for MW-scale systems. Stacks will be assembled to reach a sufficient power output. While this sounds easy, it requires significant engineering expertise. The balance of plant (auxiliaries of fuel cell) must be specifically designed and assembled for this purpose.

Ballard is the world's leader in PEM fuel cells but since its strategy is to focus on transport applications (low to medium power) it decided to give HDF a worldwide exclusive license for power generation applications. The two groups are working together on the development of a multi-MW PEM fuel cell for power generation applications.

Fig. 138: From transport to power generation



Source : Bryan, Garnier & Co

CEOG: the first Renewstable project

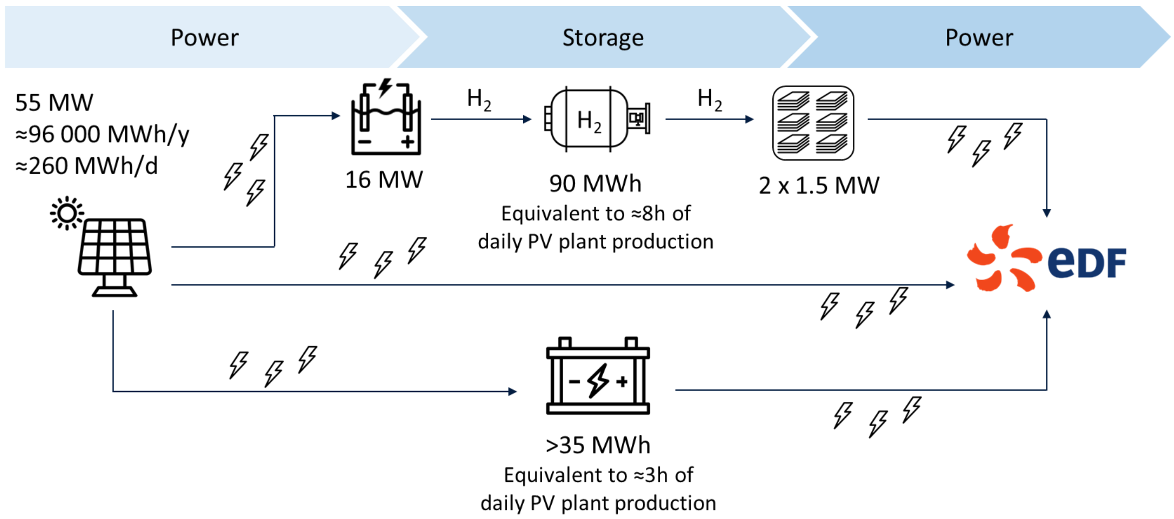
HDF's first Renewstable project

CEOG (Centrale Electrique de l'Ouest Guyanais) is an innovative multi-MW power plant designed to produce non-intermittent and clean electricity for 10,000 homes in the north west region of French Guiana. CEOG combines a PV plant with mass storage of energy in the form of hydrogen and batteries. The plant is a good alternative to conventional but highly polluting thermal power plants. With this project, HDF is introducing the concept of non-intermittent but renewable power: a Renewstable® project.

CEOG targets power production of 50 GWh each year. Fully replacing this production with conventional diesel generators would require estimated capacity of around 10 MW. Based on the technical factsheet of diesel generators (Caterpillar), we have calculated that around 13,000,000 litres of diesel would probably be required; around 500 tanker trucks per year would be required to supply such quantities of diesel, which is complex in terms of supply chain and very expensive.

Note that CEOG is the world's first utility-scale power-to-power project using hydrogen. The electricity injected into the grid is competitive even without subsidies. CEOG will be a flagship project for HDF to demonstrate its know-how and win future tender offers.

Fig. 139: CEOG project components

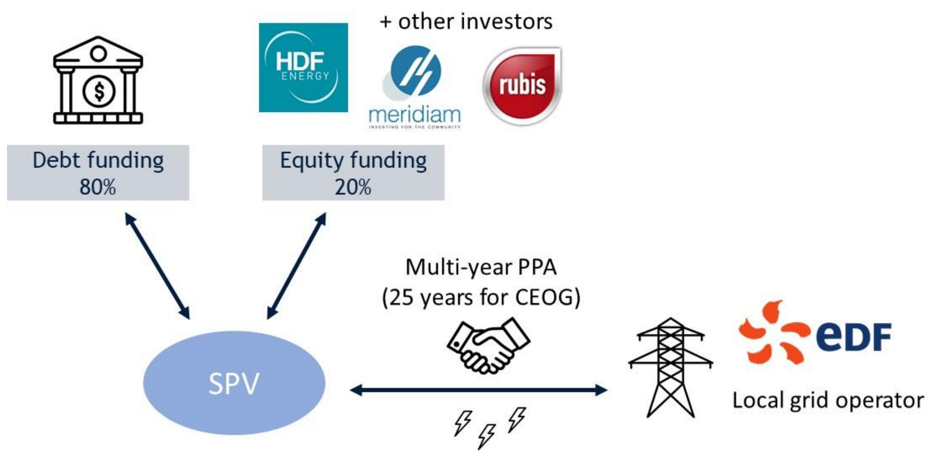


Source : Bryan, Garnier & Co

Beyond demonstration of the project's technical and cost competitiveness aspects, CEOG is a good example of the contractual structure of a Renewstable project.

For each and every project, HDF will establish an SPV; a project-specific company that will develop and operate the power plant. SPVs are ring-fenced vehicles commonly used to develop large projects while avoiding betting the entire company on the success or failure of a single project. Renewable power production projects tend to be highly leveraged and companies prefer not to have such high leverage affect their primary corporate balance sheet. Each SPV can be financed appropriately with the right ratios and sources of debt and equity. Note that the CEOG project was financed with the exact same structure as conventional renewable projects (80% debt + 20% equity), thereby demonstrating its maturity. Last but not least, SPVs facilitate asset transfer and property sales, making it easier for HDF to increase or reduce its stake in a project, depending on its strategy.

Fig. 140: CEOG - SPV structure



Source : Bryan, Garnier & Co

For a project like CEOG, HDF's revenues will stem from:

- project development fees (fixed and variable),
- the sale of its multi-MW fuel cells,
- supervision and fuel cell maintenance contracts,
- dividends paid by the SPV and,
- the sale of its stake in the SPV (proceeds from project change of control).

Strong pipeline of projects

CEOG is a flagship project for HDF as it will demonstrate its know-how and establish a track record that will be useful for winning future tender offers.

HDF already has several projects in the pipeline, representing more than EUR1.3bn in project capex. The development process is already ongoing for these projects, whether in terms of the permitting process, feasibility studies or SPV creation. The projects are set to integrate a total of around 60 MW of fuel cells.

Fig. 141: Pipeline of Renewstable projects

Project Name	REN capacity	Electrolyzer	Fuel cell	Battery storage est.	H2 storage est.	Financial closing est. date
Baja California	150 MW of PV	40 MW	9 MW	90 MWh	240 MWh	2022
Barbados	52 MW of PV	15 MW	3 MW	30 MWh	80 MWh	2022
French Guiana #2	120 MW of PV	30 MW	10 MW	70 MWh	190 MWh	2023
Cyprus	80 MW of PV	20 MW	6 MW	50 MWh	130 MWh	2023
Australia	31 MW of PV	12 MW	4 MW	20 MWh	50 MWh	n.m
New Caledonia	160 MW of PV	80 MW	20 MW	100 MWh	260 MWh	2024
Indonesia	100 MW of PV	35 MW	8 MW	60 MWh	160 MWh	n.m
Total	**693 MW of PV**	**232 MW**	**60 MW**	**420 MWh**	**1110 MWh**	

Sources : Bryan, Garnier & Co, HDF

We estimate these projects to represent around EUR1.3bn in project capex, potentially resulting in around EUR190m in revenue for HDF, a significant part of it is coming from the sale of fuel cells ; around EUR90m (≈50%). These estimates don't include additional revenues from maintenance operations and dividends paid by the SPV.

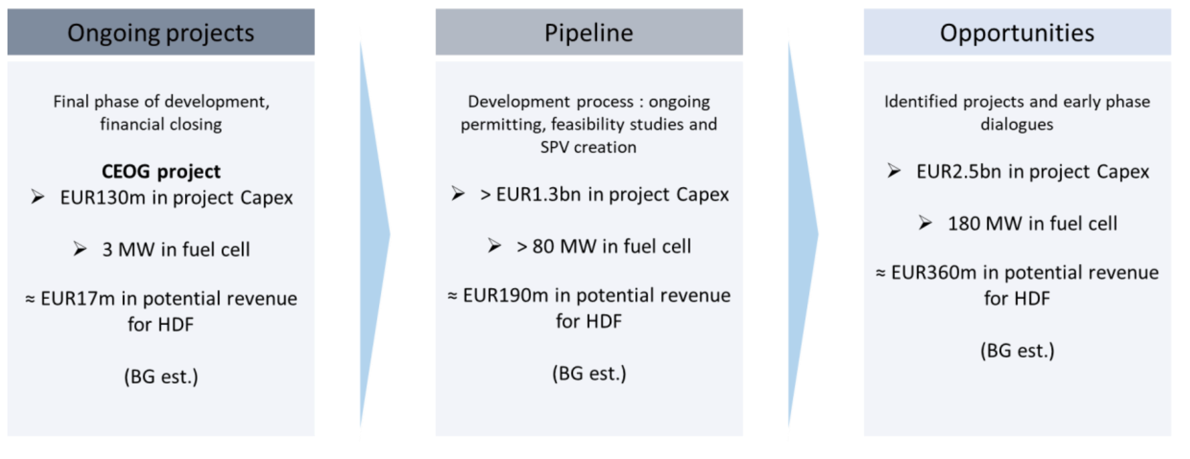
Fig. 142: Estimated capex and revenues from Renewstable projects

Project Name	Capex est.	HDF rev. est.	ow/ FC sale
Baja California	[220-240]	33	14
Barbados	[90-110]	15	5
French Guiana #2	[190-210]	29	15
Cyprus	[130-150]	20	9
Australia	[80-100]	13	6
New Caledonia	[270-290]	41	30
Indonesia	[250-270]	38	12
Total (EURm)	**1 300**	**189**	**90**

Source : Bryan, Garnier & Co

In addition to these projects, HDF has also identified project opportunities representing EUR2.5bn in project capex and 180 MW of fuel cells. These projects are at an earlier stage of development, they have just been identified or are still in the early phase of dialogue. We estimate this pipe of opportunities to represent around EUR360m in potential development fees for HDF, half of which could come from the sale of fuel cells.

Fig. 143: Renewstable pipeline and opportunities



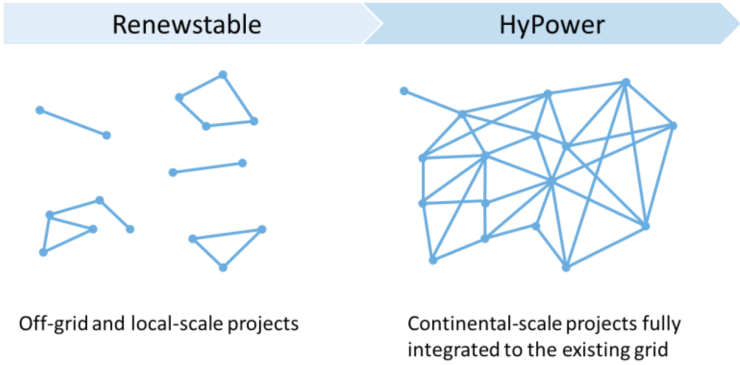
Source : Bryan, Garnier & Co

Hypower: the next step after Renewstable projects

Renewstable are just the first step towards greater integration of renewables

We consider Renewstable projects as being just the first step towards greater integration of renewables in the energy mix. Indeed, Renewstable projects like CEOG address the challenge of integrating renewables at a local or regional scale, most of the time in an off-grid context. In contrast, Hypower projects will address the challenge of integrating renewables on a national or global scale, fully integrated into the existing electricity grid.

Fig. 144: From local to continental-scale projects



Source: Bryan, Garnier & Co

While renewable energy sources are globally available, they are not evenly distributed, some regions benefit from better conditions. Obviously, in North Africa, solar energy resources are more abundant than in Northern Europe. It also means that these regions can produce cheap renewable electricity.

The good renewable energy resources in Europe, North Africa and the Middle East are often located far from the energy demand of industrial sites and cities. Hence, the challenge is to transport and store this energy at low cost and losses, from the sunny/windy places to the energy intensive areas.

Conversion of solar and wind electricity into hydrogen offers a solution to this challenge. Indeed, transport and storage costs for hydrogen are significantly cheaper than for electricity. Hydrogen transport costs by pipeline are about 10-20 times cheaper than electricity transport by a cable. It is estimated that the cost to transport hydrogen by pipeline is around EUR0.2/kg of hydrogen, or EUR5/MWh, which is reasonable.

Moreover, a fundamental difference between electricity transport by cables and hydrogen transport by pipelines is the capacity of the infrastructure. An electricity transport cable has capacity between 1-2 GW, while a hydrogen pipeline can have a capacity between 15 and 30 GW.

Hydrogen can already be blended at low percentage with natural gas and efficiently be transported through existing pipelines. Transport of pure hydrogen will however require some adaptations (new compressors, distance between compressors, new coating…).

Regional networks are already emerging

Pure hydrogen pipelines are already a reality. These are small-scale dedicated networks to transport “grey” hydrogen between industrial clusters. They are mostly operated by private hydrogen producers. However these networks demonstrate that hydrogen transport over long distance is possible and safe.

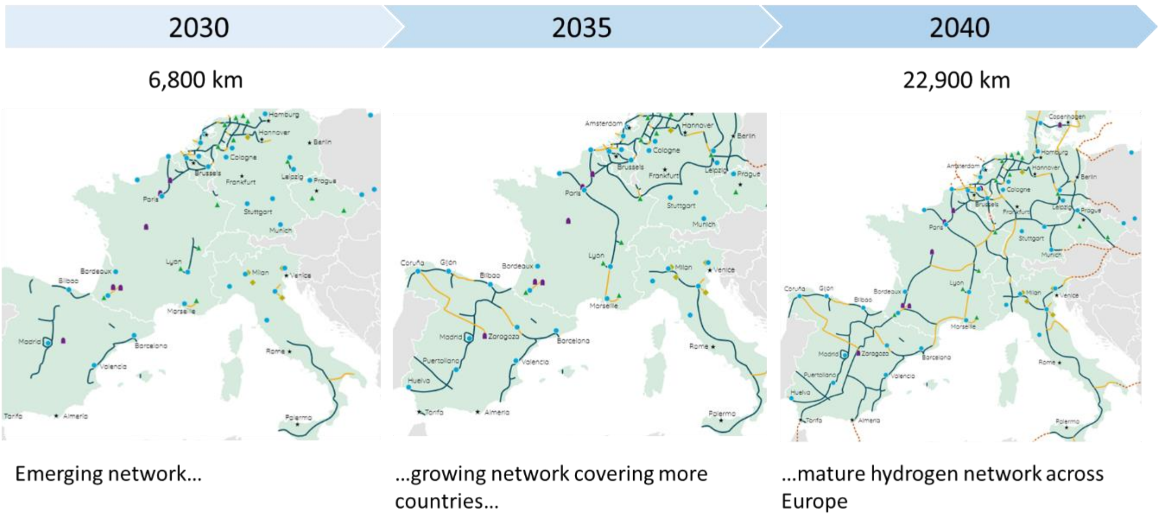
We expect the development of a large-scale European hydrogen network to take place in three different steps. By 2030, regional networks will emerge, connecting industrial clusters to an emerging infrastructure. This network is expected to reach 6,800 km in 2030 compared with around 1,600 km today. It will be concentrated in the Netherlands and Germany with branches extending into Belgium and France. At the same time, unconnected regional networks are likely to emerge in Italy, Spain, Denmark, France and Germany.

The Netherlands is a good location to start the construction of a European hydrogen backbone. Indeed, Groningen, the biggest gas field in Europe and 10-largest in the world, is located in the Netherlands. However, after decades of exploitation and in order to limit seismic risks, the Dutch state announced in 2019 that output at Groningen would end by mid-2022. The country benefits from an established gas infrastructure and has the opportunity to leverage it by retrofitting the pipes to transport hydrogen.

Then, between 2030 and 2035, the network will significantly expand to cover more countries and link sources and sinks across Europe. Its development will be enabled by the continued scale-up of renewables and the deployment of electrolysers. As a reminder, the European Commission is targeting 2 x 40 GW of electrolysers by 2030. By 2035, infrastructure should be relatively well deployed in Northern Europe thanks to abundant offshore wind resources. This should also pave the way for a connection with southern Europe and North Africa through Spain and Italy.

In 2040, a pan-EU backbone will stretch in all directions with a length of almost 23,000 km. Whereas the hydrogen backbone predominantly serves industrial demand in the early 2030s, the latter part of the decade will also see hydrogen become a significant energy vector. Green hydrogen sources will be a source of cheap wind energy resources from the North Sea and cheap solar energy from Southern Europe and North Africa.

Fig. 145: Gradual creation of a dedicated hydrogen infrastructure



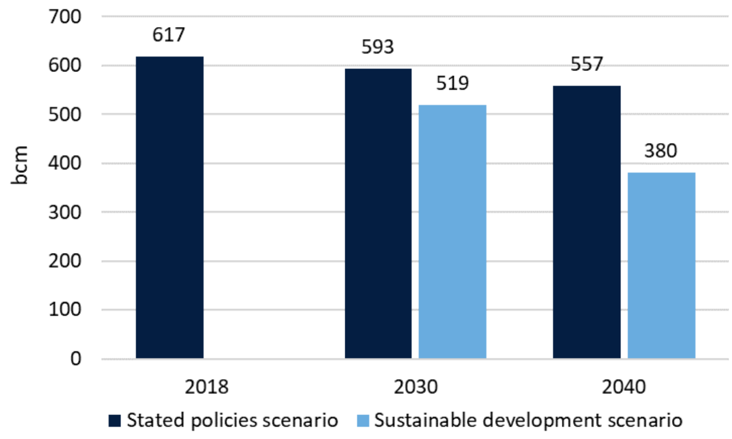
Sources: Bryan, Garnier & Co, European Hydrogen Backbone initiative

The construction of this network is estimated to require an investment of EUR27-64bn, which is relatively reasonable ; for comparison purposes, France, Germany, Spain, Portugal and the Netherlands have pledged to invest around EUR42bn to develop green hydrogen production.

This network could be deployed relatively quickly as it will consist of 75% retrofitted pipelines. Combined with a fit-for-purpose compression system, the network should be able to meet currently expected annual hydrogen flow in Europe by 2040.

Numerous Transmission System Operators (TSO) like Fluxys, Teréga, GRTgaz or Enagas are supporting the initiative of creating a European hydrogen backbone. Indeed, the development of a dedicated hydrogen infrastructure is crucial for the future of these players as it will coincide with the decline in natural gas demand partly due to the electrification of heat in buildings. TSOs need to find new opportunities to continue to grow and maintain gas volumes in their pipelines, whether hydrogen or natural gas.

Fig. 146: Demand for natural gas in Europe is expected to decrease



Sources: Bryan, Garnier & Co, IEA

HDF will plug its fuel cells into the pipes

HDF a service provider of capacity and flexibility

As the existing natural gas infrastructure is transitioning towards the deployment of hydrogen pipelines, HDF will deploy its multi-MW fuel cells to produce electricity on demand.

Compared with Renewstable projects, the positioning of HDF and its SPV is a bit different since it is not an isolated IPP in a monopolistic position. HDF and its SPV are now part of a broader, fully integrated electricity network. Hence, its electricity sales, while also backed by PPAs, can be subject to the rules of the merit order scheme. This point is further detailed in the next section, but it implies that HDF has the opportunity to provide capacity and flexibility services in addition to electricity sales.

Being part of a fully integrated electricity network also means greater competition and lower prices. Of course, it is not reasonable to expect baseload electricity prices as high as in Renewstable projects. However, given increasing intermittency of the electricity mix, capacity reserve contracts can generate good returns. In other words, with capacity reserve contracts, the SPV can make money from maintaining available production capacities that may never be called into action.

While the positioning is a bit different between Renewstable and HyPower projects, the business model is broadly the same and the sources of revenues for HDF are similar. Revenues will come from a combination of :

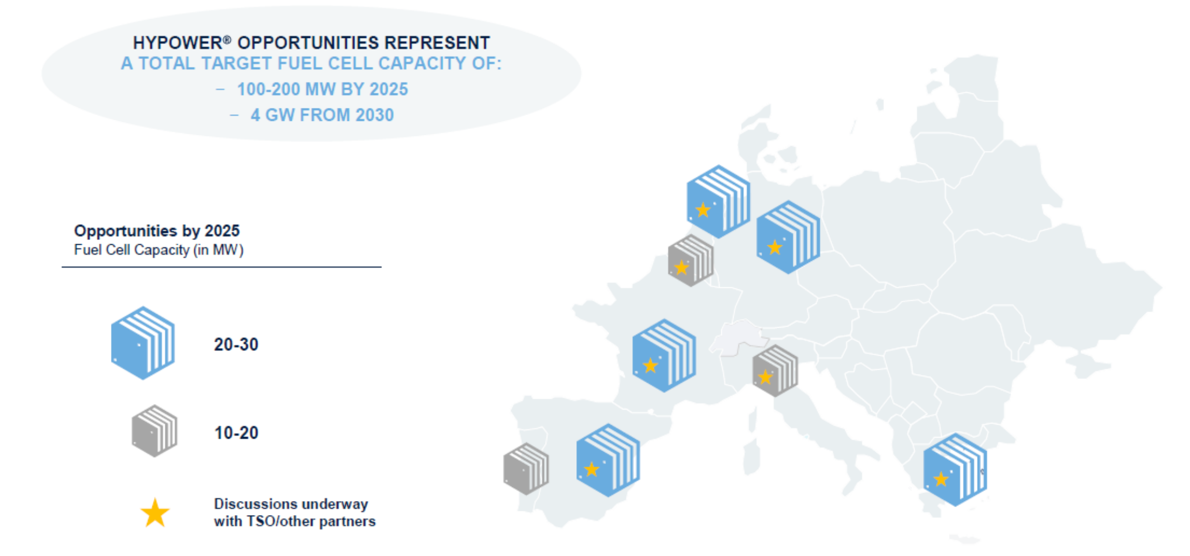
- project development fees (fixed and variable),
- the sale of its multi-MW fuel cells,
- maintenance contracts,
- dividends paid by the SPV and,
- the sale of its stake in the SPV (proceeds from project change of control).

The other difference between Renewstable projects and HyPower projects is the amount of revenues as a percentage of project capex. For HyPower projects, this percentage is far more significant since revenues represent around 70% of project capex vs around 15% for the Renewstable project.

The difference comes from the greater importance of sales of fuel cells in HyPower projects. Indeed, a Renewstable project integrates both PV panels and/or wind turbines, electrolysers, energy storage systems (batteries and hydrogen tanks) and fuel cells. Of all these elements, HDF only supplies the fuel cell. In contrast, in a HyPower project, the fuel cell is the only element and it is supplied by HDF, hence its more significant weight.

HDF has already identified numerous opportunities for HyPower projects. By 2025, 100 to 200 MW of fuel cell could be installed. By 2030, the pipe of opportunities could reach 4 GW, which sounds achievable when compared with the 2 x 40 GW of electrolysis capacity targeted by the European Commission.

Fig. 147: HyPower opportunities



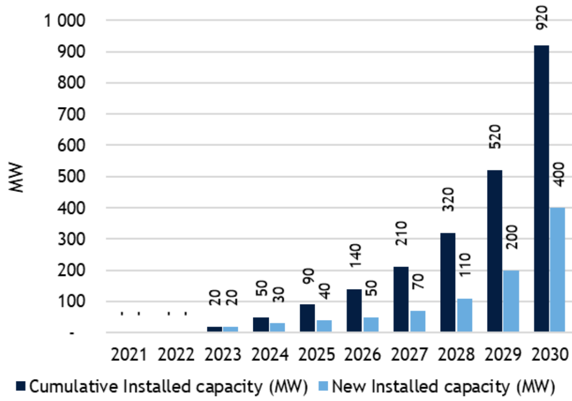
Source: HDF

In the first phase, we expect HDF to install a handful of relatively small systems, around 10 MW each. Then, from 2030, the number of projects should accelerate as well as their size. HDF's ambition over the long term is to install systems with a capacity of 100 MW+.

With around 90 MW of fuel cell capacity installed by 2025, we estimate that HDF as the potential to generate revenue of around EUR80-90m in 2025. A significant part of this revenue would come from the sale of fuel cells at around EUR60m.

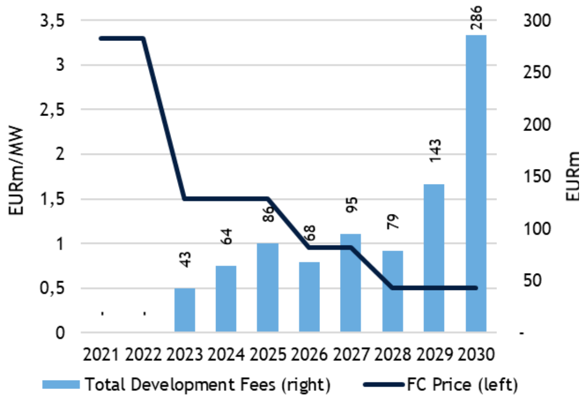
By 2030, the installed base of fuel cells could reach 920 MW, representing around EUR290m in potential revenue for 2030, of which around EUR200m would come from the sale of fuel cells. While HDF is a pioneer in this market, we expect new players to enter by 2030. Hence, HDF will only capture a fraction of this market, which is still very attractive although it is probably too early to make assumptions concerning market shares.

Fig. 148: Installed capacity



Sources: Bryan, Garnier & Co, HDF

Fig. 149: FC cost and revenue opportunity



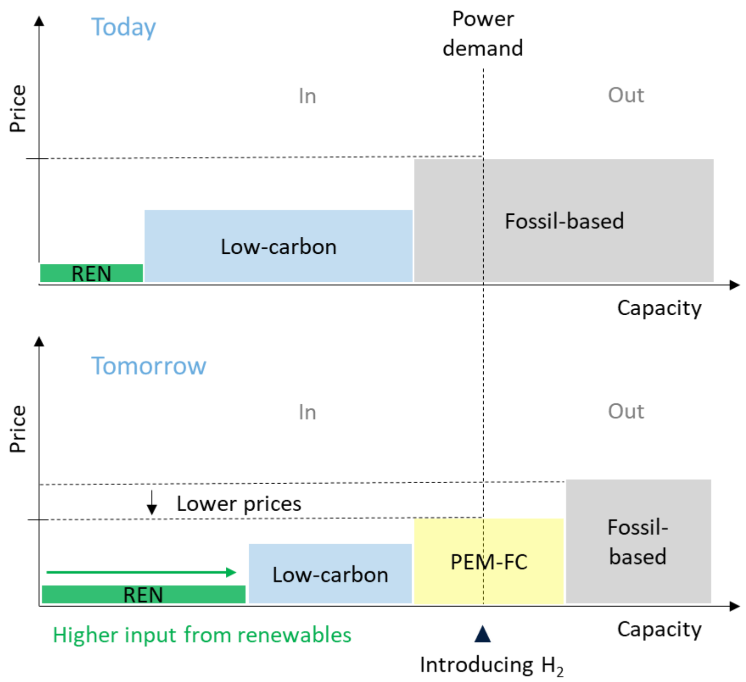
Sources: Bryan, Garnier & Co, HDF

Multi-MW fuel cells are the new thermal power plants

In the electricity market, power prices are determined by the "merit order", the sequence in which power plants contribute to the market, with the cheapest marginal cost setting the starting point. Power from renewable installations have almost no marginal operating cost and therefore enter first, lowering the entrance price and gradually pushing expensive conventional producers down the merit order.

Power stations with high generation costs such as gas-fired and coal-fired plants are vulnerable to being pushed out of the market. However, their production capacities remain crucial for the energy market as they are non-intermittent and able to satisfy peak demand since they bring stability and flexibility to the grid and therefore contribute to the rollout of renewables. We see several groups like Engie repositioning their thermal portfolio accordingly.

Fig. 150: Multi-MW FC to replace gas-powered plants in the merit order scheme

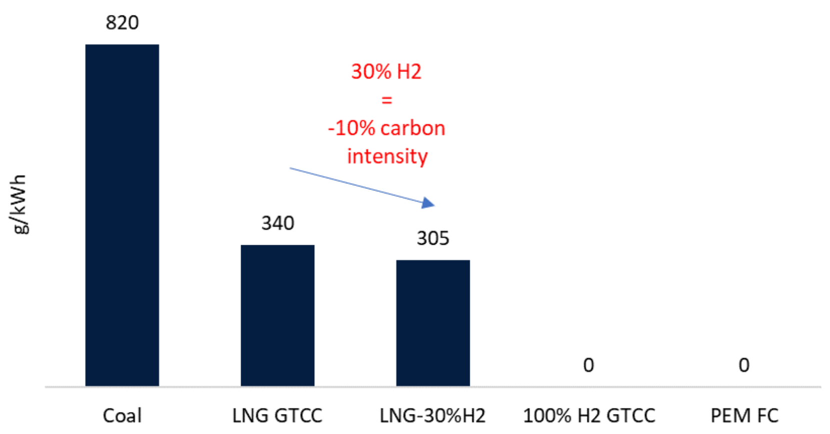


Source: Bryan, Garnier & Co

Coal and natural gas are flexible and efficient fuels that are easy to store and transport for use when needed. Hydrogen benefits from the same characteristics so it can be used to provide on-demand electricity. However, hydrogen also benefits from a cleaner environmental footprint, is not affected by rising carbon credit prices and can therefore be more competitive. We consider multi-MW fuel cells as the new thermal power plants.

Switching from coal to natural gas reduces carbon intensity by almost 60% per kWh produced. The next step could be to mix natural gas with hydrogen to further reduce carbon intensity. However, the introduction of 30% of hydrogen in the mix only reduces carbon intensity by an additional 10%. A 10% reduction is quite limited compared with the proportion of hydrogen in the mix (non-linear). To really achieve a deep cut in emissions, the percentage of hydrogen needs to be increased to 100%.

Fig. 151: CO2 emissions (g/kWh) – coal vs natural gas vs hydrogen



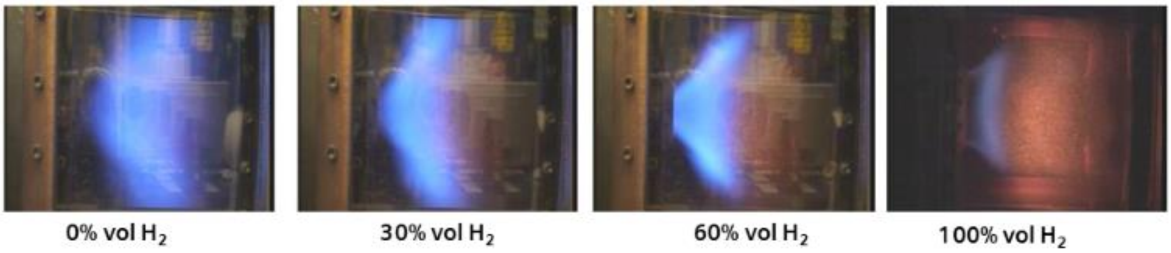
Sources: Mitsubishi Power, Bryan, Garnier & Co

Adapting gas turbines might not be sufficient – switch to fuel cells

If we consider multi-MW hydrogen fuel cells as the new gas-powered plants/turbines, then it is worth comparing the two solutions and seeing if the switch is really feasible. Can existing gas turbines simply be adapted to work with hydrogen?

Adapting or retrofitting existing natural gas turbines is not so easy. Indeed, hydrogen combustion is different to that of natural gas. The physics of hydrogen, its diffusivity and its reactiveness are different. This leads to a different sort of combustion dynamics and combustion characteristics.

Fig. 152: Comparison of natural gas and hydrogen flames



Source: Siemens

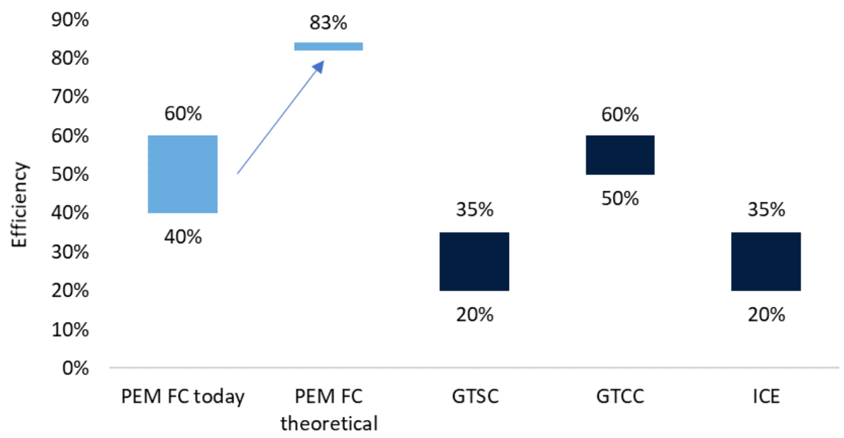
According to Siemens Energy, for up to 15% of hydrogen in the mix, no major modifications are required. Between 15 and 30%, the gas turbine must be upgraded/slightly modified. Up to 50-70%, special adjustments around the burner are required. Then, to use only pure hydrogen, a whole new burner/turbine must be developed.

Siemens Energy and GE are trying to leverage their existing portfolio of gas turbines and develop new burners, designed to optimise hydrogen combustion. Is this the best solution? Is it enough to adapt existing technologies (turbines) or is it necessary to adopt a new solution (fuel cells)?

Today, PEM fuel cells are generally 40-60% energy efficient. This range compares to 20-35% for simple-cycle gas turbines (GTSC) and 50-60% for combined-cycle gas turbines (GTCC). The US Department of Energy anticipates future hydrogen combined cycle turbines to reach 60%. Efficiency for the internal combustion engine (ICE) of a car is generally around 20-35%.

Today, we see no big difference in terms of efficiency between turbines and fuel cells but the latter are less mature and probably still have significant room for improvement. Theoretical energy efficiency of a fuel cell is 83% so we consider them a very credible option for the future. Moreover, contrary to gas turbines, there are no moving parts in fuel cells, making them highly reliable with lower maintenance.

Fig. 153: Comparison of energy efficiency



Sources: Bryan, Garnier & Co, U.S. Department of Energy, Plug Power, Wartsila

A plant to back the supply chain and address new opportunities

A EUR20m investment in manufacturing capacities

In April 2021, HDF announced that it will install its fuel cell manufacturing plant in France, on the ex-Ford Blanquefort site near Bordeaux. HDF was awarded the location by local authorities after a call for expressions of interest in order to revitalise the abandoned industrial site.

HDF is set to invest EUR20m to build the plant, which will have a capacity of 100 MW/year (long-term target), equivalent to 60-70 fuel cells (1.5 MW each). We believe this capacity is enough to cover HDF's roadmap over the next few years. The plant will assemble fuel cell systems based on Ballard's technology. It should open in 2023 and create a hundred jobs.

Fig. 154: **Location of the plant**

Source: Google Maps

Fig. 155: **Illustration of the factory**

Source: HDF

A defensive move

As already mentioned, HDF's multi-MW fuel cell is based on Ballard's stack technology. At first sight, this could suggest some sort of dependency issue and a lack of proprietary technology. However, we do not consider this element as an issue but more as a defensive move for several reasons:

- It significantly reduces execution risks by leveraging the experience of a world leading player. Ballard has a solid track record having begun working on the development of PEM fuel cells as soon as 1983 (38 years ago).
- Ballard's existing stacks provide long-term competitive advantages thanks to access to engineering support and ability to capture purchasing savings.
- It improves commercialisation timeline and penetration of markets by using existing products. Potential customers are always more confident in project developments that use seasoned components.

Furthermore, HDF will use Ballard's stacks for its Generation 1 systems but could integrate other stacks from other suppliers for its second and third generations. Ballard was an obvious choice to begin with since the company is considered as the most advanced player with cutting-edge technology and a strong track record. However, significant investments are currently being made in R&D for PEM fuel cells. Companies like Plug Power, Symbio or PowerCell Sweden have also raised a significant amount of capital and will probably intensify their R&D efforts. Hydrogen is a rapidly evolving sector so we do not rule out that, despite Ballard's current competitive advantage, new stacks could become more interesting to integrate.

Investing in proprietary assembling capacities is also a must-have for HDF because there is currently no other company with the capacity to supply these multi-MW fuel cells. We have identified some players that are currently developing multi-MW systems but they are still early-stage, have no real track record and no manufacturing capacities. Hence, outsourcing production of this element is not an option for HDF.

Should another company, develop multi-MW PEM fuel cells in the future, we believe that having its own assembling capacities is in any case a better option. Indeed, as the market is expected to experience very strong growth we do not exclude bottlenecks in the supply chain.

Leveraging the technology to address new markets and reduce costs

As already mentioned, the electricity produced from hydrogen through fuel fuels is still expensive and not competitive in several markets. To address this issue and accelerate market penetration, HDF must drastically reduce its production costs. As for many industries, economies of scale and higher production volumes are key cost-cutting drivers. Hence, HDF must find new business opportunities to fill up its factory.

To do so, HDF will leverage its partnerships with Atos and ABB to address the shipping and data centre markets. We detail these additional opportunities in the next sections.

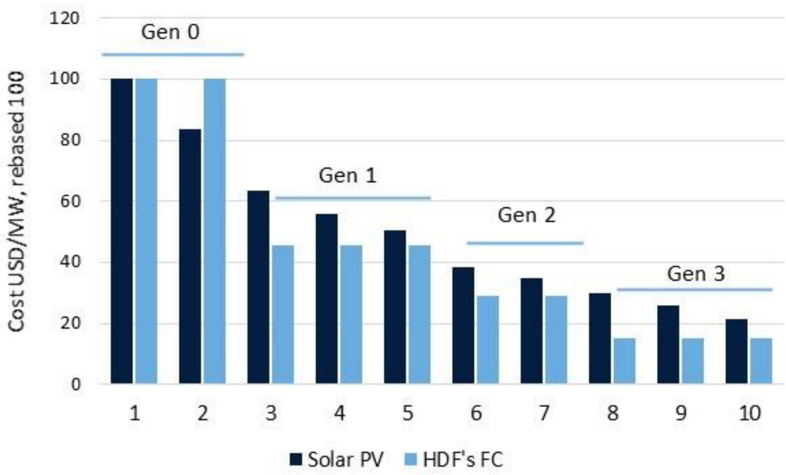
At first sight, it is easy to think that HDF could be trying to compete on too many markets at the same time. With more than one iron in the fire, the risk of over-dispersion and failure is greater. In reality, however, this is another defensive move since HDF must address multiple markets in order to quickly increase its production volume, reduce costs and make its multi-MW fuel cells competitive.

Moreover, the strategy is relatively safe since ABB and Atos are well established players in their respective markets and the marketing effort is much easier. Addressing these markets alone would have been risky but this is not HDF's strategy.

Cost reductions will not only stem from higher volumes but also from the development of new generations of fuel cells. We expect HDF to bring out a new generation of its system every three years, each bringing improved performances with higher efficiency, a longer lifetime and better resilience to hydrogen purity etc.

Today, we estimate HDF's system to cost around EUR3.5m/MW. This cost should sharply decrease to less than EUR0.5m/MW by 2030 (-85%). While this might sound aggressive it is not and is actually fully in line with the trend already observed on PV panels over the past decade: between 2010 and 2019, the total installed cost of PV panels decreased from USD4.7m/MW to less than USD1.0m/MW (-79%).

Fig. 156: Expected cost reduction in HDF's fuel cells vs effective cost reduction of PV panels



Sources : Bryan, Garnier & Co, IRENA

Making data centres more sustainable with Atos

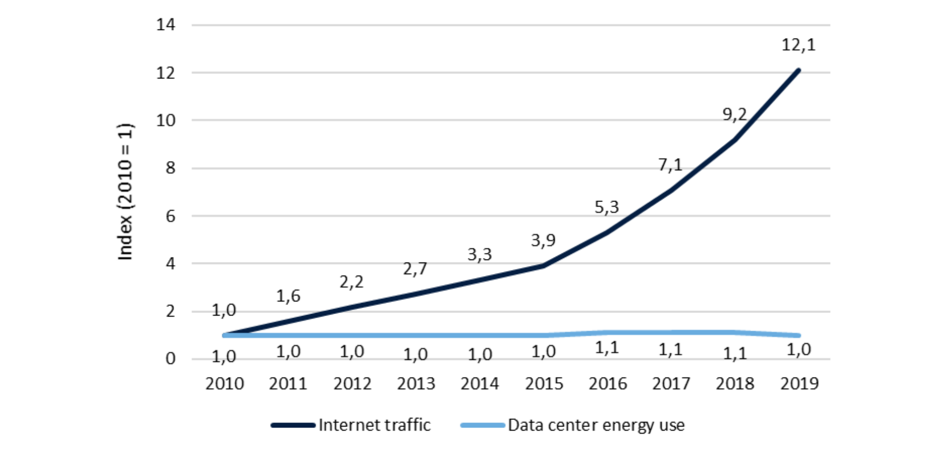
Global internet traffic is a significant source of electricity demand

Data centres are a significant source of electricity consumption, representing around 200 TWh or 1% of global electricity use in 2019. For comparison purposes, in 2019, EDF's nuclear output in France was around 380 TWh.

The energy required to power one Google search is estimated to be the equivalent of powering a low energy (10 watt) light bulb for around two minutes. (With the amount of research we did to write this report, we could have lit up the Eiffel tower instead). Browsing Google is fairly data-light but streaming video through the internet is more data/energy-consuming.

Global internet traffic has increased exponentially over the past few years, driven by ever-growing demand for video streaming, video conferencing, online gaming and social networking. This trend accelerated during the Covid-19 crisis with demand for data services rising by 40% between February and mid-April 2020. Between 2010 and 2019, global internet traffic increased by a factor of 12, or around 30% per year! In the meantime, data centre energy use was broadly flat thanks to better efficiency of hardware and data centre infrastructure. According to the IEA, if current trends are maintained, energy demand from data centres could remain nearly flat through 2022, despite a 60% increase in service demand.

Fig. 157: Global trends in internet traffic and data centre energy use



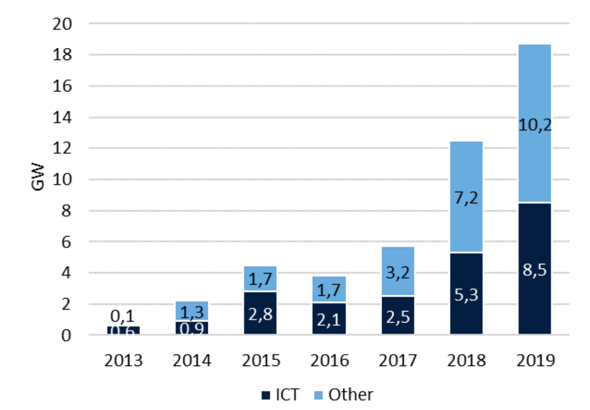
Sources : Bryan, Garnier & Co, IEA

While their consumption is broadly flat, data centre operators remain big electricity consumers.

Information and communication technology (ICT) companies like Google, Facebook, Amazon and Microsoft are major investors in renewable energy, protecting themselves from volatile power prices, reducing their environmental impact and improving brand reputation. Indeed, ICT companies accounted for about half of global corporate renewables procurement over the past five years.

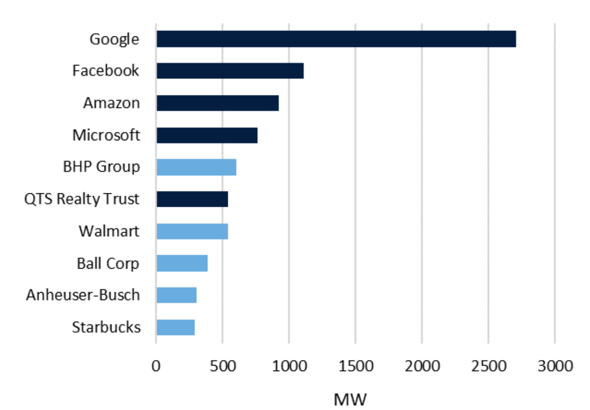
In 2019, the top four corporate off-takers of renewables were all (ICT) companies, Google being first.

Fig. 158: Global PPA volumes by sector



Source: IEA

Fig. 159: Top corporate off-takers, 2019



Source: IEA

Diesel generators are a hurdle to the development of future data centres

Matching 100% of annual demand with renewable energy is challenging since wind and solar are variable sources of electricity whereas data centres cannot afford any power outage and must be available 99.999% of the time.

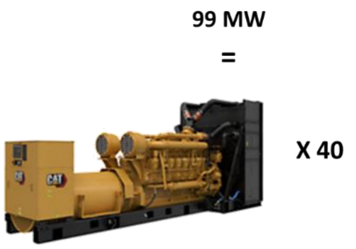
Today, most of the required power is supplied by the centralised electricity grid and backed by diesel generators. Microsoft, for example, has proposed a 99 MW diesel-backup system for a new data center in San Jose, California — one of seven co-location and enterprise data centre projects, totalling roughly 650 MW of diesel backup, that is under review at the California Energy Commission. The negative environmental impact of these gensets is obviously not compliant with climate and air quality policies.

Fig. 160: Proposed backup generation at Silicon Valley data centres

Data center facility	Ultimate Owner	City	Diesel backup (MW)
Great Oaks South	Equinix Inc.	San Jose	99
Laurelwood	Edgecore Internet Real Estate LLC	Santa Clara	99
McLaren	Vantage Data Centers LLC	Santa Clara	99
Mission College	Oppidan Investment Co.	Santa Clara	78
San Jose City	Microsoft Corp.	San Jose	99
Sequoia	CyrusOne Inc.	Santa Clara	96
Walsh	Digital Realty Trust Inc.	Santa Clara	80

Sources: California Energy Commission, The Climate Group, companies | Data as of May 12,2020

Fig. 161: Edgecore Internet's data centre with 99 MW diesel backup



Sources : Bryan, Garnier & Co, Caterpillar

The use of diesel generators is not only a brand and environmental issue for data centre operators, it is also a threat to their future growth, especially with the advent of hyperscale data centres.

> “ If we go to an authority and say, “We're going to need 200 MW of diesel backup”, they start to add that up and think “We cannot allow that. That's too much load on our air quality permits”. And if we can't get the permits, we can't grow to meet demand. ”
>
> Mark Monroe, Datacenter Advanced Development at Microsoft

Furthermore, the replacement of diesel generators by hydrogen fuel cells would enable operators to completely redesign their data centres, working with governments and grid operators to determine how renewable energy investments can benefit the whole system and contribute to energy and climate targets.

Data centres are an infrastructure to leverage as part of the overall energy optimisation framework but this cannot be achieved with diesel generators.

The data centre of the future will be both consume and produce clean power for the broader electric system, offering services like frequency response, demand response and peak shaving.

Diesel generators are expensive, polluting and do not produce electricity more than 99% of their life. Data centres running on hydrogen could play a more active role. For example, the electrolyser could be turned on during periods of excess wind or solar energy production to store the renewable energy as hydrogen. Then, during periods of high demand, the operator could start up the hydrogen fuel cells to generate electricity for the grid.

HDF and Atos to jointly develop the next generation of data centres

In this context, HDF is working with Atos to develop a solution to power data centres with green hydrogen. The first system should be ready by 2023.

Atos is set to leverage its expertise in the field of high performance computing to forecast the data centre's electrical needs and adapt the resource (green hydrogen use) accordingly. For example, the data centre can delay the start of energy intensive action or CPU frequency if necessary. This complex process is not only based on the activity and size of the data centre, but also takes into account external data related to the environment, such as the weather forecast.

Since the collaboration between the two companies is still at an early-stage, we have not forecast or included this potential market in our revenue forecasts. We see this partnership as a free call option.

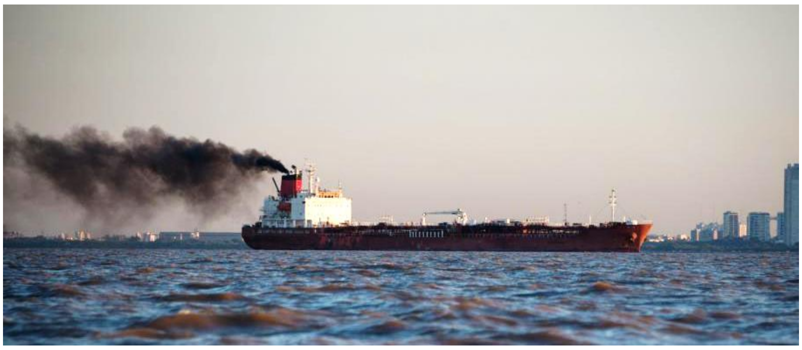
Fuel cells to power the world's marine vessels

Tighter regulations on GHG emissions

The vast majority, or roughly 90%, of all internationally traded goods arrive at their destination by sea. The ships that transport these goods are a massive source of greenhouse gas (GHG) emissions, in particular because they use "bunker fuel", the dregs of the fossil-fuel refining process. It is a cheap but highly polluting fuel, with a far higher carbon content than the diesel fuel used in cars for example.

According to the IMO (International Maritime Organization), maritime transport emits around 940mt of CO_2 annually, representing around 2.5% of global GHG emissions. These emissions are projected to increase significantly if mitigation measures are not put in place swiftly, between 50 and +250% by 2050, and undermining the objectives of the Paris Agreement.

Fig. 162: Air pollution from maritime transport



Source : Fotolia, Diego Cardini

The maritime industry's environmental footprint has been under increasing pressure over the past few years. This has resulted in:

- Rules and regulations from the IMO. In 2018, the organisation adopted a strategy to reduce the carbon intensity of international shipping by at least 40% by 2030 and 70% by 2050, compared with 2008.

- Independent commitments from ship owners. Companies like A.P Maersk, Euronav and Trafigura have pledged to work towards commercially viable zero emission vessels by 2030. Flagship projects are already expected over 2021-2023 and testing over 2024-2027. The commercial roll-out for zero emission vessels is expected in 2028-2030.

It is clear for most players in the industry that the global introduction of alternative fuels like hydrogen and ammonia (NH_3 - a compound of nitrogen and hydrogen) will be key to achieving goals in terms of reducing GHG emissions.

> “ There are many potential alternative fuels for shipping, but not all are equally promising. […] Green hydrogen and ammonia can deliver zero-carbon propulsion and can be produced in virtually unlimited quantities. ”
>
> Faïg Abbasov, Shipping Programme Director at T&E

HDF and ABB to jointly develop maritime fuel cells

In this context, HDF is working with ABB for the industrialisation of a 1 MW+ fuel cell for marine applications. ABB is at the forefront of developments in sustainable shipping and is already the leading provider of electrical power distribution and automation for the maritime industry.

Obviously, retrofitting the world’s marine vessels to run on hydrogen is a huge opportunity for fuel cell manufacturers like HDF. Based on the different assumptions detailed below, we estimate this market to be a EUR2,450m/year opportunity. Should HDF and ABB be jointly successful in capturing just a 10% market share, this would represent EUR245m in additional revenue each year.

Fig. 163: Estimated marine fuel cell opportunity

Vessels suitable for retrofit	110 000
Newbuild vessels suitable for retrofit	2 500
Share of vessels retrofit per annum	1%
Retrofited vessels per annum	1 100
Share of newbuilds using fuel cell	5%
Newbuilds vessels with fuel cell per annum	125
Average size of fuel cell systems (MW)	4
Fuel cell systems sold per annum (MW)	4 900
Average price per MW (EURm)	0,5
Annual global market per annum (EURm)	2 450
HDF and ABB market share	10%
Annuel revenue from fuel cell sales (EURm)	**245**

Sources : Bryan, Garnier & Co, TECO 2030

As for the partnership with Atos, we consider the collaboration between HDF and ABB as too early-stage to be included in our forecasts. We see this potential market as a second free call option.

A two-stage rocket

c.EUR75m in revenue by 2025

We expect HDF to experience strong growth over coming years. During the first phase (2021-2025), top-line growth will be driven by Renewstable projects. Then, from 2025, HyPower projects should take the lead. The long-term profile of the company should also gradually evolve, from that of a project developer to an IPP with fuel cell production capabilities.

We expect HDF to deliver around EUR75m in revenue in 2025. This might sound ambitious but it “only” requires the completion of a handful of projects like CEOG, while the pipeline already includes many similar projects.

We have detailed our revenue expectations by business division and type of project.

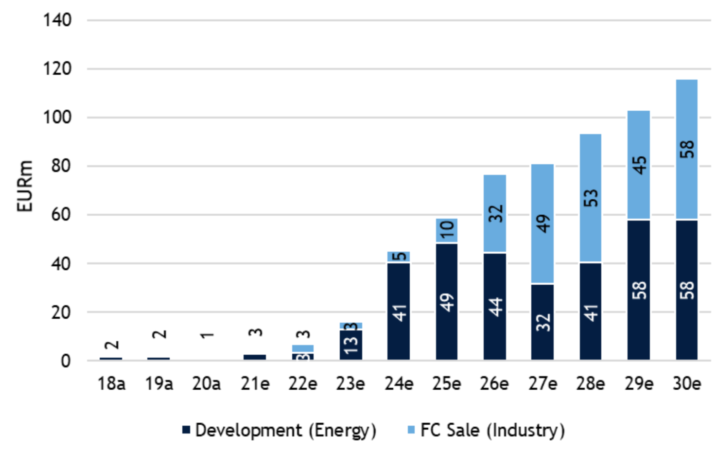
As a reminder, we have not included any revenue from the partnerships with ABB and Atos, this would come as a bonus to our estimates.

Renewstable projects

Our revenue forecasts factor in the completion of the different projects already in the pipeline plus two new Renewstable projects per year between 2023 and 2026 (eight new projects). These new projects will individually represent EUR200m in capex, in line with the average size of the projects already in the pipeline. Each of them will integrate 10 MW of fuel cells, corresponding to the required power for a project of that size. We believe that the mix could be a bit different with more projects but of smaller size, but this does not change our overall forecast. Also bear in mind that the existing pipeline of projects was built with a limited team of business developers. The fundraising will allow HDF to recruit more people to accelerate its development.

For each project, we have assumed HDF’s revenues represent around 15% of capex. For Renewstable projects, revenues from project development and from the sale of fuel cells should be broadly equivalent (50/50). We have also assumed development revenues to be accounted gradually as the development progresses: phase 1 ≈10%, phase 2 ≈30% and phase 3 ≈60%. Once the phase 3 is completed, we have assumed revenue recognition for the sale of fuel cells to be equally distributed over three years. The phasing might be different but in the end this does not change the total value of the contract and our estimates.

Fig. 164: Revenues from Renewstable projects (development and FC sale)



Source : Bryan, Garnier & Co

Fig. 165: Estimated revenues from Renewstable projects (development and FC sale)

EURm	18	19	20	21e	22e	23e	24e	25e	26e	27e	28e	29e	30e		
CEOG		7				10								€120-140m capex	3 MW FC
Baja California						19			14					€220-240m capex	9 MW FC
Barbados					4			3						€90-110m capex	3 MW FC
French Guiana #2						13				15				€190-210m capex	10 MW FC
Cyprus							4			6				€130-150m capex	6 MW FC
Australia							3				4			€80-100m capex	4 MW FC
New Caledonia							4				20			€270-290m capex	20 MW FC
Indonesia							24				12			€250-270m capex	8 MW FC
New project #1							6			10					
New project #2							6			10					
New project #3								6			10			Phase 1	
New project #4								6			10				
New project #5		by 2026							6			10		€200m capex	10 MW FC
New project #6									6			10		/project	/project
New project #7										6		10			
New project #8										6		10			
New project #9											12		10		
New project #10											12		10		
New project #11												12		Phase 2	
New project #12												12			
New project #13		from 2027										12		€400m capex	20 MW FC
New project #14												12		/project	/project
New project #15													3		
New project #16													3		

Development (dark blue)
Construction (light blue)

Sources : Bryan, Garnier & Co, HDF

HyPower projects

Our revenue estimates for HyPower projects are based on the “European Hydrogen Backbone” ambition. Several leading natural gas players such as Enagas (Spain), GRTgaz (France), Fluxys (Belgium), Terréga (France), Snam (Italy) and Gasunie (Netherlands) have teamed up to support this initiative, thereby bringing credibility to the project.

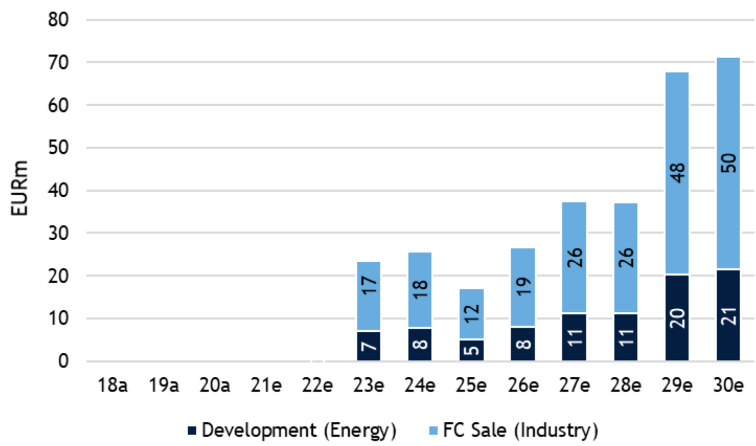
HDF estimates that the deployment of this European Backbone would result in business opportunities representing 100-200 MW of fuel cells by 2025 and 4 GW by 2030. As already mentioned, this may sound ambitious but bear in mind that, for comparison purposes, the European Commission is targeting 2 x 40 GW of electrolysers by 2030.

Admittedly, HyPower projects are more early-stage than Renewstable projects but we can nevertheless expect some demonstration or early adopter projects to emerge before 2025. HDF has already identified a handful of projects of around 10 MW each.

Our revenue forecast for HyPower projects are based on the deployment of a handful of demonstration projects by 2025. Each project should include 10 to 20 MW of fuel cells, which represents between EUR10m and EUR30m in revenue. Between today and 2025, we expect HDF to achieve cumulated revenues of around EUR47m from fuel cell sales, corresponding to “only” 21 MW. This is quite modest, but the acceleration will come after 2025.

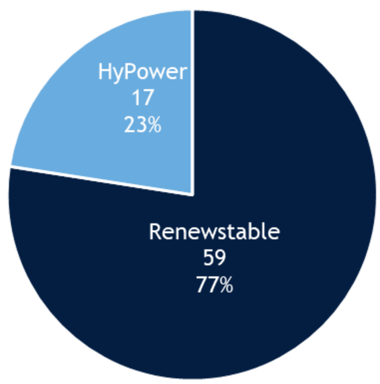
The real ramp-up of HyPower projects will come with the emergence of a large scale pure hydrogen network of pipelines. Obviously, it takes time to build such an infrastructure but we are not starting from scratch and some segments of the pipeline are already operating. Moreover, its deployment can be quick as it will mainly consist of retrofitted pipelines.

Fig. 166: Revenue from HyPower projects (development and FC sale)



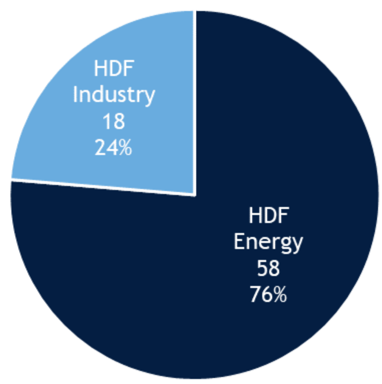
Source : Bryan, Garnier & Co

Fig. 167: 2025e revenue breakdown - Renewstable vs HyPower



Source: Bryan, Garnier & Co

Fig. 168: 2025e revenue breakdown - Energy vs Industry



Source: Bryan, Garnier & Co

EBITDA margin >45% in 2025

HDF's dual profile implies two different EBITDA margins. We expect the project development business (HDF Energy) to be more profitable than fuel cell manufacturing sales (HDF Industry).

HDF Industry

Since the fuel cell industry is still nascent, no company is profitable yet. However, we consider consensus expectations for electrolyser and fuel cell manufacturers as a good benchmark to estimate HDF's future profitability. Note the strong standard deviation from one player to another (from 5-21%) but the average of our sample stands at 12.8%.

Wind turbine manufacturers like Siemens Gamesa and Vestas can also serve as a good benchmark to back our margin estimate. These players are more mature, operate in a similar industry and probably have the same cost structure. According to the consensus of analysts, Siemens Gamesa is expected to report an EBITDA margin of around 14.4% in 2025. Meanwhile, Vestas is expected to report 13.6% EBITDA margin in 2025.

Last but not least, we consider HDF Industry's business and cost structure as very similar to that of the machinery and electrical equipment sectors in general. Using

Damodaran's data base, we note that these industries report EBITDA margins of respectively 18.8% (based on a sample of 125 companies) and 17.8% (122 companies).

Combining all these estimates and benchmarks, we consider 16% EBITDA margin as a reasonable target for HDF. However, since HDF is currently the only company able to provide multi-MW fuel cells, it is reasonable to think that it could potentially enjoy strong pricing power hence higher margins, at least for a few years.

Fig. 169: HDF Industry - Benchmark for the EBITDA margin

Company / Sector	EBITDA margin 2025e
Nel	4,9%
ITM Power	16,2%
McPhy	5,0%
Ballard	11,1%
PowerCell	18,7%
Plug Power	21,0%
FC and ELY manufacturers	**12,8%**
Siemens Gamesa	14,4%
Vestas	13,6%
Wind turbine manufacturers	**14,0%**
Machinery sector	18,8%
Electrical Equipment sector	17,8%
Benchmark for HDF	**15,9%**

Sources : Reuters, Bryan, Garnier & Co, Damodaran

HDF Energy

As already mentioned, we anticipate the project development business (HDF Energy) to be more profitable than fuel cell manufacturing sales (HDF Industry). HDF has quite a unique profile with no other company really similar and hence no peer benchmark for potential EBITDA margin.

Companies like Voltalia or Neoen are also project developers but they have majority stakes in the projects they develop hence report revenues from electricity sales. HDF will only maintain a minority stake in its SPV and will therefore report no revenue from electricity sales, just dividends but at the EBIT level. While the business is broadly similar, the cost and revenue structures are quite different.

Our EBITDA margin for the project development business is based on the estimated operating profitability of the CEOG project (≈70% BG est.). We believe that the company will be able to maintain a similar profitability for future projects. However, we adopt a conservative stance and understand that for the CEOG project, HDF benefited from a premium fee in addition to development fees. Excluding this premium fee, we estimate EBITDA margin might be a bit lower, around 50%. Our EBITDA margin assumption for future projects is the average of these two estimated numbers (70% and 50%): 60%.

Our assumptions beyond 2030

As presented above, our revenue estimates for the period 2021-2030e can be separated into two phases - a first one driven by Renewstable projects and a second one, from 2027, driven by HyPower projects. For the period beyond 2030, we have assumed the following :

- A perpetual growth rate of 2%;
- Between 2030 and 2040, top-line growth decreases at a linear pace towards the normative level of 2%/year (perpetual growth rate);
- For our DCF model, we use an extended period of time to better match the maturity horizon of the technology. Using a basic DCF model over 10 years would not have correctly captured the long term potential of the technology. 2030 is too short/early to reach maturity, changes in the energy mix will be rapid and over an extended period of time;
- An EBIT margin of 28.4% in 2031, vs 41.8% in 2025. As HyPower projects will gradually take the lead, the fuel cell manufacturing business will be dominant and have a dilutive effect on margins. We believe that HDF is able to improve its cost structure beyond 2030 but we also expect this effort to be offset by potential future competition from conventional IPP and oil majors accelerating their efforts towards a more sustainable energy mix. We adopt a conservative approach and factor in a 100bps decrease in operating margin from 2030e. Our normative operating margin should stand around 17.5%;
- A normative tax rate of 25%, in line with the general corporate tax rate to be in force in France from 2022;

Neutral – TP EUR24/share

Discounted cash-flow valuation

Our valuation is derived from our discounted cash flow (DCF) analysis. In our view, the DCF methodology is the most relevant for valuing HDF as it takes into account potential benefits of the still-nascent power from hydrogen market. Important assumptions for our explicit forecast period (2021e to 2030e) were summarised and detailed in the previous sections of this report.

Estimated WACC of 14%

In our WACC calculation, we use the unlevered beta of: i/ listed hydrogen-related companies (electrolyser and fuel cell manufacturers), ii/ listed renewable IPP and, iii/ listed providers of solutions for off-grid applications. We consider this sample to fairly reflect HDF's business and maturity profile.

We then derive our levered beta from the benchmark beta by including the target financing structure of HDF. We finally add an arbitrary 50% premium to reflect higher volatility for newly listed companies. This results in an adjusted beta of 1.65, which sounds reasonable.

In line with general Bryan, Garnier & Co research assumptions, we assume a risk-free rate of 0.6% and an equity risk premium of 7.9%. For debt, we assume a 3.5% risk premium, which might be conservative regarding the current interest rate environment but at least it factors in any potential peak in inflation and a potential future increase in interest rates.

Our cost of equity stands at 14% and our post-tax cost of debt at 3.1%. Overall, given the structure of the balance sheet, our calculation yields a WACC of 14% (equal to the cost of equity).

Fig. 170: HDF's estimated WACC

BG risk-free rate	0,6%
BG equity risk premium	7,9%
Beta	1,65
Cost of Equity	**14,0%**
BG risk-free rate	0,6%
BG risk premium on debt	3,5%
Normative tax rate	25,0%
Cost of Debt	**3,1%**
Equity as % of EV	100%
Net debt as % of EV	0%
WACC	**14,0%**

Source: Bryan, Garnier & Co

Target Price of EUR24/share based on our DCF valuation

Fig. 171: DCF model

EURm	2020	2021E	2022E	2023E	2024E	2025E	2026E	2027E	2028E	2029E	2030E	2031E	2032E	2033E	2034E	2035E	2036E	2037E	2038E	2039E	2040E	Perpetuity
Sales	2	3	7	40	71	76	104	119	131	171	187	225	266	309	355	400	444	485	521	550	571	582
Y-o-y growth in %	-20%	55%	126%	488%	79%	7%	36%	15%	10%	31%	10%	20%	18%	16%	15%	13%	11%	9%	7%	6%	4%	2%
Operating costs	(1)	(2)	(5)	(35)	(51)	(44)	(65)	(87)	(94)	(117)	(132)	(161)	(193)	(228)	(265)	(302)	(340)	(376)	(409)	(438)	(460)	(480)
Operating profit	**0,6**	**1**	**2**	**4**	**20**	**32**	**38**	**32**	**37**	**54**	**55**	**64**	**73**	**82**	**90**	**98**	**104**	**109**	**111**	**112**	**111**	**102**
Operating margin	29%	50%	29%	11%	28%	42%	37%	27%	28%	31%	29%	28%	27%	26%	25%	24%	23%	22%	21%	20%	19%	18%
Cash operating taxes	(0)	(0)	(1)	(1)	(5)	(8)	(10)	(8)	(9)	(13)	(14)	(16)	(18)	(20)	(23)	(24)	(26)	(27)	(28)	(28)	(28)	(25)
Tax rate	26%	27%	27%	27%	27%	27%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
NOPLAT	**0**	**1**	**1**	**3**	**15**	**23**	**29**	**24**	**28**	**40**	**41**	**48**	**55**	**61**	**68**	**73**	**78**	**81**	**84**	**84**	**83**	**76**
Depreciation & amortizatior	0	0	0	9	12	5	6	7	7	8	9	10	11	13	15	17	19	21	22	23	24	29
Chg. in WCap	(0)	2	(1)	(5)	(3)	0	(0)	(0)	(0)	(0)	(0)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	-
Capex (intang. & tang.)	(1)	(1)	(11)	(13)	(5)	(5)	(6)	(7)	(7)	(9)	(10)	(11)	(13)	(15)	(18)	(20)	(22)	(24)	(26)	(27)	(29)	(29)
Operating free cash flow	**(1)**	**2**	**(11)**	**(6)**	**19**	**23**	**28**	**24**	**27**	**39**	**40**	**46**	**52**	**59**	**64**	**70**	**74**	**77**	**79**	**80**	**79**	**76**
Y-o-y growth in %		n.m.	n.m.	-40,6%	n.m.	25,5%	21,6%	-17,1%	14,3%	45,0%	1,9%	14,7%	14,7%	12,0%	10,1%	8,2%	6,3%	4,4%	2,5%	0,5%	-1,4%	-2,8%
WACC		14,0%	14,0%	14,0%	14,0%	14,0%	14,0%	14,0%	14,0%	14,0%	14,0%	14,0%	14,0%	14,0%	14,0%	14,0%	14,0%	14,0%	14,0%	14,0%	14,0%	
Cum. WACC		114,0%	130,0%	148,3%	169,0%	192,8%	219,8%	250,6%	285,8%	325,8%	371,5%	423,6%	483,1%	550,8%	628,1%	716,1%	816,6%	931,1%	1061,7%	1210,6%	1380,4%	
PV of operating FCF		**2**	**(8)**	**(4)**	**11**	**12**	**13**	**9**	**9**	**12**	**11**	**11**	**11**	**11**	**10**	**10**	**9**	**8**	**7**	**7**	**6**	**46**
																					Terminal value as % of EV	23%

EV	**203**
Net Interest-bearing liabilit	126
Equity value	**328**
No of shares (m)	13,71
Target Price (€)	**24,0 €**

Source : Bryan, Garnier & Co

In our view, the terminal growth rate and long-term EBIT margin are the two key components reflecting HDF's equity story. The growth story is straightforward as demand is very strong with legal constraints to fight climate change and reduce GHG emissions. The only factor that could raise questions is the timing of the top-line acceleration. Growth will come, that's for sure, but its timing is uncertain despite the strong and encouraging pipeline of projects.

Fig. 172: Sensitivity of our valuation to key assumptions

		WACC						
		11,0%	12,0%	13,0%	14,0%	15,0%	16,0%	17,0%
Perpetual growth rate	1,25%	32	28	26	24	22	20	19
	1,50%	32	29	26	24	22	20	19
	1,75%	32	29	26	24	22	20	19
	2,00%	33	29	26	24	22	21	19
	2,25%	33	29	26	24	22	21	19
	2,50%	33	30	27	24	22	21	19
	2,75%	34	30	27	24	22	21	19

		WACC						
		11,0%	12,0%	13,0%	14,0%	15,0%	16,0%	17,0%
Terminal EBIT margin	16,0%	32	29	26	24	22	20	19
	16,5%	32	29	26	24	22	20	19
	17,0%	32	29	26	24	22	20	19
	17,5%	33	29	26	24	22	21	19
	18,0%	33	29	26	24	22	21	19
	18,5%	33	29	26	24	22	21	19
	19,0%	33	30	27	24	22	21	19

Source : Bryan, Garnier & Co

Section 07

How to play the grid stability thematic?

How to play the grid stability thematic?

Our best convictions are Alfen and Swedish Stirling while we adopt a more conservative stance on Azelio and HDF.

Fig. 173: Our different convictions

	Company	Rating	Target Price	Strengths	Weakness
1	ALFEN	Buy	EUR105	Diversified business model/asset light/leading position on very promising markets	Compete with larger player on growing verticals
2	Swedish Stirling	Buy	SEK22	Consistent commercial strategy, unique technology, good positioning in South Africa, allows grid independence	Strong dependance to two companies and one market in the short term
3	AZELIO	Neutral	SEK23.4	Strong balance sheet, promising technology, should clearly benefit from renewable and micro/off grid expansion	Client portfolio raises uncertainties, visibility on microgrid/off-grid market is weak
4	HDF	Neutral	EUR24	Pioneer in hydrogen power, profitable company	Delay risk, market ramp-up, early stage market, exotic locations, limited track record

Source: Bryan, Garnier & Co

In terms of positioning in the fast growing renewable energy market, Alfen clearly stands out from the crowd thanks to its diversified product portfolio, which is a true advantage compared to single-asset companies like Azelio, Swedish Stirling and HDF.

Thanks to its historical and oligopolistic position in the transformer substation business in the Netherlands, Alfen boasts clear visibility resulting from long-term contracts and high barriers to entry. The group's expertise places it at the heart of the grid transformation initiated by the integration of renewable energies.

Being well positioned in the defensive transformer substation business allowed Alfen to invest early in fast growing and complementary technologies like energy storage systems and EV charging stations. Alfen then managed to secure leadership status in both segments thanks to its smart positioning and above all, its integrated business model leading to cross selling and profitable opportunities.

The company should also be able to improve margins on the back of the gradual ramp-up in the installed base of batteries and charging stations enabling profitable revenues generated by maintenance and software. On the manufacturing side, Alfen still has room to optimise its cost base along with increasing volumes.

Finally, Alfen enjoys an asset-light business model with low capex and WCR ensuring good cash conversion despite double digit sales growth.

In terms of valuation, our DCF points to a TP of EUR105 implying upside of 20% (8% WACC, 2% growth) reflecting respective 2023E EV/Sales, EV/EBIT multiples of 5x and 36x, in line with Alfen's historical numbers.

Swedish Stirling is our second Buy conviction with a TP of SEK22 pointing to upside of 38%. The company manufactures and sells a unique product, the PWR-BLOK 400-F, able to produce electricity from industrial flare gases. On top of owning one of the best technologies in the world, Swedish Stirling, can enable large coal energy consumers to lower their costs and indirectly, their CO2 emissions generated by conventional based electricity.

With more than 50% of the ferrochrome industry housed in South Africa, Swedish Stirling naturally targeted this market and has managed to sign promising contracts with major ferrochrome players such as Samancor and Glencore. As such, the commercial roll-out bears an acceptable level of risk in our view since Samancor and Glencore are among the largest ferrochrome producers in the world and regularly mention the PWR-BLOK 400-F as a credible solution for their CO2 emissions. The different contracts ensure a strong top-line ramp-up and lend additional credibility to Swedish Stirling's technology.

Moreover, the PWR BLOK is an excellent way to gain independence from the grid. The massive ramp-up of renewable energies, combined with rising electricity needs is set to heighten grid instability, prompting higher prices and a wider cost base for large industrial electricity consumers. Consequently, the PWR BLOK can help these players consume less electricity from the grid thanks to their own-production and therefore to preserve their margins in order to remain competitive. In this context, the market Swedish Stirling can address is much broader than just South Africa, since all developed countries are very advanced in the renewable energy roll-out.

Assuming sales growth in line with the commitments made by Samancore, Glencore and RBA and fair pricing estimates, we obtain a TP of EUR20.50 after discounting future FCF at a WACC of 12%. Indeed, the bulk of the CAPEX needed to produce the PWR BLOK 400-F is behind the group while WCR should be handled with no difficulty. As such, FCF is automatically set to increase given the combination of strong top-line ramp-up and high operational leverage.

Finally, the whole management team has been strengthened recently (new CTO, CFO, CEO) in order to focus exclusively on top-line growth (the new CEO is the former head of sales) which we consider an excellent message sent to investors and customers.

Azelio also owns an extremely promising technology related to electricity storage. Thanks to its TES.POD, electricity can be stocked for 13-18 hours allowing electricity production for 24 hours in a row, even with power generation only made up of renewable energies. Like Swedish Stirling, the company is on the verge of a potentially strong commercial roll-out.

However, we adopt a more conservative stance on this company for various reasons. Firstly, compared with Alfen and Swedish Stirling, Azelio's addressable market suffers from weak visibility. Azelio mainly targets off-grid locations in sunny countries, meaning that potential projects are usually executed in isolated regions in developing countries.

In addition, Azelio's customer portfolio is not as good Alfen's or Swedish Stirling's. The bulk of its clients are small companies which, in some cases, have promised massive orders while generating low revenues. Given that the clients are not well-known or large companies, we cannot tell whether these potential orders are one-off requests or if they could represent the beginning of a promising customer relationship.

Consequently, in view of poor visibility on customers and the addressable market as a whole, it seems more realistic to filter the top line suggested by the current MoUs using probability of success ratios (5-50%). In this context, our DCF leads to a TP of SEK23.4, pointing to downside relative to the current share price. We therefore adopt a Hold rating.

Regarding HDF, we think the company could experience a strong growth over the coming years thanks to its two-stage trajectory and its good positioning on the hydrogen market. During the first phase (2021-2025), top-line growth will be driven by Renewstable projects. Then, from 2025, HyPower projects should take the lead. The long-term profile of the company should also gradually evolve, from that of a project developer to an IPP with fuel cell production capabilities. While hydrogen will be a key part of the power transition, we think that the market is currently pricing the potential over the next years.

In all, we believe Alfen could be an interesting vehicle to play the EV roll-out and stationary battery storage thematics in Europe. While Swedish Stirling could clearly benefit from grid instability issues in markets where large industrial electricity consumers are located, starting with the ferrochrome industry in South Africa, Azelio on the other hand, will have to generate sales quickly to remove any doubts regarding its client portfolio. Apart from the short term commercial outlook, Azelio’s technology represents a strong innovation meeting electricity storage needs in many parts of the world. In this respect, Azelio is among the few players in the world to bring the market a modular solution that is not battery-based.

Bryan Garnier stock rating system

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The highest possible rating, based on a very strong conviction in the mid/long-term outlook and strategic choices made by a company, and should therefore be reflected in the extent of upside in the associated target price. There is no reason to limit the number of CONVICTION BUY ratings, however they must also reflect some kind of preference in relative terms within a sector.

BUY

Positive opinion for a stock where we expect a favourable performance in absolute terms over a period of 6 months from the publication of a recommendation. This opinion is based not only on the FV (the potential upside based on valuation), but also takes into account a number of elements that could include a SWOT analysis, momentum, technical aspects or the sector backdrop. Every subsequent published update on the stock will feature an introduction outlining the key reasons behind the opinion.

NEUTRAL

Opinion recommending not to trade in a stock short-term, neither as a BUYER or a SELLER, due to a specific set of factors. This view is intended to be temporary. It may reflect different situations, but in particular those where a fair value shows no significant potential or where an upcoming binary event constitutes a high-risk that is difficult to quantify. Every subsequent published update on the stock will feature an introduction outlining the key reasons behind the opinion.

SELL

Negative opinion for a stock where we expect an unfavourable performance in absolute terms over a period of 6 months from the publication of a recommendation. This opinion is based not only on the FV (the potential downside based on valuation), but also takes into account a number of elements that could include a SWOT analysis, momentum, technical aspects or the sector backdrop. Every subsequent published update on the stock will feature an introduction outlining the key reasons behind the opinion.

CONVICTION SELL

This is the lowest possible rating reflecting a strong disagreement with the main strategic choices made by a company, pointing to the risk of de-rating and value destruction and which is obviously also reflected in downside potential between the share price and the target price.

DISTRIBUTION OF STOCK RATINGS

Conviction BUY	6.3%
BUY ratings	61.3%
NEUTRAL ratings	17.6%
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