WHITEHELM ADVISERS

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FEATURE ARTICLE: UNDERSTANDING THE RISKS AND CHALLENGES OF INVESTING IN RENEWABLES

INTRODUCTION

The global economy is transitioning to lower carbon forms of energy production. The adoption of the Paris Agreement, which has now been ratified by 175 parties, aims to limit the global temperature rise to less than two degrees Celsius. In order to achieve this outcome, rapid, far-reaching and unprecedented changes are necessary across all aspects of society[1]. There are many ways in which this transition can and must continue and a variety of technological solutions will be required. Under all scenarios, however, renewable energy will be an important part of the solution.

Renewable energy assets comprise a broad range of technologies, including wind, solar, hydro and geothermal. Considering a broad definition of renewable energy, these technologies have been used for centuries – for example, to drive sail boats, or to pump water using windmills. Expansion of investment in the sector over the last several years has reduced a number of countries' dependence on traditional fuel sources, thereby diversifying their generation bases. The charts overleaf provide a snapshot of the total share of renewable energy (by consumption) and the historical investment in the sector over the last several years.

Wind, solar and hydro are the most common form of renewable energy generation today, and these sectors have benefited from a surge in private investment over the last decade, often spurred by government incentives (either on pricing or taxation), an increasing demand for sustainable generation practices from energy consumers, as well as significant fund raising efforts from institutional investors.

[1] Intergovernmental Panel on Climate Change Climate Report 2018.

Chart 1: Energy Source by Consumption (2016)

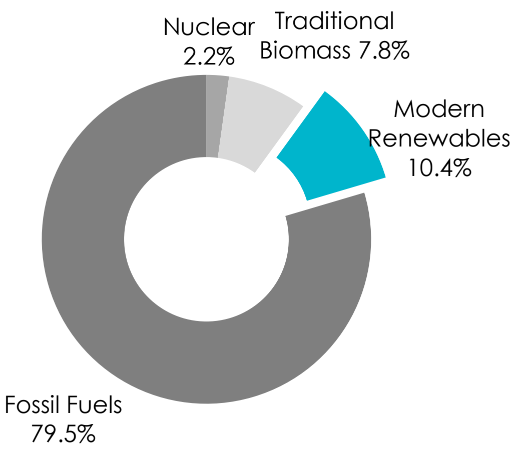
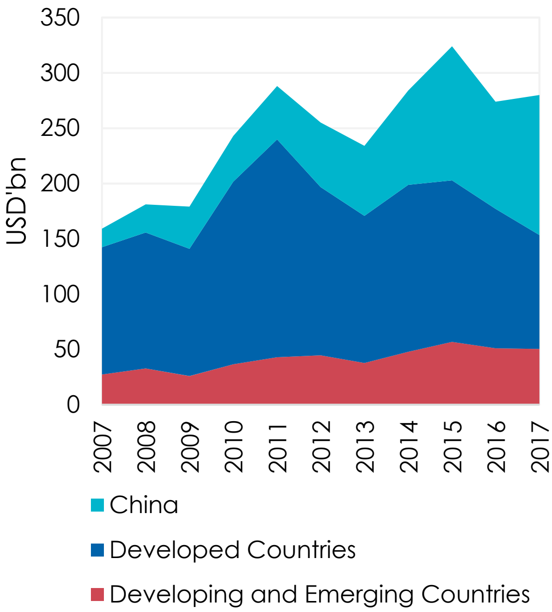


Chart 2: Investment in Renewables (2007 - 2017)



Source: REN21

However, this has not been without risk. The wall of "green money" flooding into the space not only expands the pipeline of projects but also puts downward pressure on investment returns for all parties involved. Lenders are willing to reduce credit margins and increase gearing to be selected to provide funding for projects. Equity investors are accepting lower returns to secure assets or keeping their required rate of return the same but moving up the risk spectrum for an asset. For example, committing to a greenfield project (where no prior renewable assets exist on site) for a similar return to what you could have earned on a brownfield asset (where there is an existing asset, with ongoing operations) a few years ago.

This feature article explores the key risks in renewable generation assets for investors and ways these can be addressed (either mitigated or priced into the project return). It then turns to an often-overlooked risk – regulatory risk – and how this can be a far greater risk than investors may appreciate. The article presents case studies from a number of countries where sudden changes to the regulatory environment have impacted the viability of renewable energy projects. A worked example is provided, which highlights the significance of a revenue shock to a generic renewables project – whether this is a reduction in feed-in tariffs (Italy), changes to the assessed marginal loss factors (MLF) in Australia, or a change in direction from governments around renewables-related tax policies in the United States (US).

ASSESSING THE RISKS

Institutional equity investors face mounting challenges when investing in renewable projects. Most developed countries are currently in a falling interest rate environment with increased investor allocations to renewable assets. Given these two factors, among others, investors are needing to accept lower returns in order to deploy capital in renewable assets. The question we pose is this – given these market pressures, are investors being adequately compensated for the specific risks of renewable generation investments?

As is the case in the majority of infrastructure projects, equity investors must negotiate an appropriate risk allocation among key partners, stakeholders and service providers so that there is an acceptable "residual risk" (or "equity risk") remaining in the project for equity investors to take on.

It is possible to mitigate most of the project risks through this process, however as evidenced in subsequent sections, there are some risks that will remain with equity and these need to be priced and accepted by equity investors. We have listed the more material risks facing equity investors in renewable generation projects below, however it should be noted that this is not an exhaustive list.

Greenfield Risks

The first few key risks at the greenfield stage of a renewable development relate to land purchase, site approvals, securing relevant permits and gaining transmission access. If a developer or project sponsor spends two years securing these approvals and permits, that equates to two years of receiving no return on invested capital. An investor can assume these risks or pass them on to a developer or project sponsor, only committing to funding the project once they are secured. There are typically high margins available to renewable energy sponsors who are willing to use their expertise to purchase appropriate land parcels and navigate the site approval and permitting processes, including grid connection access for the project.

The next step is the actual construction period. Greenfield construction and completion risks typically include quality of the construction, cost overruns (which are impacted by potential labour disputes) and construction delays. All of these factors can act as a drag on an investor's return, however delays can have more significant consequences if the project fails to meet the scheduled operation date set in a Power Purchase Agreement (PPA), being the agreement that governs how much, and at what price, electricity from the project is sold.

An investor can mitigate many of the construction risks through negotiation and execution of a risk transfer mechanism with a reputable engineering, procurement and construction (EPC) contractor. EPC contractors usually accept pass-through obligations which typically include damages for delay (another way is offering a fixed price, turn-key contract). That said, there are often termination events embedded within PPAs should there be excessive delays that stretch beyond a predetermined period. As such, it is difficult for an investor to completely address delay risks through an EPC contract.

GENERATION RISKS

For wind and solar farms, revenues earned by the project depend on the wind or solar resource at the site. While it is possible to structure the project such that this risk is passed through to the buyer of power (through a PPA), this structure is uncommon and usually results in significantly lower returns for the asset (given the much lower risk of the project).

Engaging an experienced wind or solar consultant is an important way to manage this risk. Variability of wind speeds tends to be higher than irradiation, so setting a suitable P50 base case is important (a P50 case is the expected base case where there is a 50% likelihood of outperforming the forecasts and a 50% probability of underperformance). P50 forecasts tend to be more accurate for operational assets due to the availability of historical performance data, relative to greenfield projects that rely on data collected from nearby masts or from satellite data to estimate solar irradiance. This further increases the generation risks for greenfield projects.

Generation risks associated with wind speeds and irradiation levels are typically retained by the equity investor.

DNV GL issues a report[2] regularly on wind power project performance assessing how these compare to original P50 forecasts. This was last updated in July 2017 and looks at 1,400 projects across North America that commenced operations from 2000 to 2016.

The report shows that projects commissioned since 2011 have on average performed close to the DNV GL prediction of annual output with a negative project performance gap of only 2%. The previous report from 2014 showed projects from 2010 to 2013 underperformed the P50 case by 5% on average while projects from 2001 to 2009 underperformed by 9%.

Wind forecasters are continually trying to improve their forecasting models to reduce the generation risks faced by renewable investors. It is evident from this report that the gap in wind forecasts relative to actual performance has been almost completely eliminated.

[2] Wind Power Project Performance White Paper 2017 Update by GNV GL (dated 21 July 2017)

Pricing Risks

Electricity produced by a generator, where this is not subject to an underlying pricing contract, is sold into a general market pool. The price of electricity bought and sold in this manner is determined based on supply and demand at that particular point in time. As such, this price is volatile and can change materially over a short period. Over the longer-term, the overall price level is impacted by the addition/removal of generators, overall level of consumption and investment in the network. As a result, selling electricity into the market exposes an asset to the risk of short-term and long-term pricing changes.

Pricing risk is incredibly important as it impacts a range of factors other than just ensuring a lower and more competitive cost of equity for an investor. Having a solution on this aspect of the project also ensures a more competitive debt financing package can be secured. A long-term, fixed-price PPA from a strong counterparty purchaser will be viewed favourably by debt financiers when it comes to negotiating leverage, margins and amortisation profiles. This is discussed in further detail in the financing section below.

Pricing risk, and the extent to which a project's value is recouped earlier or later in the asset's life is impacted by the level and duration of an overarching price contract, the financing and amortisation profile, and indirectly, the location of the investment. In Australia, pricing contracts (PPAs) are typically relatively short, and projects are exposed to a greater degree of pricing risk over the life of the asset (that is, when the contract ends, it's generally assumed the project sells electricity into the market, and is subject to the prevailing market price). Financing is also relatively shorter term, with a more aggressive amortisation profile over this initial period. Conversely, in many European countries, the feed-in tariffs (FiT) regimes or pricing contracts, and the financing available to such projects, generally cover a longer period of the asset's life. As a result, from an equity investor's perspective, value is recouped earlier in the European setting compared to a more back-ended structure more common in Australia.

There are many overseas jurisdictions that have favourable regulatory regimes that guarantee a specific feed-in tariff for so long as the renewable asset is operational – this provides a guaranteed price for any electricity sold by the project. Italy and Taiwan are examples of this (among others). In Australia, asset owners have to negotiate PPAs with counterparties to secure a similar level of pricing certainty. That said, PPAs in Australia typically have lengths of up to 10 to 15 years (or sometimes only 5 years) as opposed to the useful life of the project for feed-in tariffs that are set (up to 25 to 30 years). This highlights the uncertainty around the existing regulatory scheme in Australia after 2030, relative to other countries. However, changes to the pricing regimes are not unprecedented, as evidenced by the solar industry's experience in Italy, as discussed overleaf.

Case Study: Numerous Changes to Italian Incentives

The Italian government has supported renewable energy projects with a range of economic incentive schemes provided over the last 15 years. However, with the installation costs declining rapidly during this period, these incentives became quite generous, and were provided at a high cost to the government.

A green certificates scheme was introduced in 2004, and a FiT system was announced for solar systems in 2005 which provided for a fixed premium over a 20-year period. The green certificates system was abolished by 2015, and the plants receiving these certificates were transferred to the FiT system. In 2014, the Italian Government approved a retrospective change to the FiT regime for solar projects, reducing the tariff paid to generators by up to 25% in some cases. Developers and investors challenged this decision in the Italian Constitutional Court, however the court upheld the FiT regime change by the Government.

While investors in effected projects had made decisions based on government-supported schemes at the time of the investment, the unilateral decision by the Italian Government to amend the pricing had material implications on future earnings from these projects.

Case Study: FiT changes in Taiwan

In the past, Taiwan's FiT regime has been viewed favourably by investors. Projects are paid an agreed price for a 20-year period – essentially a PPA between the project and the state-owned Taiwan Power Company as off taker. Developers planning projects over the course of the year, many of which had progressed through to grid allocation, were caught on the backfoot with the announcement from the Taiwanese Government of a 13% reduction in the FiT for 2019.

The Danish energy company Orsted, which successfully won a competitive auction process for the 900MW Changhua 1 and 2 projects, noted that it would have to revisit the project's viability based on the changes to expected pricing for the electricity produced from the project. Given the time taken to develop renewables projects, many other investors would have been left in a similar predicament – reassessing if the reduction in future earnings would provide a sufficient return for shareholders. Noting how competitive the sector has become, we expect many investors would have deferred breaking ground on the projects.

It is important to note that, despite the significant implications this FiT change had to the viability of projects in development, it was not a retrospective change to the overarching FiT regime, and it did not impact operational projects.

In addition to traditional energy retailers and state governments, corporates are now entering into PPAs. Corporate interest has been driven by green agendas and to hedge against increases in wholesale electricity costs. Globally, companies bought twice as much renewable energy through PPAs in 2018 as they did in 2017, with Facebook alone buying as much renewable energy as all businesses in the Asia-Pacific region.

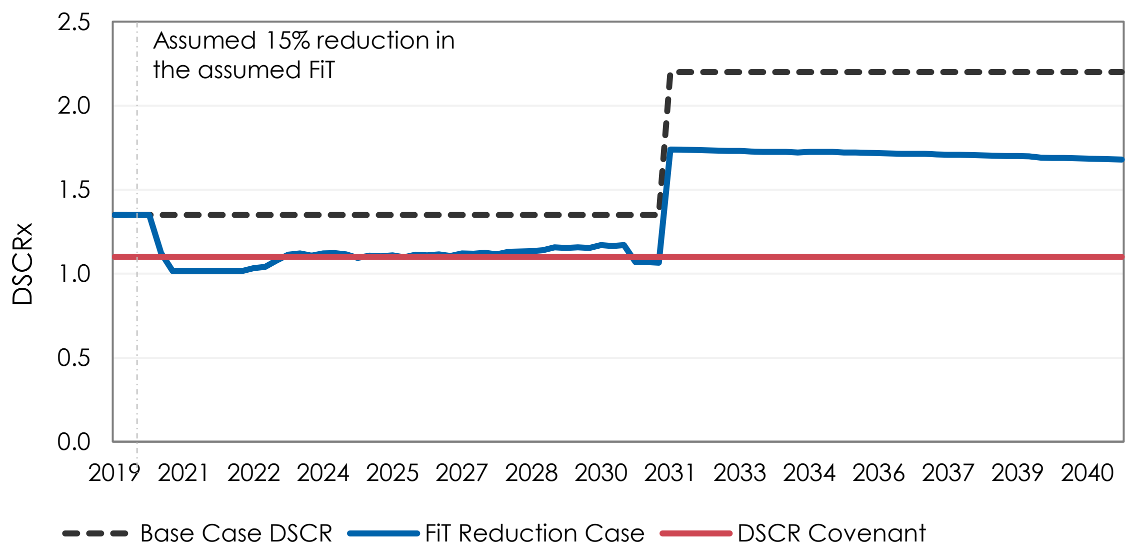
Worked Example – Unforeseen Price Shock

We have taken a typical wind farm asset to model out the cash flows. We have assumed a 25-year useful life, with 12 years remaining under a FiT regime and exposure to market pricing from years 13 to 25. That is, electricity produced for the initial period is sold at an agreed price to an off taker, and thereafter the electricity is sold into the general market at the prevailing prices at that time. The market price (year 13 and onwards) is higher than the contracted PPA price as it assumes there will be ongoing support from governments for renewable energy projects over the longer term – often generically referred to as an Emissions Intensity Scheme. Generally, market pricing for future years is provided by industry experts that assess supply versus demand for future periods, and the relative impact this will have on pricing. In this example, debt is sized to a 1.35x Debt Service Coverage Ratio (DSCR) which reflects a long-term FiT for 100% of the electricity generated. The resulting entry gearing level in this example is 65% and decreases to 35% over the FiT period with a 1.35x DSCR level over this time.

Let's assume we have invested in our typical wind farm and took for granted the view that the agreed price per the FiT regime would apply for the agreed duration of the FiT regime. On that basis, debt financing was sourced with a DSCR default covenant in place of 1.1x (that is, the project enters default if the coverage ratio drops to 1.1x or lower, unless investors provide an 'equity cure' to the project by investing additional cash into the business).

In our wind farm example, we have run a downside shock case that includes a reduction in the FiT regime price of 15% in the second year of operations – this is not dissimilar to the reductions applied by the Italian Government in 2014. As a result, the project's revenues are negatively impacted for the remainder of the duration of the FiT regime before improving in the post-FiT period. Chart 3 below summarises the negative FiT shock to the project's DSCR, relative to the assumed DSCR covenant of 1.1x.

Chart 3: Price Impact on Project Viability



Source: Whitehelm Capital

The immediate impact of the reduction in the FiT is a fall in the project's cash flows, impeding its ability to service debt. In fact, the project breaches the 1.1x DSCR threshold, placing it in a technical default. An equity cure at this time could include a cash injection by investors (in this case equating to almost 13% of the investor's original equity investment), or the project debt financiers would be able to accelerate the debt repayment and take ownership of the asset. This is a significant adverse outcome for the project caused by a risk that is challenging to mitigate. In this example, the project life equity IRR falls from 8.5% to around 4%. Even in situations where the FiT decreases by less than 15%, the revenues will fall in the early years and so will the DSCR, below the base case.

Operations & Maintenance Risk

Operations and maintenance (O&M) services are an important consideration for financial investors. While large electricity producers have in-house teams able to maintain their renewable assets, other investors may not. In these situations, O&M services need to be outsourced to a third-party provider.

The performance of an O&M provider is critical in ensuring returns are maximised for an investor. Say, for example, a turbine malfunctions and the O&M contractor's resources are stretched due to committing to too many wind farm O&M contracts. The turbine might remain idle for a week or two, unable to generate electricity which directly impacts the asset's revenues. This is a risk that is beyond the control of the investor and unable to be rectified without the O&M contractor.

For this reason, O&M contracts typically contain availability guarantees (market standard is around 97%, depending on the age of the turbines, or 97% to 98% for solar projects). This means a payment will be made by the O&M contractor if the availability falls below this level to compensate the equity investor. For this reason, credit worthiness of the O&M counterparty also needs to be considered to stand behind the availability guarantee.

O&M contracts typically offer long-term (generally five to 15 years), fixed-price services that result in high cost visibility and low variability. It is possible to have all maintenance (including replacement parts) included in the contracted price. The benefit for asset owners is obvious – you know what you are going to pay each month, you have experts on call to fix your mechanical faults when they occur and they provide a guarantee that the wind or solar farm will be operational to produce power for close to 100% of the time. If the O&M contractor is of sound financial standing, then this is a "no brainer" for financial investors. The alignment of interest with the O&M provider is often enhanced where the contractor has a minority investment in the project (sometimes as a result of being the project developer), which can improve availability relative to a simple O&M contractor arrangement.

Financing Risks

Financing risks in renewable assets are no different to other asset classes. Including gearing in the structure will inevitably lead to financing risks around quantum of debt sourced and its cost (base rates and margins). Interest rate risk can be managed through interest rate swaps, however assets will always be susceptible to downside shocks (attributable to any of the risks discussed in this section).

Furthermore, debt financiers in Australia will not provide full lifecycle financing, instead only increasing tenor to five to seven years. This places refinancing risk on the assets. These more in-depth considerations are discussed in more detail in the following section.

Regulatory Risks

Renewable energy projects are often supported by government policies that recognise the environmental benefits of clean energy generation. It is essential to understand both the commercial market for the energy and the policy environment in order to negotiate power purchase agreements or to manage merchant risk if the energy is being sold on the spot market. It is also vital to understand the relevant regulatory frameworks – planning, environmental, electricity grid, corporate governance, taxation, financial, employment, or occupational health and safety. All these factors need to be considered when assessing the cost of the project and the risks associated with the investment.

When people think of regulatory risk, they usually think of the risk of entering foreign markets and have the regulator either cancel licenses or, as is more often the case, hand down a ruling to materially decrease the revenues of operators despite having contractual protections. One only needs to look at what transpired in Italy as an example of how regulatory risk can rear its head.

Investors usually discount regulatory risk as something of low priority when investing in developed countries. However, there can be other elements to regulatory risk that aren't linked to a government trying to save money at the expense of investors. Just turn to the recent determination handed down by the Australian Energy Market Operatory (AEMO) on MLFs as a prime example of regulatory risk for renewable assets in Australia. This wasn't an arbitrary decision made by AEMO to prop up the bottom line, it was a real factor that reflects the congested transmission grid and resulting power losses for specific assets, which is a result of the rapid development of the sector.

Case Study: Australian MLF Reductions

AEMO is responsible for operating gas and electricity markets in Australia, including the National Electricity Market (NEM). On an annual basis, AEMO analyses the electricity network, assessing the interplay between generation load, transmission constraints and distances to determine the final 'net' electricity generated. AEMO publishes Marginal Loss Factors (MLFs) annually, which attempt to measure the loss of energy during the journey along transmission lines, and are applied to pricing across the NEM. Generators that supply electricity to a constrained transmission node that is a significant distance from the ultimate end user are paid less per unit of electricity supplied than a generator on an unconstrained line that is close to the demand source. This ensures the transmission losses are paid by the generator (not covered by AEMO or the end users).

AEMO provided an update to the relevant MLFs for generators in the NEM in June 2019. A number of material reductions across the market were included in the determination (reductions in MLFs were more prevalent than increases in MLFs) – this included a reduction of 23% for the Broken Hill Solar Farm. These material reductions in the assessed MLFs significantly reduce potential earnings over the course of the next 12 months and potentially beyond should the transmission lines not be upgraded (something out of the control of the generators).

In describing the reasons for the reduction in MLFs, AEMO noted:

"New generation is increasingly connecting at the periphery of the transmission network, including north-west Victoria, south-west New South Wales, and north and central Queensland. In these areas, access to renewable resources is good, ***yet the network is electrically weak and remote from the regional reference node*** *[emphasis added]. This additional generation has resulted in a large reduction in MLFs in these areas."* [3]

Furthermore, the reduction in MLFs is exacerbated by the high correlation in generation profiles, where new generation tends to be running at the same time as other nearby generators, as well as during periods of light load in the area. This is particularly evident when observing the renewable generators which experienced large reductions in MLFs over time. Simply put, the success of developing renewables in certain parts of the NEM has negatively impacted future profitability of projects within these regions. The development of competing projects, as well as the Australian Government's investment response in upgrading transmission lines, are well out of the control of individual investors.

A full explanation is provided in the Appendix.

[3] Updated Regions and Marginal Loss Factors FY 2019-20, AEMO, June 2019.

DEBT FINANCING RENEWABLE PROJECTS

Historically, there has been broad support from banks and other major lending institutions to fund renewable generation projects. Banks view these projects as a shared value initiative – that is, in addition to generating a return on capital, they also help to address a major societal issue – climate change. This has been strongly influenced by the Paris Agreement, which aims to strengthen the global response to climate change, as well as an evolution in the general public's perception of environmental factors.

The problem with this ulterior motive for lenders is that it results in heightened competition for debt financing, lowering lenders' returns and therefore increases financing risk for equity investors through more aggressive capital structures. This competition has also resulted in margin compression, however this positive tends to be bid away by equity investors seeking to secure an acquisition.

However, banks in different countries have diverged in their approaches to the length of the loan (or tenor) and the amortisation profile – this is particularly evident comparing Australia versus some European countries, as discussed below.

Loan Tenor

Australian banks, and their competing offshore banks operating in Australia, offer "mini-perm" financing. This means that short-term financing is typically used to fund and refinance assets. While corporate loans tend to be three to five years in length, lenders are willing to increase the tenor for renewable projects up to seven years. This remains the case even where assets have 12 to 15-year PPAs.

Regardless of the structure of the renewable project, asset owners then face refinancing tasks halfway through the initial PPA period. This refinancing task adds to the overall risk for an equity investor. Furthermore, depending on the performance of the asset (against its P50 forecasts), the debt markets at the time and how the various other risks outlined above have fared, the refinancing task may prove challenging.

Compare this to some overseas jurisdictions, particularly in Europe, where longer-term financing is commonplace, and the debt for these projects covers a larger proportion of the useful life of the asset. This materially reduces refinancing risk as the debt outstanding at that point in time would be lower, and the asset would have a well-defined operating history over several years.

Amortisation Profiles

Similar to the issue with loan tenors above, lenders typically take a conservative approach regarding the repayment period for Australian renewable projects. They like to minimise their exposure to market price risk – that is, they seek to be repaid the vast majority of their exposure to an asset within the PPA period, and not be subject to the price volatility typically observed in selling electricity into the electricity market. For example, say a project has a 10-year PPA – lenders will seek to sculpt an amortisation profile so that only 25-35% of the debt is outstanding after the initial 10-year PPA period. This seems counterintuitive given assets usually have 25-30-year useful lives.

As mentioned above, German banks are happy with an amortisation profile for renewable projects of up to 20-25 years. The resulting difference in the two markets is distinct – there are minimal equity returns in Australia during the initial contracted PPA period, whereas German equity investors are able to source their returns through the entire life of a project. Australian investors are therefore more susceptible to downside shocks in a project's initial life.

This is best highlighted with an illustrative example.

Worked Example

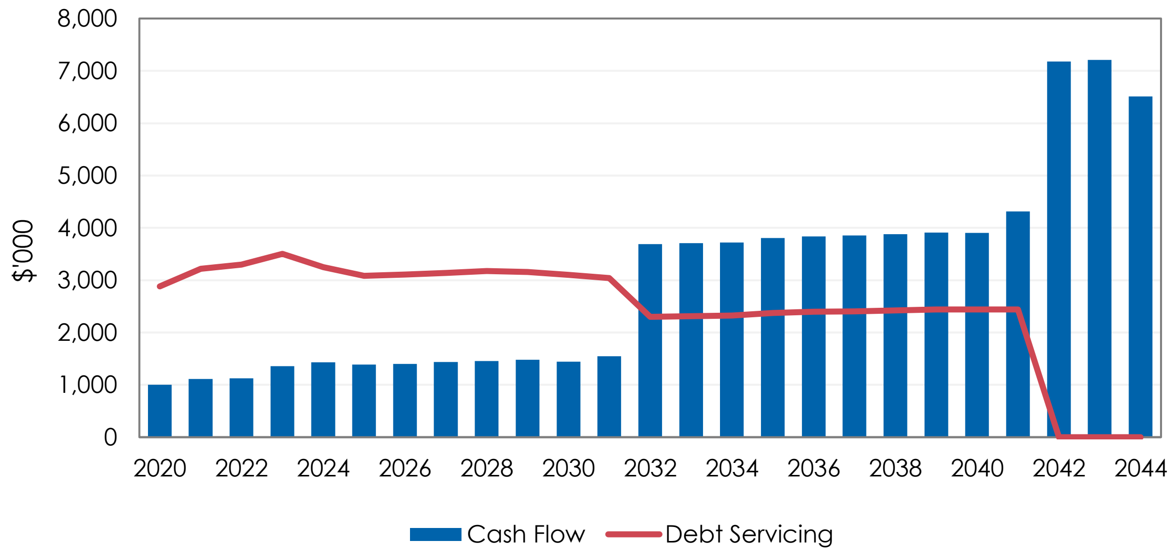
The following example is broadly similar to the earlier example, however in Australia there is no FiT – investors seek revenue certainty through PPAs. As outlined above, Australian lenders will seek to minimise their exposure beyond the PPA period, sculpting the amortisation profile to attain this.

In this example, the debt sizing on acquisition is 65% and decreases to 35% over the FiT period with a 1.35x DSCR level over this time. The final 35% of indebtedness is then repaid over the subsequent 10-year period, leaving an effective three-year debt tail where there are 100% distributions to equity with no debt outstanding. The lower debt payments in the back half of the project life result in a DSCR of 2.2x, meaning the shareholder distributions ramp up over this period and ultimately all cash flows to equity for the final three-year period. This is shown in Chart 4.

It's clear that from an equity perspective, most of the returns are coming from the merchant period after shareholders have repaid the vast majority of debt. In fact, 60% of the net present value in this example can be attributed to the post-PPA pricing period.

This structure has some significant shortcomings for equity investors. There is limited ability to withstand short-term downside shocks relative to a situation where longer-term financing and smoother amortisation profile is available (such as some offshore markets). A project like this would likely have a lock-up and default DSCR of 1.1x and 1.2x respectively. A revenue shock of only 9% and 15% is required to send the project into lock-up and default, as was explored in the prior worked example.

Chart 4: Free Cash Flow to Equity



Source: Whitehelm Capital

RENEWABLE TRANSACTIONS – RETURN COMPRESSION

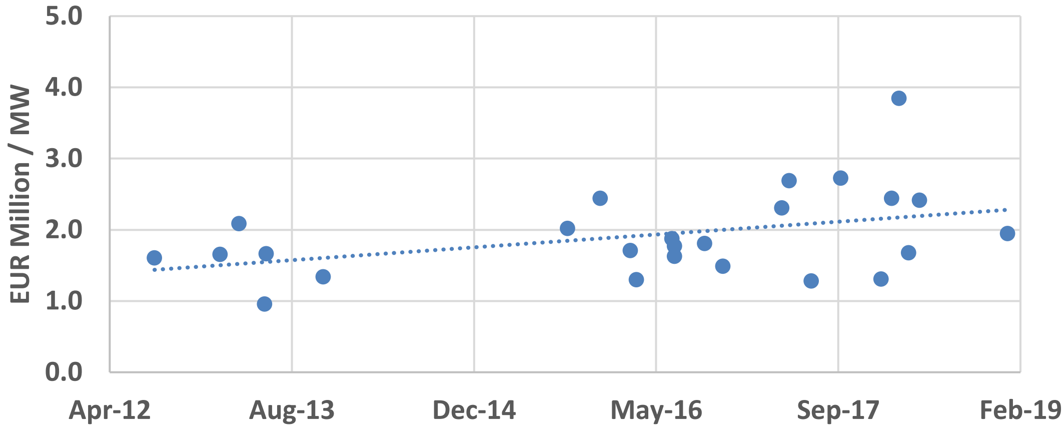
While the prior discussion has elaborated on the risks impacting renewable energy projects, the key part of this article is to explore whether investors are being adequately compensated for the specific risks presented. In order to address this question, we must first turn to market pricing and how this has changed over time.

With offices in both Sydney and London, Whitehelm Capital is in a unique position to observe how renewable energy pricing has evolved over recent years globally. This has been a function of both falling interest rates as well as investors assuming more equity risk for similar assets over time.

We have presented European (Chart 5) and Australian (Chart 6) observed transaction multiples (on a per MW basis) to highlight the return compression we are observing in markets (overleaf). For the European chart, data has been sourced from InfraDeals and covers only operational, onshore wind farms in developed European countries for which data was available – namely France, Germany, Ireland, Sweden and the United Kingdom. Data in this sector is seldom reported publicly, so the analysis presented is for those deals that have been reported and available on InfraDeals.

Notwithstanding the data limitations, it is clear from Chart 5 a strong upward trend of higher enterprise values per MW for operational onshore wind farms. The trend line is included in the chart which has increased by around EUR1 million per MW over the past seven years.

Chart 5: Observed European Onshore Wind Transactions (2012 – 2018)

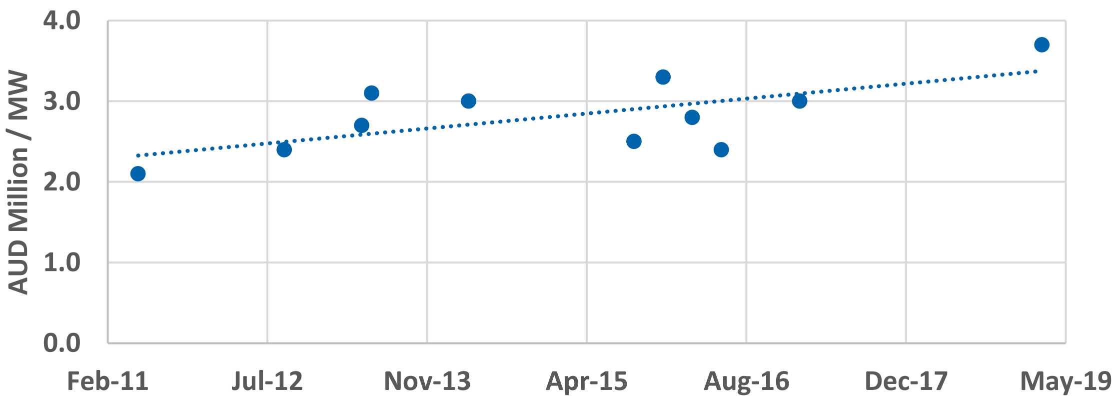


Source: InfraDeals, Whitehelm Capital

Chart 6 tells a similar story in Australia. This data has been sourced from observable transactions disclosed in the market – the Australian onshore wind farm market is a much smaller sector than in Europe with market participants often not disclosing the details of their trades.

Where once investors were paying around \$2-2.5 million per MW for brownfield onshore wind assets, recent transactions show that this has increased significantly to now be close to \$4 million per MW. The trend is similar to Europe – an increase of around \$1 million per MW over the last seven to eight years.

Chart 6: Observed Australian Onshore Wind Transactions (2011 – 2019)



Source: Whitehelm Capital

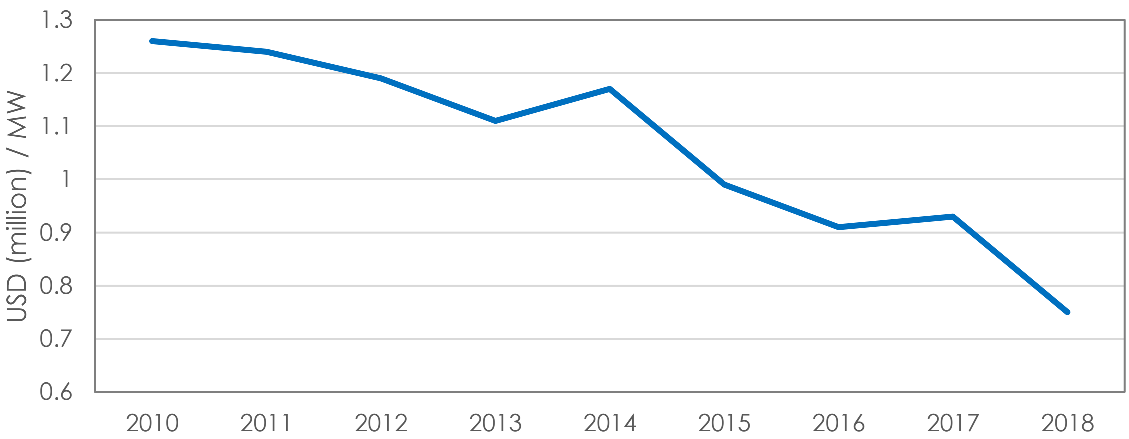
It is an even more interesting situation when you consider these increasing prices against the cost of developing the renewable assets. It is a well-known fact in the industry that the cost of developing wind and solar assets is falling. In the case of solar, advances made in solar panel technology have dramatically reduced construction costs for these assets.

Given we are looking at wind farm transaction multiples, we will turn our attention to turbine costs (this cost makes up the vast majority of a wind farm asset). Bloomberg reports a Wind Turbine Price Index and this has been falling significantly in recent years as shown in Chart 7.

The net price per paid for these assets is exacerbated when considering the replacement cost for wind farms. That is, an investor is having to pay increasing multiples for these assets that are actually becoming cheaper to build and intrinsically worth less.

It is not a difficult conclusion to draw from these charts – investors pay higher prices for assets and this directly impacts the equity returns, compressing the "equity risk premium" on offer. The key question is whether investors are being adequately compensated for the specific risks presented in this article. We provide our views below in the conclusion.

Chart 7: Bloomberg Wind Turbine Price (USD million / MW)



Source: Bloomberg

CONCLUSION

Investment in renewable energy has increased significantly, and it now an integral component of most countries installed generation base. Government policy initiatives promoting the transition to a lower carbon intensive fuel mix support the future development of the sector, and this has been matched by investor demand for green investments.

This wall of "green money" flooding into the sector globally is placing downward pressure on investors' return requirements and is exacerbated by current market conditions (low interest rate environment – in some instances base rates are at an all-time historic lows). We have provided some examples of return compression in different markets demonstrating that pricing has been elevated for several years, and there has been a significant compression in returns without a commensurate reduction in risk for investors.

Reviewing the "Equity Risk Premium" (ERP) that investors have been prepared to accept for renewable assets demonstrates that investors' risk perception is anchored around their confidence in a stable regulatory environment. ERP is effectively the premium earned in excess of the long-term government bond yield (risk-free rate). Typically for operational, contracted renewable projects, this equity risk premium lies somewhere between 5.0% and 6.0%. This premium is supposed to compensate investors for all specific risks of the project – generation, pricing, O&M (availability and O&M counterparty risks), financing and regulatory.

However, as highlighted in the case studies presented throughout this article, there have been repeated instances globally where changes to regulatory structure has resulted in revenues falling by 15% (or more in some instances). The worked example provided shows that a 15% decrease in revenues corresponds to a 4.5% fall in the project life equity IRR. This could be due to the Italian FiT issue or the Australian MLF determination (among others).

This means for these projects, the vast majority of the equity risk premium is consumed by the regulatory factor with the remaining risks still "in play" – that is, a residual equity risk premium of 0.5% to 1.5%. This seems extremely tight and backers of these projects have clearly been left scratching their heads when doing a post-mortem analysis. Fundamentally, investors have mispriced the regulatory risk inherent in renewable transactions, by not appreciating the political and social risk imbedded in the transition to a low carbon economy. Whilst most government renewables policies have been ambitious in its target setting, the practical and commercial reality of the transition has resulted in frequent reversals of decisions and underappreciation of risks.

Governments set subsidies to attract money into the renewables space in light of their climate change goals. It was on these subsidies that investors were attracted to markets such as Italy. When fiscal constraints hit, these subsidies were scaled back and in hindsight the regulatory risk was far greater than first appreciated.

Similarly, in Australia where investors have been hit with higher loss factors. The transmission lines proved that they could not cope with the capacity being added to the grid in certain sections. The Government was faced with a decision – do they roll out the vast amounts of capital required to improve the transmission lines, pass these losses onto the consumer or let the renewable asset owners wear it? The answer was simple thus far, although it may be reassessed in future years following the fallout (and potential impact on future renewable investment).

Going forward in Australia, we believe much more due diligence will be focussed on network issues and potential loss factors – what will the network look like in 3, 5, 10, 15 years? Where will developers concentrate on building new projects and where is the future demand for electricity? These factors all impact the transmission losses of existing generation assets.

Similarly, in European and North American markets, equity investors need to consider the specific risks of any market before committing to a project. What protections are in place in Taiwan to shelter investors from a future tariff change? It confirms a simple principle of investing – you need to know the market you are investing in intimately because generation risk, pricing, O&M and financing risks can be priced in, but country specific regulatory risk can have a far greater impact on returns and is a much harder beast to understand.

As Warren Buffet said – "***Risk comes from not knowing what you are doing***".

APPENDIX: MARGINAL LOSS FACTORS IN AUSTRALIA

Overview of the Australian Market Operator

AEMO is responsible for operating gas and electricity markets in Australia, including the NEM. The NEM includes the five regional market jurisdictions – Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia and Tasmania. AEMO's key responsibilities include:

- power system security and reliability;
- acting as a clearing house for settlement of generator revenues; and
- planning and forecasting to support the long-term investment in electricity infrastructure.

The ongoing development of the physical generation and transmission assets affects AEMO's activities across all three of these key responsibilities. Adding generation capacity to the network (ignoring the impact of different generation technologies) would normally have the effect of improving the overall security and reliability of the network and have a price impact on electricity traded in the NEM, all else held constant. However, additional generation is not normally added evenly across the network, resulting in constraints on certain grid connections where the generation load is more heavily concentrated.

The greater the electrical load placed on transmission lines via additional generators, the greater the resulting electrical losses associated with transporting the electricity along those specific transmission lines. The incremental (or marginal) cost of additional generation impacts pricing at various points in the network – the cost of the transmission losses is borne by the generators, not the end users.

What are Marginal Loss Factors?

AEMO analyses the network in order to account for the interplay between generation load, transmission constraints and distances to determine the final 'net' electricity generated. AEMO publishes MLFs annually which are applied to pricing across the NEM. Generators that supply electricity to a constrained transmission node that is a significant distance from the ultimate end user are paid less per unit of electricity supplied than a generator on an unconstrained line that is close to the demand source. This ensures the transmission losses are paid by the generator (not covered by AEMO or the end users).

Depending on network configuration and generation load, MLFs are generally slightly below or above 1.0. AEMO released their most recent MLF determination in June 2019 which covers the 12-month period ending 30 June 2020. MLFs for generators throughout the NEM range between 0.7566 to 1.0314. The quantum of the MLFs are generally related as follows:

- MLFs less than 1.0: occurs where there is an abundance of generators relative to demand and/or where there are significant transmission distances from the point of connection to the area of demand; and
- MLFs greater than 1.0: in instances where there is a scarcity of generators relative to demand and the transmission distances are short.

Figure 1 and Figure 2 provide an illustrative example of the MLF issue. The transmission line in Figure 1 runs from Cairns/Townsville to Brisbane where the Regional Reference Node (RRN) is located. Despite the extensive distance between the power station and the RRN (where the electricity price is determined), there are minimal competing generation assets feeding into the same transmission line. Compare this to the large number of power projects in Figure 2, which will result in higher transmission losses and a lower MLF.

Figure 1: Power Flow and Losses (Uncongested Transmission)

Figure 2: Power flow and Losses (Congested Transmission)

Source: AEMO

WHY ARE MLFS IMPORTANT?

An MLF determined by AEMO has two important, but correlated impacts on generators:

- The settlement price received by the generator; and
- The stack order of the generator relative to competing generators.

The figure below provides an example comparing two generators with MLFs between 0.95 and 1.05.

In the example set out above, if both generators bid into the NEM at $30/MWh, as a result of MLFs determined by AEMO, there is a difference in pricing ultimately assessed at the regional reference node. As Generator A is effectively bidding $28.6/MWh (versus $31.6/MWh by Generator B), the generator with the higher MLF will be dispatched. In order for Generator B to compete at the regional reference node, it will effectively have to bid a price equivalent to $27.2 at the connection point (pre-MLFs).

In addition to the impact on the stack order of the generators, and the settlement pricing received, MLFs will also impact the large-scale generation certificate calculations by the Clean Energy Regulator, which further impacts financial performance of large renewable projects subject to reductions in MLFs.

Figure 3: MLF Impact on Stack Order

Source: AEMO MLF Engagement Session, September 2018

Recent AEMO Determination

As mentioned above, AEMO provided an update to the relevant MLFs for generators in the NEM in June 2019. A number of material reductions across the market were included in the determination (reductions in MLFs were more prevalent than increases in MLFs). These material reductions in the assessed MLFs significantly reduce potential earnings over the course of the next 12 months and potentially beyond should the transmission lines not be upgraded (something out of the control of the generators). The charts below set out the quantum of the annual change by generator, and a summary of some of the larger MLF reductions observed.

In describing the reasons for the reduction in MLFs, AEMO noted:

"New generation is increasingly connecting at the periphery of the transmission network, including north-west Victoria, south-west New South Wales, and north and central Queensland. In these areas, access to renewable resources is good, ***yet the network is electrically weak and remote from the regional reference node*** *[emphasis added]. This additional generation has resulted in a large reduction in MLFs in these areas."*[4]

Furthermore, the reduction in MLFs is exacerbated by the high correlation in generation profiles, where new generation tends to be running at the same time as other nearby generators, as well as during periods of light load in the area. This is particularly evident when observing the renewable generators which experienced large reductions in MLFs over time.

Chart 8: Distribution of MLF Determinations (FY20)

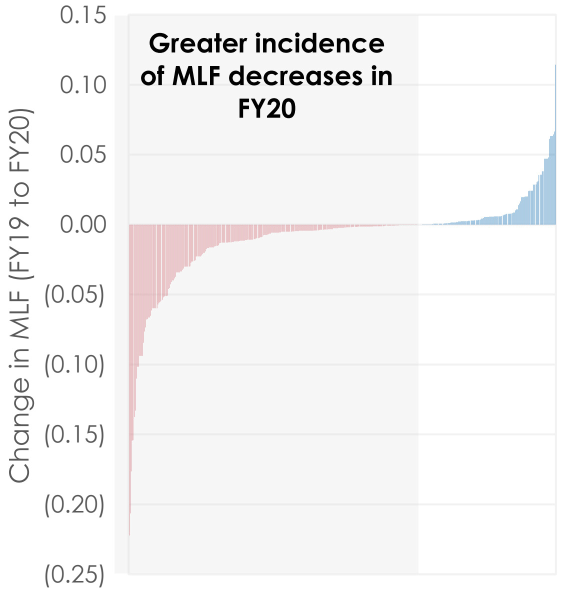
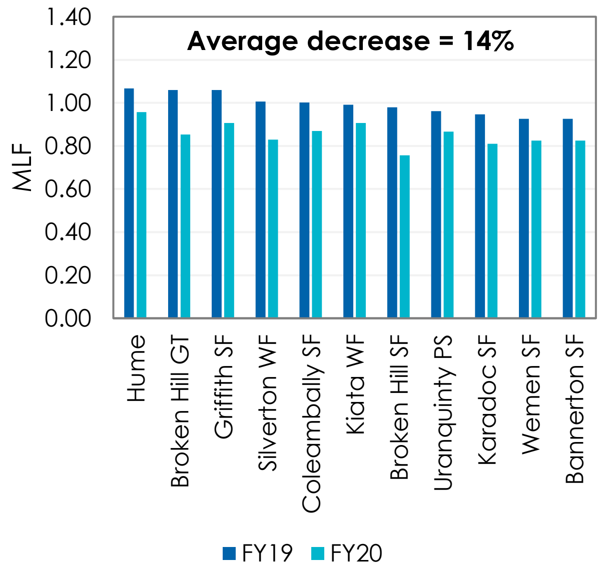


Chart 9: Major Changes to MLFs (FY20)



Source: AEMO

[4] Updated Regions and Marginal Loss Factors FY 2019-20, AEMO, June 2019.

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