Introduction

As we go to print the Australian yield curve is inverted out to five years and has continued to step down across all points on the curve relative to last quarter. However, while the yield curve is inverted and has some market participants sounding recessionary warnings, we are yet to see an associated sharp move wider in credit spreads which would indicate that fear is spreading.

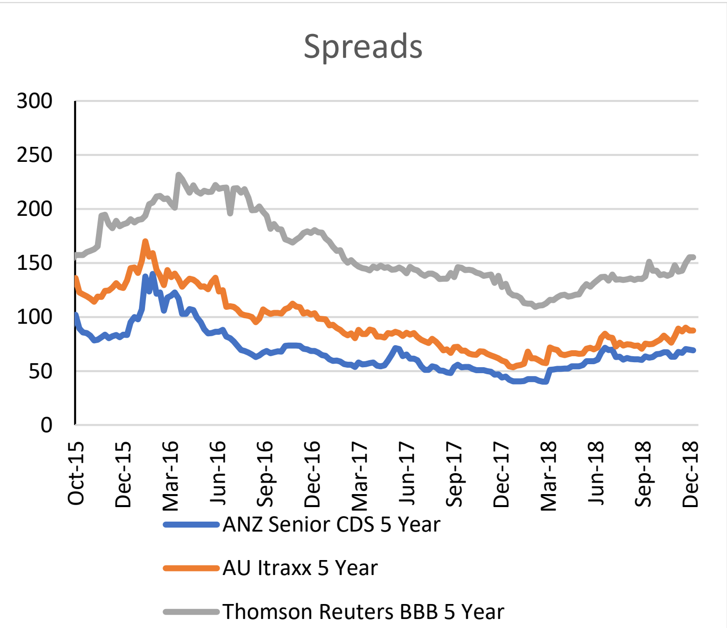
This quarter we have two articles on electricity. The first looks at investing in renewable energy from two different standpoints, the first being of an equity investor, and the second as a debt investor. The second electricity article looks at marginal loss factor risk that until now has not been paid much attention by renewables investors. Finally, stepping away from the energy sector, we take a look at airports and review airport passenger numbers focusing on Chinese passenger growth.

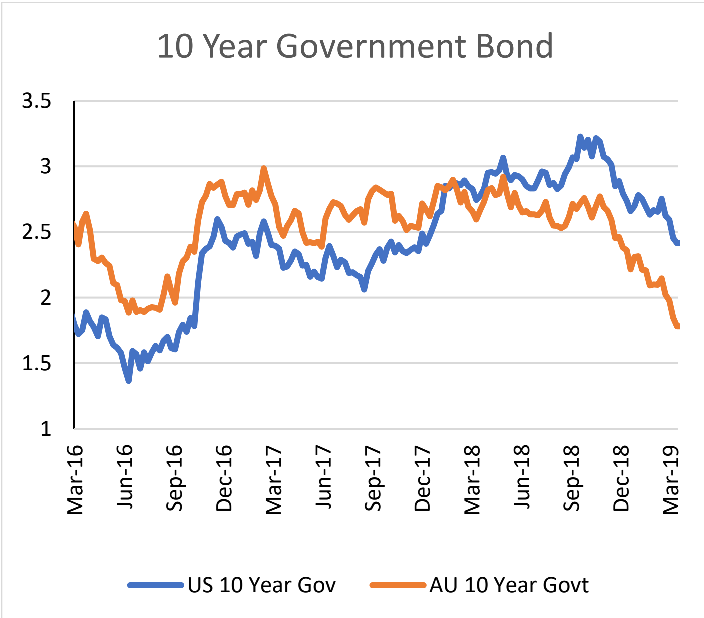
Markets update

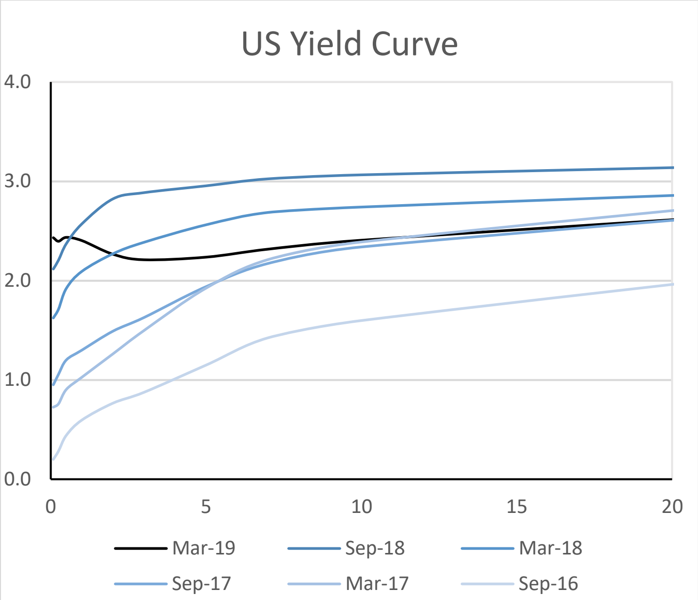
The equity markets have rebounded with a V shaped recovery since the last quarter. Over the last few years the US Federal Reserve (the Fed) has been steadily raising rates from zero to the current range of 2.25 to 2.50%. The Fed's monetary policy stance changed over the quarter to a *'patient approach'* with rates effectively on hold, with further rate raises unlikely. Interest rate derivative markets are pricing no further interest rate hikes for the rest of 2019 and even some chance of a rate cut before the end of the year. The change in Fed stance has caused interest rates to fall and, in the US, has pushed out the yield curve inversion to the 10 year mark.

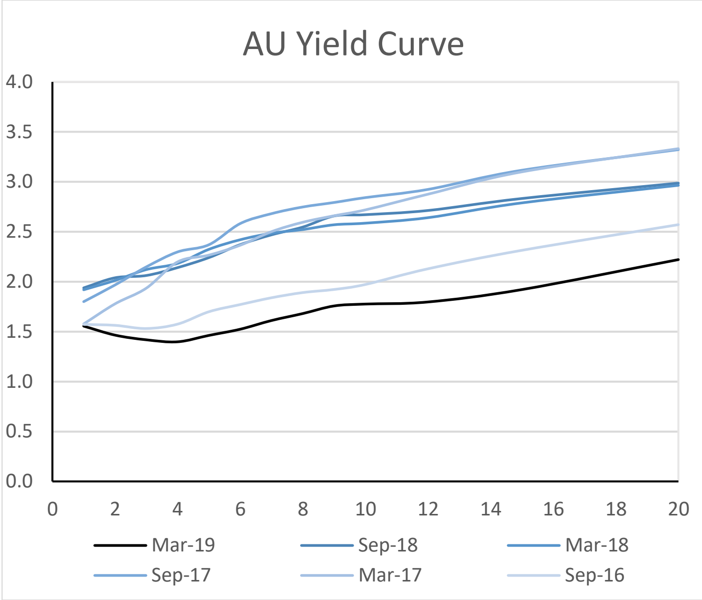
The Fed also announced this quarter that it would scale back its balance sheet runoff this September (which is still four times the size it was prior to the GFC at about $4 trillion). In summary, bond markets are now pricing in a greater probability of an economic slowdown than in the prior quarter and the Fed is responding as it moves away from its tightening bias and the reduction in pressure on US dollar liquidity. Interestingly, equity markets appear unfazed with a quick recovery from the ructions of at the end of 2018 over the course of the quarter.

At home, and as mentioned in the introduction above, the Australian yield curve is inverted out five years and materially lower across all time horizons relative to last quarter. But we are keeping an eye on credit spreads, which at present are remaining stable (indicating that credit markets are not seeing a recession on the horizon).









New issuance and refinancing

Date	Borrower	Instrument	Size (m)	Term (Yrs)	Curr.	Pricing/Notes
January	NSW Land titles	Loan	1800	5	AUD	Refinance
January	Victorian Schools	Loan	100/100	5/10	AUD	Refinance
January	Queensland Schools	Loan	190	5	AUD	Refinance
January	Perth Waste to Energy	Loan	250		AUD	
January	IntelliHUB	Loan	35		AUD	Smart meters
February	Momentum Trains	Loan	990	7	AUD	BBSY+170. NSW rolling stock.
February	Epic Energy	Loan	200	5	AUD	Moomba to Adelaide and Southeast System pipeline
February	Flinders Ports	USPP	U$91/A$50	10/20	USD/AUD	4.08%/4.72%. Refinance
March	Eastlink Toll Road	Bond	177	7	AUD	Refinance
March	Townsville Airport (QAL)	Loan	50			NAIF loan
March	Transurban/QML	USPP	144/245/180	10/12/15	USD	3.96%/4.06%/4.16%
March	Transurban/QML	USPP	30/40	10/15	AUD	4.16%/BBSW+2.15%

Equity and other news

- A consortium of Pacific Partners and DIF have won the Momentum Trains contract to design, build, finance, and maintain a new generation of rolling stock to replace the aging NSW train fleet. The contract includes the construction of a maintenance facility at Dubbo. Deliveries of 117 vehicles are due to occur in 2022 with all trains entering service in 2023.
- Macquarie Global Infrastructure Fund is looking to sell its 51% stake in Hobart Airport. A Macquarie consortium took control of the airport in a $350m deal in December 2007. The sale comes as the airports planned terminal redevelopment and 500m runway extension is due to be finalised.
- The Northern Australia Infrastructure Facility (NAIF) has agreed to provide a $50m loan to Townsville Airport as part of a $80m project upgrade to terminal facilities.
- AMP Capital has won the auction to buy a 100% stake in ANU student accommodation from Infratil and the Commonwealth Superannuation Corporation. The ANU student accommodation deal includes a 30 year concession over nine student residences on campus.

Renewables – perspectives from different parts of the capital structure

Superannuation funds assign the bulk of their infrastructure allocations to infrastructure equity. Infradebt is an active lender to renewable energy projects. We thought newsletter readers might be interested in the different perspectives – that is debt versus equity – of the same underlying project – using a typical renewable energy project as an example.

While the results of this show that there are some risks that both debt and equity need to worry about, there are also significant divergences.

Project Perspective

Let's start our analysis of a renewables project by looking at it from a whole of project basis. On this basis, the most important drivers of returns are construction costs, revenues and operating costs.

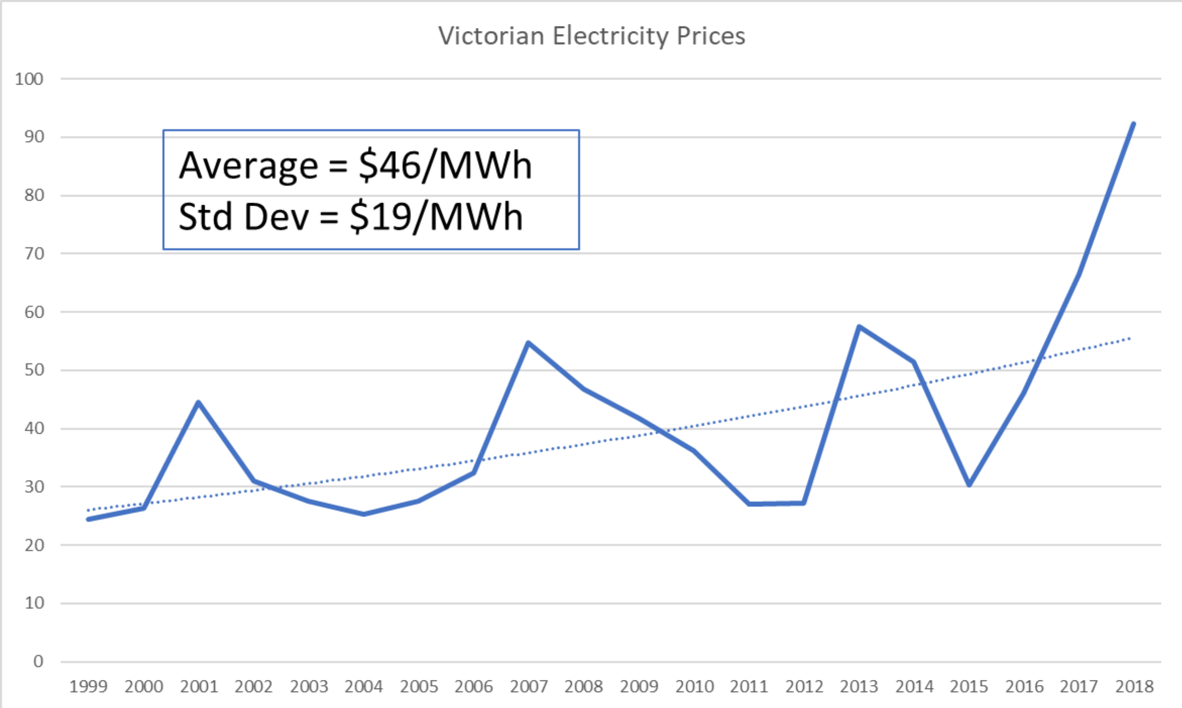
Construction costs

Solar construction costs vary based on site acquisition costs, Engineering, Procurement, and Construction (EPC) arrangements as well as grid connection costs. Often the biggest variant between projects relates to grid connection. Single axis tracking costs range from $1.20-$1.50/W. Fixed tilt solar farms such as the Belectric system, are materially cheaper, at around $0.90-$1.10/W. Although fixed tilt is cheaper, total forecast generation is usually 15% or so less. Wind project construction costs are $1.90-$2.10/W with the most significant variations between sites relating to grid connection and forecast yield.

While costs have fallen substantially compared to even two or three years ago, the pace of construction cost decline has stalled on the back of a lower Australian dollar (most equipment components are effectively priced in USD or Euro). Assuming the AUD stabilises at current levels and looking out longer term, it would be reasonable to expect that costs will continue to fall in real terms through technological improvements. This has important implications for long-term revenue assumptions, as projects commencing today, will end up competing against new entrants with lower capital and operating costs.

Revenues

Electricity in the National Electricity Market (covering Eastern Australia and SA) is traded via a five minutely auction system, whereby generators bid to supply the prevailing level of demand. Prices are extremely volatile (they vary between -$1,000 and $14,500 MWh). The following chart shows the history of annual average prices for the Victorian pool. Even on an annual basis, volatility is high with a standard deviation of $19/MWh or around 40% of the long-run average.



The majority of projects have some form of offtake in place with varying degrees of credit quality. The latest Power Purchase Agreements (PPA) we have seen are coming in are at the low $40s/MWh (2018 real) for high credit quality counterparties. PPA tenor and indexation arrangements vary. Contracts with full CPI indexation are less common. PPA contract terms have shortened from the 20 years contracts in the era of the ACT government (S&P AAA) reverse auctions, these days PPAs are typically 10 years and in some cases shorter, off-takers may be low investment grade, but increasingly off-takers are also unrated.

Over the last year or two, projects have been entering into lower and lower PPAs offtake prices. Effectively proponents are willing to sacrifice substantial amounts of project revenue (compared to current spot/near term futures prices) for the certainty of having at least a portion of revenues locked in via a PPA. The contracted proportion of generation has also been falling, nowadays it is common for projects to follow a hybrid revenue model – with 40-60% of revenues locked in via a PPA (over say 10 years) and the balance on a merchant basis. Given the shorter tenor of the PPA, on a Net Present Value (NPV) basis, these projects might have less than 20-33% of revenue locked in with a PPA (that is, less than half of debt).

This strategy aims to take advantage of the substantial premium between expected merchant pricing (typical assumptions are long term real spot prices of $70-80/MWH in 2018 dollars) and PPA pricing ($40-50/MWh). For these projects, the PPA is a necessary evil as part of securing debt financing, with the implicit Internal Rate of Return on the merchant portion of the project substantially above that of the contracted portion.

Operating costs

The older wind turbines carry a higher variable cost component when compared to the more modern wind farms we are seeing. In simple terms, maintenance costs are reasonably consistent on a per turbine basis, which means if you double the capacity of the turbine then operating costs per MWh fall substantially. This is reinforced by the higher capacity factors of new taller turbines (which can take advantage of lower wind speeds). Wind operating costs are around $20-30/MWh, and solar $10-15/MWh.

Solar operating costs are lower than for wind and are often significantly lower for large projects compared to smaller projects.

WACC/Valuation Multiples

It is difficult to assess WACC/valuation multiples across renewables projects due to the multitude of different merchant price assumptions. An 8% WACC on the assumption that long-term merchant pricing is $100/MWh, is not comparable with to a 6% WACC for a project that assumes $60/MWh.

With this caveat – that assumptions vary massively – fully contracted projects are often on a 5%-6% WACC (reflecting high leverage and low equity returns) where projects with a substantial merchant component have WACCs more in the 7-10% range.

Project Operating Lives

Most projects are assessed on assumed operating lives of 25-30 years. It is usually possible to get major component warranties for 20-25 years. For windfarms, which are more operationally complex than solar, major turbine manufacturers will provide fixed price Operations and Maintenance (O&M) contracts (including lifecycle replacement) running out 25 years. Some equity investors include re-powering assumptions (i.e. running the plant for an extra 5-10 years beyond planned life). Debt investors normally assess projects (and require debt to be fully amortised) over an 18-20 year period.

The practicality of extending plant life is relatively untested (given that most projects are quite new). For wind, one challenge will be that by the time the plant gets to 25-30 years of age, the turbines are likely to have been superseded by new models – which may mean sourcing parts/O&M is expensive compared to new projects.

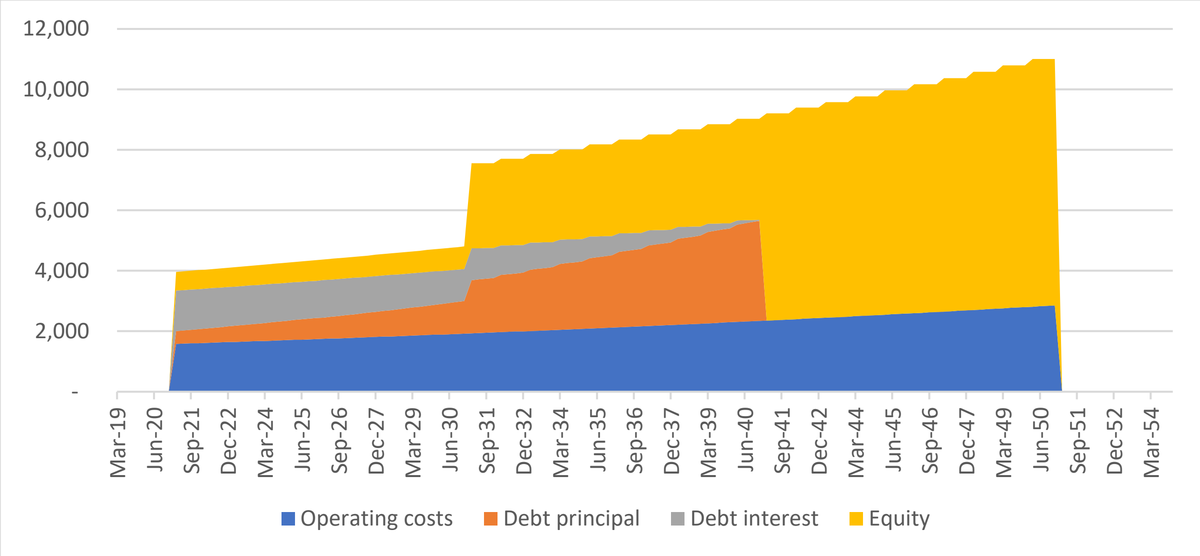
Concluding Remarks at Project Level

When comparing renewable energy projects with other infrastructure projects, we would make three key points:

1. Merchant revenues are significantly more uncertain than for other infrastructure asset classes.
2. Technological cost deflation. Existing projects need to compete against new entrants often with lower construction/development costs. This is a deflationary headwind on project revenues and, hence, asset values.
3. For projects with a PPA – counterparty credit risk is a key element of transactions – which often doesn't exist for other infrastructure assets, where either key counterparties are governments (hopefully very low credit risk) or a diffuse set of users (eg ports, toll roads and, hence, individual counterparties don't usually have a material impact on returns)).

Equity versus Debt – Example of Stereotypical Wind Project

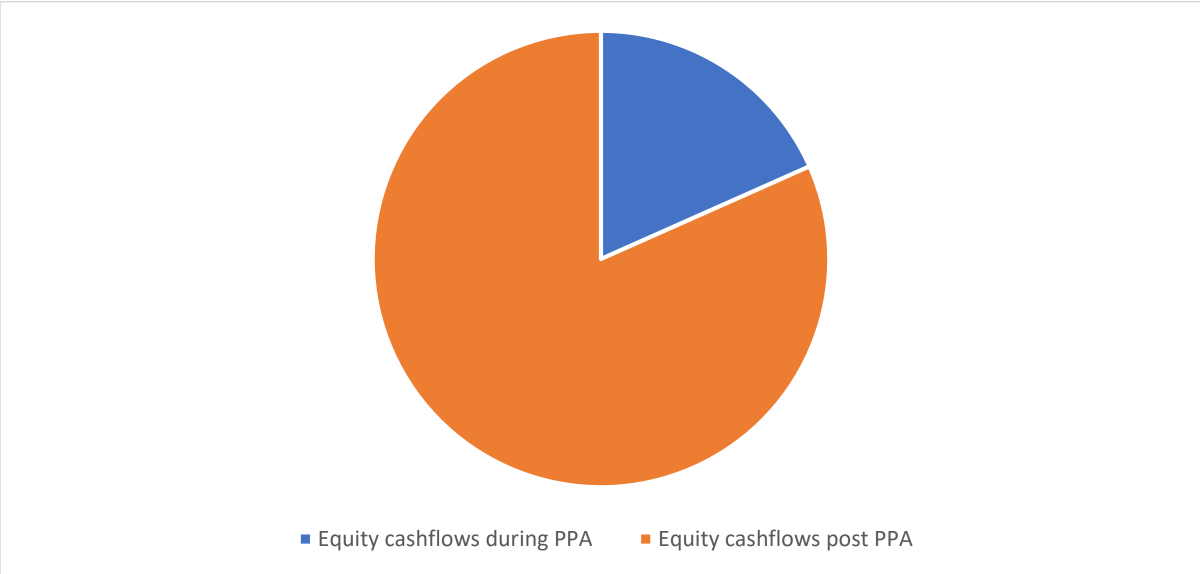
The following section considers a typical wind farm project with a fully contracted 10 year PPA (30 year operating life) and financed with 60% senior debt and 40% equity. The chart below shows the attribution of operating cash flows. In this example, the long term merchant price is $67/MWh real and the PPA price is $45/MWh. The unlevered project IRR is approximately 7% p.a (pre tax).



Using a 7% discount rate, the NPV of PPA versus merchant revenue is split 40%/60%. Investors have approximately 60% of the project exposed to merchant prices. That is, the NPV of the merchant portion of revenues is 1.5x the equity of the project.

Equity Perspective

A key feature of renewable energy projects – from an equity perspective – is that equity cash flows are quite back-ended. This reflects the fact that revenues are lower during the PPA period and PPA revenues are disproportionately used to paydown debt.

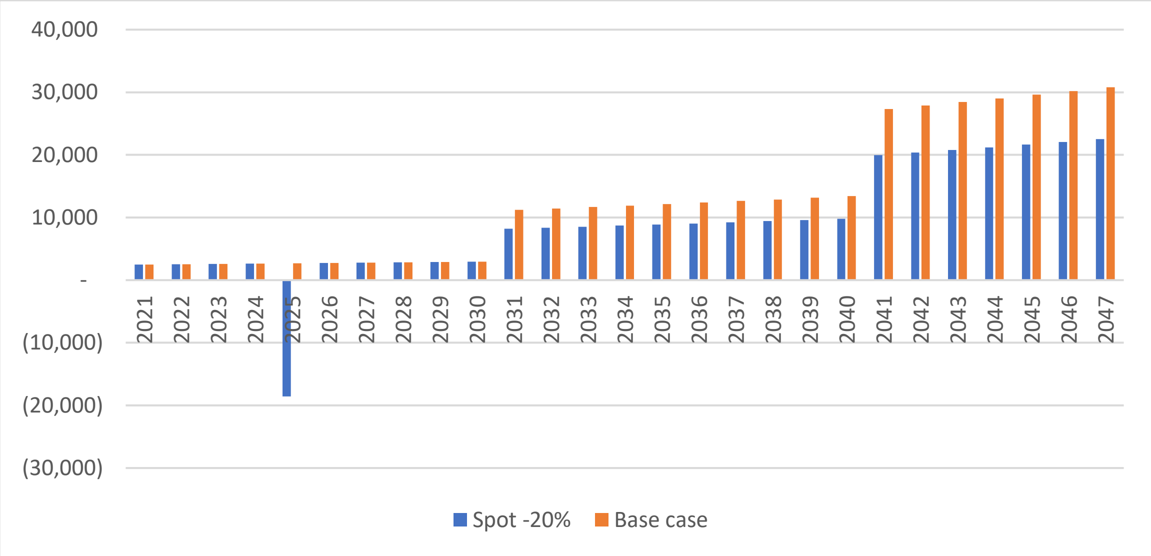


The back-ended nature of equity distributions has three key implications:

- equity valuations will be quite sensitive to level of interest rates. In our example project, the weighted average tenor of the equity cash flows is 23 years (or the 21st year of operations). A 1% increase in equity discount rates would result in a 14% fall in equity valuations.
- Equity returns are highly sensitive to assumptions about merchant revenues. For example, if merchant revenues were 10% lower than forecast, then the NPV of equity falls 18% (using an 8% discount rate).
- It is important to understand that lower expected merchant revenues can even substantially impact equity during the PPA period via the need to refinance the project's debt. Typical financing structures for renewable

projects is the inclusion of a 20 year "mini-perm" with five yearly refinances. That is, debt is structured as a sequence of five year loans, each ending with a bullet maturity, over a 20 year amortisation profile. This amortisation profile is sized based on the project's expected revenues. Thus, if merchant revenue falls (or more importantly, is expected to fall) then the target amount of debt outstanding is reduced. This implies a lower debt size at the next refinancing point.

In our example project, if expected merchant revenues post year 10 fell by 20% (from $67/MWh to $53/MWh), this would result in an approximately 18% lower debt size at the first refinancing (assumed to be at the end of year 5) and a substantial equity injection (26% of the original equity amount). The equity IRR would fall from 8.7% to 6.3%. Clearly this is a downside scenario, the converse also applies, an increase in expected revenues would allow an increase in debt size and a substantial one-off super distribution to equity.



This means that even for a fully contracted project, equity returns can be quite sensitive to the long-term outlook for merchant prices, despite being contracted in the short term.

Another important issue from an equity perspective, is that returns are quite sensitive to generation outcomes. This is relevant at both a short time and long-term time scale – for example it is not uncommon to have windy or below average wind years where generation for a windfarm is 10% below (or 10% above) the long term average.

In particular:

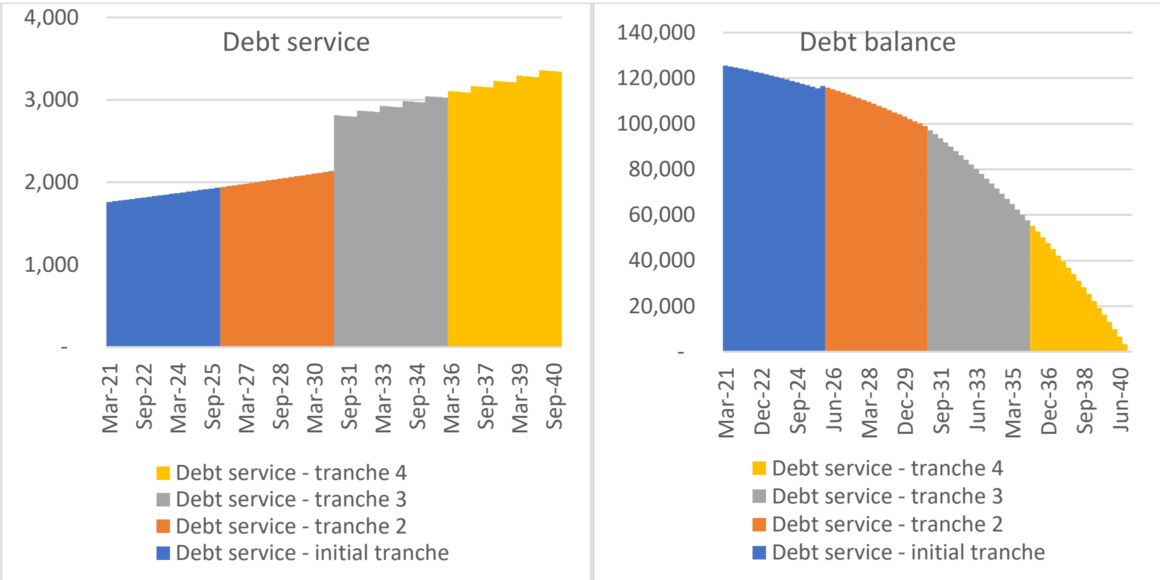
- Short term basis. For contracted projects debt is usually sized at 1.25-1.35x DSCR during the PPA period. This means that debt service is sized at 74%-80% of forecast operating cash flow. This means a 10% shortfall in generation (which would result in a 10% fall in revenue) could result in a 40%-50% reduction in equity distributions (or payments could be completely cut off if debt covenants are triggered). Thus, year to year equity distributions are likely to be quite volatile.
- Long-term basis. Putting it politely, the history of forecasting the generation yield of windfarms is patchy. Many projects have ended up with long-term generation well below pre-construction forecasts – a Fitch study found that three quarters of wind Projects were operating below their P50 levels, and 43% were lower by more than 10%. A 10% permanent shortfall would reduce the value of equity by 20%.

Debt Perspective

As noted above, most renewable projects are financed using a mini-perm financing structure. That is, debt is sized on the basis of a notional amortisation profile (typically 18-20 years) with a refinancing every five or so years. This means the legal maturity of the debt at any point of time is five years or less. To mitigate interest rate risk, projects usually enter into interest rate swaps, usually matching the tenor of the PPA (and sometimes longer).

Typical debt structures for renewable projects:

- have low interest rate risk – ie most commonly structured on a floating rate basis;
- have a much shorter life than equity. The maximum tenor of debt is typically 5-7 years, allowing debt investors get to reset credit margins and debt size every five years. This creates a refinancing risk for equity (and existing debt if the changes are big enough). This substantially reduces the valuation volatility of debt. For example, a 1% rise in credit margins (the equivalent of a 1% rise in equity discount rates – for a debt investor) would only result in a 4-5% fall in debt values (and that is a worst case, if it happened immediately following issuance).
- debt investors can be much more sanguine about generation outcomes. Given debt sizing parameters (target DSCRs of 1.35x during the PPA period and 2.0x on the operating period) normal year to year variation in generation can be relatively easily absorbed (it just reduces equity distributions). Similarly, these buffers can absorb reasonably significant long-term forecasting risk (provided there aren't other adverse events at the same time).



That all sounds great – but what are the key risks for debt investors?

Ultimately the key risks to debt are scenarios (including combinations of adverse events) that result in the value of the project falling below the value of debt. When this happens – equity is no longer available as a buffer – and the pain will fall on debt.

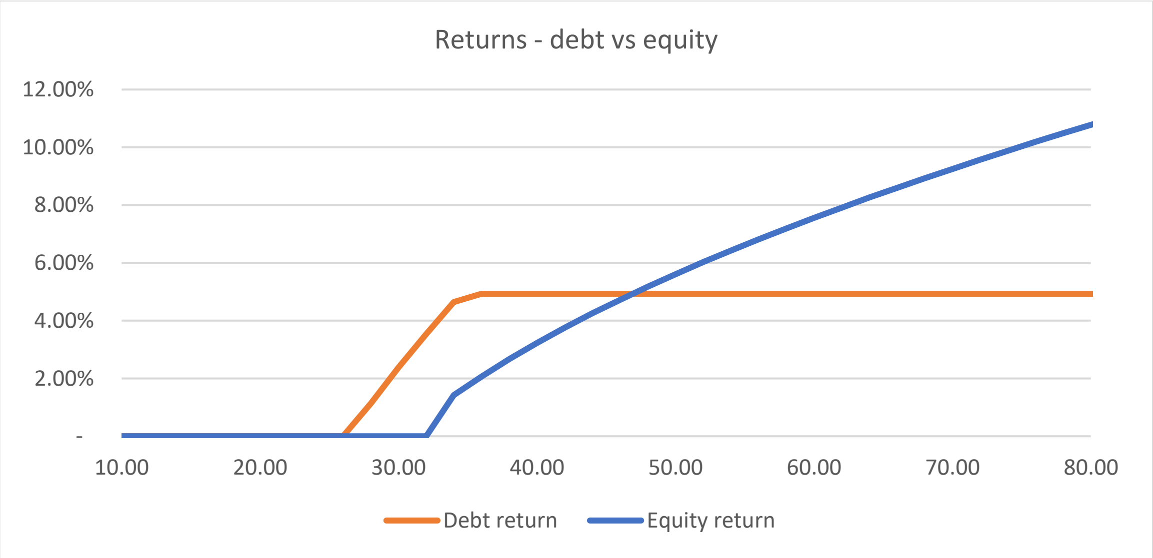
The key risks debt investors need to worry about are:

- <u>Substantial construction delays/cost overruns</u> (eg builder insolvency during construction). Most projects are financed with buffers to absorb a 3-6 month delay in construction. In these instances – equity returns will be affected, and debt interest may need to capitalise for a period – but it is unlikely that debt will suffer a permanent loss. More substantial delays/overruns – and in particular a mid-construction contractor insolvency – are likely to be more challenging. Perversely, fully contracted projects which have higher gearing are likely to have a higher risk to debt from construction issues (as higher gearing means a smaller equity buffer). Also, PPAs often have penalties if electricity isn't delivered by a certain date (resulting in a doubling up of losses).
- <u>PPA counterparty insolvency</u>. Insolvency by the PPA counterparty has the potential to have catastrophic impacts on project value. Critical to the impact is whether the PPA contract locks in prices above or below merchant pricing at the time of insolvency – i.e. is the PPA in the money or out of the money? The hit to project value comes in two forms. First, the extent to which current and prospective merchant revenues are

lower/higher relative to the PPA price at the time of insolvency. Second, the project will have less locked in revenue and, hence, even if the overall level of cash flows was unchanged, the amount of debt those now more volatile cash flows can support will have fallen considerably (ie DSCR sizing goes from 1.25-135x to 1.90x-2.0x).

- Substantial falls in the long-term merchant revenue assumptions. As outlined above, even with a 10 year PPA in place, a relatively substantial proportion of project NPV (around 60%) is exposed to merchant pricing. These merchant sizing assumptions drive the size of the debt outstanding at the end of the PPA. Given this is 10+ years in the future, a key risk for current renewable projects is technological progress driving a substantial fall in levelised costs, and these lower cost new entrants then competing down electricity prices. To illustrate this – current PPA prices are $40-50/MWh (for a 10-15 year contract with a high quality offtaker), while merchant pricing assumptions are often $60-80/MWh (real 2018) in years 10+ of a project. What would happen if future prices turned out to be consistent with current PPA pricing? In this scenario – ie a 40-50% shortfall compared to current merchant expectations – it is possible for the debt outstanding at the end of the PPA to exceed the value of the project (or at least be very close to it). In this scenario, it would be extremely difficult for existing debt to be refinanced and debt may suffer a loss (or forced conversion to equity) through the process.

Another way of looking at the above issues (in particular the last bullet point) is to compare debt and equity returns under consistent merchant price assumptions. Under the base case, in this example, debt is expected to return circa 5% and equity around 9%. In low price scenarios, say $30-50/MWh debt returns would actually exceed those for equity. To get double the debt return and earn a 10% equity IRR, requires a merchant energy price around $70-80/MWh (2018 real). Large energy users are currently locking in energy at a $40-50/MWh price. Time will tell who is correct!



Conclusions

Hopefully this analysis of a renewable energy project through two different lenses has been useful. The key conclusions to be drawn from this analysis are:

- Debt and equity – even in the same project – are very different. For renewables, equity is long-duration and back-ended, while debt is short duration with a fixed return.
- Which risks matter depends on your perspective. From an equity perspective, there are many factors that can have a meaningful positive or negative impact on returns. For debt, many smaller risks are easily absorbed by the buffer of equity (and that's why returns are much lower).

- For both equity and debt – long-term outlook for merchant pricing can be a critical driver of returns. This is an issue on which there are more opinions than market participants – but given its importance, no investor in renewables can afford to be without their own opinion.

Airports – the Changing Composition of Australia's International Passenger Mix

International passenger growth is a key driver of profits for Australian airports. This article outlines the substantial changes in the composition of international passenger travel through Australia's major airports.

International passengers are more profitable and, hence, more important for airports. In particular, international passenger landing charges are typically substantially higher than those for domestic passengers. For example, at Sydney airport international passengers are only 38% of total passenger movements but 70% of aeronautical revenues. On top of this, international passengers also spend significantly more while at the airport – providing a substantial proportion of the retail portion of an airport's revenue streams.

Over the last decade, the greatest contributor to international passenger growth in Australia has come from China. Since Deng's reforms in 1979, Australia has ridden the coat tails of the Chinese boom. While sales of coal and iron ore are probably what people think of first, there has also been a significant surge on international travel built on an emerging middle class in China. This has seen China/Hong Kong passenger numbers surge from 2.6 million to 6.4 million over the past decade. This growth is all the more extraordinary when you think that the baseline passenger numbers were dominated by Hong Kong and that airport's role as part of the "Kangaroo" route to Europe.

There are signs that the break neck economic growth in China is slowing, there are also rising geopolitical tensions as China asserts its increasing sway on the global stage. For example, in 2019 we have seen the Chinese Government implement import restrictions on Australian coal as well as turning back an Air New Zealand flight to Shanghai.

We are not geopolitical experts at Infradebt, however we can see that China's rise is unsettling the existing world order. Australia's tourism and overseas education sectors – both of which are big drivers of airline travel between Australia and China – could be caught in the cross fire of broader geopolitical tensions.

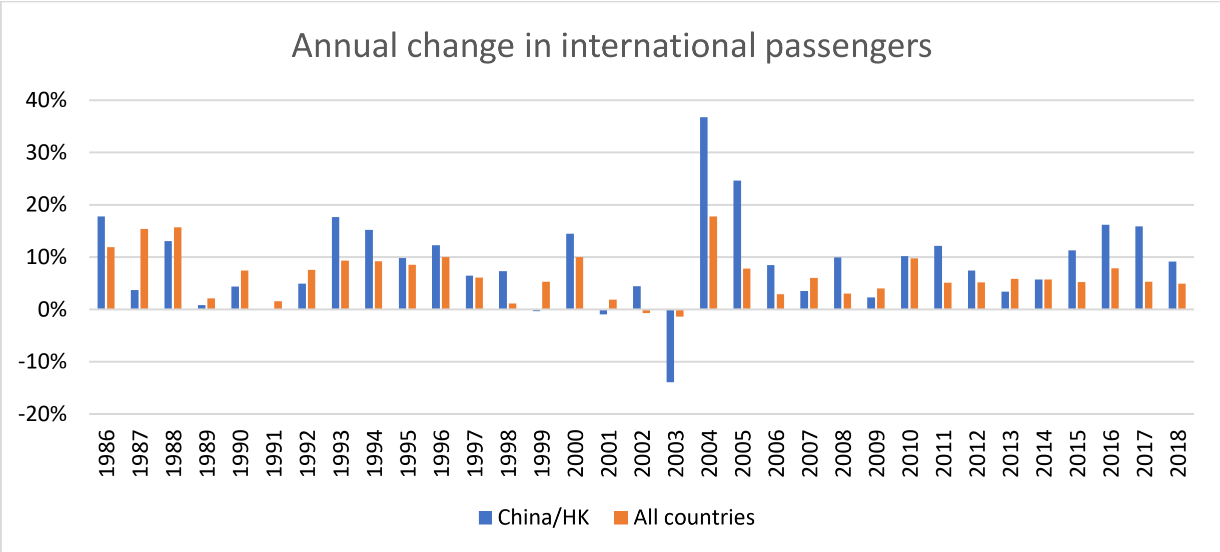
Across all Australian airports, New Zealand continues to be the highest international country pair but will soon be overtaken by China in the coming years growth remains on trend. China currently is the second largest source and destination of international passengers and is the main driver behind Australia's international passenger growth numbers. Other major contributors are Singapore and the UAE which act has hubs for passengers travelling from Europe and the broader Asian/Indian region.

Rank	Country	2018	2008	10Y Growth %	2018 % total
1	New Zealand	7,159,633	5,133,323	39%	17%
2	China/HK	6,395,767	2,632,952	143%	15%
3	Singapore	5,626,014	4,095,673	37%	14%
4	UAE	3,778,420	1,267,385	198%	9%
5	USA	3,233,473	1,685,284	92%	8%
6	Indonesia	3,149,349	824,499	282%	8%
7	Malaysia	2,286,119	1,145,128	100%	5%
8	Thailand	1,595,441	1,364,246	17%	4%
9	Japan	1,469,247	1,253,627	17%	4%
10	Other	6,877,436	4,069,913	69%	17%
	Total	41,570,899	23,472,030	77%	100%

How disruptive would it be for Australian airports if Chinese passenger numbers were to fall sharply due to some geopolitical manoeuvring or perhaps due to a sharp slowdown in growth or Yuan devaluation?

One of the great things about airports – from an investor's perspective – is that history is littered with crises and catastrophes of all sorts. These can be used to understand the potential aggregate impact of an event as well as to provide a sense of how quickly it may take to recover to the underlying trend.

In this context, the SARs epidemic (2002/2003) provides a useful comparator. As can be seen in the chart below, this saw very substantial falls on individual routes (blue bars) – but as you can see (orange bars) the impact of aggregate passenger numbers was pretty modest and recovered quickly.



A further mitigant is the changing nature of international passengers from China to Australia. Overtime we expect that visiting family, friends and relatives (VFFR in industry parlance) will become an increasing share of international travel between the two countries. VFFR travellers are less price sensitive and less volatile than tourist travel. Many Chinese immigrants return to China every year for the Lunar New Year, where an estimated 3 billion people journey to their home towns.

Overall, while the share of passengers to/from China has grown substantially (to 15%), it is still relatively modest and so even a substantial shock to these passengers would be more likely to result in a slowing/flat-lining of aggregate passenger growth rather than anything more substantial. Of greater importance to airport investors is probably the potential for sharply higher interest rates (which doesn't seem to be a problem in the short-term given the massive rally in bond yields over the past few months) given their high valuation multiples.

MLFs – an underappreciated risk to renewables projects

Marginal loss factors (MLF) are an often overlooked element of the regulation of the National Electricity Market (NEM). The Australian Energy Market Operator (AEMO) has just released its draft MLFs for 2019-20. These results provide a sharp reminder of the risks posed by MLFs to generation projects.

What is a MLF? A MLF is a measure of the marginal transmission losses for a generator (or load) on the NEM. It reflects the physics inherent in our electricity network – that energy suffers losses due to resistance, relative to the distance travelled between the generator and end user (and the capacity of that part of the transmission network). MLFs are a multiplier that decreases (or increases) the revenue for generators to account for transmission losses between the generator and the regional reference node (the notional load centre point of each State). Formulaically, from a revenue perspective, the impact of MLFs can be seen as follows:

Revenue = MLF x RRP x Output

Where

MLF = marginal loss factor

RRP = regional reference price

Output = output in MWh measured at the plant gate (ie before transmission losses).

MLFs scale up (or down) generation at the farm gate. Historically, they have typically been between 0.95 and 1.05. That is, a generator with a MLF of 0.98 would get 98% of the state pool price per MWh for each MWh generated.

AEMO calculates MLFs for each generator on a financial year basis. MLFs are estimated based on the pattern of generation and demand for the last year. This accounts for when a generator generates as well as its location relative to demand. Generators that are distant from load centres (at the time they generate) and/or transmit over weak or congested parts of the transmission network will have poor MLFs (ie an MLF less than one). By contrast, generators that are close to large demand centres (that are using power at the time they generate) will have good MLFs (ie MLFs greater than one).

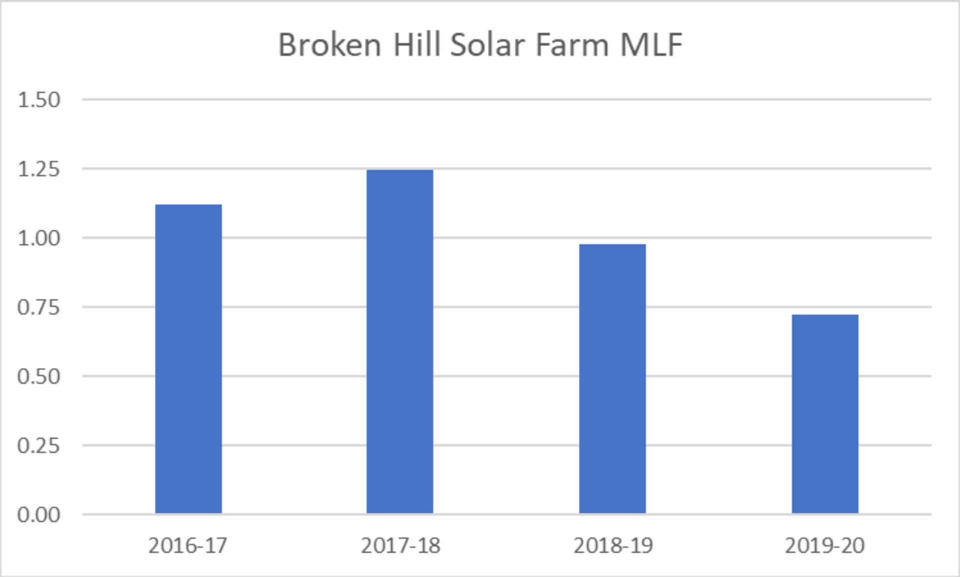
Exactly the same process is applied to load centres, and electricity users have their demand for electricity scaled up or down by the MLF for their local substation. This provides a fair basis by which transmission costs are allocated between generators and users of electricity.

While this is fair, there are some dynamics of MLFs that are particularly important to renewable generators that mightn't feel particularly fair at the moment. In particular, MLFs can change rapidly as new generation is built in a particular location. Let's consider an example of a new solar farm being built in the west of NSW (although this dynamic is broadly applicable elsewhere). This generator will initially have a very attractive MLF – often above 1 – as it is effectively supplying the local demand (and therefore saving the transmission costs of power that would otherwise be transmitted from large baseload generators – which are mainly on the east coast).

However, as more generators are built in the same area, that part of the network will move to be a net exporter of power (as generation exceeds local usage) and, hence, generation effectively then needs to be transmitted to large load centres to the east (eg Sydney). This is a long transmission distance involving high losses (as transmission losses are largely a function of distance (and voltage)) and, hence, the MLF will fall sharply.

This MLF applies to all generators in the area, so the first generator is "penalised" by a fall in MLF that affects all generators in the region. That is, the first mover is penalised by the crowding caused by late arrivals.

An example of this is the Broken Hill Solar Farm. It has seen its MLF go from well above 1 in 2016-17 and 2017-18, before falling to 0.98 in 2018-19 and an estimated 0.73 for 2019-20. These are incredible swings – a 40% decline from peak to the current estimate. This means at a constant pool price – output from Broken Hill Solar farm has fallen in value by more than 40% (and 25% over the past year).



The decline in MLFs has been driven by the surge in new generation in the same part of the network. The largest driver of MLF falls for Broken Hill Solar Farm is probably the Silverton Wind Farm (MLF 0.7990) which has also been developed by AGL/PARF (so a significant portion of the MLF is probably self-inflicted and, presumably was factored into their investment case).

Importantly, in most cases, even a fully contracted project is hit by the impact of MLF changes (there are some legacy PPAs where the MLF impact is borne by the offtaker). Most power purchasing agreements are drafted as contracts for difference, where the offtake counterparty pays the difference between a fixed price and the regional reference price (or pool price) and the project is assumed to earn the regional reference price in the spot market for its own generation. For these contracts, MLF risk sits with the project, that is a lower MLF will feed directly through into lower revenue.

The MLF changes in the latest draft decisions from AEMO are particularly violent. The table below summarises the key results – from the perspective of renewable generators.

Solar	**NSW**	**VIC**	**QLD**	**SA**
Average Change in MLF	-6.88%	-12.93%	-2.64%	0.30%
Largest Fall	-25.90%	-17.38%	-6.45%	-0.11%
Largest Rise	0.15%	-7.42%	0.09%	1.13%
Average MLF	0.9905	0.9007	1.0023	1.0086
Lowest MLF	0.7254	0.7826	0.824	0.9689
Observations	11	4	18	3

Wind	**NSW**	**VIC**	**QLD**	**SA**
Average Change in MLF	-3.82%	-3.71%	-1.65%	0.67%
Largest Fall	-20.59%	-13.12%	-1.89%	-1.80%
Largest Rise	3.51%	0.67%	-1.41%	6.14%
Average MLF	1.0163	0.9948	0.9778	1.0065
Lowest MLF	0.799	0.8611	0.9381	0.813
Observations	12	23	2	21

In summary:

- Solar has experienced larger falls in MLF than wind;

- Victoria and NSW have had the largest declines on a State basis. In part, this reflects the relatively modest new build activity in SA compared to other States.
- The largest moves in MLFs seem to be focused in particular areas within some states – most notably the far West of NSW and the North West of Victoria.

The next table shows the five largest declines in MLFs for wind and solar projects (irrespective of location).

Wind MLF Change	Project	Solar MLF Change	Project
-20.59%	Silverton Wind Farm	-25.90%	Broken Hill Solar Farm
-13.12%	Kiata Wind Farm	-17.38%	Karadoc Solar Farm
-10.48%	Challicum Hills WF	-13.46%	Bannerton Solar Farm
-8.87%	Ararat WF	-13.46%	Wemen Solar Farm
-8.12%	Crowlands WF	-13.13%	Griffth Solar Farm

The scale of the largest changes, if confirmed with the final MLFs for 2019-20 are released, will have very substantial impacts on project revenues. Typical fully contracted projects have debt sized based on target debt service coverage ratios (DSCRs) of 1.25-1.35x and debt covenants at 1.1-1.15x. This usually provides a 15-20% buffer between expected revenues and debt covenants. Clearly some of these changes are big enough to potentially to tip projects into default/lockup.

While many investors will be shocked by the draft MLFs – they shouldn't be shocked by the direction. After they have had some time to digest the direct impacts – the next question inevitably will be – what about next year? Can MLFs fall even further? In this regard, it is worth heading AEMO's words in the report covering the 2019-20 outcomes.

> *"As more generation is connected to electrically weak areas of the network that are remote from the regional reference node, then the MLFs in these areas will continue to decline."*

The key driver of the MLF falls is expansion in new capacity – particularly in locations a long way from large load centres. While AEMO have accounted for projects currently under construction and expected to be in operation in 2019-20 in their calculations, there are further projects in the pipeline. These would see MLFs fall further.

However, beyond what is currently under construction, for projects in the development phase, the fall in MLFs will be sufficient to see projects cancelled. An example of this, although there may be other issues at play as well, is Windlab's decision to defer development of its "Big Kennedy" project in Queensland.

Variation in MLFs are a substantial source of uncertainty for new projects. While most projects obtain MLF forecasts prior to construction – the usefulness of these forecasts is pretty low. This raises the question of whether there is a better way? Once policy idea out there is a for renewable energy zones, where strong transmission networks are constructed to areas with attractive wind/solar resources, and where generators who connect to that part of the network would be guaranteed a MLF floor. This would remove a key risk for generators – which is a positive – but it is important to remember the other side of this for consumers. Putting a floor on MLFs would inevitably shift the burden of transmission losses onto power users.

All of this highlights the key role that MLFs play in allocating transmission losses – which can be substantial – amongst electricity users. If nothing else, the size of changes in the 2019-20 has ensured that they will be on market participants' radars going forward.