Introduction

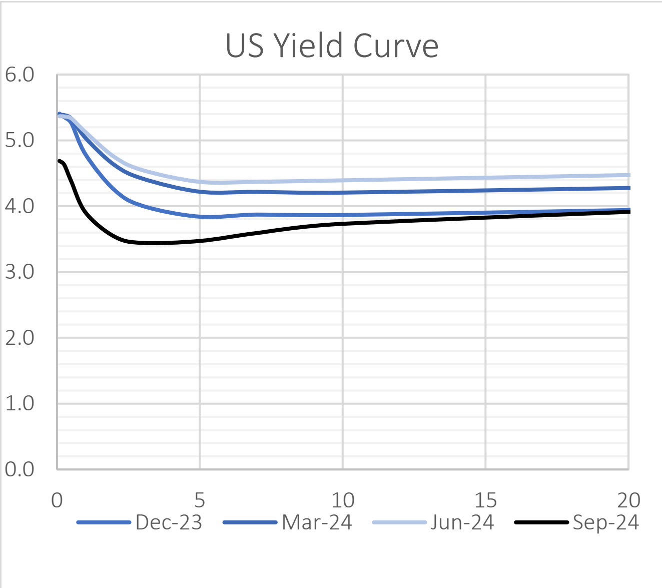
I'm struggling for a pithy opening intro to this quarter's newsletter. Sure, it's been exciting if you are a Japanese investor playing the carry trade, but other than that it's been a fairly ho-hum quarter – but to quote Ryan Reynolds in the Hitman's Bodyguard *"boring is always best."* This quarter we have a few different articles, looking at the dissonance between medium term ISP targets and new project commencements, renewable developer economics (questioning the often-mooted *platform* or vertically integrated strategy), the nexus between immigration and infrastructure, and unique challenges facing Victorian renewable generators.

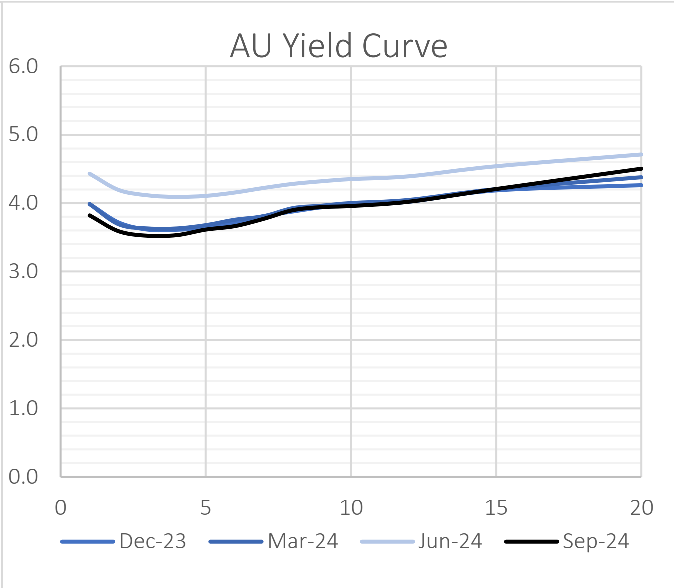
Markets Update

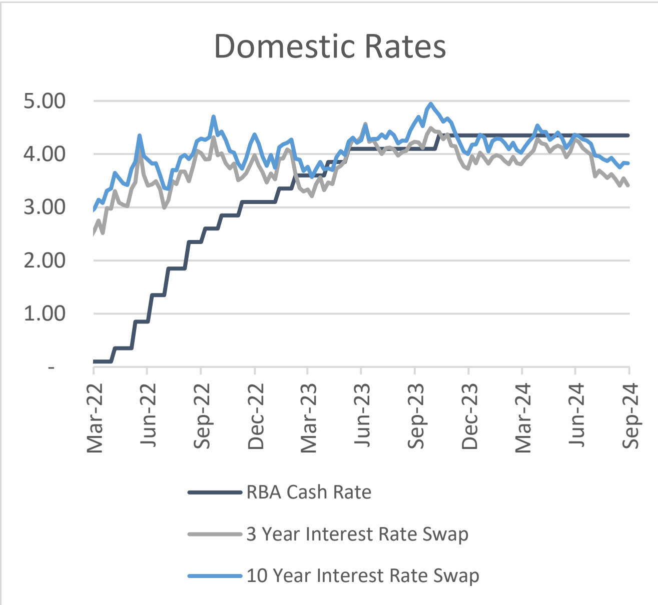
Financial markets experienced a bit of volatility this quarter. The US unemployment rate rose to 4.3% in July, up from 4.1% in June. Fears of a recession, coupled with bleak job numbers in early August, triggered a concern in equity markets. For Japan it was worse, on Monday, August 5, the benchmark Topix index and the Nikkei 225 Stock Average both plunged 12%, marking their steepest declines since the Black Monday crash of 1987. The Bank of Japan's decision to raise interest rates to 0.25% in July, along with weak macroeconomic data from the US, unravelled one of the largest Yen carry trades, briefly shocking the markets.

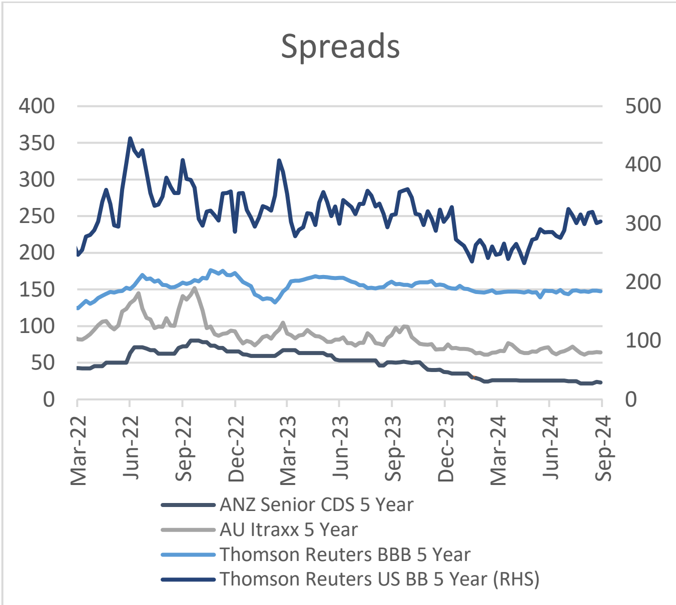
However, equity markets rebounded quickly in the following days amid growing expectations that central banks across major economies would heed Jerome Powell's eight pivotal words at the annual Jackson Hole Symposium: "The time has come for policy to adjust." Shortly after, the FOMC delivered its first 50 basis point rate cut since the 2008 global financial crisis. In the statement following the meeting, the FOMC explained that the decision was based on confidence that inflation is moving sustainably toward the two percent target, while acknowledging that unemployment, though still low, has risen in recent months. As an aftereffect, the US yield curve saw a sharp downward shift. After a historic 793-day inversion, the curve has now normalised, with the spread between two- and ten-year yields returning to positive territory.

Although inflation in Australia has slowed from its peak of 7.8% in December 2022 to 3.8% in June 2024, the decline has been more gradual than anticipated by the RBA. In the August Statement on Monetary Policy, the RBA revised its inflation forecasts. It now expects headline consumer price inflation to reach 3% by December 2024, driven by Federal and State government cost-of-living initiatives, but to rise again to 3.7% a year later as these one-off measures expire. By December 2026, inflation is forecasted to settle at 2.6%, hitting the mid-point of the RBA's target range. Trimmed mean inflation is projected to be 3.5% by December 2024, just under 3% by December 2025, and to reach the mid-point of the target by late 2026—approximately six months later than previously estimated by the RBA. Should the 2.7% print of August change course for restrictive monetary policy? Our answer is most likely no for three reasons. Firstly, the August number has a denominator problem. Inflation rebounded in August 2023 and therefore the 2024 number is compared to a higher base. Secondly, labour market conditions are still strong in Australia. The official unemployment rate has remained steady at 4.1%. Third, subsidies (eg energy rebates) from State and Federal Governments, while generating a one-off impact on inflation (and this reverses when the rebates end), are actually stimulatory (the money saved from the rebates is available to households to be spent elsewhere). We expect the RBA to keep the restrictive monetary policy in place and, in particular, to be slower than offshore central banks to cut rates. Despite the volatility in equity markets, credit spreads (credit indices often lead equity market sentiment) have remained steady and ignored the noise echoed by equity markets.









Source: Refinitiv Eikon

New issuance and refinancing

Detailed below is publicly available infrastructure debt issuance for the quarter:

Date	Borrower	Instrument	Size ($m)	Term (Yrs)	Pricing (bp above BBSY)
September 2024	Delorean Corp Limited	Loan	5+25	3,	300 / 600
September 2024	Indara (former Australian Tower Network)	Loan	3020	3-7	-
September 2024	NextDC	Loan	2900	5-7	160 / 175
August 2024	Airtrunk	Loan	4000	5	-
August 2024	Capella Capital	Loan	6000	5	-

Date	Borrower	Instrument	Size ($m)	Term (Yrs)	Pricing (bp above BBSY)
August 2024	Enel Green Power	Loan	140.8	-	-
August 2024	Iona Gas Facility	Loan	345	15	-
August 2024	Endeavour Energy	Loan	500	7-10	130/140
August 2024	Lumea	Loan	950	4-7	-
August 2024	Student Accommodation (Griffith)	Loan	70	5	-
July 2024	FRV Portfolio	Loan	1240	5	-
July 2024	Towers Infrastructure	Loan	1525	3-7	105/125/145
July 2024	Wellington Battery Project	Loan	745	3	-
June 2024	Collgar Wind Farm	Loan	198	5	-
June 2024	Strike Energy	Loan	153	5	-

*over semi-annual mid-market swap rate

Source: LoanConnector, Refinitiv Eikon (Infrastructure 360), PFI

Equity and other news

- Blackstone and the Canada Pension Plan Investment Board have acquired the Sydney-based data centre company AirTrunk for $24 billion.
- Foresight Solar Fund has begun a process to sell its Australian portfolio, comprising 170MW of operational solar farms and 122MW of battery energy storage in development. Foresight Solar Fund is listed in the UK and owns three Queensland solar farms and partially owns a Victorian solar farm.
- Origin Energy has abandoned the 130MW South Australian Morgan Solar Farm development and the 74MW Carisbrook solar farm in Victoria due to unfavorable conditions. Carisbrook, which also includes a co-located battery, was acquired from ib vogt in 2022.
- Regen, a co-op formed by farmers and landowners, is raising $51 million of equity to fund its carbon farming initiatives.
- J-Power's takeover of Genex Power at $0.275 per share has been approved by the majority of shareholders.
- J-Power is looking to sell 50% of Genex's 775MW Bulli Creek Solar Farm in southern Queensland. The project has signed a PPA with Queensland government-owned Stanwell Corporation under a 15-year agreement.
- New Zealand energy generator and retailer Contact Energy has agreed to buy Manawa Energy for NZD $2.34 billion. Manawa, which is listed on the New Zealand Exchange, has a portfolio of 25 hydro schemes in New Zealand with 500MW of generation capacity.
- Morrison & Co is considering selling its 15 percent stake in Perth Airport, which it manages on behalf of Utility Trust, an $8.5 billion open-ended infrastructure fund.

- Canberra Data Centres, backed by Future Fund, Infratil, and Commonwealth Superannuation Corporation,is in search of new capital partners to fund part of its capital expenditure over the next few years.
- John Liang has agreed to terms to acquire Aware Super's 62.5 percent stake in Sydney Light Rail, increasing its stake to 95 percent.
- Aussie Broadband has sold its 12 percent stake in Superloop.
- Mitsubishi Corp's DGA Energy Solutions Australia, Samsung C&T Corp, and Lion Energy have signed a joint development agreement for a 300-tonnes-per-annum green hydrogen production hub at the Port of Brisbane in Queensland.
- Queensland state government-owned CS Energy has acquired the 285MW Lotus Creek Wind Farm from Vestas.
- Enel Green Power is acquiring the 1GW Tallawang solar and battery hybrid project in NSW from RES.
- Symphony Infrastructure, a transmission infrastructure and grid connection service provider, has raised $488 million of equity from Blackstone.
- AGL Energy is acquiring the battery developer Firm Power and solar developer Terrain Solar for approximately A$250 million. Firm Power and Terrain Solar have a combined development pipeline of 8.1GW of grid-scale batteries, solar projects, and onshore wind in Australia.
- HMC Capital is committing $50 million over three years to buy a majority stake in Australian battery project developer Stor-Energy, which owns a portfolio of six battery developments with over 1.4GW capacity.
- Quinbrook Infrastructure Partners is running a sale process for the energy business Energy Locals and Energy Locals Urban.
- Greece-based Melton Energy & Metals (Mytilineos) is running a sale process for its Australian renewable portfolio, comprising eight solar and hybrid projects.

Sources: AFR, PV Magazine, RenewEconomy.

Are we heading in the right direction?

There have been two reports from AEMO this year that highlight the dissonance between what is actually happening on the ground in the National Electricity Market (NEM) and what is meant to happen over the rest of the decade. Dissonance is always interesting – when two signals are pointing in different directions – the interesting question is which is right?

Focusing on the medium-term first, the AEMO 2024 Integrated System Plan (ISP) is a planning document that provides multiple scenarios for the development of the NEM over the period to 2050. It is interesting because it is built around projections of hourly demand data and ensures that there is sufficient capacity to meet demand over the forecast horizon (including *when the wind doesn't blow and the sun doesn't shine*). The ISP projects potential paths for a future NEM under different scenarios.

The Step Change scenario, which is considered the most likely, shows total capacity (excluding rooftop solar) growing from 65GW in 2023-24 to 109GW in 2029-30. Within this, there is approximately 11GW of coal and gas retirements, offset by 54GW of additional wind, solar and storage. The amount of capacity added is much larger than that removed, both due to growth in underlying electricity demand, and because each MW of retiring coal (which operates at 60-70% on a 24x7 basis) needs to be replaced by multiple MW of wind and solar and batteries. Within this 54GW of additions, 50% is forecast to be wind, 11% is forecast to be utility scale solar, and 39% is forecast to be storage (both utility scale batteries (largest portion) and also household batteries).

The key feature of this, is that wind is forecast to be the largest single component of new generation. The ISP forecasts 4.5GW per year of new wind farm construction over the balance of the decade.

Why is wind so much larger than utility scale solar within the ISP forecast?

Wind dominates as a source of bulk energy in the ISP because:

- Storage is expensive and wind generators naturally generate a significant proportion of their output at night (usually more than half). This makes wind the cheapest source of zero carbon emissions electricity to meet night time power needs (and we need lots of power at night).
- Utility solar generates at the same time as rooftop solar. Rooftop solar, under current network tariff rules, has a fundamental cost advantage over utility scale solar. Thus, the vast build out of rooftop solar – 23GW of capacity in 2024-25 and forecast to grow by a further 15GW by 2029-30, means there is limited opportunity for utility scale solar in the overall generation mix. This dynamic is reinforced by the extremely low dispatch weighted price for solar projects (eg in Vic the average solar dispatch weighted price was $27MWh in 2023-24)

Ok that all makes sense, but what is happening in terms of the current build out?

In the Electricity Statement of Opportunities (ESOO) AEMO trumpets 5.7GW of projects reaching final investment decision/committed status over the past year. This comprised 3.9GW of utility scale batteries, 1.2GW of utility scale solar, 0.4GW of wind and 0.2GW of hydrogren.

What does this say:

- the overall level of new commitments is too low – 5.7GW vs 9GW per year under the ISP;
- storage is overrepresented at 68% of this year's new projects, compared to the ISP average of 39%;
- wind is running massively behind, at 7% of new projects - compared to the ISP expectation of 50%; and
- solar is perversely high – at 21% of new additions compared the ISP forecast of 11%.

So there is substantial dissonance between the short term action and the medium term plan – why and what does this mean?

Part of the answer to why lies in costs. The cost of building a windfarm has risen very substantially over the past few years. Where Infradebt's typical cost benchmarks used to be around $2/W – most projects we see these days cost more than $3/W. This is reinforced by the latest cost prognostications from the experts (eg the Climate Change Authority sector pathways report quotes a benchmark cost for onshore wind of more than $3/W).

The challenge for $3/W windfarms is that their levelised cost of energy is basically $100/MWh. There aren't a lot of electricity users out there willing to enter into long-term $100/MWh plus offtakes. This makes the viability of building wind challenging. Layer on top of this an extremely difficult and slow environmental approval process, and projects increasingly needing to be built in more remote and/or more technically challenging sites with on average lover wind speeds, and it all just becomes a bit hard. That is why the pace of wind construction is slow. By contrast, solar and battery construction costs are falling after the spikes around Covid and Russia/Ukraine and there in inherently a much larger pool of potential project locations.

In short, what's getting built is what is easiest to build, not necessarily what the ISP says we need.

Taking this one step further, the ISP is based on a range of assumptions around what different technologies cost (e.g. cost of wind vs solar vs batteries). These assumptions could be wrong. In particular, if solar and batteries are sufficiently cheap, and wind farms are sufficiently expensive, at some point it becomes optimal to deliver nighttime power needs by building more solar and batteries.

Thus, one of the lessons of the last year might be that the generation mix in 2030 ends up being different to what is expected.

Watch this space.

Renewable Developer Economics

Historically, renewable energy projects have been developed by 'developers' who progress projects to a shovel ready state and then sell the project rights to a long-term equity investor (for example, an infrastructure fund) who builds the project and owns it long-term. However, there is an increasing trend of infrastructure investors investing in platforms that undertake both development and long-term project ownership activities. From the investor side, this trend seems to be driven by a desire to boost overall returns, with a view that platforms offer materially higher returns compared to investing solely in renewable energy projects. This additional return is important in the current market context, where equity investment in renewable energy projects is struggling to attract capital, particularly in a higher base rate world, compared to private debt investment or investment in more traditional infrastructure assets (e.g. regulated utilities, airports, etc.).

Therefore, we thought it would be interesting to talk about the economics and lifecycle of renewable energy development and provide our opinion as to whether this is an appropriate move (spoiler: we don't think it will materially improve returns).

Let's start with an explanation of each step of the process for a project developer.

Step 1 – Land Option

The first stage of a renewable energy project is to find an attractive location for a project e.g. close to existing/planned transmission infrastructure and strong solar irradiance/wind resources. If a site is suitable, the developer will secure an option to enter into a lease over the land with the landowner(s). For a solar/battery project this would usually be with one or two landowners. For wind projects, it is not uncommon to have quite a number of landholders involved. The upfront cost of the land lease option is usually pretty low (eg $10-100k per landholder). The option for a land lease grants the developer the right to conduct investigations on the land to determine the feasibility of the project including making grid connection, environmental and development applications. For wind projects, it is common for meteorological equipment to be installed to establish a baseline for wind speeds at the site.

Step 2 – Grid connection and Development/Environmental Approvals

The developer will then submit a grid connection application to the relevant grid operator, as well as AEMO, and a development application to the relevant government body for approval. For smaller-scale solar and BESS projects the development application is submitted to the local council. For larger scale solar, wind and BESS projects, State and Federal Government approval may also be required. Larger projects often need to run the gauntlet of the so called EPBC approval process (under the *Environmental Protection and Biodiversity Conservation Act 1999)*.

Parallel to this process is engagement and consultation with stakeholders, particularly First Nations communities and affected landholders in the area to build community support for the development.

Overall, the approvals process will generally cost 0.5-3% of the total build cost, taking around two years for solar/BESS projects and much longer for wind projects.

The breadth of the overall approvals process means many projects fail at this stage. It takes only one bad outcome for a project to be cancelled. This could be because approval cannot be obtained, for example due to community opposition, environmental issues (e.g., impact on local wildlife), or a concern from First Nations stakeholders. It could also be due to additional costs to achieve a grid connection or to mitigate environmental or community issues which render the project unviable, for example, the project is unable to connect to the grid without a large grid upgrade cost.

Step 3 – Construction Arrangements/EPC

Assuming the developer has been successful in navigating the various approval processes, they now must decide on what equipment to use. The grid connection and approvals process often locks in some of this equipment at an early stage, for example, the grid connection for a solar farm/BESS would often require specification of which model inverter will be used.

Developers also often seek to have a third-party contractor to take responsibility for the Engineering, Procurement and Construction (EPC) of the project on a fixed price basis. However, with the growth in the size/complexity of projects, it is becoming increasingly common to see unbundled delivery arrangements with separate contracts with key equipment suppliers (e.g., battery manufacturers or turbine manufacturers) and balance of plant contractors (who install this equipment on site and connect it to the grid).

Every project is different, and it is only at this point the developer will know how much the project will cost to build!

Step 4 (Optional) – Revenue Contracting

Most greenfield renewable projects seek to have a material portion of their revenue contracted with an offtake for the initial years of operations (usually the first 10 or so years). This makes the cash flows of the project more predictable and, hence, more attractive to potential capital providers(both equity and debt).

A key issue is the relativity between project revenues and project costs. If costs are high relative to expected revenues, then expected returns would be poor. Poor returns make it difficult to attract equity (and debt).

Step 5 – Equity (and Debt)

Traditionally, renewable energy project developers didn't have access to sufficient capital to fund the construction of projects. Thus, the final step of the development process was to sell the project rights (eg the land options, the various approvals and the rights under the various EPC and offtake contracts) to a counterparty who will undertake (and fund) the project. This will be an infrastructure investor or vertically integrated retailer which is looking to own the project over the long-term. These parties are not usually interested in taking development risks (i.e. the possibility of grid connection/development/environmental approvals not being obtained) but are better placed to fund the high capital costs of building a project (and are better placed to take long-term electricity price and operational risks).

Fundamentally, a project with an attractive risk/return profile to investors will be 'saleable'.

The 'risk' side of the equation can be improved through an appropriate allocation of risk stipulated in construction (EPC) and operations and maintenance (O&M) contracts with third parties. For example, arrangements where the EPC contractor compensates the investor for any delivery issues/delays will lower construction risk from the perspective of the investor and incentivises the contractor to meet project deadlines.

The 'return' side can be improved by obtaining attractive revenues, commonly an offtake from a counterparty with a strong credit quality (eg Government entity or big 3 retailer). The developer can also generate return by improving capital and operating costs relative to revenue, that is, negotiating competitively priced EPC and O&M contracts.

Higher returning projects will command a high development fee i.e., premium over future costs paid by equity investor for project rights. A low returning project will earn a low fee, or it might not even be possible to attract equity. In this case, the project wouldn't proceed.

Development premiums are typically in the 5-20% of total project costs range. For a renewable energy asset owner that undertakes its own development activities, this development premia is effectively captured through a lower cost base for projects it self-develops (compared to projects acquired from 3rd parties where a development fee is paid and forms part of the project cost).

Why developers earn their multiples

Renewable energy development is a risky game. It involves coordinating a lot of moving parts, the vast majority of which are outside the developer's control. At any point in the development process, the project may be stalled, rejected by the relevant grid/development authority, or face material opposition to the project by stakeholders. Even if a project is awarded a grid connection and development approval, there is no certainty that the developer can obtain an attractive offtake or EPC arrangement, find an investor that likes the risk/return profile of the project, and is willing to pay the developer's expected premium. This is worsened by a multi-year development timeline which exposes the project to unpredictable macroeconomic cycles and conditions which change return hurdles for investors and inflate construction costs from what was previously envisaged.

If the developer is unable to line-up all elements of the development process up, they will lose all their initial capital spent on the land lease option, investigative works, grid connection and development applications and supporting studies.

For the risk developers take on, they definitely earn their premium!

Renewable Energy Development vs Venture Capital

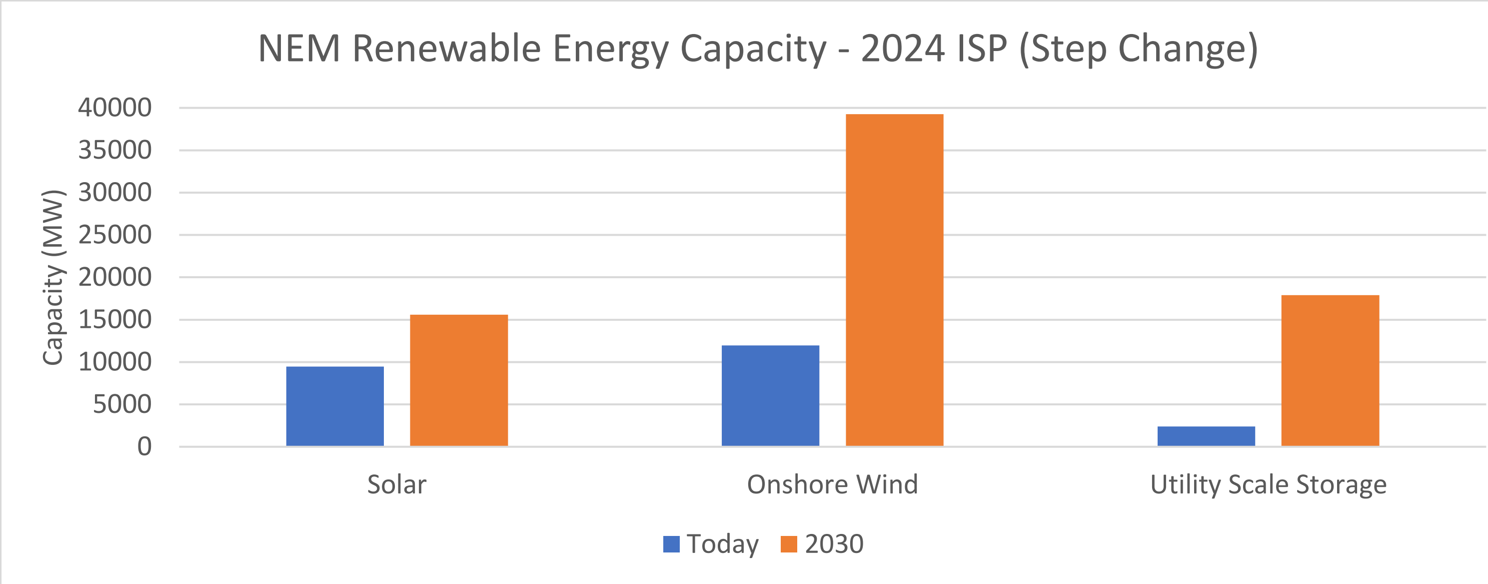
Developers are in a lot of ways the 'venture capitalists' of the renewable energy industry. Where a VC fund invests in a portfolio of different early-stage companies, developers will undertake development activities on a portfolio of project sites at any given time. Theoretically, the strong payoff from one successful development will offset the losses on those that end up not proceeding.

Developers are also like VCs in the way they think of returns. VCs are chasing 'multiples' on their money, for taking on the risk of investing in an early-stage company. Likewise, the developer has likely spent up to 2-4% of total project capex in the hope of receiving 5-20% of total capex from an equity investor, generating a multiple on the costs incurred.

Critical to realising prospective multiples is having the skill to both (1) secure locations that have a high probability of housing a successful development, and (2) be able to quickly identify and cancel projects that will not be successful before spending significant amounts of money. This is a difficult task even for experienced developers.

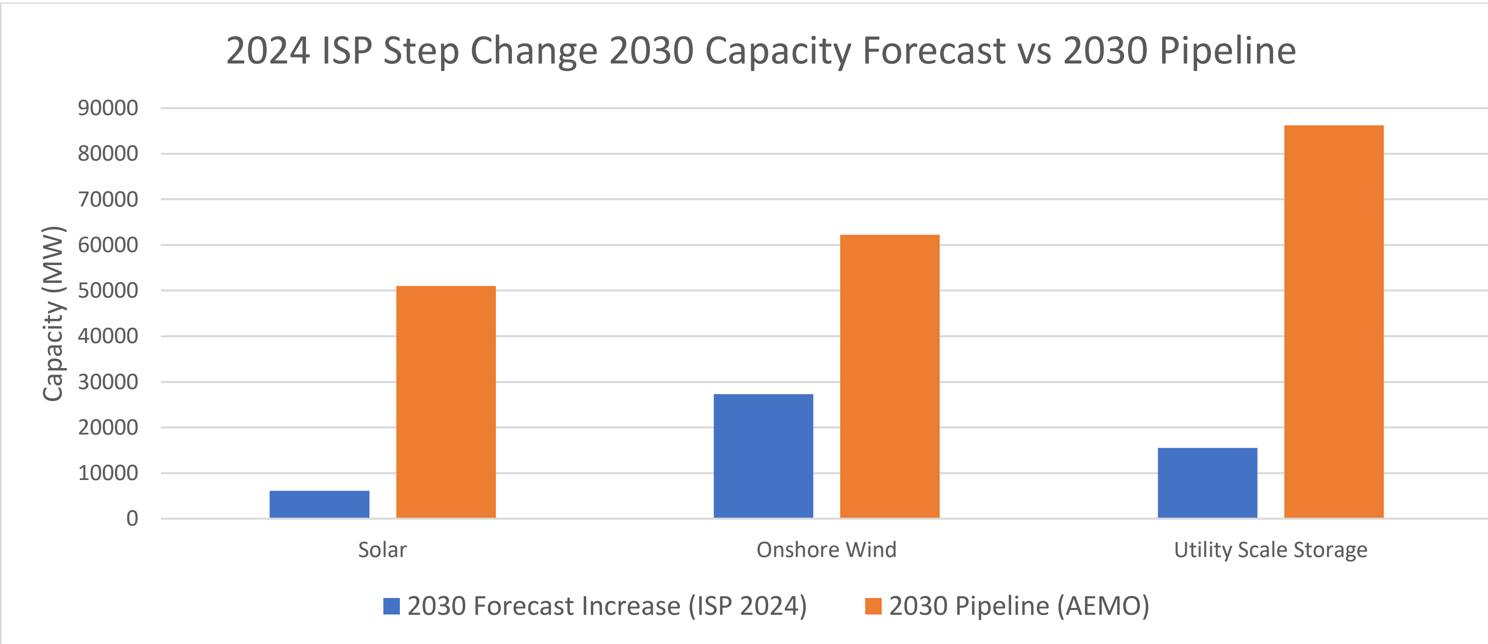
Demand vs Pipeline

AEMO's 2024 Integrated System Plan (ISP) includes forecasts with respect to how much capacity of each renewable technology should be installed in an ideal world for Australia's energy transition. It displays a large demand for new renewable energy projects out to 2030 and beyond under the highest likelihood 'Step Change' scenario. This is to replace coal and gas-fired fleet, as well as potentially meeting growth in electricity demand. Per the below graph, solar capacity is expected to increase 65% from today's capacity, onshore wind at 228% and batteries at a staggering 650%.



Source: AEMO ISP

This sounds all good and well for developers, but let's compare this to the pipeline forecasted to be operating by 2030.



Source: AEMO ISP

The renewables pipeline overshoots the ISP forecast quite dramatically. For wind this is 35GW over, solar is 45GW and utility scale storage is a massive 70GW over!

Therefore, it is likely that only one in four pipeline projects will actually be built. Note the other 75% have already incurred material development costs.

Institutional equity & development – a good match?

We see claims that moving from investing purely in projects to investing in a platform that is a developer plus a portfolio of completed projects can boost returns by 1-2% year. That is, a 9% project only return might become 11% blended platform return.

Mathematically this seems hard to achieve as, while the development premium is very high return on deployed capital, it is a small sum for a short period and, hence, has a reasonably weak impact on total IRR.

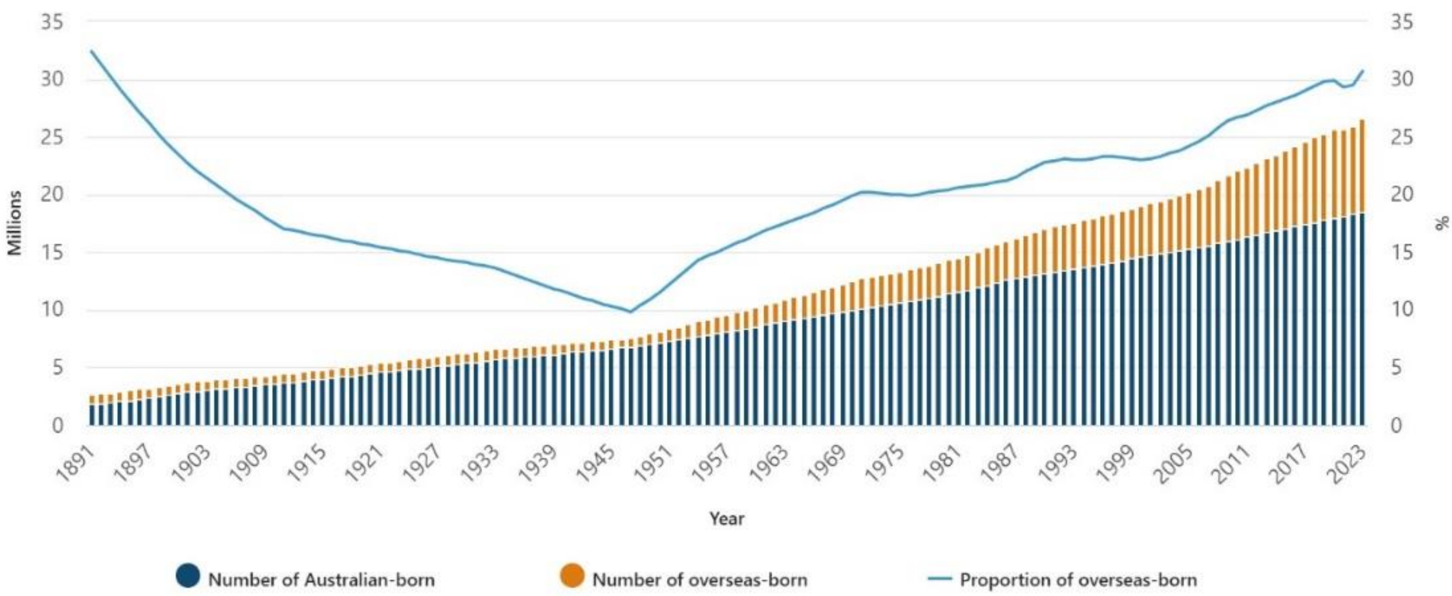
To illustrate this, we took an imaginary $100m project with an underlying equity IRR of 9% over a 35 year life. We then blended these returns with a notional development phase with $2m million invested. The key parameter is what multiple does this development stage development capital deliver in terms of notional development fee (which is effectively a saving in cost compared to a typical shovel ready project)?

To boost returns by 2%, requires a multiple of just under 6x. That is, the $2m in costs delivers a $12m development fee. This would be a fantastic result for a developer, and would be achieved for some projects. Where it isn't realistic, in our view, is that you need to account for all the losses on projects that never proceed (as well as the development fees on the ones that do) to fairly assess the benefit of getting involved in development. In our view, a net multiple of 2x, is more realistic. In this case, while the development is still very profitable (an IRR of more than 40% on the $2m of development capital), it has a de minimus impact on overall equity IRR – increasing only 0.3%. That is, given the small dollar amounts and short period (relative to the life of the underlying project), adding in developments probably doesn't add as much to returns as people might think.

Immigration, Population Growth, and Infrastructure in Australia: A Crucial Nexus

Immigration has long been a key driver of Australia's population growth and economic prosperity. Over the past several decades, the proportion of overseas-born residents has steadily increased, with 30% of the population being born overseas in 2023. This trend reflects Australia's continued appeal as a destination for work, study, quality of life, and climate (although I suspect not many people move to Canberra for this!).

Graph 1.1 – Estimated resident population – proportion born overseas(a)(b)



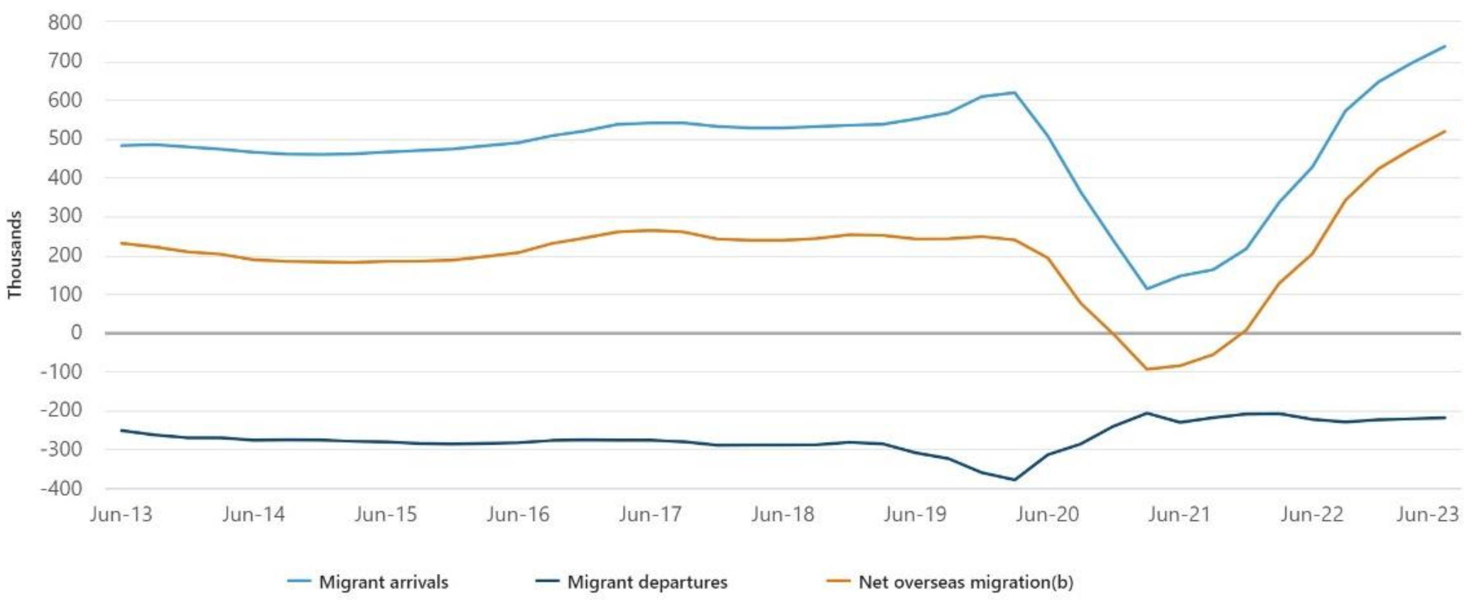
Source: ABS

The Role of Net Overseas Migration (NOM)

Net overseas migration (NOM) is a key measure in Australia's population dynamics. It measures the net gain or loss of population through international migration, encompassing those arriving and departing the country. Historically, Australia has experienced a net gain of migrants each year, with 2023 marking a significant peak. In FY23, NOM contributed a net gain of 518,000 people—the highest on record. Temporary visa holders, particularly international students and skilled workers were the largest contributors to this increase.

In total, Australia's population grew by 624,000 people in FY23, a 2.4% increase from the previous year. This growth was composed of 518,000 people from net overseas migration and 106,000 from natural increase. With natural increase (births minus deaths) slowing over the past few decades, immigration has become the primary source of population growth.

Graph 1.1 - Overseas migration - Australia - year ending(a)



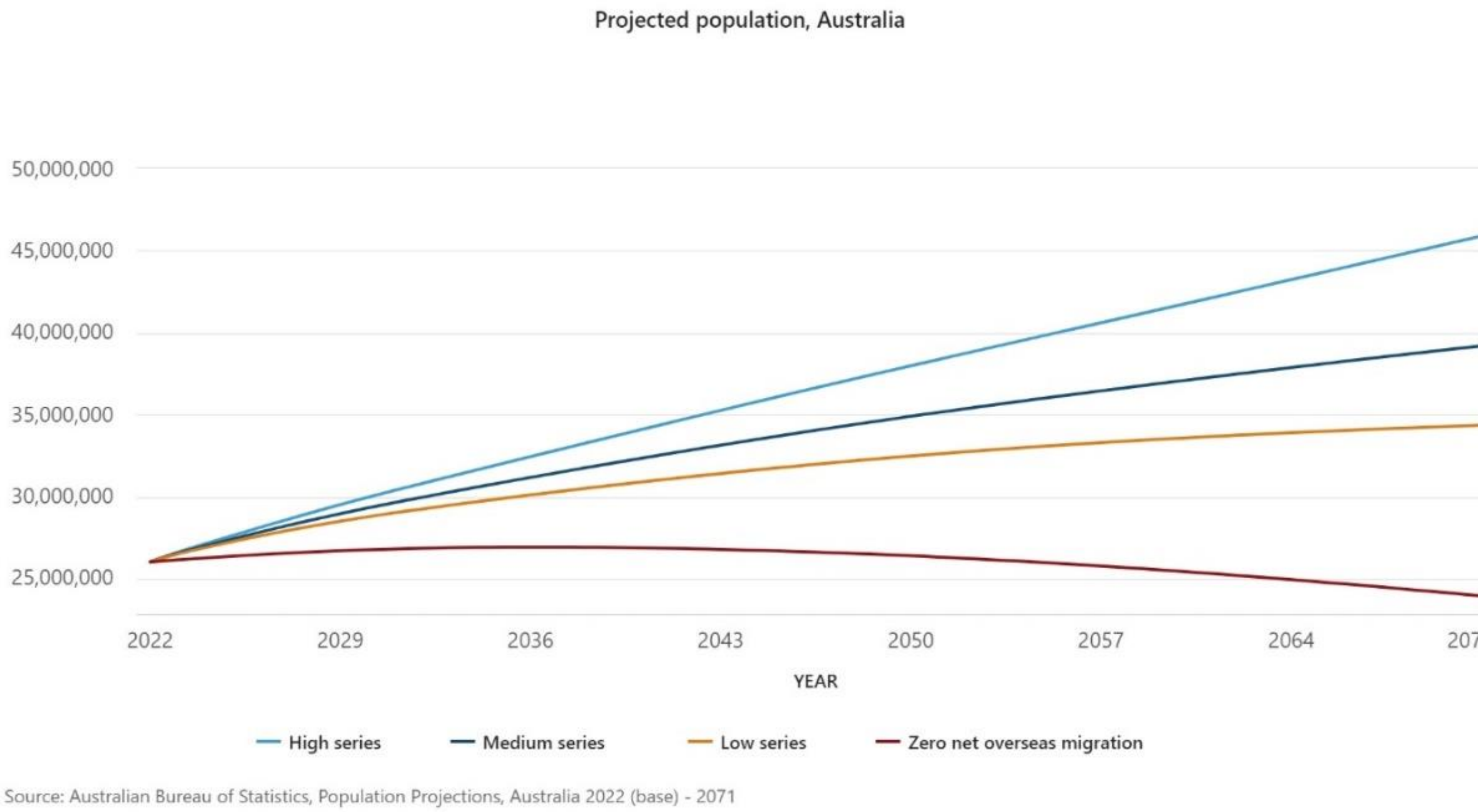
a. Estimates from September quarter 2022 onwards are preliminary. See revision status on the methodology page.
b. Net overseas migration is calculated by the number of migrant arrivals minus the number of migrant departures.

Source: Australian Bureau of Statistics, Overseas Migration 2022-23 financial year

Source: ABS

Population Projections with different levels of NOM

According to the Australian Bureau of Statistics (ABS), without overseas migration, Australia's population would begin to decline in the 2030s. This underscores the critical role immigration plays in sustaining population growth. The ABS's projections highlight various immigration scenarios, each reflecting different implications for future growth.



Source: ABS

Immigration as a Political Flashpoint

Immigration has become a key political issue – particularly as the political narrative has increasingly linked housing affordability (or should we say unaffordability) to Australia's rapid population growth. In response, the two major political parties, the Australian Labor Party (ALP) and the Liberal-National Coalition (LNP), have both announced changes to immigration policy.

ALP's Approach: Government Caps on Temporary Migration

Previously, somewhat perversely, the Australian government did not directly control migration numbers. The net migration outcome each year is determined by the net of:

1. New permanent migrants;
2. *less* Australians who have permanently migrated overseas;
3. *plus* New temporary migrants; and
4. *less* temporary migrants who leave

Under previous policy, the Commonwealth Government through its permanent migration quotas effectively set a cap on permanent migrant intake (item 1, above). Australians moving overseas permanently tends to be reasonably small and steady.

The big movers are all on the temporary side. The record outcome in 2023 reflects the impacts of universities reopening post Covid (and, hence, record student intakes) combined with relatively few historic temporary migrants leaving Australia.

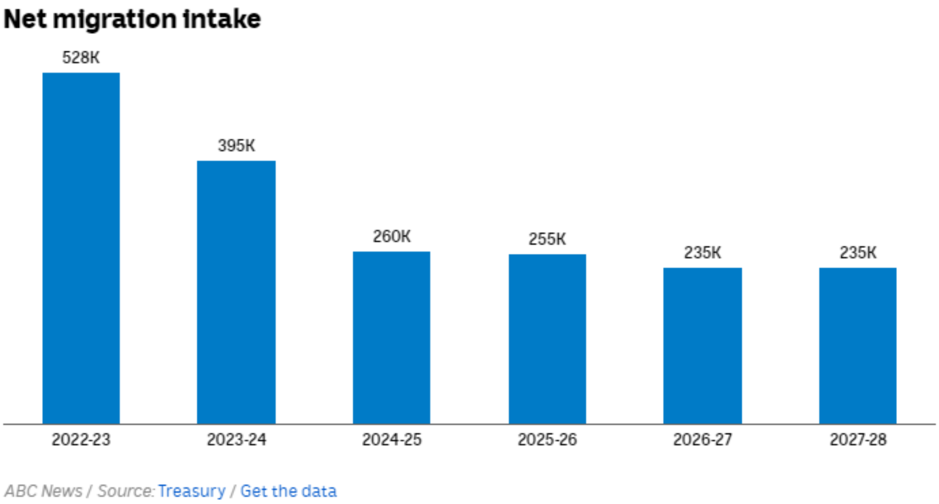
In FY23, total net overseas migration (NOM) reached a record 518,100. This included 195,000 permanent migrants, 17,900 humanitarian visa holders, and 305,200 temporary visa holders, the majority being international students. The

2023 record reflected the reopening of universities post-COVID, leading to a surge in student intake, while relatively few temporary migrants left the country.

Facing backlash, the ALP has announced policy changes, which if implemented would see the Commonwealth Government take direct control of the aggregate number of university and education places offered to overseas students. That is, the Government would take direct control over item 3 and 4.

The ALP's policy change now focuses on controlling student numbers by setting caps for each university, with proposed caps 16% lower than 2023 levels. As a result, the flow of students is expected to slow, leading to a notable reduction in population growth. If these lower caps are sustained over time, temporary migration could actually turn negative (as the students associated with the record 2023 intake ultimately leave).

With the introduction of these caps, the government will allow 270,000 new student enrolments. Alongside reductions to permanent migration, this will bring the projected NOM down to 260,000 in FY25 and 235,000 by FY26–27, essentially halving the 2023 migration numbers. The ABS projects a high NOM scenario of 275,000 and a medium scenario of 225,000, with the budgeted NOM aligning more closely with the latter. If we assume the natural increase will be the medium scenario of 119,000, the population in FY25 will increase by 379,000. (FY23 increase was 624,000 people).



Source: ABC News

The Impact of Immigration on Infrastructure

Why should Infrastructure investors care about immigration? Outside of PPPs and regulated assets, most infrastructure investments have a fundamental patronage or GDP growth driver. Think of an airport or toll road, the value of this asset is driven by usage. Likewise, for a container port, the throughput through the port will be driven by the level of GDP (and the population catchment it serves).

Thus, population is often the most fundamental revenue driver of 'patronage' investments. In this context, a change to immigration policies which is likely to have a meaningful impact on population growth (particularly in the next 2-3 years) is actually quite important.

Would lowering immigration solve the housing crisis?

The debate surrounding immigration has been heavily influenced by Australia's housing crisis. Many view immigration as a key contributor to rising property prices, particularly in major cities like Sydney and Melbourne. There is a good element of truth to this, but it isn't the whole storey.

It is not just immigration that has driven Australia's house prices to crazy levels. There is a much wider range of policies (capital gain tax free status of the family home, negative gearing rules, bank credit norms in Australia, exclusion of the family home from assets tests for pensions and aged care, etc etc). Just changing immigration is unlikely to make housing instantly affordable and, for the broader economy and government finances, there are likely to second round affects from lower economic growth and tax revenues, which are not necessarily positive.

In summary – if fixing housing was this easy – we would have done it 20 years ago.

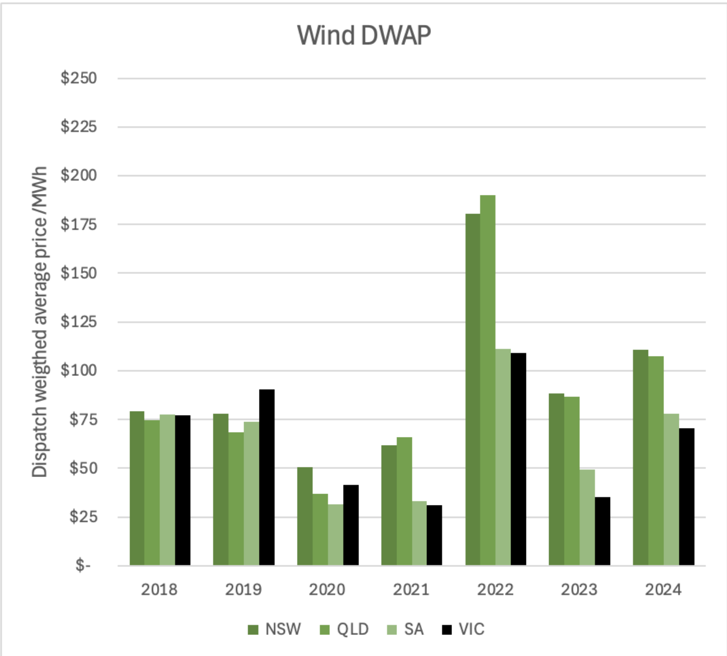
Trouble in the *Cabbage Patch*

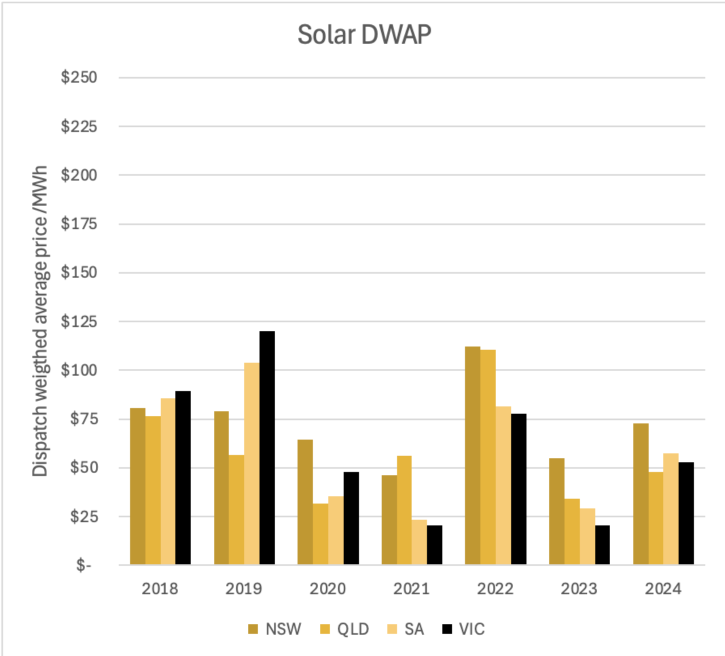
Over the past decade, the surge in renewable energy has steadily driven down wholesale electricity prices across Australia. However, this trend has played out unevenly, with each state following its own trajectory, shaped by unique renewable resources, government policies, and market challenges.

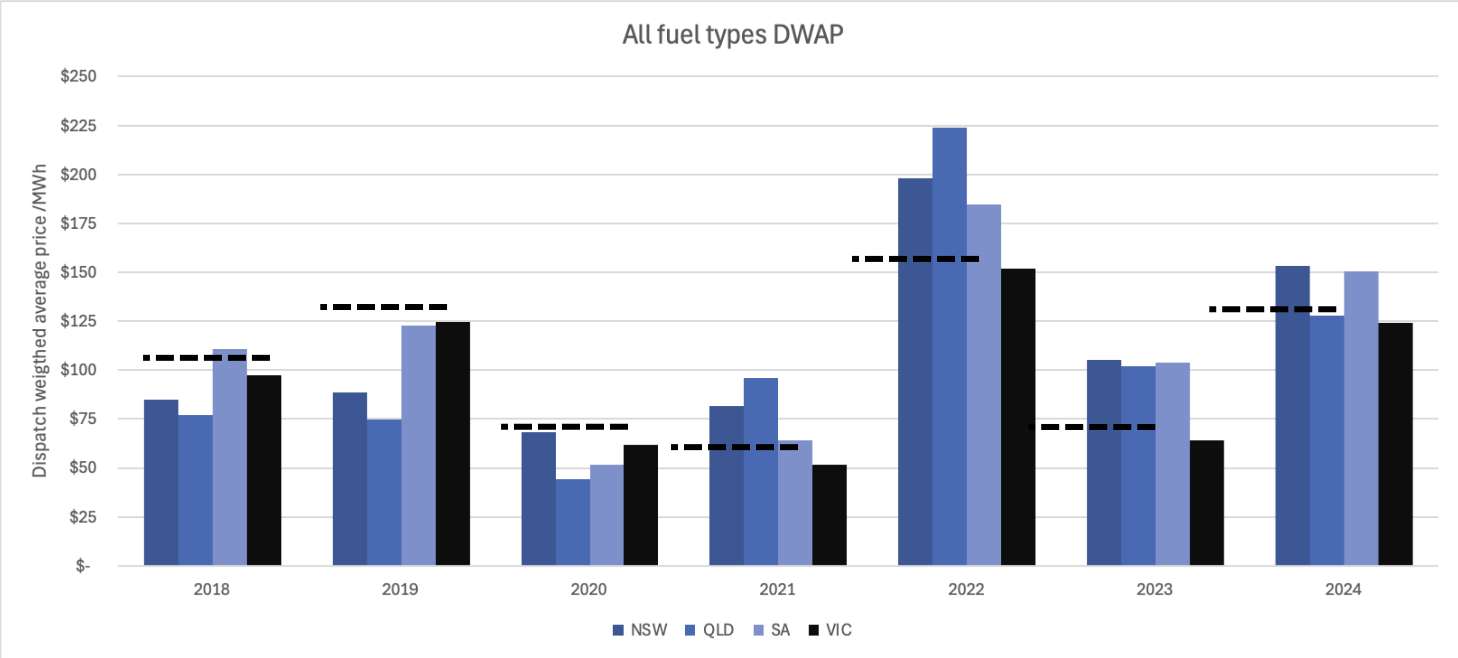
In this article, we'll examine the current state of the energy transition through the lens of pricing, identifying which states are the most and least favourable for renewable energy projects (most favourable for energy users) in 2024. We'll also take a closer look at challenges facing Victoria—a state that has fallen from being a leader in merchant renewable profitability, to the bottom of the pack, in just a few years.

NEM Pricing Snapshot

We've compiled dispatch-weighted average prices (DWAP) for the past seven years in the charts below. DWAP represents the average revenue generators earn per megawatt-hour (MWh) of energy they supply to the grid. To avoid overwhelming you with too many charts, we've focused on the four major states within the National Electricity Market (NEM).







Data Source: OpenNEM

Winners and Losers

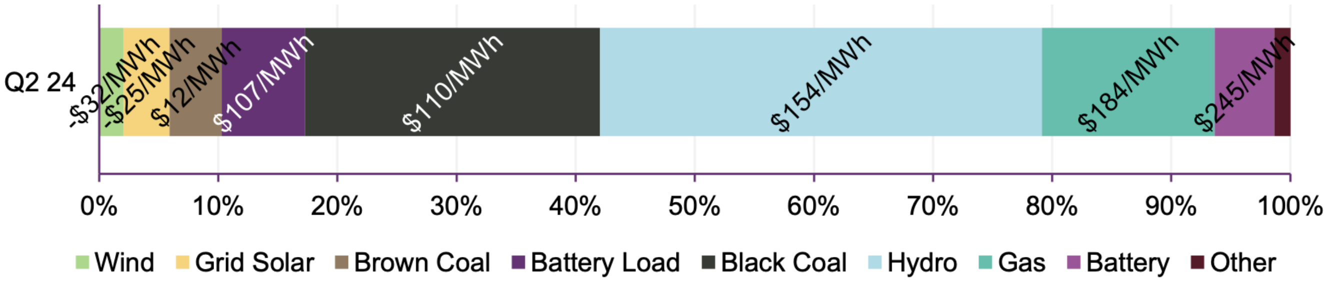
New South Wales is emerging as the clear leader, offering the highest average prices for wind and solar generation. With the largest energy demand and relatively low renewable penetration, it remains the most profitable state for renewable projects, with Queensland close behind for wind.

However, what's particularly interesting is that Victoria (highlighted in black on the chart), which topped the price charts alongside NSW from 2018 to 2020, has now dropped to the bottom. Victoria (alongside SA) has consistently been the worst-performing state for renewables over the past four years. Before we dive deeper into the reasons behind Victoria's price decline, let's first dissect the pricing dynamics a bit more.

Pricing Dynamics

To provide some high-level background, all generators bid a price to dispatch during each trading interval in a day. The NEM operates by dispatching the cheapest bids first. Since renewables typically have near zero short-run marginal cost they bid a very low price to ensure they are always dispatched. For example, it's common for renewables to bid a negative LGC price (~ minus $40MWh). The price of the last generator needed to meet demand sets the spot price. As demonstrated in the bands below, if demand can be met entirely by renewables, the spot price will be negative. Conversely, if gas (which has a high short-run marginal cost being the cost of gas) is required to fill in demand, the spot price will be very high (north of $180/MWh in Q2 this year). Coal generators (e.g. brown coal plants), which have slow ramp-up/down requirements would typically also bid low (less than their short-run marginal cost) during high renewable generation periods to ensure they are dispatched such that they're available for the evening/morning peaks.

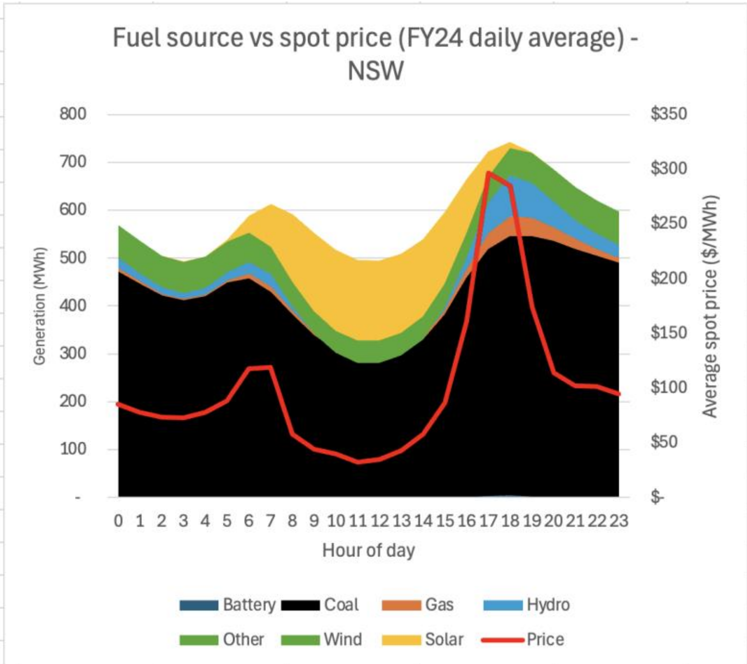
NEM price-setting frequency and average price when price-setter by fuel type – Q2 2024

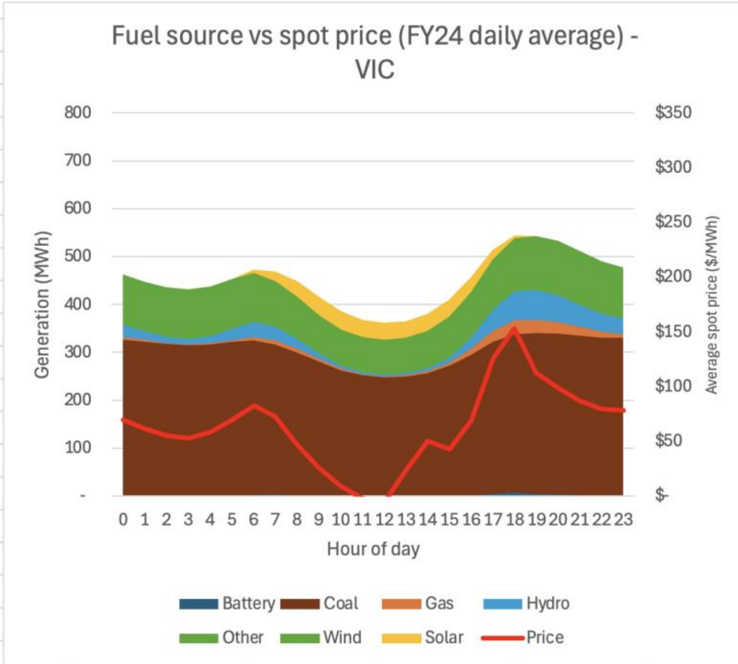


Source: AEMO Quarterly Energy Dynamics June 2024

With this in mind, let's take a look at the intraday charts below. These show what a typical day in the NEM looked like during FY24. The x-axis represents the 24 hours of the day, while the "mountain ranges" illustrate the net load at each hour and the fuel source of generation used to meet that load. The red line overlay shows the average electricity price for each hour.

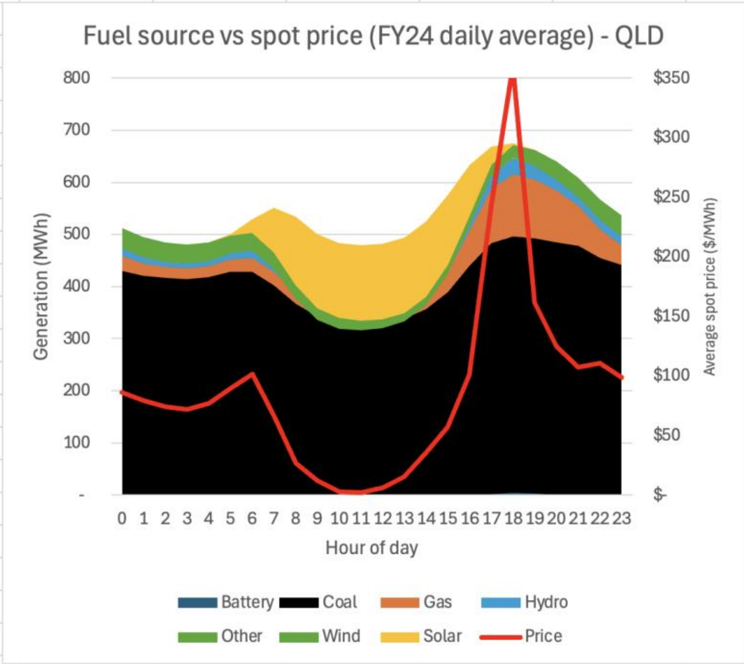
Lower prices tend to occur around midday when solar resources are at their peak, while higher prices correlate with peak demand in the evenings, typically met by fossil fuel generation.

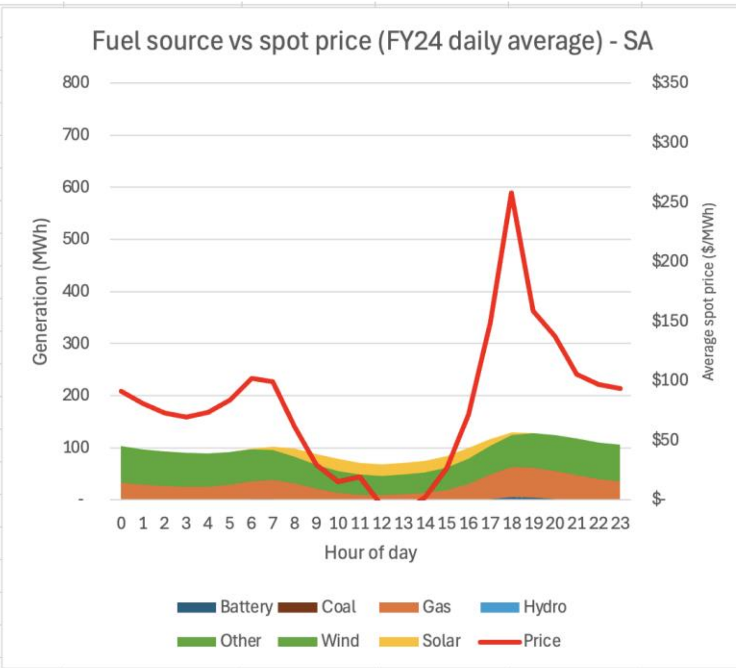




Data Source: NEM Review

Zero or negative prices during midday are a defining feature of a renewable grid without sufficient battery storage to absorb excess supply. Over FY24 Queensland peaks have been significantly higher due to reduced coal generator capacity caused by both scheduled and unscheduled outages. In Victoria, the intraday spread is much closer, as brown coal generation is cheaper and Victoria can import surplus power from SA, NSW and Tasmania (reducing the need to run its gas peakers).

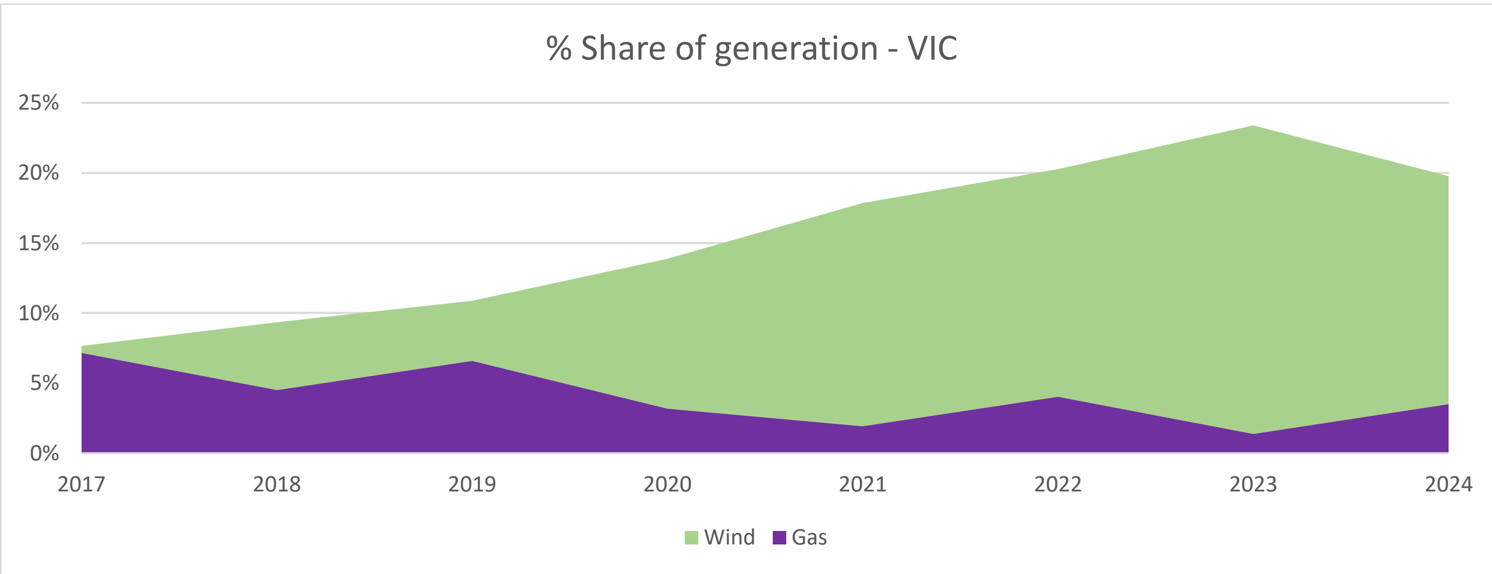




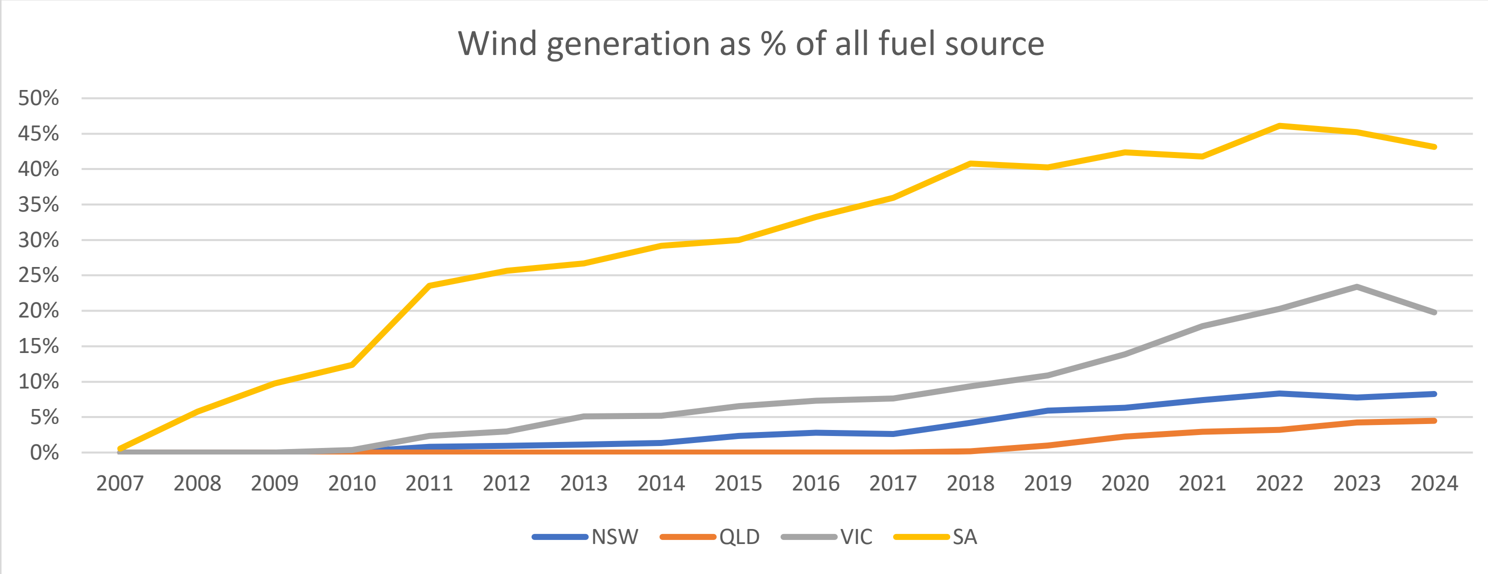
Data source: NEM Review

Victoria: The more advanced energy transition state

So, what caused the rapid fall in prices in Victoria? The primary catalyst for the price shift has been the rapid growth of wind capacity. The share of electricity generated by wind has risen from 7% in 2017 to over 20% in 2024. The high prices seen in 2017 were due to the closure of Hazelwood, which forced gas generators to fill the gap. However, as more wind capacity has come online, the reliance on gas has diminished. With more price intervals set by wind and brown coal, prices have shifted from the upper gas band of $150+ to the sub $20 range for wind and brown coal. Effectively, brown coal has replaced gas as the marginal price setter, explaining the rapid decline in spot prices.



Source: OpenNEM



Data source: OpenNEM

Another key factor driving the price disparity is the interconnector constraint between Victoria and New South Wales. Typically, interstate price disparities would be corrected by the lower-priced state exporting excess energy to the higher-priced state. However, the transmission network near the VNI (Victoria-New South Wales Interconnector) is becoming increasingly congested as more renewable projects are built in that area. As shown in the chart below, VNI flow has been increasingly constrained around midday, limiting the northward flow of energy from Victoria to New South Wales. This has widened the price gap between the states over the past few years.

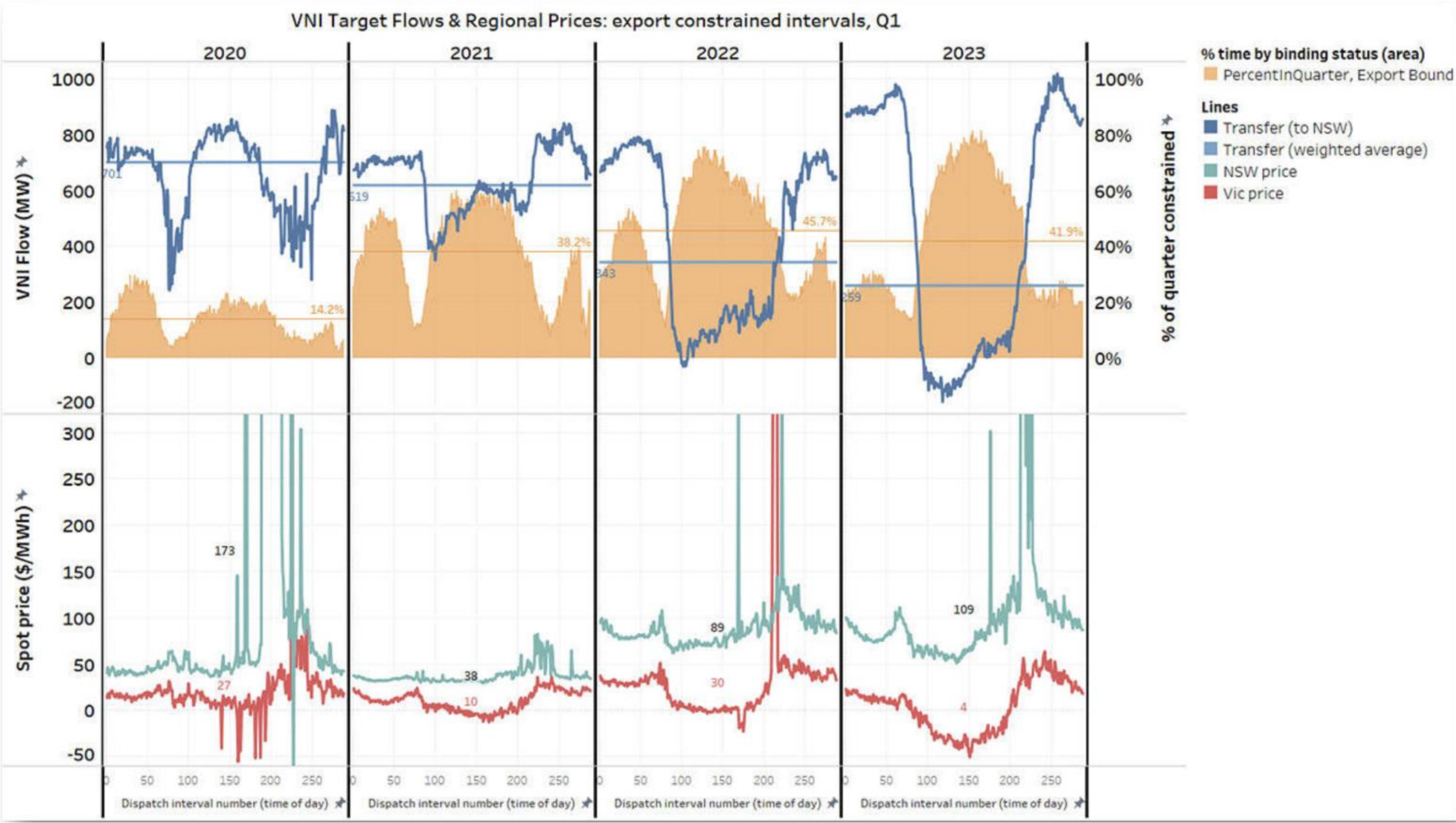


Chart source: Watt Clarity

The growth of renewables, the continuance of incumbent brown coal generators in combination with interconnector constraints, is making Victoria a challenging landscape for new renewable projects. Unless there's a major coal plant outage (or bring forward of scheduled closure dates) or a significant drop in wind generation, Victoria is likely to remain in this challenging situation for the foreseeable future, at least until the eventual closure of Loy Yang. The completion of VNI West (a new 500kV interconnector via Kerang) will ease the constraint and allow export to NSW, but we do not believe it will fundamentally shift pricing dynamics.

Key Takeaways

It would be wrong to look at challenges in Victoria in isolation or see them as temporary, while New South Wales and Queensland are currently the most favourable states for renewables, as more wind and solar capacity comes online in these states, high prices will also be competed away, and the intraday price trough will deepen in northern states. At some point, all coal-fired plants will be shut down and replaced by renewables with battery firming (and gas in the interim). Victoria is simply in a later phase of the energy transition. However, with the increase in battery storage, we expect to see some stabilisation in the intraday price spreads between different fuel types. It's a space worth watching closely.