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Name	Student ID	Task
Nafi Al Hasan	48207152	1
Le Hai Anh (Hanie)	47702141	2
Abdullah Abdul Wahab	48493155	3
Afi Noor	48444030	4
Ridwan Bin Khalid	48457515	5

Executive Summary

This report looks at carbon and energy trends in the National Electricity Market from 2019 to 2025. It studies six areas: the market as a whole and the five main regions. It also checks how people and companies use power during the day, how different generators set their prices, and what this means for future investment.

The share of clean power in the market rose fast. Solar, wind and hydro pushed the average carbon rate down from about seventy six hundredths of a kilo per unit of electricity to about sixty two hundredths. New South Wales, South Australia and Tasmania led this fall. Queensland and Victoria moved more slowly because old coal plants stayed online and new power lines were late.

Solar power is strongest at midday, so the grid is cleanest then. Carbon rates still climb each morning and evening when coal and gas fill the gap. Companies use most power in daylight, so their average carbon is lower than that of homes. Homes use much more in the early evening when the grid is dirtiest.

Price data shows clear patterns. Solar bids almost all of its power at very low or even negative prices so it can always run. Coal now offers less cheap power and keeps more in higher price bands to earn more when demand peaks. Fast gas plants stay idle most of the time and bid very high prices so they run only when the grid is short.

The study points to three main steps for investors. First, add batteries to new solar and wind farms so they can sell power in the evening peak. Second, place these projects in renewable energy zones where the grid is strong. Third, keep a small fleet of modern quick-start gas units for rare peak hours until long storage grows. This mix will lower carbon, give steady income at midday and capture price spikes after sunset.

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Video presentation link

Introduction

Australia's National Electricity Market (NEM) is undergoing a rapid transformation, driven by renewable energy integration, coal retirements and policy shifts. This report analyzes emission trends, intra-daily carbon intensity patterns, consumption behaviors, and bidding strategies across NEM regions for years 2019–2025 to guide investment decisions. We will diagnose the data provided, deduce valuable insights, put them into aesthetic visualizations and propose recommendations for lucrative investments all in a cohesive and inter-dependent steps of data analysis. Key findings reveal that NEM-wide intensity in emissions has dropped by 18%, led by solar growth, but regional disparities persist for e.g., Tasmania at near-zero vs. Victoria's coal reliance. Price volatility occurs as solar power floods midday markets, depressing prices, while gas and black coal dominate evening peaks, creating steep bid-stack curves. Demand patterns are seen where companies benefit from lower-carbon daytime usage, while households face higher emissions during evening peaks.

Task 1: Analysing the emission trends of NEM and All 5 regions

National Electricity Market (NEM)
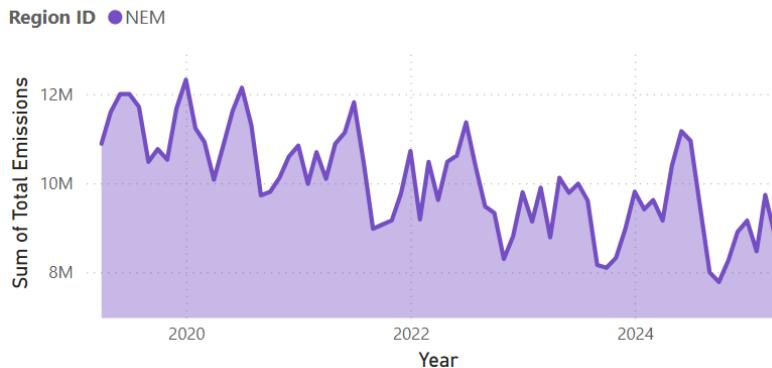
Figure 1: Emissions trend of NEM from April'19 till April'25
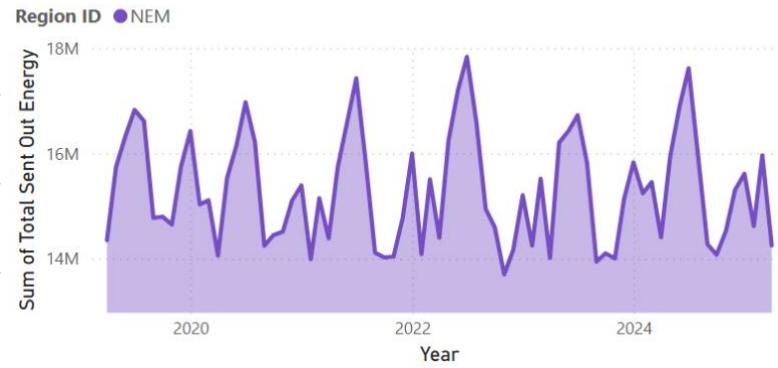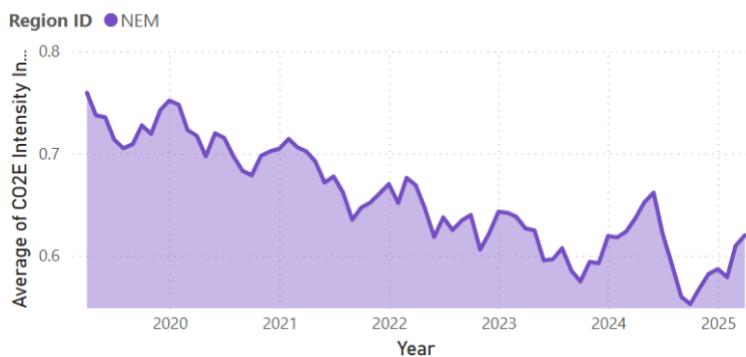
Figure 2: Demand trend of NEM from April'19 till April'25

Data Insights

From April 2019 to April 2025, the NEM's emissions intensity dropped from 0.76 to 0.62 kg/MWh. The lowest point was 0.55 in October 2024. Total sent-out energy remained steady (Figure 2), while emissions fell from 12M to 9M tonnes (Figure 1). This was driven by cleaner generation, not lower demand (Figure 3).

Key Drivers of the Trend

- The closure of Liddell in April 2023 removed 2 GW of coal and reduced AGL's emissions by 17%, co   Figure 3: CO_2e intensity trend of NEM from April'19 till
- NSW approved 10.3 GW renewables and 13.2 GW storage (NSW Department of Planning, 2025). SA moved toward 100% renewables (South Australian Government, 2024). Tasmania's hydro kept emissions near zero.
- The Climate Change Act 2022 and Capacity Investment Scheme (CIS) underwrote 32 GW of projects nationally (Australian Government, 2024; CER, 2024).
- 20+ GW installed by 2023, but with limited firming, much was curtailed during peak hours (Eglon, 2025).
- Queensland delayed coal retirements and cancelled wind projects (Messenger, 2025a; Jarrett & Willcox, 2025). Victoria's brown coal and delayed transmission held it back (Livingston, 2025; Vorrath, 2025).
- Grid congestion, workforce shortages, and approval delays still hamper rollout (AEMO, 2024; Hay, 2025).

Summary Insight for the Client

The NEM's emissions intensity fell due to structural generation changes led by NSW, SA, and Tasmania. But progress remains uneven. Reaching future targets depends on faster transmission delivery, strong policy signals, and clearing systemic grid and planning barriers.

Region: New South Wales (NSW1)
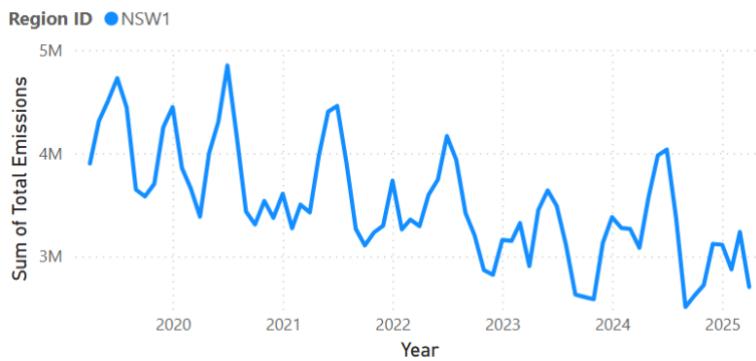
Figure 4: Emissions trend of NSW from April'19 till April'25
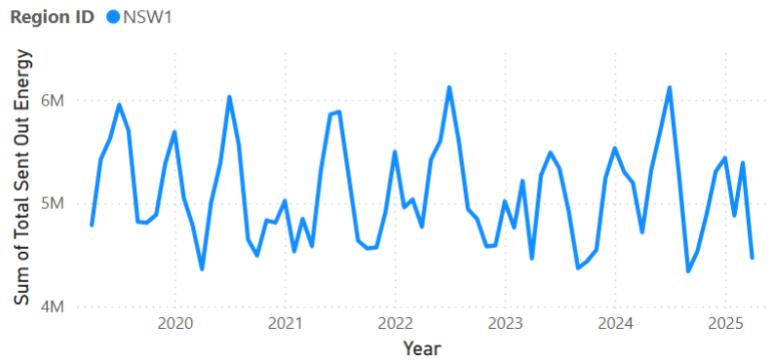
Figure 5: Demand trend of NSW from April'19 till April'25
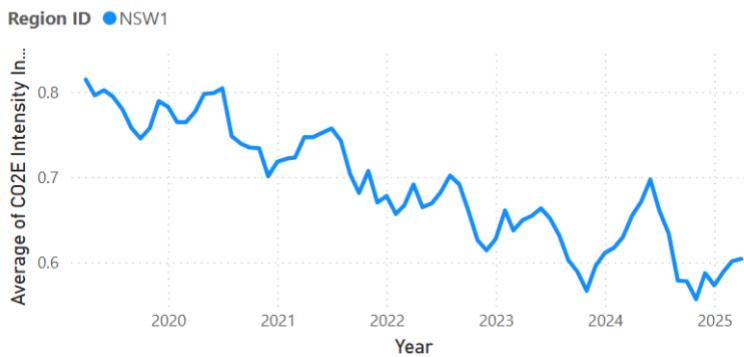
Figure 6: CO_2e intensity trend of NSW from April'19 till

Data Insights

From April 2019 to April 2025, NSW's emissions intensity fell from 0.8 to 0.6 kg/MWh, a 25% reduction. As shown in Figure 6, the trend was steady until 2021, then fell more sharply from 2022. Figure 5 shows demand stayed stable, while Figure 4 shows emissions declined. This confirms cleaner generation, not falling demand, drove the change.

Key Drivers of the Trend

- The April 2023 retirement of Liddell coal generator cut AGL's emissions by 17%, creating a visible mid-2023 drop (Nelson & Gilmore, 2023).
- NSW approved 10.3 GW of generation and 13.2 GW of storage by mid-2025 (NSW Department of Planning, 2025). The Central-West Orana REZ alone is expected to avoid 10.29 Mt CO_2e annually (NSW Government, 2025a).
- The Climate Change Act 2022 and national targets improved investor confidence and accelerated projects (Australian Government, 2024).

- Grid-scale batteries like Waratah supported reliability and reduced coal reliance (NSW Department of Planning, 2025).
- Though extended to 2027 or later, Eraring runs below 50% capacity and has not reversed the emissions trend (Leading Edge Energy, 2024).

Summary Insight for the Client

NSW achieved a clear and sustained drop in emissions intensity through coordinated coal exit, strong renewable uptake, and grid firming. With policy certainty and infrastructure momentum in place, the path to 2030 targets now depends on speed of execution.

Region: Queensland (QLD1)

Total Emissions (kg) for Region: QLD1
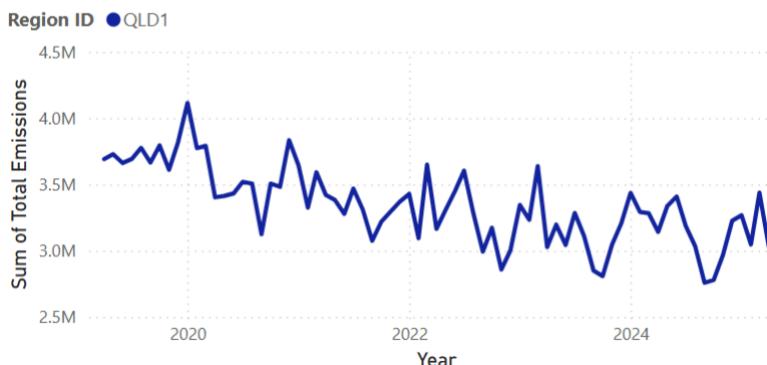
Figure 7: Emissions trend of QLD from April'19 till April'25

Total Sent Out Energy (MWh) for Region: QLD1
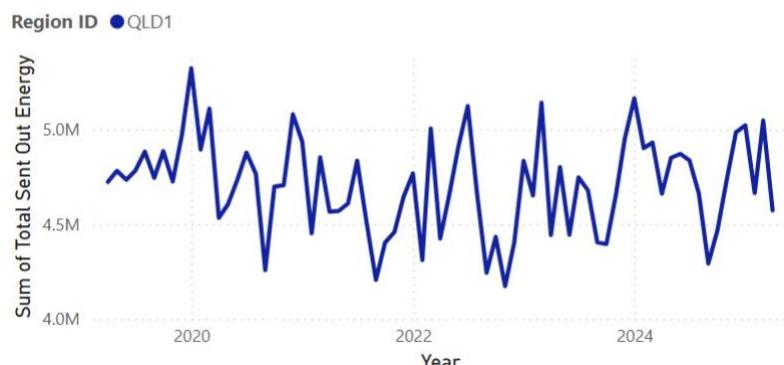
Figure 8: Demand trend of QLD from April'19 till April'25

Average CO2 Emissions Intensity Index (kg/MWh) for Region: QLD1
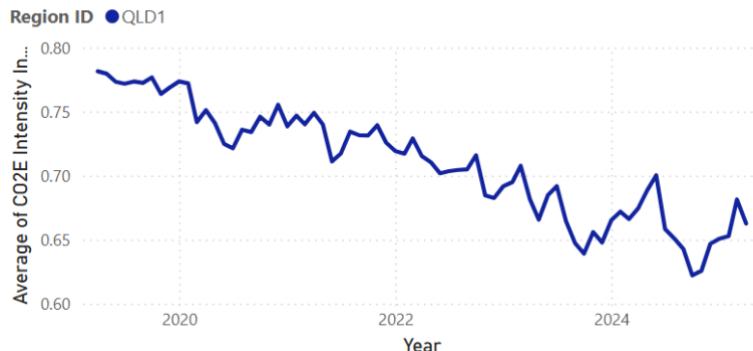
Figure 9: CO_2e intensity trend of QLD from April'19 till

Data Insights

From April 2019 to April 2025, Queensland's emissions intensity fell from 0.78 to 0.66 kg/MWh, a 15% drop. As shown in Figure 9, the decline was slow and uneven. Figure 8 shows demand remained steady, while Figure 7 shows emissions fell modestly. The reduction was not structural. Fossil generation stayed dominant.

Key Drivers of the Trend

- Unlike NSW, Queensland made no major retirements. Black coal stations continued running, and the generation mix remained mostly unchanged.
- In April 2025, the new government reviewed the Clean Economy Jobs Bill and extended Callide B past 2028, costing $420 million and signalling a retreat from earlier targets (Messenger, 2025a; 2025b).

- New rules from May 2025 added legal hurdles for renewables, including Social Impact Assessments and Community Benefit Agreements (Hamilton Locke, 2025). Coal projects faced fewer constraints.
- The $1 billion Moonlight Range Wind Farm was cancelled under ministerial powers despite prior approval. The move highlighted growing political risk (Jarrett & Willcox, 2025).

Summary Insight for the Client

Queensland's emissions intensity decline was modest and lacked structural change. No coal closures, added planning burdens, and political reversals held back renewable investment. With the highest intensity in the NEM and mounting investor uncertainty, Queensland risks becoming a major drag on Australia's clean energy transition.

Region: Victoria (VIC1)

Total Emissions (kg) for Region: VIC1
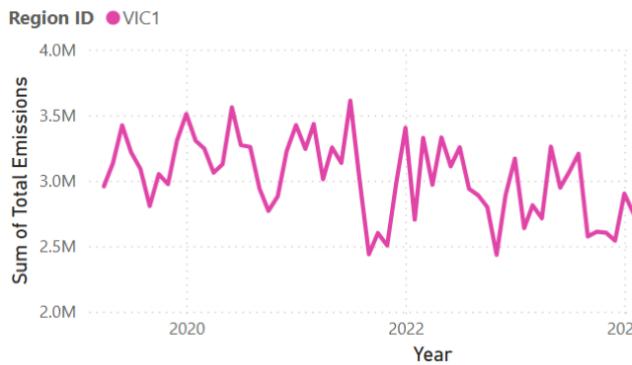
Figure 10: Emissions trend of VIC from April'19 till April'25

Total Sent Out Energy (MWh) for Region: VIC1
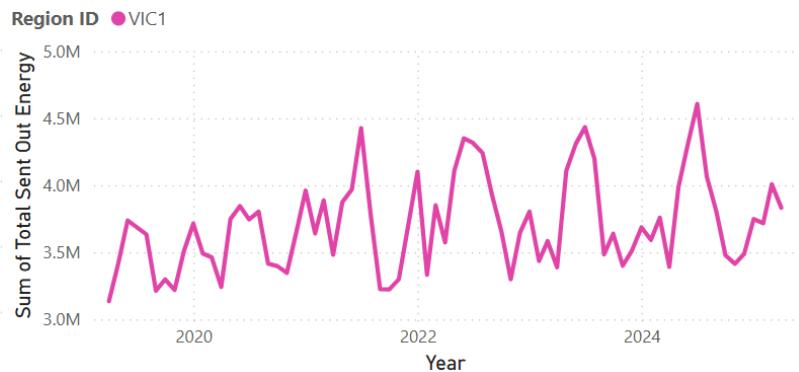
Figure 11: Demand trend of VIC from April'19 till April'25

Average CO2 Emissions Intensity Index (kg/MWh) for Region: VIC1
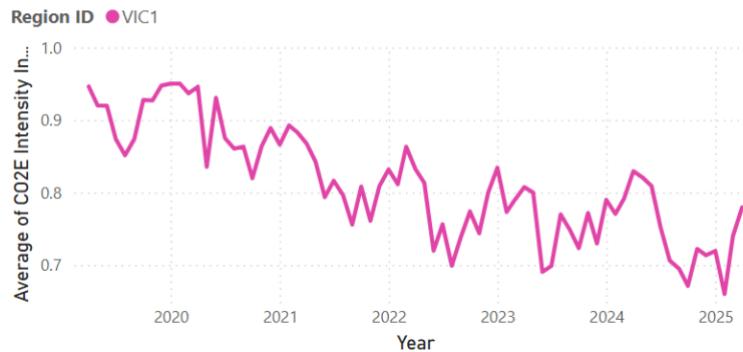
Figure 12: CO_2e intensity trend of VIC from April'19 till

Data Insights

Between April 2019 and April 2025, Victoria's carbon emissions intensity declined from 0.95 to 0.78 kg/MWh, the highest starting point in the NEM. As shown in Figure 12, the drop was uneven, with no clear structural shift. Figure 11 confirms steady demand, while Figure 10 shows emissions stayed between 2.8 and 3.8 million tonnes. Brown coal remained dominant.

Key Drivers of the Trend

- Both Yallourn and Loy Yang A ran throughout the period. Yallourn will close in 2028, while Loy Yang A is expected to remain into the 2030s (Livingston, 2025; EnergyAustralia, 2025).
- While new wind and solar projects were added in Western REZs, delays to key links like VNI West limited their impact. This led to curtailment and more coal in the mix (Nexa Advisory, 2023; Vorrath, 2025).

- VicGrid's plans for seven REZs and four new transmission lines were still in development by 2025. Without faster delivery, clean generation remains stranded (Vorrath, 2025).

Summary Insight for the Client

Victoria's emissions intensity declined, but progress was limited. Brown coal stayed online, and new infrastructure lagged behind. Despite new renewable capacity, delays in grid expansion blocked deeper decarbonisation. Reaching 2030 targets will require fast-tracking project execution and firming capacity.

Region: South Australia (SA1)
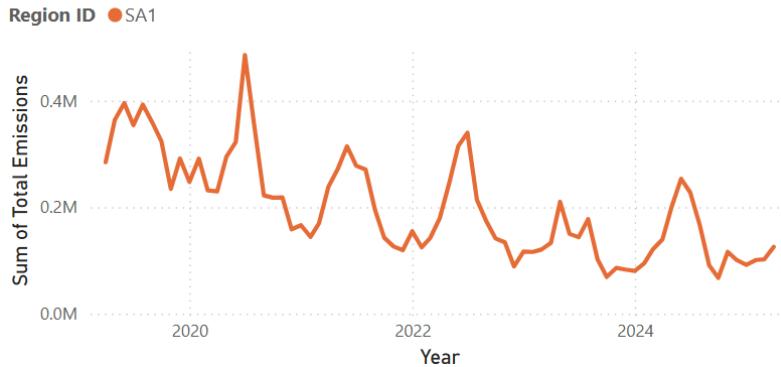
Figure 13: Emissions trend of SA from April'19 till April'25
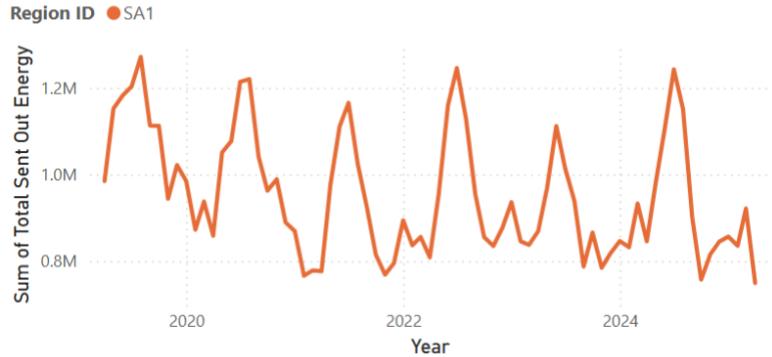
Figure 14: Demand trend of SA from April'19 till April'25
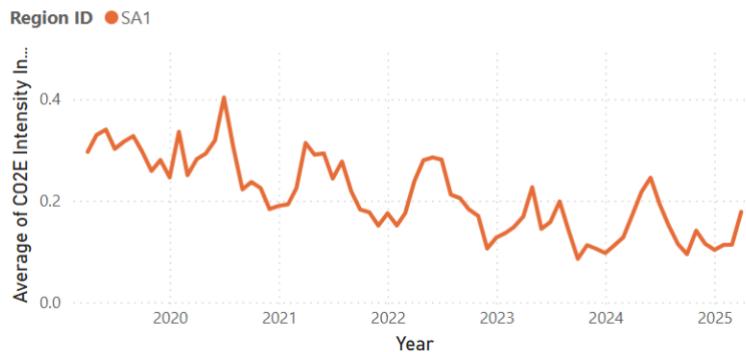
Figure 15: CO_2e intensity trend of SA from April'19 till April'25

Data Insights

From April 2019 to April 2025, South Australia's emissions intensity fell from 0.30 to 0.18 kg/MWh, one of the sharpest drops in the NEM. As shown in Figure 15, the decline was fast and consistent. Figure 14 confirms steady energy output, while Figure 13 shows emissions fell from over 400,000 to below 150,000 tonnes. The shift came from cleaner generation, not falling demand.

Key Drivers of the Trend

- In 2024, SA moved its renewable target forward from 2030 to 2027 as part of the Hydrogen Jobs Plan and Hydrogen and Renewable Energy Act. In 2023, renewables met 100% of demand during part of the day on 289 days (South Australian Government, 2024).
- Battery systems like Hornsdale and Blyth reduced the need for gas. By 2024, SA reached negative demand during rooftop solar peaks (Parkinson, 2024).
- Project EnergyConnect added 750 MW of interstate capacity, improving stability and enabling exports (Parkinson, 2024).

- ElectraNet is planning for over 2,000 MW of new industrial load, which will require 6,000 MW of renewables (Parkinson, 2024). This demand is driving more investment.

Summary Insight for the Client

South Australia's intensity decline was structural. The state replaced gas with firmed renewables, upgraded its grid, and created clean energy demand. SA is now using decarbonisation not only to cut emissions but to attract industry and boost economic resilience.

Region: Tasmania (TAS1)
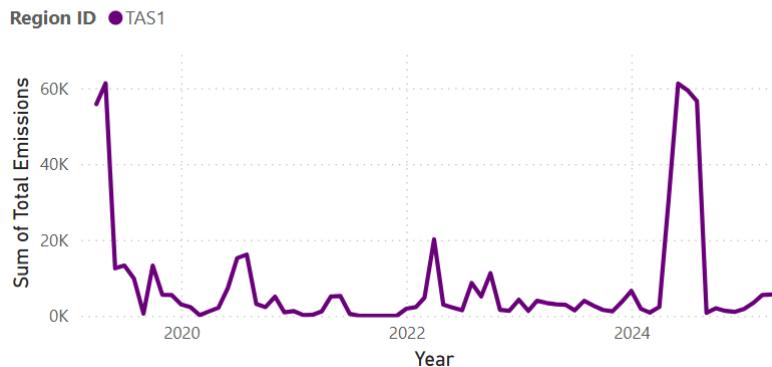
Figure 16: Emissions trend of TAS from April'19 till April'25
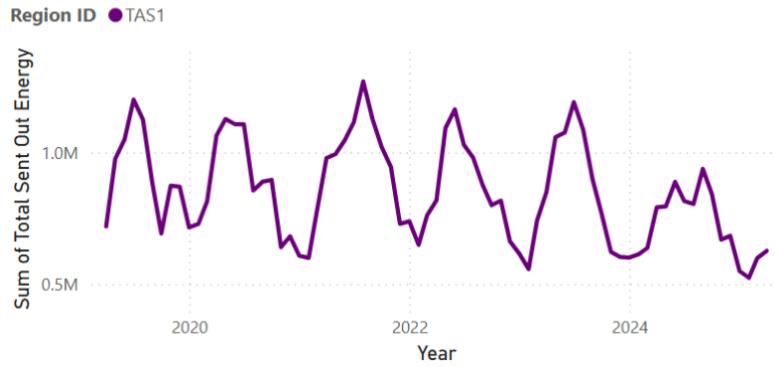
Figure 17: Demand trend of TAS from April'19 till April'25
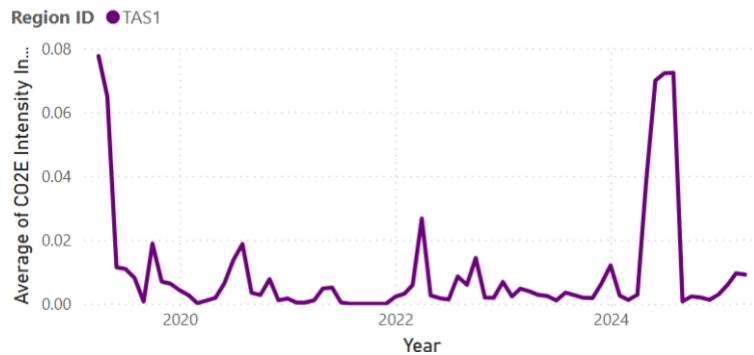
Figure 18: CO_2e intensity trend of TAS from April'19 till April'25

Data Insights

From April 2019 to April 2025, Tasmania's emissions intensity dropped from 0.08 to 0.01 kg/MWh. As shown in Figure 18, the trend was nearly flat, with two brief spikes in early 2019 and mid-2024. These were not structural. Figure 17 confirms consistent output, and Figure 16 shows near-zero emissions throughout. The state already runs on renewables.

Key Drivers of the Trend

- Tasmania reached net self-sufficiency through its hydro and wind fleet, supported by decades of public investment (Department of State Growth, 2024; Tasmanian Government, 2024a).
- Spikes in 2024 likely came from Tamar Valley gas or Basslink outages. These were rare backup events, not systemic shifts (Department of State Growth, 2024).
- Tasmania aims to double renewable generation to 15,750 GWh by 2030, targeting mainland exports and green hydrogen (Tasmanian Government, 2024a; 2024b).

- Demand is forecast to grow 48% by 2033. Fast-tracked approvals for projects like Cellars Hill Wind Farm support clean industrial development (Langenberg, 2025).

Summary Insight for the Client

Tasmania is not transitioning, it is already there. Its low emissions reflect structural reliance on hydro and firm policy commitment. Looking ahead, Tasmania is scaling clean energy to power growth, attract industry, and export low-carbon solutions.
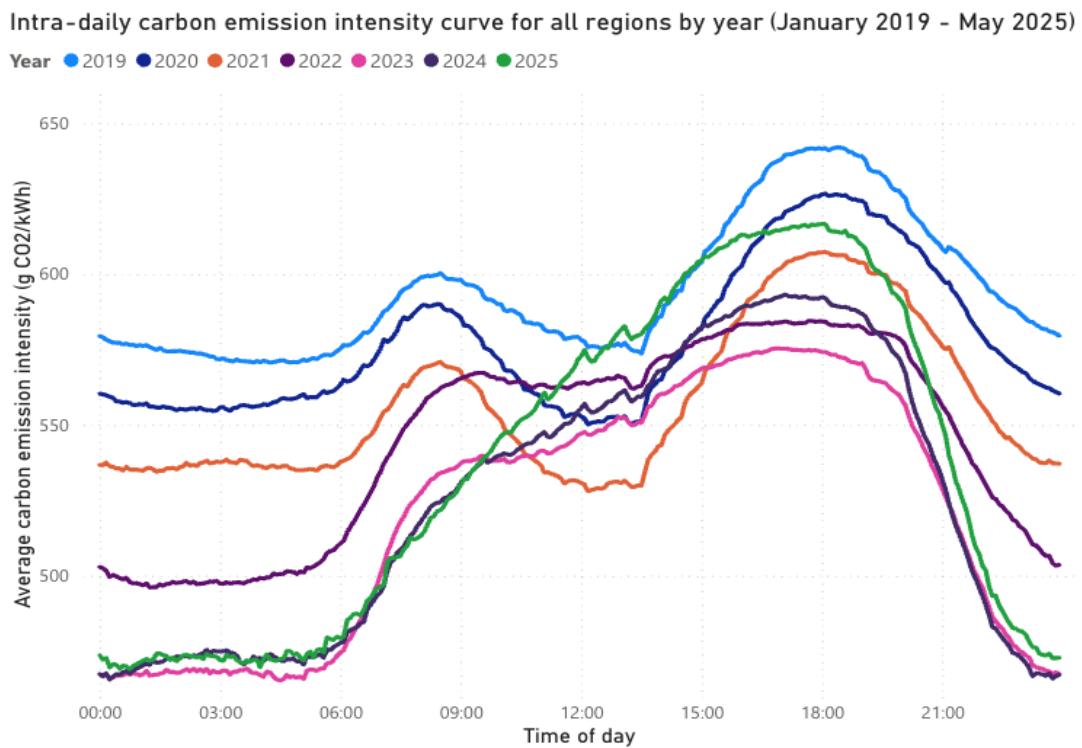
Task 2 Intra-daily Carbon Emission Intensity Patterns and Consumption Impacts

2.1. Intra-daily carbon emission intensity curve for the NEM and for the five regional markets

For this task, I used Python to pull data and PowerBI to visualise the curve. Detailed steps are noted in Appendix A.

Visualisation 1 - Intra-daily carbon emission intensity curve of all regions by year (January 2019 - May 2025)

       To analyse intra-daily carbon emission intensity in the National Electricity Market (NEM), average values across all regions were calculated from January 2019 to May 2025. Data for 2025 covers only the period from 1 January to 15 May due to incomplete records.

Intra-daily carbon emission intensity curve for all regions by year (January 2019 - May 2025)
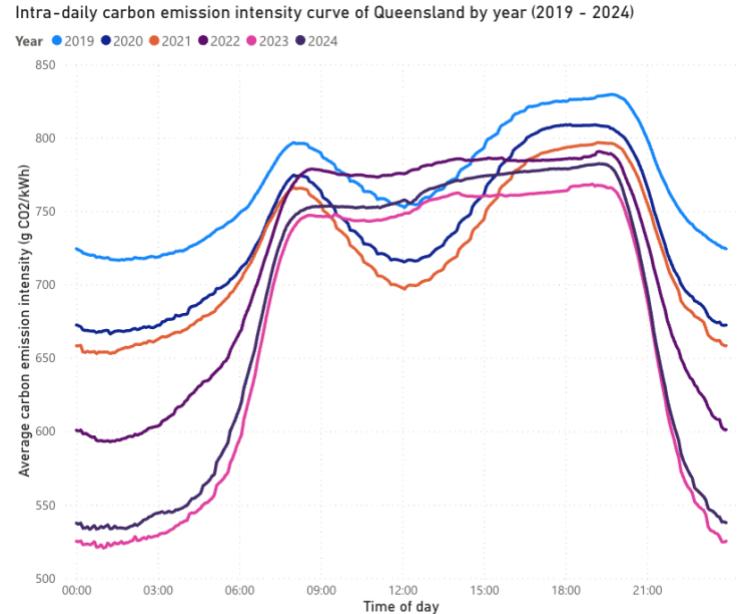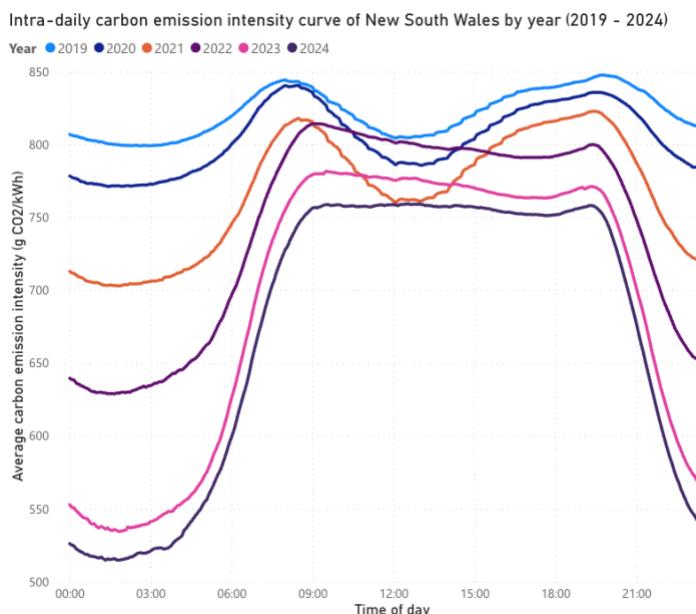
       The intra-daily emission intensity curve retained its characteristic twin-peak U-shape from 2019 to 2024, with peaks around 8-10 AM and 5-7 PM, and a midday trough between 11 AM and 1 PM. Each successive year exhibits a lower overall curve, reflecting progressive decarbonisation, particularly during solar-dominated daylight hours. However, the persistence of morning and evening peaks suggests continued reliance on carbon-intensive generation during low-renewable periods, underscoring the importance of storage and flexible dispatch solutions. As this chart reflects NEM-wide annual averages, regional and seasonal variations are not visible here and will be examined in the following section.

Visualisation 2 - *Intra-daily carbon emission intensity curve of each region by year (2019 - 2024)*

We analyse 5-minute interval emission intensity curves for the five regional markets (New South Wales, Queensland, Victoria, South Australia, and Tasmania) covering the period 2019 to 2024. Data from 2025 is excluded due to incompleteness.

New South Wales and Queensland

Given the similar intra-daily patterns observed in NSW and Queensland, their visualisations are presented side-by-side for direct comparison below:

Intra-daily carbon emission intensity curve of New South Wales by year (2019 - 2024)

Intra-daily carbon emission intensity curve of Queensland by year (2019 - 2024)
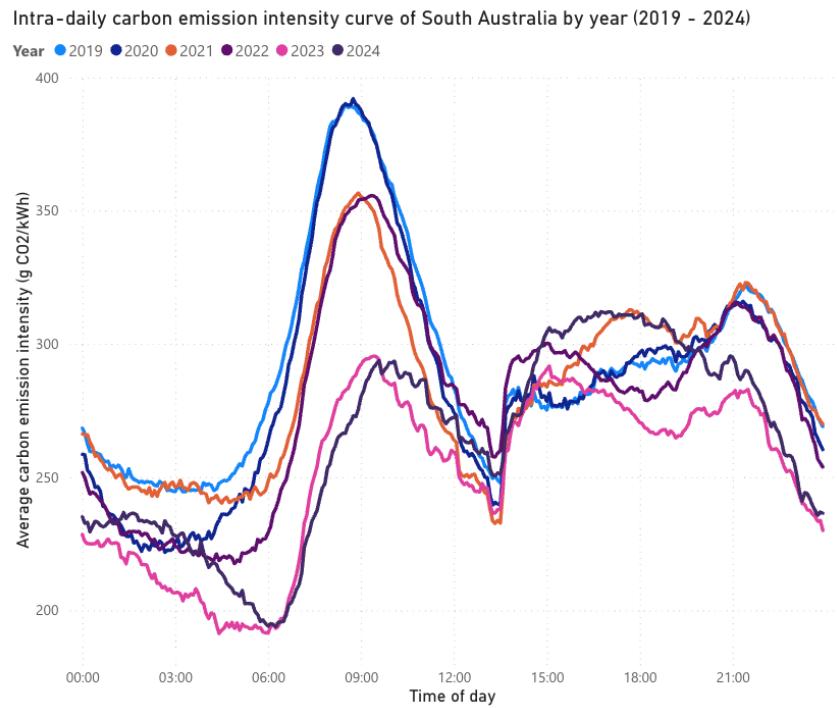
Between 2019 and 2024 both regions reduced their midday carbon-intensity by approximately 150 g CO_2/kWh (around 19%), driven by rapid solar deployment that deepens the 10AM - 2PM dip. However, early morning and evening peaks remain prominent, indicating continued reliance on non-renewable energy generation during these periods.

While the overall reduction in peak intensities is modest compared to the midday improvements, both regions exhibit a "widening gap" between daytime lows and peak-hour emissions. This suggests that, although renewable integration is driving significant decarbonisation during sunlight hours, further progress will require targeted investments in storage and flexible generation to address residual emissions during non-solar periods.
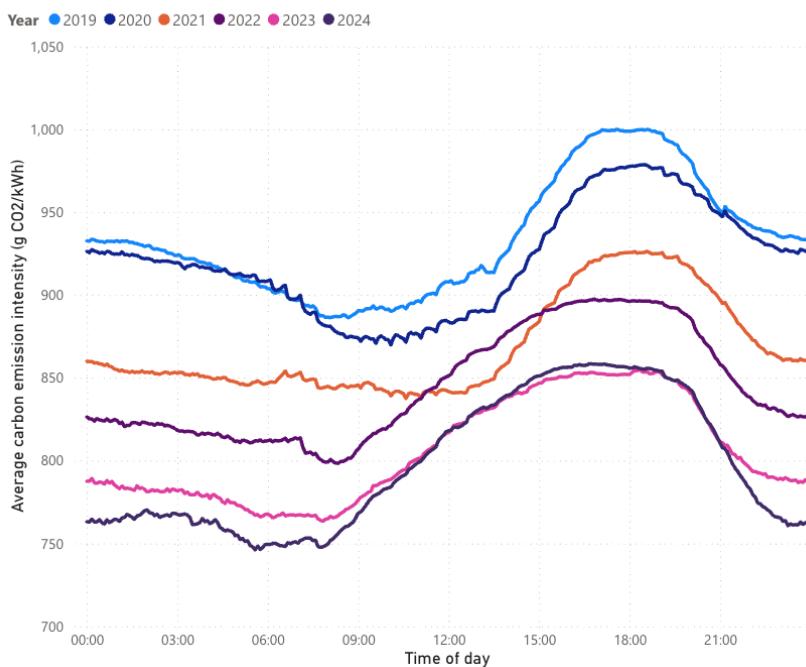
South Australia

South Australia, on the other hand, exhibits the most dramatic shift in intra-daily carbon emission intensity, with a significant midday drop that has deepened significantly from 2019 to 2024. Emission intensity during daylight hours now routinely drops below 200 g CO_2/kWh, a direct result of high levels of solar and wind generation. This midday decline contrasts sharply with the steeper morning and evening peaks observed in earlier years.

By 2024, South Australia's intra-daily emission intensity curve demonstrates the lowest midday values on record, frequently dropping below 200 g CO_2/kWh, while both morning and evening peaks remain considerably lower than in earlier years. This marks a significant achievement in decarbonisation, highlighting the effectiveness of large-scale renewable integration.

Intra-daily carbon emission intensity curve of South Australia by year (2019 – 2024)
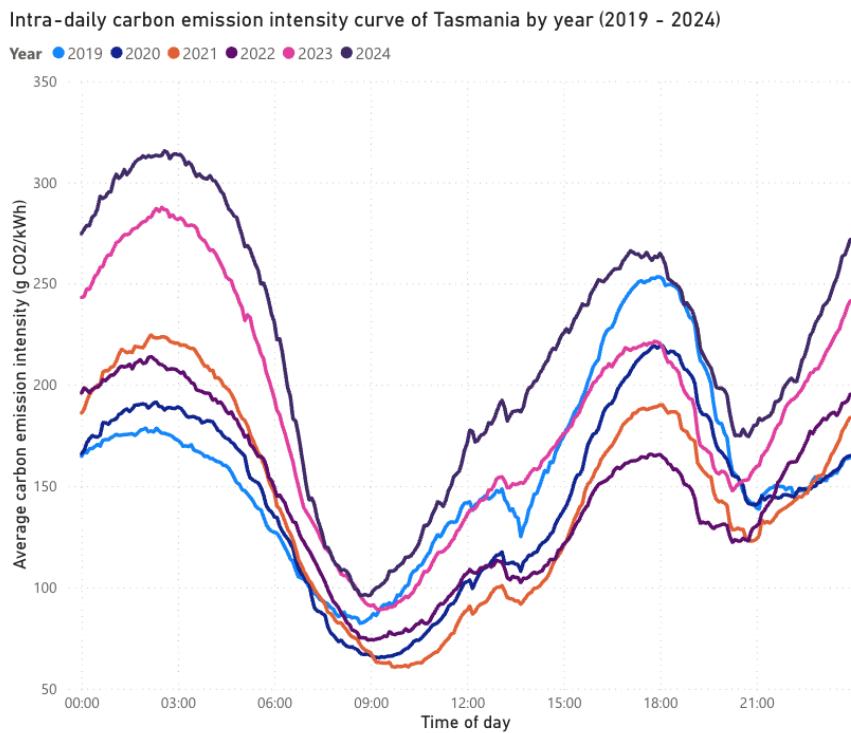
Victoria

Intra-daily carbon emission intensity curve of Victoria by year (2019 – 2024)

Victoria remains the highest-emitting region in the NEM but has made notable progress between 2019 and 2024. A midday decline of over 100 gCO₂/kWh now distinguishes a previously flat profile, reflecting reduced brown coal generation and increased renewables. Nonetheless, persistent morning and evening peaks indicate continued reliance on fossil fuels. Further decarbonisation will require additional storage capacity and demand-side management to reduce reliance on coal outside of daylight hours.

Intra-daily carbon emission intensity curve of Tasmania by year (2019 - 2024)

Year ● 2019 ● 2020 ● 2021 ● 2022 ● 2023 ● 2024
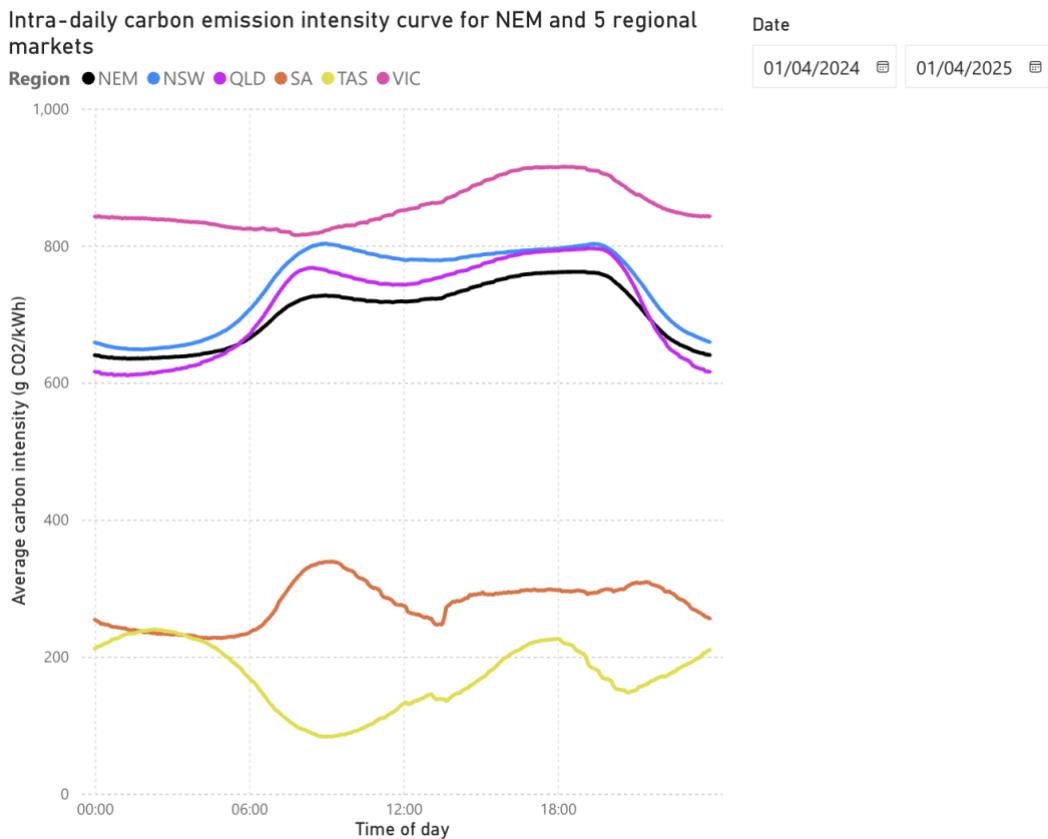
Tasmania

Conversely, Tasmania consistently records the lowest carbon emission intensity in the NEM, with values frequently falling below 100 gCO_2/kWh during daylight hours from 2019 to 2024. The intra-daily profile remains relatively flat, marked by a shallow morning peak and minimal evening increases, likely due to supplementary generation during peak demand. This sustained low-emission pattern reflects Tasmania's strong reliance on renewables, though continued attention to evening demand management will be important as system conditions evolve.

From 2019 to 2024, all five NEM regions show progress in reducing intra-daily carbon emission intensity, with the most significant gains during midday due to increased solar penetration. New South Wales and Queensland exhibit clear midday improvements but retain high peak-period emissions. South Australia leads in decarbonisation, while Victoria, despite improvements, remains the most carbon-intensive. Tasmania maintains the lowest and most stable profile.

Overall, renewable integration is driving daytime decarbonisation, but persistent peak emissions highlight the need for greater investment in storage, flexible demand, and low-emission dispatchable generation.

As the 2025 data is incomplete beyond April, the following visualisation presents the emission intensity curve for the most recent full year, from 1st April 2024 to 1st April 2025, covering both the weighted-average NEM and its five regional markets.
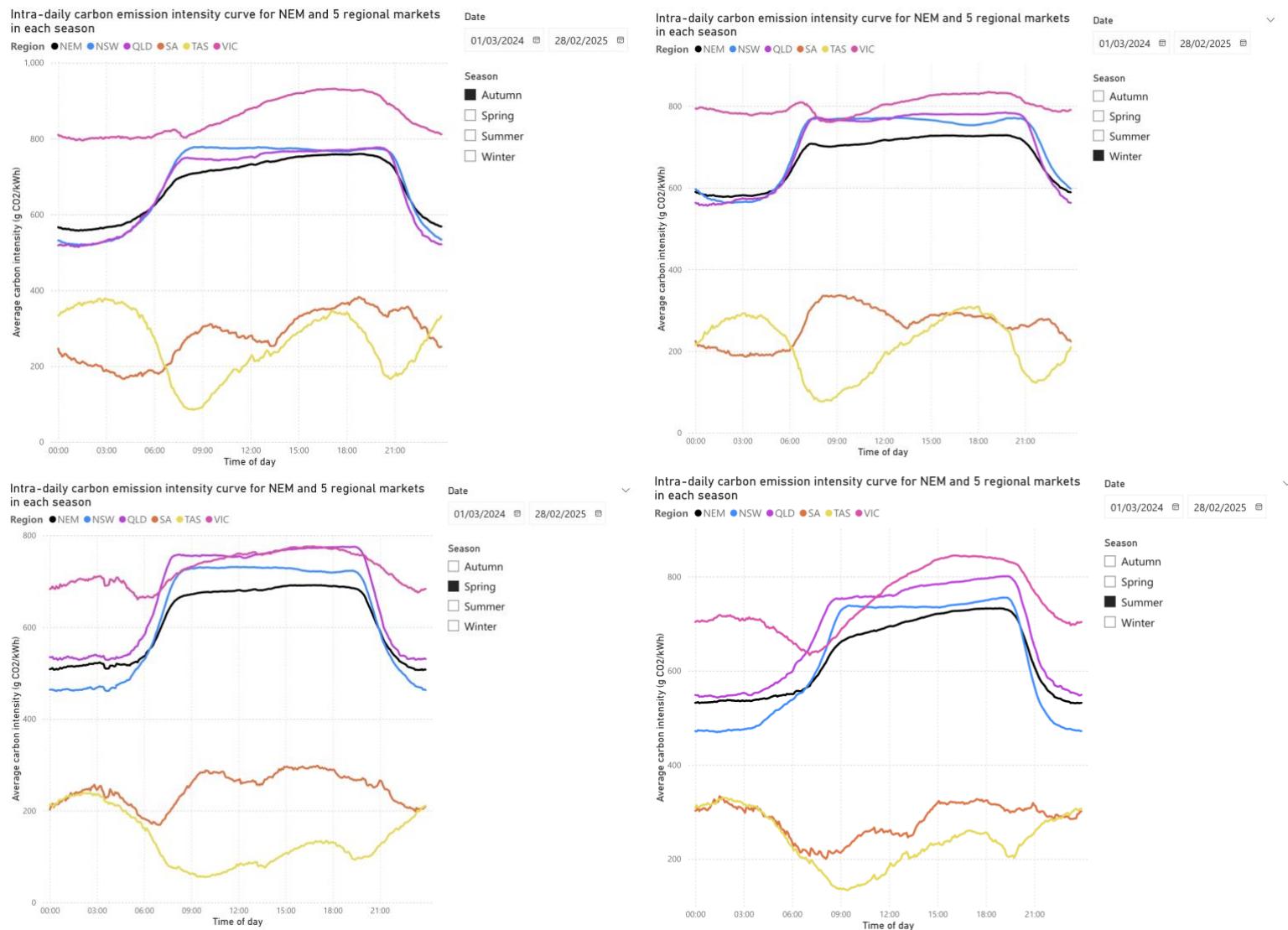
The intra-daily carbon emission intensity curves (April 2024-April 2025) show clear regional differences. Victoria, Queensland, and New South Wales had higher intensities, while Tasmania and South Australia were notably lower. This likely reflects population density and industrial activity, with more populated regions demanding more electricity and thus producing higher emissions.

Victoria recorded the highest carbon intensities, often exceeding 820 g CO_2/kWh during peak times. Queensland and New South Wales followed closely, while the NEM average was substantially lower, reflecting the influence of lower-emission states. South Australia and Tasmania stood out for their low emission intensity profiles. Tasmania remained the lowest, often under 220 g CO_2/kWh. South Australia showed a midday dip from strong solar and wind input while maintaining relatively low emissions at other times. These patterns illustrate the ongoing impact of regional generation mixes and highlight the growing divergence in decarbonisation progress across the NEM.

Since the graph is showing the average of carbon emission over the whole year (averaging 365 days), some seasonal patterns might be missing here. We will now explore how emission intensity changes over each season.

Visualisation 4 - Intra-daily carbon emission intensity curve for NEM and 5 regions in each season

To capture a full seasonal cycle, data from 1st March 2024 to 28th February 2025 is used. Seasonal patterns show that in autumn and spring, midday emission dips are most visible, particularly in solar-rich regions like South Australia and Tasmania due to strong solar output and moderate demand.
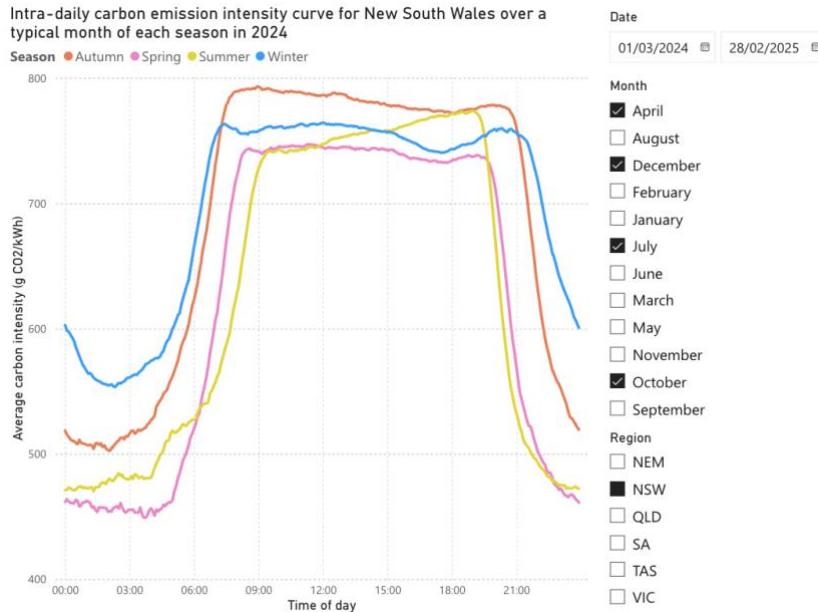
Autumn and Winter 2024 show relatively flat and elevated emission profiles, especially in Victoria, Queensland, and New South Wales, where limited solar output and steady fossil generation lead to minimal midday reduction and persistent peak emissions. Winter has the highest intensities overall, reflecting reduced renewable availability.

In contrast, Spring and Summer exhibit clear midday dips across the NEM, driven by strong solar generation. South Australia and Tasmania show the most significant drops, with emissions frequently falling below 150 gCO_2/kWh. Meanwhile, Victoria and Queensland maintain high, flat curves, indicating slower progress in renewable integration.

Overall, emission intensity is lowest in summer and highest in winter, highlighting the seasonal impact of solar generation and the need for storage and flexible capacity during low-renewable periods. Next, we shall look further into each state and see how the emission intensity changes over a typical month of each season.

Visualisation 5 - _Intra-daily carbon emission intensity curve for each region over a typical month of each season in 2024_
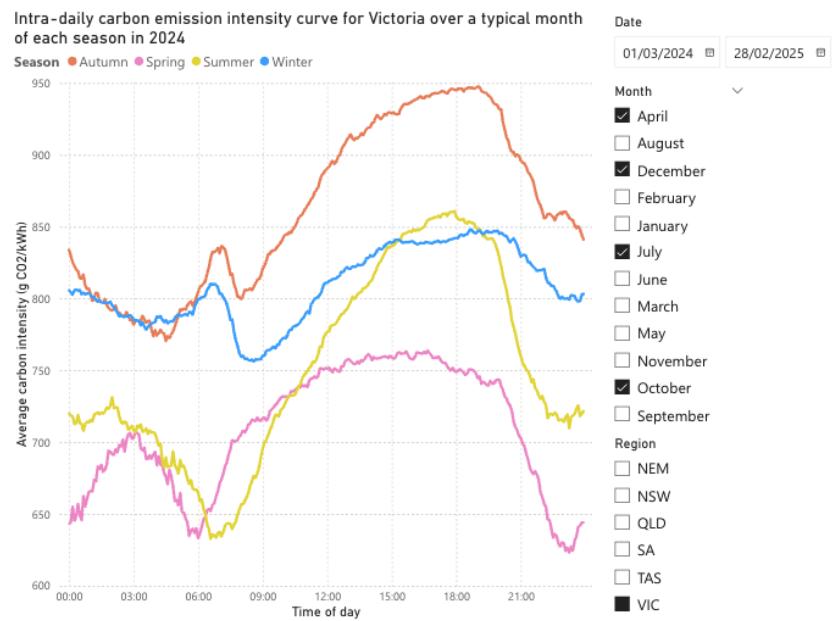
New South Wales
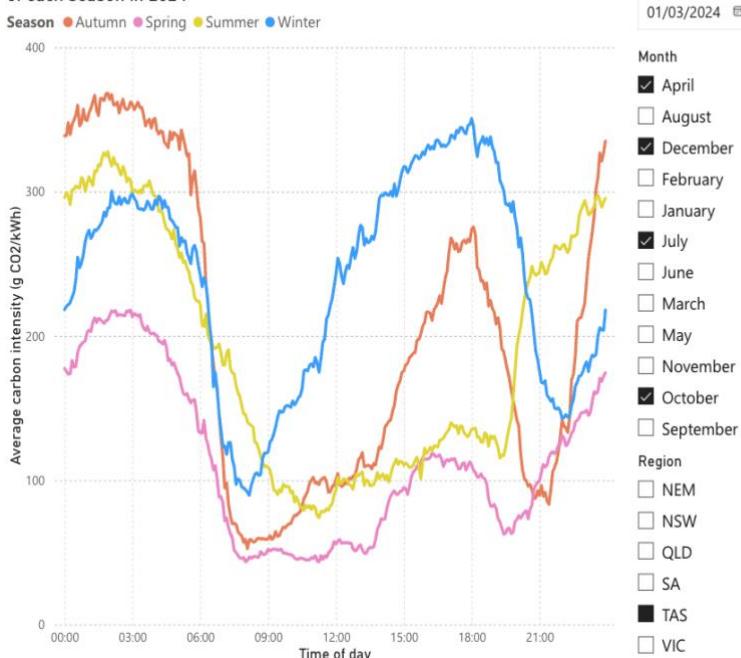
The intra-daily carbon emission intensity curve for New South Wales retains a distinct flat-topped profile across all seasons, with sharp increases in the early morning and steep declines after 6 PM. While the overall level varies, winter and autumn display the highest intensity throughout the day, reflecting higher demand and reduced solar availability. In spring and summer, emissions are lower, particularly at midday, as increased solar generation suppresses the curve. Despite these seasonal shifts, the persistence of a broad plateau during daylight hours highlights the continued dominance of non-renewable energy generation in NSW's supply mix.

Victoria

Victoria's intra-daily carbon emission intensity curves show a broad, elevated increase throughout the day, with notable seasonal shifts. Autumn displays the highest intensities, with emissions steadily rising from morning and peaking late in the afternoon. Winter follows a similar but slightly lower pattern, while spring and especially summer feature a more pronounced midday dip, reflecting greater solar penetration. Despite seasonal variation, Victoria's curve remains consistently high and relatively flat compared to other regions, highlighting the state's ongoing reliance on coal-fired or gas generation, particularly during cooler months.

Intra-daily carbon emission intensity curve for Victoria over a typical month of each season in 2024

Intra-daily carbon emission intensity curve for Tasmania over a typical month of each season in 2024

Tasmania

Tasmania's intra-daily carbon emission intensity curves show significant seasonal variation but remain lower than other regions throughout the year. All seasons display a deep trough in the late morning to early afternoon, with emissions often falling below 100 g CO_2/kWh in spring and summer. Winter and autumn have higher baseline emissions, particularly overnight and in the early evening, but still maintain relatively low levels. The strong midday dip across all seasons highlights the dominance of renewable hydro generation, while the seasonal peaks suggest some reliance on supplementary sources during periods of higher demand.

In conclusion, the intra-daily carbon emission intensity curves across New South Wales, Victoria, and Tasmania reveal clear regional and seasonal differences in generation profiles. NSW and Victoria exhibit consistently higher emission intensities, particularly during cooler months, driven by their continued dependence on fossil fuel-based generation. In contrast, Tasmania maintains the lowest intensity levels year-round, underpinned by its strong hydroelectric base. Seasonal midday dips, especially in spring and summer, underscore the growing impact of solar generation across all regions. Overall, the analysis reflects both the challenges and progress in decarbonizing electricity supply in the National Electricity Market, with Tasmania leading in renewable integration and Victoria and NSW facing steeper paths toward cleaner energy.
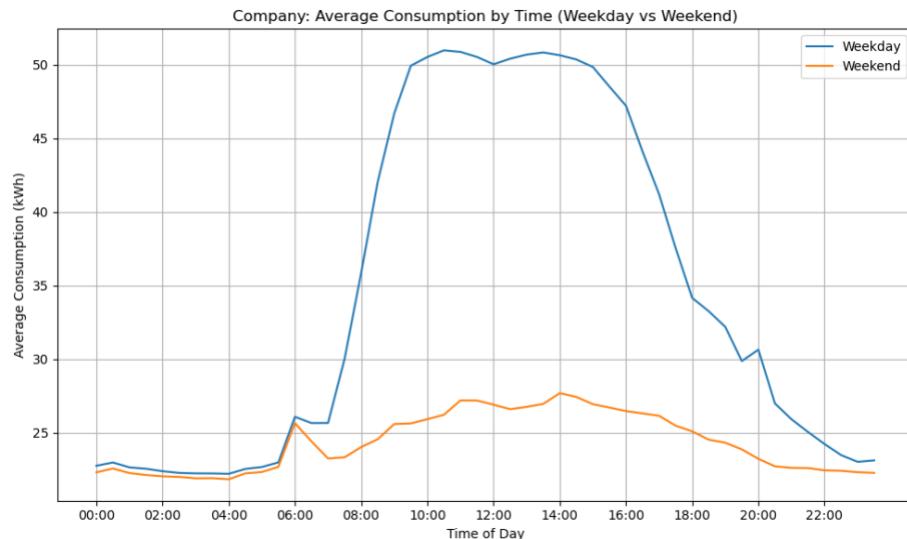
2.2. Comparison on the consumption pattern of household versus company

For this task, I used Python. Detailed steps for data transformation in Appendix B

Comparison of Emission Intensity per kWh: Household vs Company Consumption Patterns

The company and household consumption profiles exhibit distinct intra-daily patterns that directly influence their average emission intensity per kWh.

Companies have a concentrated usage profile:
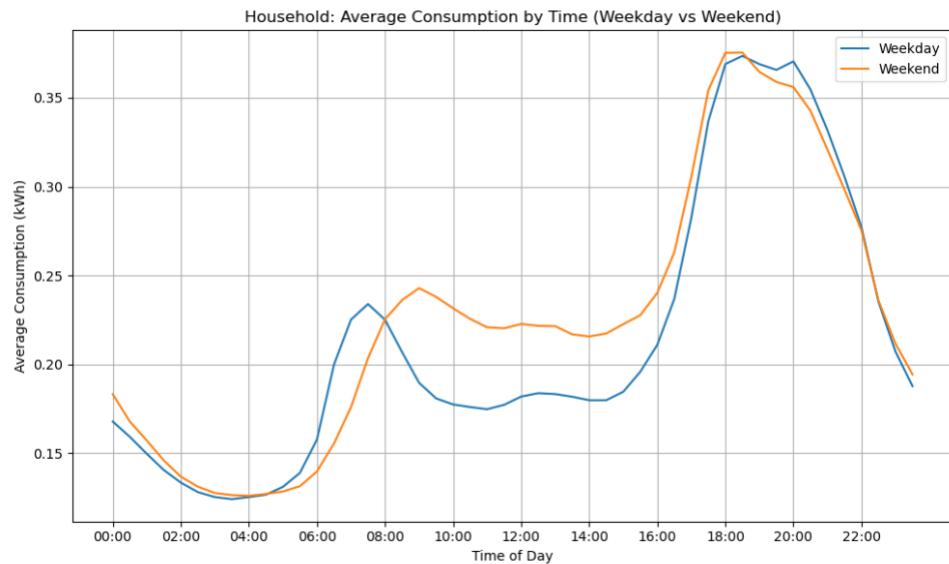
- Weekdays: Consumption rises sharply after 6 am, peaks during standard business hours (9 am–5 pm), and declines after hours.
- Weekends: Usage is relatively steady and much lower throughout the day.

Company demand is highest during weekday daylight hours (8AM-5PM) which are the office/working hours when business operations take place. Conversely, weekend demand remains lower overall, consistent with non-working days. However, a moderate rise from 10 AM-

4 PM on weekends may reflect retail business hours, where shopping malls and in-door leisure activities take place.

Households show a different pattern:

- On both weekdays and weekends, household consumption is low during typical work hours (8 AM–4 PM), aligning with higher usage in the company profile as people are likely at work. There are noticeable peaks in the early morning (around 7 AM) and especially in the evening (6–9 PM) when people get up and return home. On weekends, daytime consumption is slightly higher and more sustained, suggesting that people spend more time at home or engage in daytime activities.

[**Source code**: source_code_T2.ipynb (2.6)]

Company demand is highest during daylight hours, precisely when grid emission intensity is lowest due to strong solar generation. By contrast, household consumption peaks in the evening of both weekday and weekend, overlapping with the grid's emission intensity peaks when fossil fuel generation is most relied upon.

Companies are more likely to achieve a lower emission intensity per kWh of electricity consumed, simply because their demand profile aligns with periods of higher renewable generation and lower grid emissions. Households, with their heavy evening usage, are more exposed to high-emission periods, resulting in a higher average emission intensity per kWh. Based on this assumption, the emission intensity per kWh of electricity consumption for households and companies shall be calculated and evaluated in the following part.

Comparison on the carbon emission intensity per KWh of electricity consumption of household versus company in NSW

[**Source code**: source_code_T2.ipynb (2.7)]

As the household and company data does not specify a region, this analysis assumes it represents data from New South Wales (NSW). To compare carbon emission intensity per kWh between households and companies, we analysed half-hourly electricity usage in NSW. By merging consumption data with corresponding carbon intensity values, we calculated each group's weighted average intensity as:

Average Intensity (gCO$_2$/kWh) =Total Emissions (gCO$_2$) / Total Consumption (kWh)

The final results were as follows:
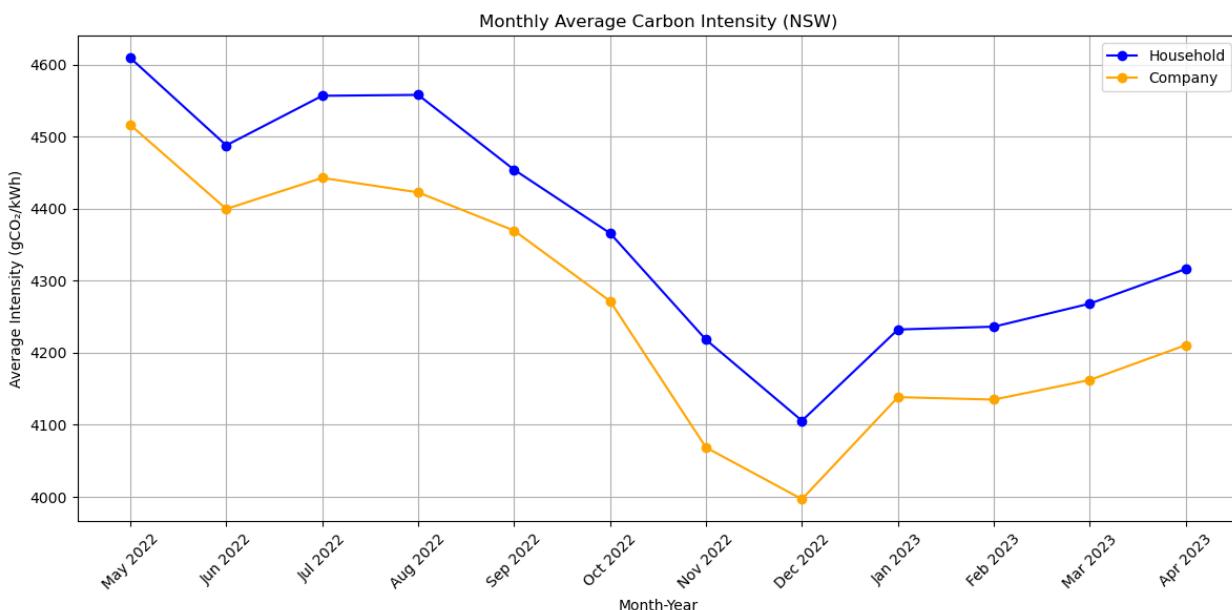
```
=== OVERALL SUMMARY FOR NSW ===

Household Total Emissions:    1108228.80 gCO₂
Household Total Consumption: 253.25 kWh
Household Average Intensity: 4376.04 gCO₂/kWh

Company Total Emissions:      144547508.54 gCO₂
Company Total Consumption:    33911.31 kWh
Company Average Intensity:    4262.52 gCO₂/kWh
```

On average, companies in NSW consume electricity with slightly lower carbon intensity per unit of energy compared to households. This is likely due to time-of-day differences in usage patterns:

- Company consumption is concentrated during daytime hours, when solar and other lower-emission sources are more prevalent on the grid.
- Household demand peaks in the evening, particularly between 6-9 PM, when fossil fuel generators tend to supply a larger share of electricity, increasing emission intensity.
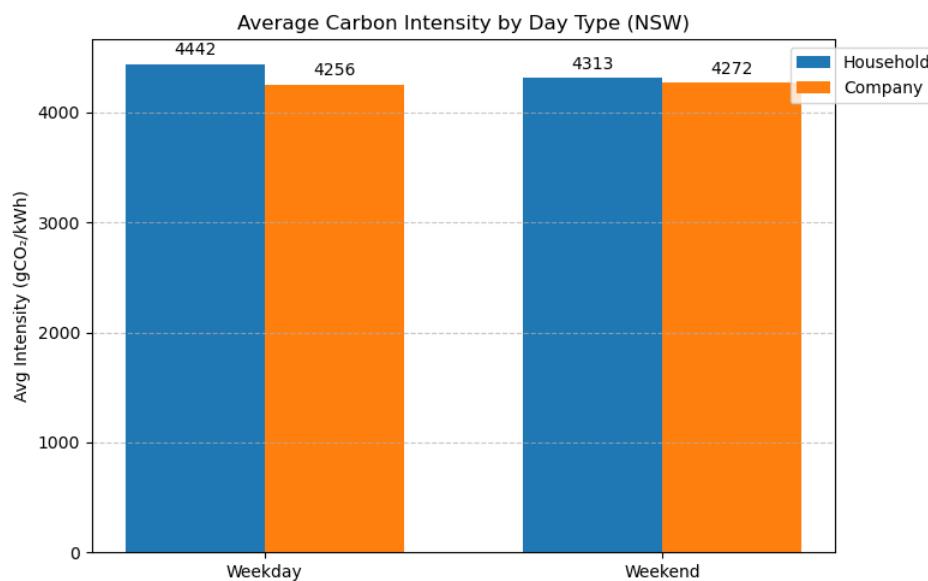
Thus, companies are more likely to have a lower emission intensity per kWh than households, primarily due to the cleaner generation mix available during business hours.

2.2.1. Monthly breakdown

Households run about 150-200 gCO$_2$/kWh higher than companies on average, peaking around 4,600 gCO$_2$/kWh in winter (May-August) and dipping to ~4,100 gCO$_2$/kWh in early summer (December). Both sectors mirror seasonal supply: summer solar depresses intensity, winter demand and low renewables drive it up, but companies show a slightly lower-volatility profile by leaning more on daytime (lower-carbon) consumption.

2.2.2. Day-type breakdown

Average Carbon Intensity by Day Type (NSW)

Households see a bigger weekend dip in intensity than companies:

- Weekdays: around 186 gCO2/kWh gap.
- Weekends: around 41 gCO2/kWh gap.

That suggests household consumption shifted away from high-carbon evening peaks on weekends, whereas company usage (more tied to daytime hours) actually matched into slightly higher-carbon periods when retail and industrial demand remained flat. Overall, companies maintain a steadier profile, while households benefit most from lower-intensity weekend supply.

2.2.3. Peak-emission breakdown
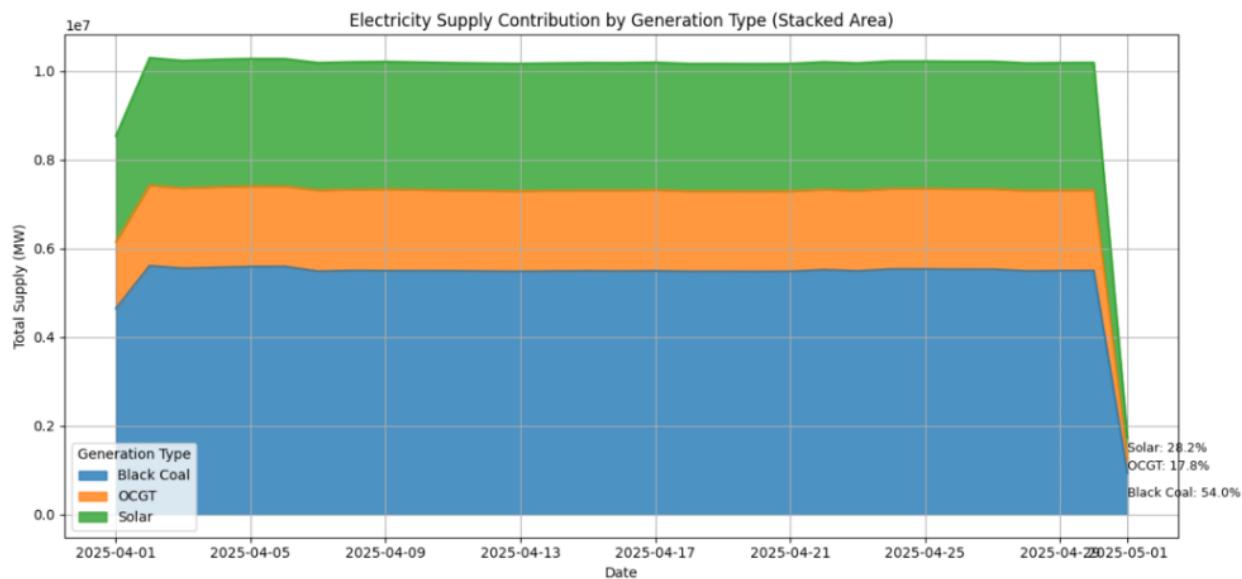
```
=== PEAK EMISSION INTERVAL (SINGLE HIGHEST HALFHOUR) ===

Household Peak Interval:
Year                   2022
Month                   Jul
DAY_TYPE            Weekend
Interval                 37
time              18:30:00
Emissions_gCO2   2813.242568

Company Peak Interval:
Year                   2022
Month                   Jun
DAY_TYPE            Weekday
Interval                 34
time              17:00:00
Emissions_gCO2   230636.56627
```

Household peak occurred on a winter weekend (July 2022) at 18:30, with 2,813 gCO$_2$ emitted in that half-hour, reflecting evening heating and low solar output while company peak hit on a weekday in June 2022 at 17:00, with a massive 230,637 gCO$_2$ in one interval, driven by end-of-day operational loads. Household emissions spike in cold-season evenings when renewables are weakest, whereas corporate emissions climax during late-afternoon business hours, highlighting distinct demand-driven stress points in the grid.
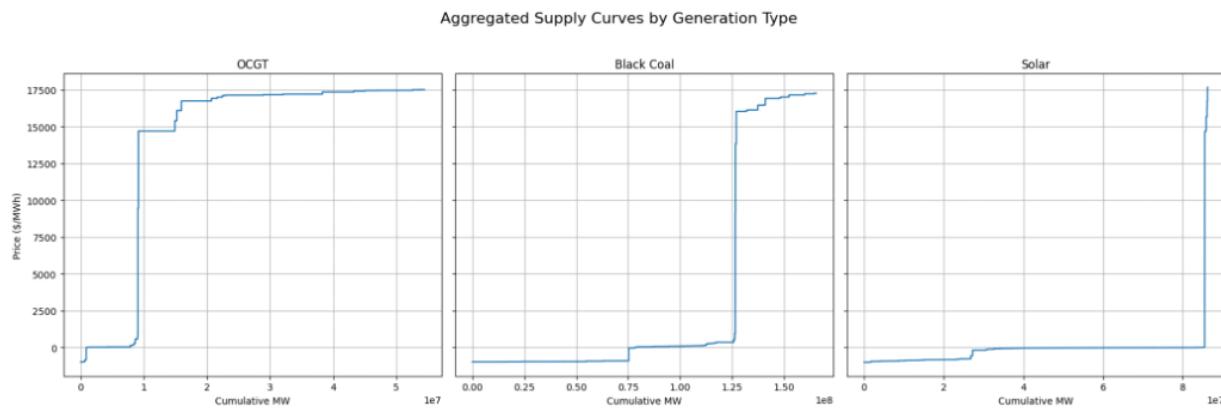
Task 3: Comparing Generation Types w.r.t to Bidding Behaviour, Supply Curves and Time of the Day.

The purpose of this task is to compare different generation technologies in terms of their price bidding patterns and the resulting aggregate supply curves in April,2025. Following is an in-depth analysis and data-driven insights which will help us recommend investment decisions going forward.

To begin our analysis, we will start off by seeing all generation technology's share of electricity supply potential in NEM. The area chart below shows the percentage contributions for generation types. Black Coal has supplied more than half (54%) of all electricity in 2025; Solar has contributed 28% share while OCGT has least share hovering around 18% throughout NEM in April 2025.

Generation Types Analysis w.r.t Bidding behaviour and AS Curves

Aggregated Supply Curves by Generation Type

Generation Type Black Coal *Findings*

Observed Pattern:

Coal-fired technology supplied a wide range of offers, mostly in the moderate-price band. There is a flat portion offering a large block of capacity at a low-price level. This indicates a strong incentive to be dispatched, likely to avoid costly shutdown/startup cycles or meet minimum load levels.

Large coal capacity is offered between roughly $50 and $200/MWh, with additional MW moving into lower bands as fuel costs fell. Sharp jump in prices after a point and the remainder of the capacity is offered at very high prices (>$15,000/MWh). This is likely strategic withholding; bidding a portion of capacity at the market cap so it's only dispatched when prices spike.

Coal's aggregate supply curve is more gradual than Solar's. Capacity ramps up steadily as price increases. However, some coal generators also shift significant capacity into high-price bids (for example, over 3,000 MW moved above $60/MWh in recent comparisons) to capture peak returns. In summary, coal bids fill much of the middle of the curve and some at the top, reflecting moderate marginal costs and occasional strategic high offers (e.g. to avoid uneconomic dispatch).

Generation Type <mark>Solar</mark> Findings

Observed Pattern:
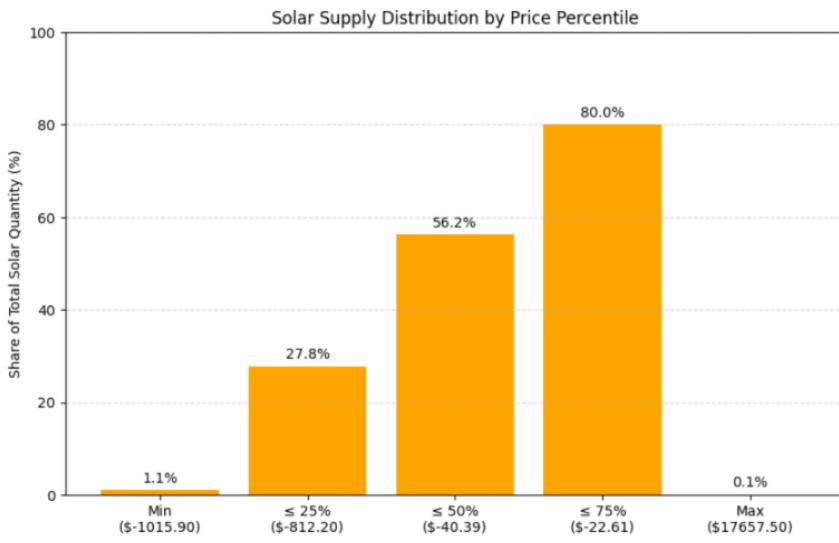
Marginal cost ≈ $0, so bids are often as low as -$1,000 to $0/MWh with substantial MWs offered especially if they benefit from subsidies (e.g., Large-scale Generation Certificates in Australia), with almost no capacity offered at high prices. Bids reflect the desire to be dispatched whenever available, regardless of price.

Highly variable, depending on weather. Often leads to steeper and flat supply curves with less control over volume. Price is constant for major supply bands as supply is limited. After a certain point, a sudden jump in price but then prices are insensitive to supply (Supply inelastic) as there is a production halt (Resource Exhaustion).

Observed Bidding Behaviour:

In practice solar supply is essentially all at low price, driving frequent negative-price intervals during high-sun conditions. The spike at the end represents capacity that is technically available but priced high to avoid dispatch.

The bar chart below also shows that almost all the MW quantities are supplied at negative prices by all solar generators combined under NEM. Around 80% of all the electricity is supplied at or below 75th percentile of the price range, 56% at or below median prices and 28% at or below 25th percentile and 1% at minimum prices which are all negative price slabs. Almost none of the electricity is supplied at max prices.

Solar Supply Distribution by Price Percentile

Generation Type OCGT Findings

Observed Pattern:
- The supply curve is almost entirely flat at a very high price (~$14,500/MWh) until the end.
- A small volume at the beginning appears to be offered at a negative price, likely a placeholder or error, or strategic low-volume dispatch.
- The final jump to ~$17,000/MWh occurs only for a small final portion of capacity.

Observed Bidding Behaviour:
1. High Price Offers:
These gas peaking plants have very high marginal costs, so they bid almost entirely at the top end of the market. OCGTs require about 10 GJ of gas per MWh, implying fuel costs around $400/MWh if gas is $40/GJ. Consequently, OCGT supply is essentially zero at low-to-moderate prices and jumps sharply only at very high prices. In practice almost all OCGT capacity is offered near the market cap (reflecting their expensive fuel). The OCGT supply curve is thus extremely steep meaning little capacity until price is high enough to cover their costs, then a big step of available MW at the top end. Moreover, the high pricing across most of the volume reflects that these units are intended to be dispatched during peak demand or supply shortfalls.
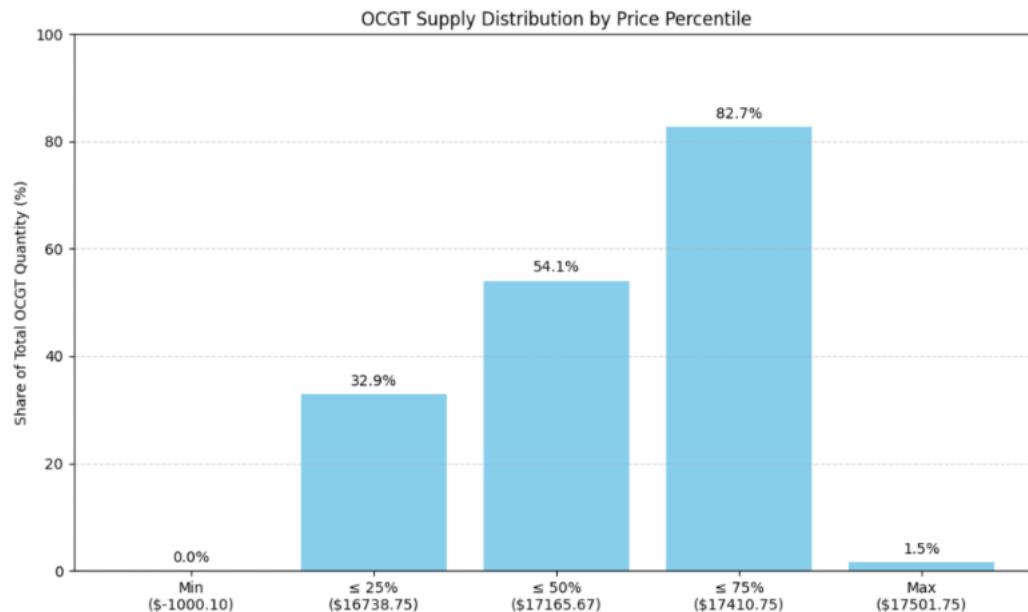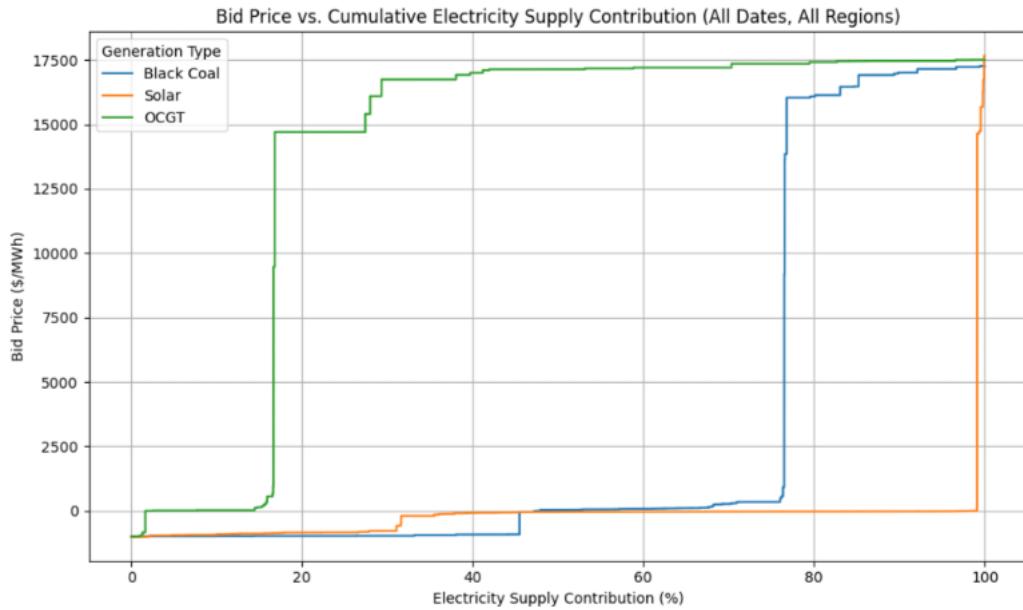
2. Peaking Strategy:

- The operator is not seeking to be dispatched under normal conditions.
- Instead, they offer capacity at or near the Market Price Cap (typically ~$15,500–$17,500/MWh in the NEM).
- This ensures they're only called upon when prices spike, and when they can make a significant margin.

Similarly, the bar chart below shows the electricity supply for OCGT at different price percentiles. As evident, generators are willing to supply most MWs at a higher spectrum of bid prices and not intending to supply at minimum or negative prices.
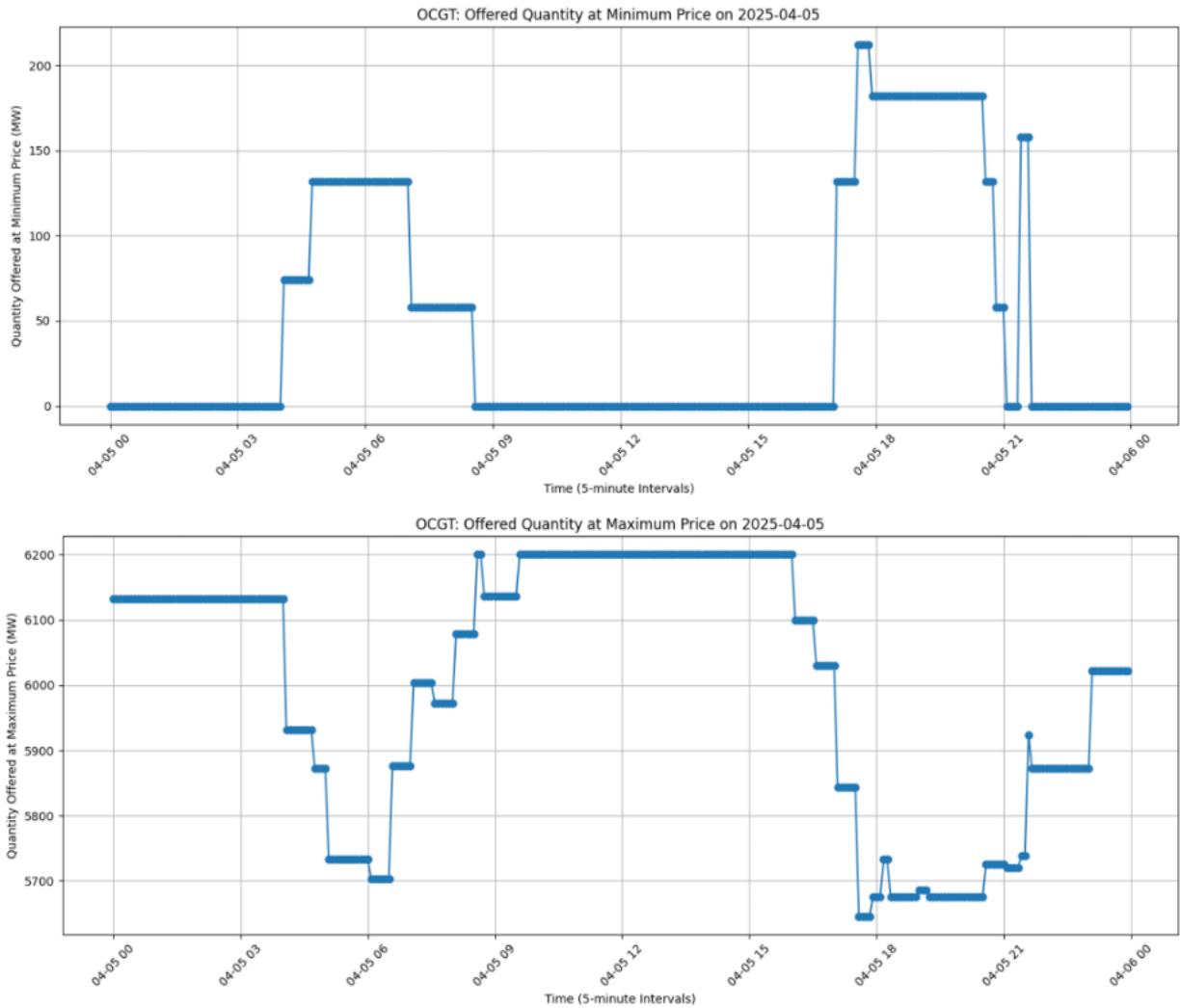
Lastly, the graph below shows cumulative supply contributions on different price ranges for all three generation types. Solar supplied 100% of electricity at minimum prices. OCGT, on the other hand, supplied more than 85% of their electricity at higher prices above ~$500 while black coal supplied ~30% of their electricity at higher prices (supplied remaining quantities ~70% on prices at or below zero).

Bid Price vs. Cumulative Electricity Supply Contribution (All Dates, All Regions)

In summary, solar sits on the far left of the bid stack (large volume at ~$0/MWh and below, none at high prices); black coal spans the middle (significant capacity from mid-range up into higher bands) and OCGT sits on the far right (almost all capacity at very high prices). Solar's curve is very steep at the bottom, coal's is moderate, and OCGT's is very steep at the top. Strategically, solar bids low to stay dispatched (even into negative pricing), whereas coal and gas units often bid higher (even up to the cap) to avoid low-price dispatch or cover high fuel costs.

Time of the day Comparisons

Generation Type OCGT Findings

Graph 1: Quantity Offered at Minimum Price

Pattern:

- There is no offer at minimum price for large stretches of time (especially overnight and early morning).

- Bids appear in blocks around morning (05:00–08:00) and evening (17:00–21:00).

- Sharp spikes (e.g., ~210 MW at ~17:30) show intermittent and reactive supply behavior.

Interpretation:

- OCGT plants are often peaking generators, used only when demand spikes or during price volatility.

- They offer some capacity at minimum price likely to guarantee dispatch during high-demand intervals, especially when other baseload or renewable options are insufficient.

Graph 2: Quantity Offered at Maximum Price:
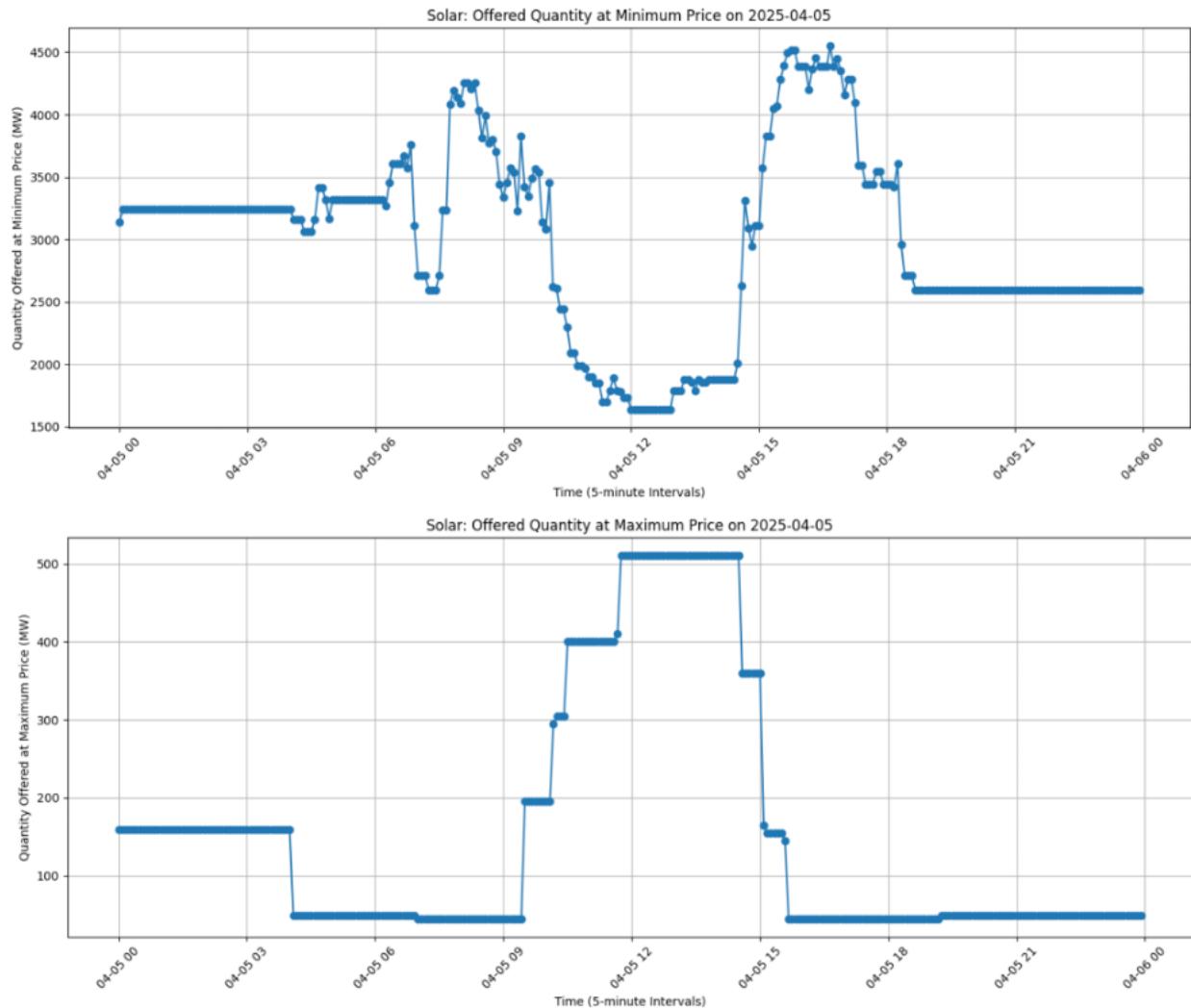
Pattern:
- Quantity offered at the maximum price (>$14,000/MWh) is consistently high across all time intervals.

- There is some day-time fluctuation, but the magnitude remains significant (~5700–6200 MW range).

- Drop-offs occur slightly around afternoon and evening, but not as dramatically as minimum price offers.

Interpretation:

- OCGT generators bid most of their capacity at the market cap to be available as last resort, often not intending to be dispatched unless absolutely needed (scarcity pricing).

- The consistent presence of max price offers represents a strategic bidding behavior, creating a supply ceiling while ensuring availability.

Generation Type <mark>Solar</mark> Findings

Solar: Offered Quantity at Minimum Price on 2025-04-05

Solar: Offered Quantity at Maximum Price on 2025-04-05

Key Differences in Offered Quantity and Bidding Behavior:

1. **Offered Quantity Levels:**

   Minimum Price: Quantities range from ~1,700 MW to ~4,500 MW.
   Large volumes are consistently offered, especially from early morning to evening.

   Maximum Price: Quantities are significantly lower, maxing around 520 MW, with near-zero values for the rest of the day.

Interpretation:

Most solar generators prefer to offer their output at minimum prices, ensuring they are dispatched into the market. Only a small fraction of capacity is held at maximum prices, likely as a strategic signal rather than a serious bid.

2. Time-of-Day Dependency

Yes, bidding behavior is clearly dependent on solar generation patterns throughout the day:

Midday Peak (approx. 10:00 to 15:00): Max price offers increase significantly, peaking above 500 MW. This corresponds to solar generation peak hours, possibly when generators expect demand or price spikes and test the market with higher price offers.

Early Morning & Night: Near-zero offers at max price (likely due to no generation). Minimum price offers remain stable during night (possibly automated or default behavior) but are likely not dispatched. Generators are aggressive with high bids during solar peak but maintain baseline supply at minimum price to secure dispatch.

3. Aggregated Supply & Market Strategy
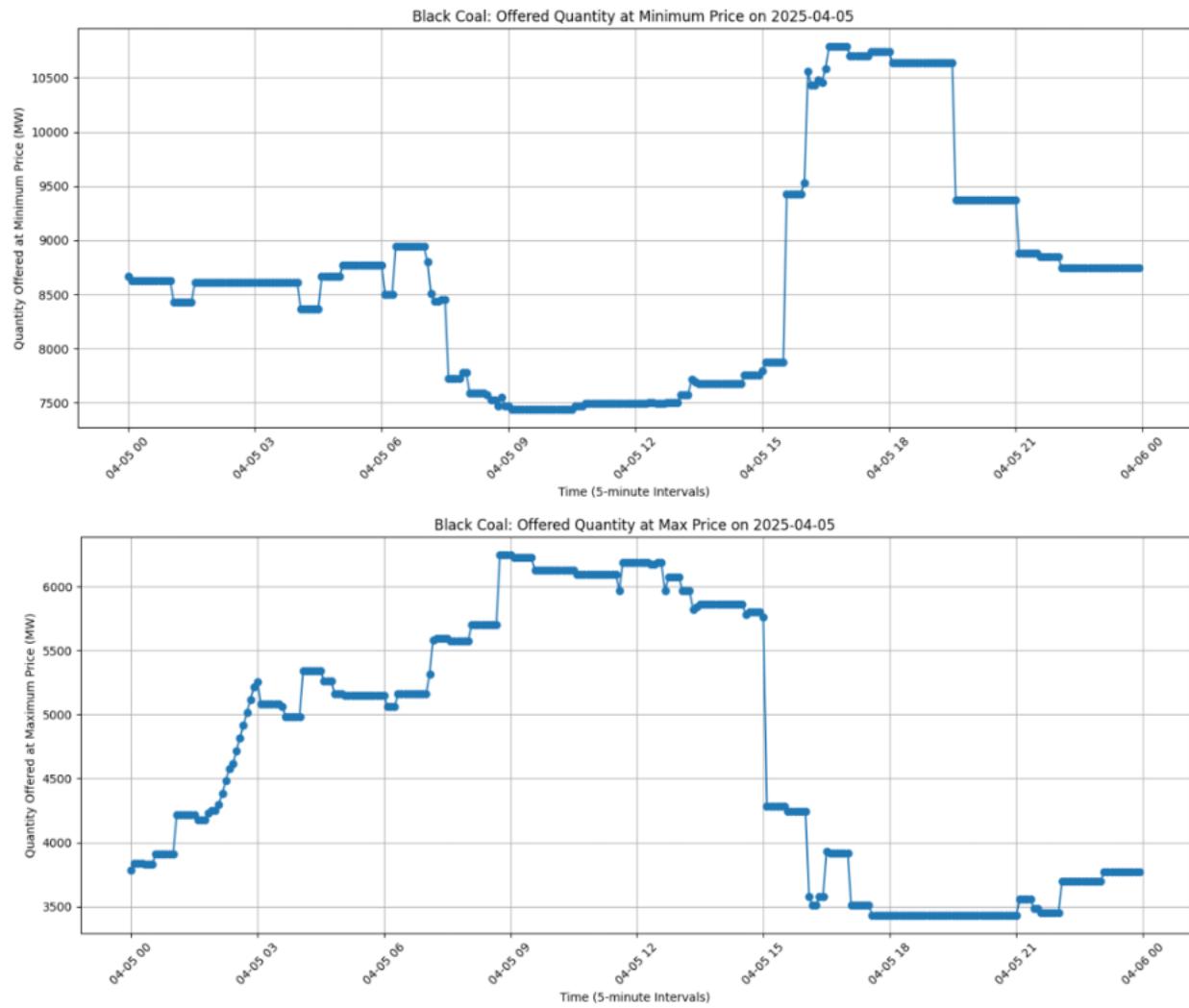
Minimum Price Offers = Base Supply Strategy
Most solar capacity is offered at or near zero price to ensure dispatch (common with renewable generators under subsidy/PPA arrangements).

Maximum Price Offers = Opportunistic Strategy
Small quantities at maximum prices indicate a scarcity pricing tactic during peak generation hours when system stress or higher prices are anticipated.

Generation Type Black Coal Findings

Black Coal: Offered Quantity at Minimum Price on 2025-04-05

Black Coal: Offered Quantity at Max Price on 2025-04-05

1.Time-of-Day Dependency

Characteristic	Minimum Price Plot	Maximum Price Plot
Early Hours (00:00–06:00)	Stable around **8,500 MW**, slight dips and bumps	Ramping from **~3,800 MW** to **~5,300 MW** steadily
Morning Dip (06:00–09:00)	Sharp drop to **~7,400 MW**, lowest point	Sustained peak at **~5,500–6,200 MW**
Midday Peak (10:00–14:30)	Rapid rise to peak **10,600+ MW**	Maintains **>6,000 MW**, peak bidding hours
Afternoon Decline (15:00–18:00)	Gradual reduction to **~9,400 MW**	Sharp fall to **~3,500 MW**, indicating exit of high-price bids
Late Evening (18:00–00:00)	Slight fluctuations, settles around **8,800 MW**	Low levels **3,500–3,800 MW**, mostly baseline bids

2.Bidding Behavior Analysis:

Minimum Price Bids (Base-Load Strategy):
Used to guarantee dispatch in the merit-order system. High availability throughout the day reflects commitment to market participation.
The midday spike reflects increased output availability likely to match solar curtailment or higher net demand.

Maximum Price Bids (Strategic Pricing):
Strong time-of-day dependency: Rises early morning anticipating higher price opportunities. Maintains high levels until ~15:00, then sharply retreats. Suggests opportunistic market behavior, aimed at capitalizing on system stress or peak demand.

3.Strategic Takeaways:

Aspect	Minimum Price Bidding	Maximum Price Bidding
Market Intent	Secure dispatch	Extract higher margins
Time Sensitivity	Low–Moderate (mostly steady)	High (peaks in daylight/peak hours)
Typical Users	Base-load generators or contracts with obligations	Traders or generators with flexible units

Task 4: Market-Share Shifts and Regional Bidding Leaders (2019 vs 2025)

This section shows who supplies the most electricity bids by generation and by region and how that picture changed between 2019 and 2025. Seeing these shifts first tells us proportion of each generation type's supply, giving the essential context for every later finding about their detailed bidding tactics.
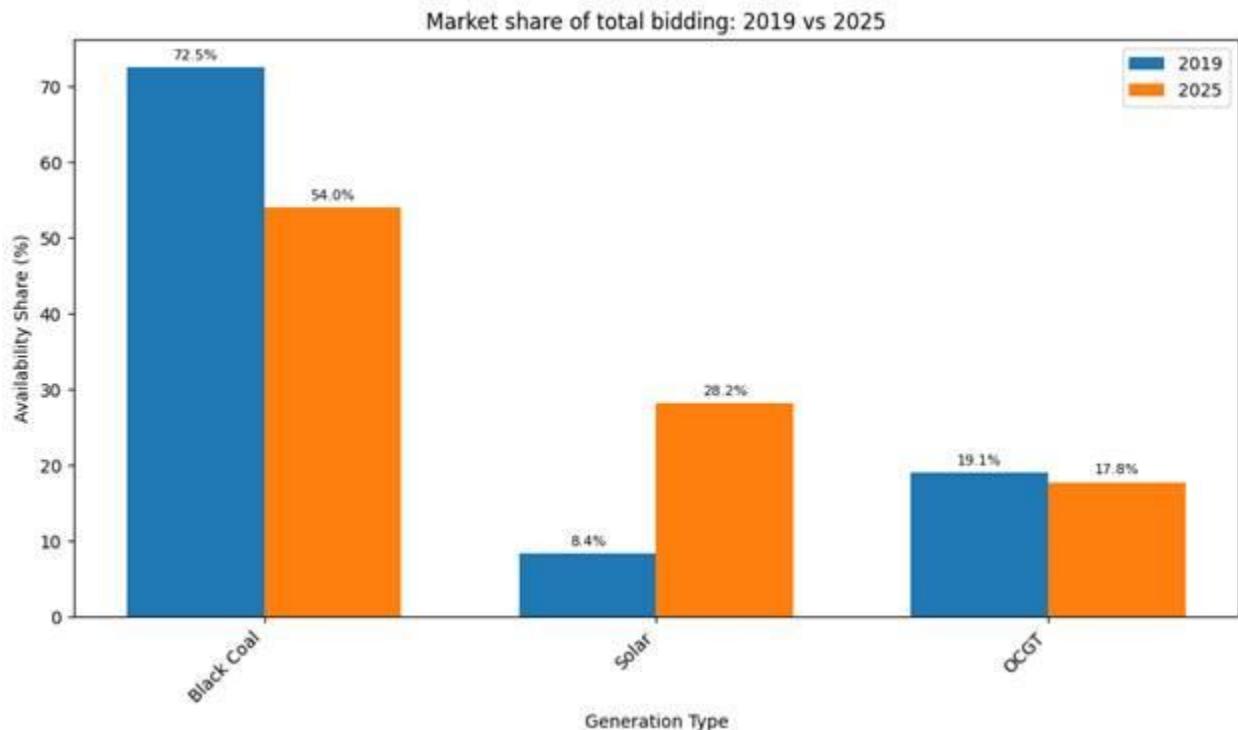
Figure 1: Market Share of each generation type

From Figure 1, solar's massive growth in market share is evident. From 2019 to 2025, its share of bids jumped from 8% to 28%, driven by three times as many solar units joining the market (Figure 2). On the other hand, Black coal's market share dropped sharply, down by nearly 19 percentage points (Figure 1), and there are four fewer coal units operating now (Figure 2). Finally natural gas plants (OCGT) have stayed relatively stable, with a slight increase in the number of units but a small decrease in market share.
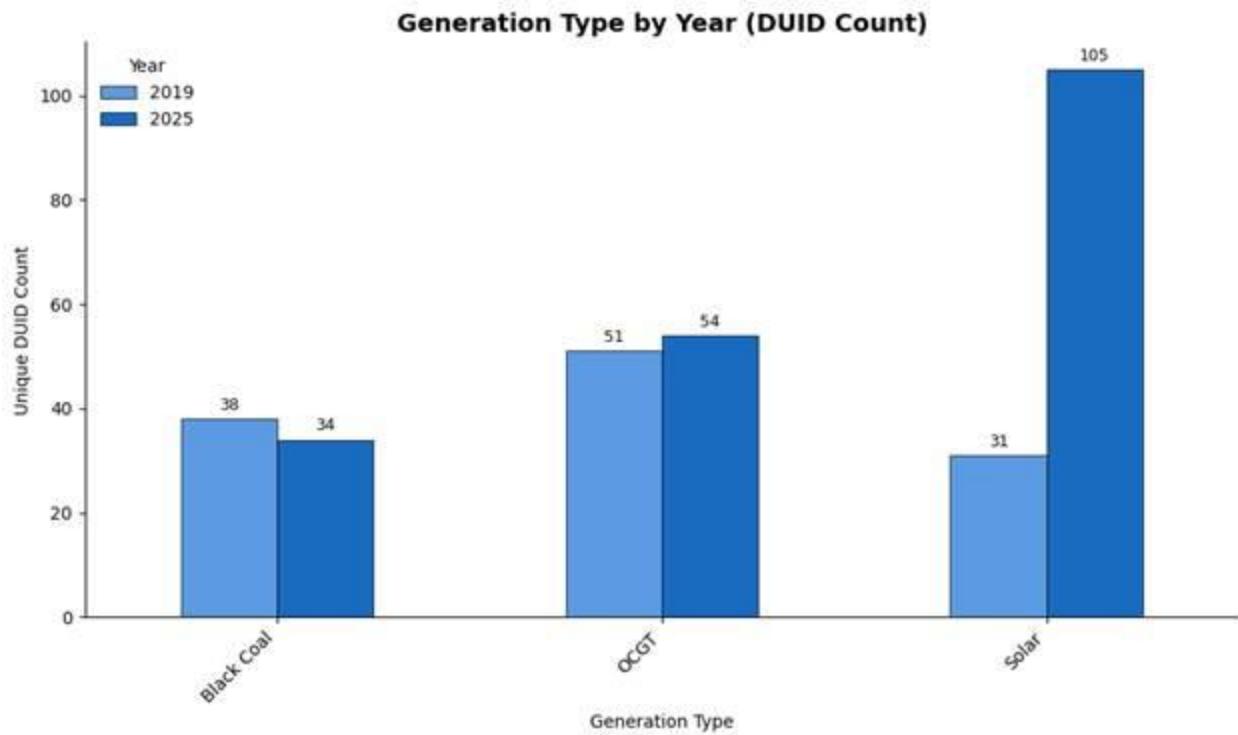
Figure 2: generation type by year (DUID Count)

In Figure 3 the story is similar across the regions: coal and gas are losing ground to solar. In NSW coal's share falls from about 84 % to 56 %, with solar jumping from 4 % to 30 %. Queensland shows almost the same pattern wher coal drops to 72 % and solar climbs to 24 %. South Australia is still led by gas peakers, yet solar now tops one-third of bids. Tasmania is unchanged, remaining fully flexible hydro/gas. Victoria posts the biggest swing, with its gas-tagged capacity sliding from 87 % to 63 % while solar rises from 13 % to 37 %. Everywhere except Tasmania, large-scale solar is eating into coal or gas market share of total bidding.
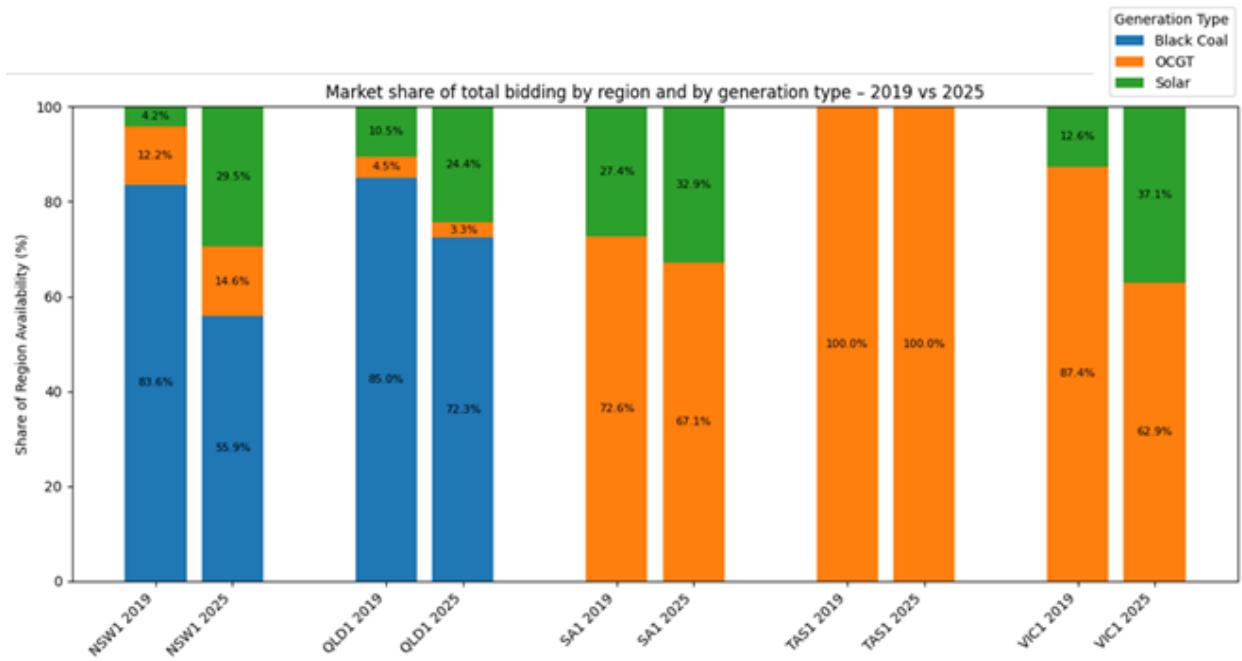
Figure 3: Market share by region and by generation type

Changes in aggregated supply curves (2019 vs 2025)
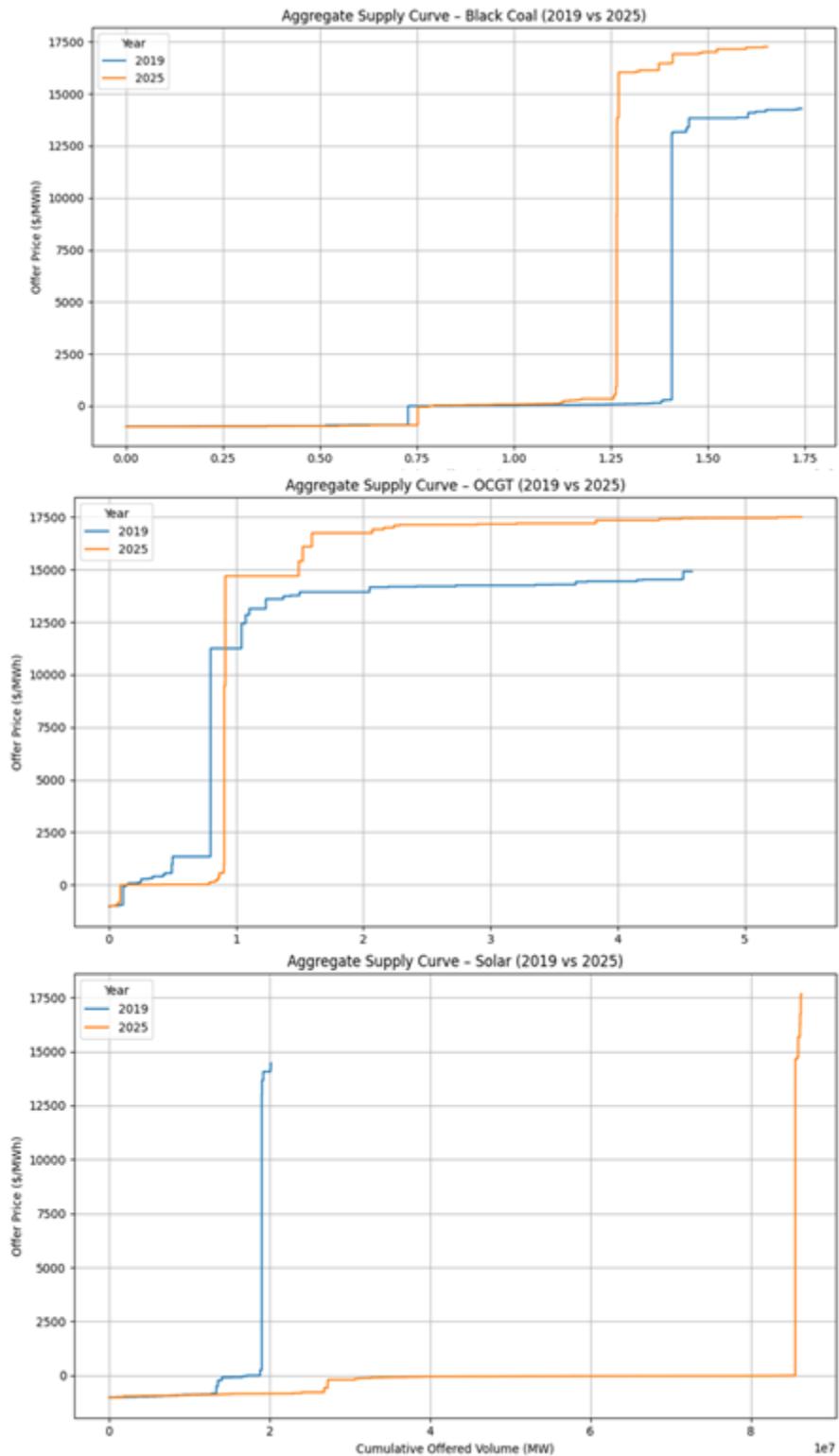
Figure 4: Aggregated supply curve of each generation type

Figure 4 Interpretations:

· **Black coal:** The blue line is 2019 and the orange line is 2025. Both start with some coal capacity offered at very low (even negative) prices. As we move right, prices then climb more sharply in 2025, and the big leap up to the market cap happens sooner and at a higher level than in 2019. In plain terms, black-coal generators now withhold more low-cost volume and push prices higher when supply is tight.

· **OCGT:** Natural gas is now more expensive, for instance at roughly 2 million MW of cumulative offers, the gas curve now clears about $2 500/MWh higher than it did in 2019. In other words, generators need much more money to switch on the same volume of OCGT capacity. Because this steeper 2025 line reaches the market cap far sooner, any moderate rise in demand now pushes prices into spike territory, making gas the costlier and more volatile supply option.

· **Solar:** Solar bids barely react to price. Both years show a long, flat line at slightly negative dollars, meaning almost all solar megawatts are offered no-matter-what just to be dispatched.

The big change is size: the 2025 curve stretches out to roughly 90 million MW before it finally shoots up to the $17,500 cap, while 2019 tops out near 20 million MW. So the solar total available supply has grown more than four-fold yet remains almost totally price-insensitive meaning that prices stay at the floor until the very last slice of capacity is reached.

Investigating bidding behavior shifts across price quantiles
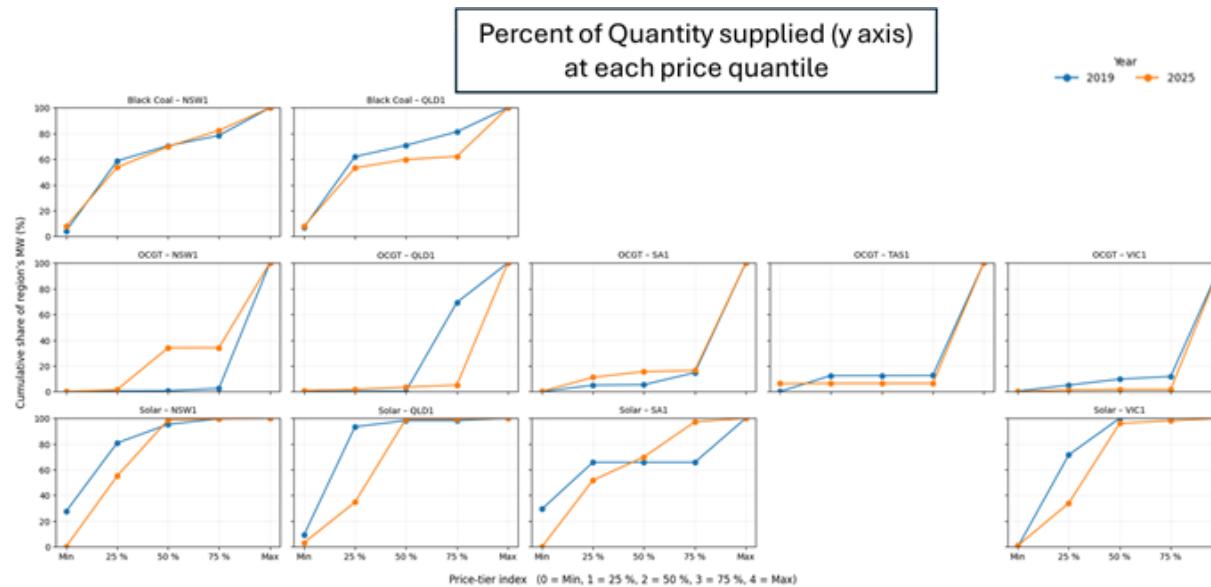
Figure 5: Proportion of quantity supplied at each price quantile

The quantile chart compares where each technology placed its megawatts along the price ladder in 2019 and 2025. Reading left-to-right means moving from the cheapest bids (floor price) toward the cap.

- **Black coal**
  - In New South Wales, coal now bids more volume right at the price floor yet also keeps a fatter tail in the top half of the ladder. Coal units are hedging: they still bid some blocks cheap to stay dispatched but hold back a growing slice for higher prices.
  - In Queensland the change is starker. Much less coal capacity sits in the lower half of the ladder, and a bigger share is pushed to the very top. Fewer hours online and higher costs mean coal there now relies on scarcity intervals to earn margin.
- **Gas peakers (OCGT)**
  - Both years show almost no gas volume in the lower tiers, but the 2025 line becomes even steeper. Nearly the entire stack sits in the highest price band, underscoring that gas now fires mainly as an emergency option. When called, it arrives late and dear—consistent with the earlier VWAP surge.
- **Solar**
  - The solar lines stay almost flat through the first three quartiles in both years, proving their bids remain price-insensitive. The only change is length: the 2025 line stretches far further before it rises, reflecting the big increase in solar capacity while keeping the same zero-price strategy.

Take-away:
Coal redistributes volume upward, gas doubles-down on scarcity pricing, and solar floods the floor. These moves amplify the daytime price dip created by solar and deepen the evening spike when only coal and gas remain, reinforcing the supply-curve and VWAP patterns seen in the previous sections.

Volume weighted average price
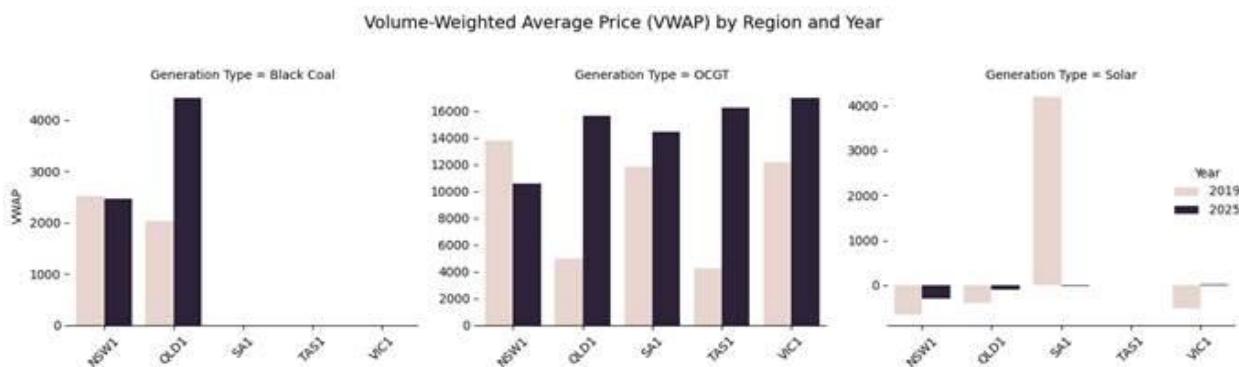
Figure 6: volume weighted average price by region and by year

Generation Type	Region	VWAP - 2019	VWAP - 2025	percent change
OCGT	NSW1	13,759.09	10,600.55	-23%
OCGT	SA1	11,832.40	14,433.31	22%
OCGT	QLD1	4,983.65	15,668.33	214%
OCGT	VIC1	12,207.38	16,967.97	39%
OCGT	TAS1	4,236.67	16,270.85	284%
Black Coal	NSW1	2,520.10	2,469.61	-2%
Black Coal	QLD1	2,035.58	4,432.15	118%
Solar	NSW1	-653.55	-296.59	-55%
Solar	SA1	4,180.47	-28.54	-101%
Solar	QLD1	-391.35	-93.12	-76%
Solar	VIC1	-526.73	12.23	-102%

Table 1: VWAP values

Across all regions, VWAP shifts line up with the market-share and supply-curve changes discussed earlier.

- **Gas peakers (OCGT)** now clear at much higher prices everywhere up to **$17 000/MWh in Victoria and over $15 000/MWh in Queensland**. Higher fuel costs play a part, but the main driver is scarcity: as coal capacity is controlled and solar flooding the midday supply, as evidenced by market share of supply increase of solar.
- **Black coal** stays cheap on average in NSW (little change around $2 500/MWh) but almost **doubles in Queensland**. The rise in price confirms what we saw in the 2025 coal supply curve: less volume offered at the floor means the remaining coal MW earn a better margin when they are dispatched, yet they also leave more room for price volatility.
- **Solar** remains the price-taker. VWAPs are negative in three regions even in 2025, though the losses are significantly smaller than in 2019 (e.g., NSW improves from –$654 to –$297/MWh). A four-fold jump in offered solar volume pushes prices to—or below— zero more often, echoing the long flat section of the solar supply curve.

Task 5: Recommendations for Investors

Overview

The four analytical tasks reveal a National Electricity Market (NEM) that is both cleaner and more volatile than it was just six years ago. Average emissions intensity has fallen by about 18 percent since 2019, driven mainly by a surge of large-scale solar and wind entering the grid. Spot-price curves now feature a pronounced "solar dip" between 11 a.m. and 3 p.m. often falling below A$0/MWh, followed by steep peaks well above A$200/MWh after sunset. Industrial consumption is concentrated during the lower-emission, solar-rich daytime hours, whereas household demand peaks in the higher-emission 6–9 p.m. window when fossil-fuel generators dominate supply. Generator bidding data confirm that almost all renewable capacity offers at or below the market floor to guarantee dispatch, whereas open-cycle gas turbines (OCGTs) withhold capacity and then bid at, or near, the price cap during the evening peak and Coal's share of price-setting intervals has therefore fallen sharply, ceding that role to fast, flexible assets.

Recommendations for Renewable Generation Assets

Co-locate storage: Every new solar or wind project should include at least four hours of battery. Storage capitalises on the widening gap between the lunchtime supply and the 5–8 p.m. shortfall, turning volatility into margin while further lowering peak-hour emissions

Build inside Renewable Energy Zones (REZs): Projects connected inside declared REZs avoid curtailment and marginal-loss-factor penalties that have plagued plants in weaker parts of the grid. By contrast, New South Wales's Central-West Orana REZ has more than 10 GW of generation and 13 GW of storage progressing precisely because connection risk is lower as mentioned earlier in Task1.

Adopt smarter power-purchase agreements: Because midday revenue is cannibalised by negative-price bidding, long-term offtake contracts should be negotiated that reward delivery in the 4-to-8 p.m. block. Pair those PPAs with floor-swap hedges, which will top up revenue whenever prices fall below zero, and high cap options, which monetise the evening spike..

Price carbon explicitly: Investment models should apply the Commonwealth's Value of Emissions Reduction shadow price, about A$66/t CO_2-e in 2023, rising above A$100/t before 2030 and exceeding A$400/t by 2050 to future-proof financing assumptions (DCCEEW, 2023a).

Recommendations for Gas Fired Plants

Invest only in modern machines: Modern OCGTs that start in under ten minutes and run for two-to-four-hour bursts align perfectly with current price spikes. 2025 data show these units offering nearly their entire block at the A$17 000/MWh cap and dispatching mainly at breakfast and dinner.

Keep the fleet lean: Roughly ten percent of a balanced portfolio should be ultra-flexible gas. A larger share risks idle capacity and heightens carbon exposure, especially as coal's price-setting role continues to fade.

Secure flexible fuel: New projects should look to negotiate flexible gas supply contracts to prevent overpaying for fuel and hurting peak-hour profits (Energy Action, 2025). Historical bidding shows long stretches with no low-price gas offers, underlining the need for flexible supply.

Future-proof equipment: Rising shadow-carbon prices will push variable costs higher. Turbines specified to accommodate hydrogen or bio-methane blends preserve dispatchability as the Value of Emissions Reduction schedule escalates (DCCEEW, 2023a).

Lock in reliability revenues: With coal retirements widening the evening gap, state and federal schemes foreshadowed in the NEPS consultation process are paying availability fees plus energy at the cap for proven fast-start megawatts. Pre-registering OCGT capacity for these tenders secures a second, policy-backed income stream (DCCEEW, 2023d).

Portfolio Implementation

A smart allocation will be key to a successful portfolio. We recommend committing roughly 80–90 percent of fresh equity to storage-backed solar located in well-connected Renewable Energy Zones, and reserve the remaining 10 percent for fast-start OCGT peakers.

The storage-centric bias is justified by three facts from the class analysis: (i) deep midday price troughs and evening peaks are now structural rather than cyclical; derived from Task 2 (ii) batteries convert those spreads into gross margins that rival or even surpass historical baseload returns; derived from Task3; and (iii) New South Wales, South Australia and Tasmania already demonstrate smoother commissioning timetables when projects connect inside planned REZ transmission corridors; derived from Task1.

Implementation should proceed in two parallel work-streams:

Stream A (Renewables + Storage)

We recommend starting with a rolling pipeline of five to seven projects at different geographies and consent stages. Early projects go into REZs with shovel-ready lines, while later tranches can target Victoria or Queensland once new transmission flagged in the National Energy Performance Strategy reaches financial close (DCCEEW, 2023c). Each project should lock in a 10- to 15-year power-purchase agreement(PPA) that pays a premium for 4–8 p.m. delivery and is secured with floor-swap protection for midday prices. Caps provide incremental revenue and accelerate debt amortisation, which lenders will now recognise given the Commonwealth's rising shadow-carbon value.

Stream B (Quick-start Gas)

We recommend acquiring or constructing a small portfolio of about 10 percent of total capacity of modern OCGTs sized for two-to-four-hour duty cycles. Development contracts should stipulate <10-minute start times and minimal warm-up fuel, and fuel procurement must be structured on an interruptible flexible basis to avoid paying for unused gas during long stretches of negative lunchtime pricing. Immediately after commercial operations date, each unit should be pre-registered for reliability or firming-capacity auctions foreshadowed in the NEPS consultation paper, locking in an availability fee on top of energy-at-cap revenue (DCCEEW, 2023d). The fleet must also be scheduled for a phased retrofit programme of 10 percent hydrogen co-firing by 2030, scaling toward 100 percent by 2040 to preserve dispatchability as the federal Net Zero Plan tightens sectoral-emissions benchmarks (DCCEEW, 2023b).

Execution

Financial-risk management wraps the two streams together. On the renewables side, floor swaps guarantee a minimum daytime cash inflow, while cap options monetise evening price spikes perfectly matching the deeper lows and sharper highs documented in 2025 supply curves shown in task 4. Gas units, in turn, retain the upside on those caps but hedge fuel price exposure by locking in a spread contract against the ACCC benchmark hub. Both asset classes are screened with an internal VER-aligned carbon hurdle, ensuring capital remains economic under any future tightening of climate policy.

Finally, the portfolio governance must be adaptive. There should be quarterly re-tests of storage depth, cap-strike effectiveness and carbon-price sensitivity. Projects that lose capture-rate advantage should be either retrofitted with additional storage or sold into yield-seeking infrastructure funds. Conversely, new peaking capacity should be added only when supply-curve modelling indicates that scarcity rents will persist after the next coal retirement. By treating volatility as a revenue engine and pricing carbon risk up-front the portfolio can convert the NEM's evolving price dynamics into a resilient, policy-aligned return stream.

Conclusion

This report set out to translate detailed market evidence into an actionable investment roadmap for Australia's National Electricity Market. What started off as just another project quickly turned into one of the most insightful and rewarding tasks we have undertaken throughout the span of our degrees.

Working with real-time data and taking into account supply, demand, pricing, policies and the economics of it all, we have evaluated how location, contracting, and policy incentives amplify or erode the value of energy generation assets. Renewable Energy Zones emerged as essential hubs where transmission capacity, community approvals, and developer pipelines align. Storage proved indispensable, converting volatile spreads into reliable earnings and unlocking additional revenue streams from grid-support services. Hedging techniques have turned out to be a crucial part of the market operation and even with the strong push for a green future, we have undismissable evidence of the role fossil fuel still plays in the generation of electricity in Australia.

The portfolio strategy that flows from this work is both simple and robust: direct most new capital to firmed renewables in strong-grid locations, maintain a lean fleet of quick-start gas as a market pressure valve, and wrap both with shape-specific hedges and an explicit internal carbon price. By aligning financial structures with physical market realities, the recommended approach turns volatility from a liability into a source of long-term, policy aligned returns.

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Appendices

Appendix A

No.	Step	Notes	Output file	Source code
1	Pull carbon emissions intensity of the National Electricity Market data	Using Python, data was pulled from API based on instructions in the link1 and link2 provided on iLearn >> Assignment 3 >> Data on Carbon Emission Intensity.	carbon_emission_intensity_Jan 19_May25. parquet (data from 1st January 2019 to 15th May 2025)	source_code_T2.ipynb (2.1)
2	Convert .parquet into .csv file	Using Python	carbon_emission_intensity_Jan 19_May25.csv	source_code_T2.ipynb (2.2)
3	Import & transform data	Using PowerBI Import carbon_emission_intensity_Jan19_May25.csv Tables in Power Query: [raw_data]: original dataset [carbon_emission_intensity_Jan19_May25]: unpivot all region columns, add new columns to visualise later [electricty-generation]: include total_sent_out_energy to calculate weight (data from NEM_CO2EII_2019_2025(in).csv in task 1) [T1_NEM]: calculate total weight for each region [NEM_calculated]: calculate NEM intra-daily weighted average for each region [Append_5regions_NEM]: combine rows from 2 tables [carbon_emission_intensity_Jan19_May25] and [NEM_calculated]		
4	Visualise the intensity curve	Using PowerBI	BUSA8031_FinalAssig_Hanie_T2.pbix	

Intra-daily carbon emission intensity is the grams of CO_2-equivalent emitted per kilowatt-hour actually consumed from the grid, calculated every five minutes. Using CSIRO's flow-tracing algorithm, emissions from each generator (coal, gas, hydro, solar, etc.) are followed through the transmission network, adjusted for losses and rooftop solar panels, and allocated to the region where that electricity is used. Plotting this metric over 24 hours shows when the grid mix is dirtiest (peaks driven by coal or gas) and cleanest (dips when renewable energy dominates), providing insights on how generation choices translate into the carbon footprint of end-users.

Appendix B

No.	Step	Notes	Output file	Source code
1	Import & transform [Consumption Company Example.csv] dataset	- Aggregate to 30-min intervals: Sum every two 15-min intervals to get 30-min consumption totals - Extract date, assign interval numbers (1–48 per day) - Group & average: Calculate the average consumption for each combination of year, month, interval, and day type (weekday/weekend) - Filter: Keep only months from May 2022 to April 2023 (*) - Export: Save the transformed data as a CSV.	df_company_transformed.csv	source_code_T2.ipynb (2.3)
2	Import & transform [Consumption Household Example.xlsx] dataset	- Copy "Weekday" and "Weekend" data to different sheets & import both sheets - Add a DAY_TYPE column for each. - Concatenate both sheets into 1 dataframe. - Melt the data from wide (months as columns) to long format (each row is a month-interval). - Assign Year: Classify months as either 2022 or 2023 (*) - Export: Save the reshaped data as a CSV.	df_household_transformed.csv	source_code_T2.ipynb (2.4)
3	Import & transform [carbon_emission_intensity_Jan19_May25.csv] dataset	- Extract date: Add Month & Year columns, calculate 1-48 intervals, classify days as Weekday/Weekend - Group & average carbon intensity (Intensity_gCO2_per_kWh) for each. - Export: Save the transformed data as a CSV.	df_intensity_transformed.csv	source_code_T2.ipynb (2.5)

(*) The original Consumption Household Example.xlsx contains data of average consumption of each month from January till December, while Consumption Company Example.csv data only contains data from 1st May 2022 until 1st May 2023. Therefore, I will assume that the data was collected in the same period, which is May until December 2022 and January through April 2023.