AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Quarterly Energy Dynamics Q4 2021

January 2022

Important notice

Purpose

AEMO has prepared this report to provide energy market participants and governments with information on the market dynamics, trends and outcomes during Q4 2021 (1 October to 31 December 2021). This quarterly report compares results for the quarter against other recent quarters, focusing on Q3 2021 and Q4 2020. Geographically, the report covers:

- The National Electricity Market (Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania).
- The Wholesale Electricity Market and domestic gas supply arrangements operating in Western Australia.
- The gas markets operating in Queensland, New South Wales, Victoria and South Australia.

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Version control

Version	Release date	Changes
1	28/01/2022	

Executive summary

East coast electricity and gas highlights

A return to rising prices

- In Q4 2021, the first quarter in which the National Electricity Market (NEM) operated with five-minute settlement (5MS), movements in NEM and east coast gas market prices reversed the falling trends observed through the previous quarter.
- NEM mainland electricity prices averaged $39 per megawatt-hour (MWh) in October but reached $75/MWh[1] by December, lifted by strongly rising prices in Queensland with growing volatility in that state and in South Australia. For the quarter as a whole, mainland prices averaged $57/MWh, still below Q3's average of $66/MWh but 31% higher than Q4 2020's $44/MWh.
- While less volatile in Q4 than in Q3, east coast gas market prices returned to high average levels in November and December, yielding a quarterly average of $10.60 per gigajoule (GJ) across AEMO's spot markets, comparable with Q3's $10.74/GJ but well above their $5.95/GJ average in Q4 2020.
- The gap between higher average electricity prices in the mainland NEM's northern regions (Queensland and New South Wales) and those in the southern regions remained pronounced at $45/MWh for the quarter, having first opened up in Q2 this year. This divergence was reflected in electricity futures for Calendar 2022, which by the end of the quarter ranged in price from $91/MWh for Queensland to $56/MWh for Victoria.
- Energy transfers from the southern to northern regions also grew:
  - Victorian gas exports to other regions were 34.5 petajoules (PJ), their highest quarterly level since Q4 2018, while net transfers north from Moomba via the South West Queensland Pipeline (SWQP) reached 14.9 PJ, the highest level since Q4 2017, to cover a net reduction in domestic supply from Queensland producers. Quarterly supply for liquefied natural gas (LNG) exports from Curtis Island reached its second highest level on record at 369 PJ, with Asian traded LNG prices at record highs.
  - Interconnector transfers from Victoria to New South Wales increased in response to higher prices in the northern NEM, record low black coal generation (down by 693 megawatts [MW] or 6.5% on Q4 2020), and reduced gas generation (down by 12% in the north), although these transfers were constrained during daylight hours.

Renewables and cool weather influencing daytime prices and demand

- Daytime electricity prices continued to fall, particularly in the southern regions which saw record negative price incidence in South Australia and Victoria, especially in October. Drivers included continued growth in grid-solar output, which at 269 MW exceeded wind output growth of 156 MW, coupled with lower operational demand (down 465 MW) due to strong growth of distributed photovoltaic (PV) output and cool wet La Niña conditions which reduced cooling loads and maximum demand levels. However evening and overnight prices were not affected by these trends, remaining substantially higher than a year ago.

[1] Uses the time-weighted average which is the simple average of spot prices in the quarter excluding Tasmania. The Australian Energy Regulator (AER) reports the volume-weighted average price which is weighted against native demand.

- New minimum operational demand records were seen in New South Wales (down 211 MW on the previous minimum set in 1999), Victoria (down 196 MW), and South Australia (down 132 MW), while minimum operational demand for the NEM as a whole fell to a record low of 12,936 MW, down 1,257 MW on the prior low set in Q3 2021.
- Instantaneous renewable penetration achieved a new high of 61.8%, up marginally from 61.4% in Q3 2021. Average renewable penetration levels for the quarter increased more substantially from 31.6% in Q3 to 34.9%.

Other highlights

- Frequency control ancillary services (FCAS) costs remained elevated at $132 million, again driven by extreme FCAS price volatility in Queensland on days where outages related to upgrades of the Queensland to New South Wales interconnector (QNI) required significantly increased local supply of Contingency FCAS products.
- Full commissioning of the four new synchronous condensers in South Australia late in November 2021 allowed substantial reductions in gas generation directed to run for system security purposes. Prior to this, high gas prices and very low daytime electricity prices led to frequent direction of multiple gas units. While provisional quarterly direction costs of $34 million were up substantially on previous quarters, a large majority of these costs fell prior to full commissioning of the synchronous condensers.
- Readily observable impacts of the transition to 5MS on 1 October included the cessation of prices falling regularly to the market price floor of -$1,000/MWh shortly after high price events. A separate rule change also implemented in Q4 2021 saw registration of the NEM’s first three Wholesale Demand Response (WDR) units.

Western Australia electricity and gas highlights

A late heatwave drives high demand and price events in the WEM

- Four consecutive days exceeding 40°C in the Perth metropolitan region, between Christmas Day and 28 December 2021, saw the Wholesale Electricity Market (WEM) reach its highest Q4 maximum operational demand on record at 3,869 MW on 27 December, 7% above Q4 2020’s maximum and just 137 MW lower than the all-time WEM record maximum demand set in February 2016.
- With high demands during the heatwave and relatively low non-scheduled generation, there were 12 maximum price events in the WEM’s Balancing Market, 10 more than in Q3 2021 and nine more than in Q4 2020.

Increasing renewable contribution leads to record low WEM minimum demand

- Increasing levels of distributed PV and large-scale renewable generation resulted in nearly 40% of total underlying demand being met by renewable energy in Q4 2021. Distributed PV and large loads not consuming also resulted in a record minimum operational demand for the WEM of 761 MW on 14 November 2021 over the 1130 hrs interval. Approximately 78% of underlying demand in this interval was supplied by renewables, with supply from distributed PV estimated at 67%. This minimum demand was a 12% decrease on the previous quarterly record set in September 2021.
- Increased renewable supply also led to reductions in gas and distillate powered generation in the WEM of 16%. Overall, there was a decrease of around 3% in Western Australian domestic gas consumption, as reductions in electricity generation, minerals processing and industrial use were partially offset by increased mining consumption.

Contents

1 NEM market dynamics

1.1 Electricity demand

1.1.1 Weather

During the quarter, temperatures were cooler than 10-year averages (Figure 1), with rainfall also well above the average (Figure 2). Across the east coast, temperatures were 1.3°C below the 10-year average, with Adelaide, Melbourne and Sydney experiencing their coolest November in at least 20 years, including Melbourne's coldest November day on record.

Rainfall was well above average for the quarter, with the Bureau of Meteorology (BoM) declaring a La Niña under way[2]. Nationally, November was the wettest in 122 years on record[3] with heavy October rainfalls in Tasmania and in November on the mainland.

Figure 1 Cooler across the East coast

Average maximum temperature variance by capital city

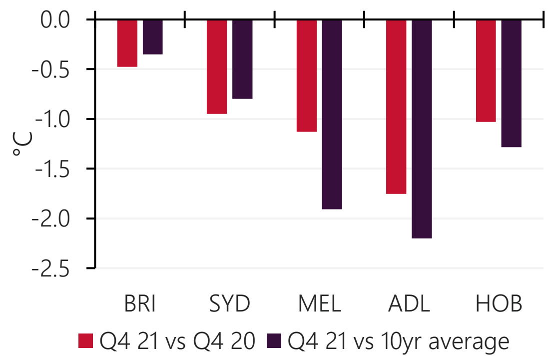
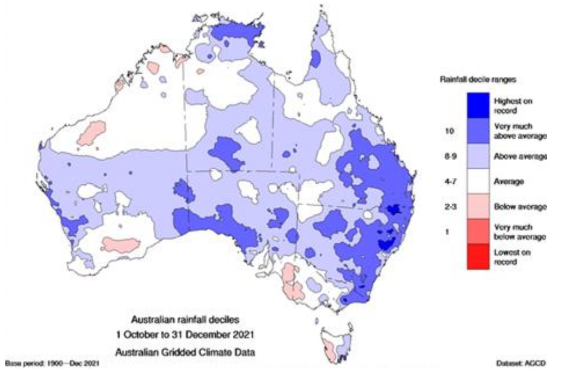


Figure 2 La Niña conditions in Q4 2021

Australian rainfall deciles – 1 October to 31 December 2021

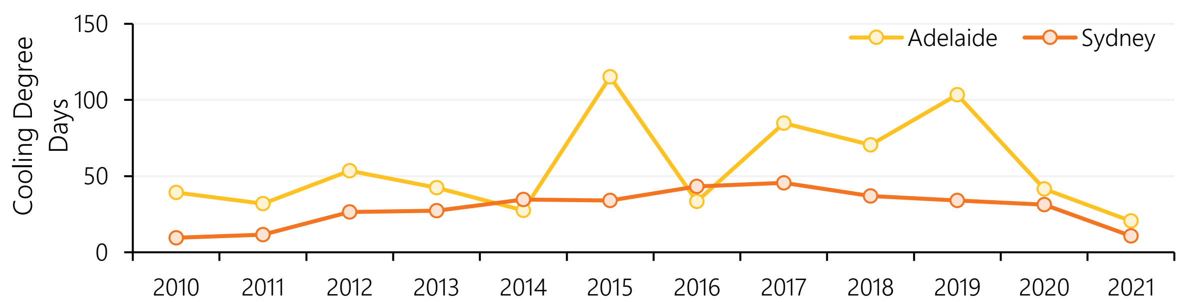


Source: Bureau of Meteorology

The cooler average temperatures and absence of extreme heat days for the quarter saw reduced air-conditioning requirements in some regions, as measured by aggregate cooling degree day totals for the quarter (Figure 3).

Figure 3 Decreased cooling requirements in Adelaide and Sydney

Cooling degree days[4] (Q4s) – 2010 to 2021



[2] BoM 2021, Bureau of Meteorology declares La Niña underway: https://media.bom.gov.au/releases/914/bureau-of-meteorology-declares-la-nina-underway/.

[3] BoM 2021, Bureau of Meteorology wettest November in 122 years: http://www.bom.gov.au/clim_data/IDCKGC1AR0/202111.summary.shtml.

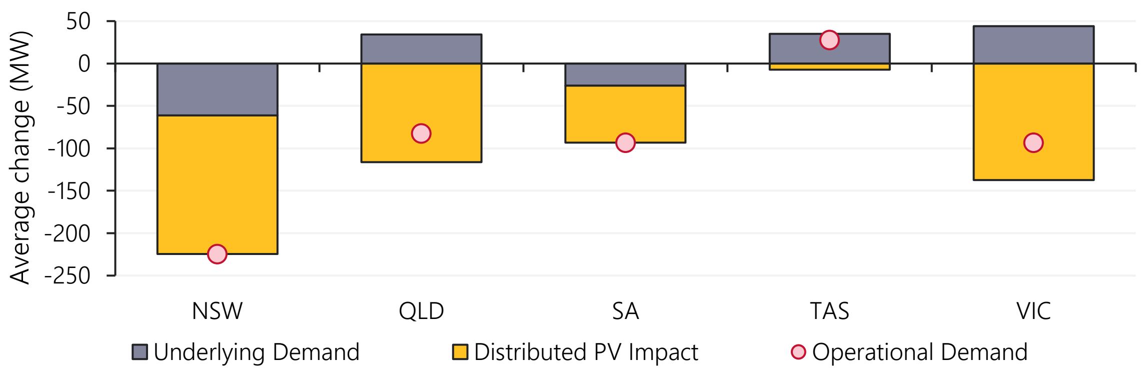
[4] A "cooling degree day" (CDD) is a measurement used as an indicator of outside temperature levels above what is considered a comfortable temperature. CDD value is calculated as max (0, average [maximum temperature, minimum temperature] – 24).

1.1.2 Demand outcomes

NEM quarterly average operational demand fell to 19,876 MW, its lowest Q4 average since Tasmania joined the NEM in 2005 and 465 MW lower than Q4 2020 (-2.3%, Figure 4). Reductions occurred across all NEM regions, apart from Tasmania (+28 MW), with the largest decrease occurring in New South Wales (-224 MW), followed by Victoria (-93 MW), South Australia (-93 MW) and Queensland (-82 MW). Notably, operational demand in three out of the five NEM regions (New South Wales, South Australia and Victoria) declined to record low Q4 levels.

Figure 4 New South Wales leads underlying demand decrease

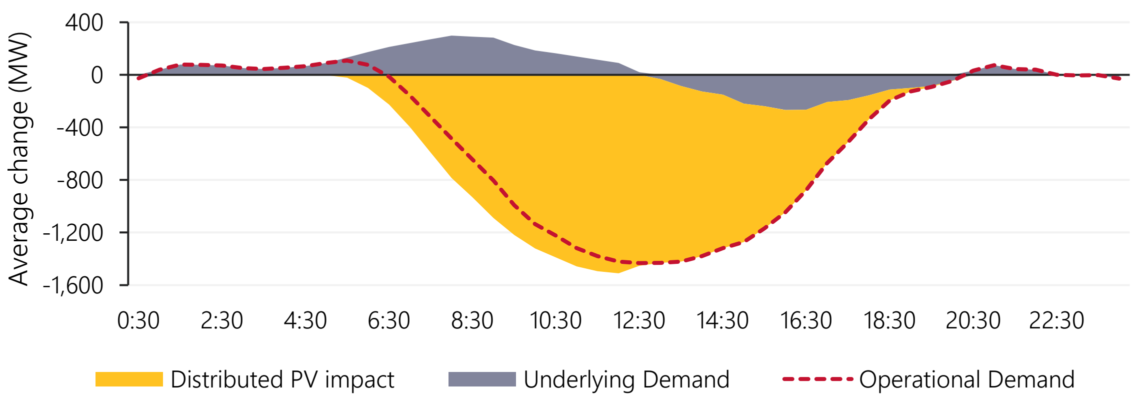
Change in average operational demand – Q4 2021 vs Q4 2020



This was largely due to the marked increase in distributed PV output (+492 MW)[5] compared to Q4 2020, as changes in underlying demand[6] were small (+26 MW). Despite significantly less distributed PV output in November with high levels of rainfall and increased cloud cover influenced by La Niña, very high levels of output in October and December driven by record uptake of distributed PV capacity (estimated to be approximately 3.2 gigawatts [GW] in 2021[7]) drove quarterly output to new highs in Q4, contributing to substantial daytime demand reductions (Figure 5).

Figure 5 Distributed PV output substantially reduces daytime demand

Change in average NEM operational demand – Q4 2021 vs Q4 2020



[5] Increased distributed PV generation results in reduced operational demand because its production lowers supply required from the grid. Distributed PV production is based on AEMO estimates using ASEFS2.

[6] Underlying demand is calculated by adding estimated production from distributed PV to operational demand, to yield an estimate of total electricity demand.

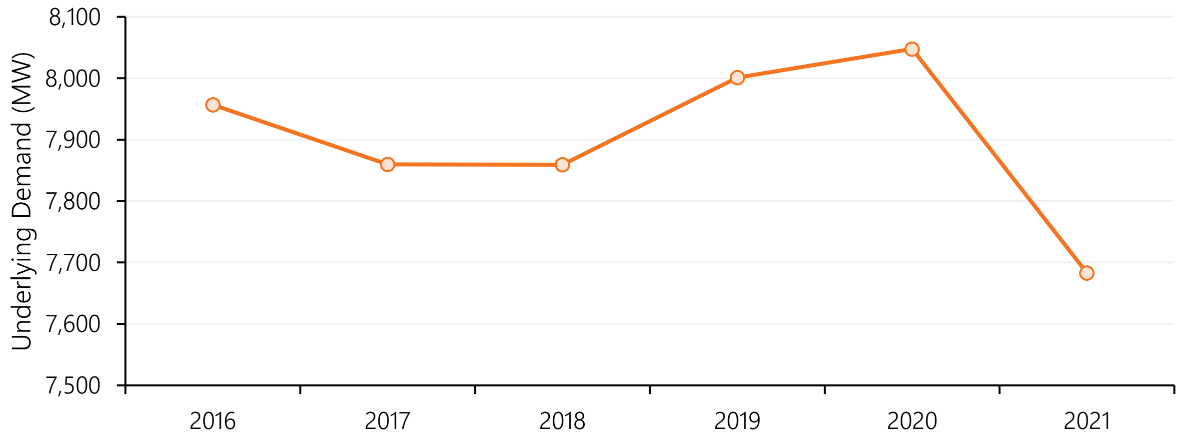
[7] Clean Energy Regulator 2021, Quarterly Carbon Market Report: http://www.cleanenergyregulator.gov.au/DocumentAssets/Documents/Quarterly%20Carbon%20Market%20Report%20-%20September%20Quarter%202021.pdf.

While average underlying demand was similar to Q4 2020, changes by region within the quarter varied.

- Average underlying demand in New South Wales and South Australia reduced by 61 MW and 26 MW, respectively, partly driven by large reductions in November due to cold and wet conditions.
  - Of note was New South Wales' average underlying demand in November, which declined to its lowest levels in recent years and was 365 MW lower than November 2020 (Figure 6), as cooler temperatures saw lower requirements for air-conditioning load.
- In Victoria, underlying demand was up by 44 MW on average compared to Q4 2020, with increases occurring during the morning peak due to cooler conditions.

Figure 6 Lowest November underlying demand in recent years for New South Wales

Average New South Wales underlying demand - Novembers



Maximum and minimum demands

The continued rapid uptake in distributed PV, coupled with Q4 being typically the sunniest quarter of the year, saw minimum operational demand continue to trend downwards across the NEM. Most notably, the NEM-wide minimum demand record was lowered on three separate days in Q4 with a new low of 12,936 MW set on Sunday 17 October 2021 at 1300 hrs, 1,257 MW lower than the prior quarterly record of 14,193 MW set in Q3 2021. During this interval, distributed PV output accounted for 40% of NEM underlying demand.

In addition to the NEM record, new all-time minimum demand records were also set in three NEM regions – South Australia, New South Wales and Victoria:

- South Australia's minimum demand trended down rapidly this quarter, with its record half-hourly low being broken on two separate days – 31 October and 21 November. On Sunday 21 November, South Australia set a new minimum demand record of 104 MW at 1300 hrs[8], 132 MW lower than the previous quarterly record set in Q3 2021 and 84 MW under the October low (Figure 7). Mild sunny conditions, coupled with low underlying weekend demand and reduced industrial load due to planned maintenance, were key drivers of the result. During this interval, distributed PV provided 1,220 MW of output, accounting for 92% of underlying demand.

[8] The 5-minute South Australian scheduled demand cleared in the spot market by the NEM dispatch engine (NEMDE) was negative for dispatch intervals 1225 hrs to 1240 hrs and reached a minimum of -38 MW at 1235 hrs. Operational demand minimums are half-hourly and include large-scale generation not scheduled through NEMDE. For more information, see: https://aemo.com.au/newsroom/news-updates/negative-electricity-demand-in-south-australia.

- Both New South Wales and Victoria set new minimum operational demand records during the quarter (Figure 8), with drivers similar to those in South Australia.
  - New South Wales' new minimum demand record of 4,425 MW was set on the same day as the NEM record on Sunday 17 October 2021 at 1300 hrs and was 211 MW lower than the previous minimum set in 1999 and 945 MW below 2020's minimum.
  - Victoria's new minimum demand record of 2,333 MW occurred at 1300 hrs on Sunday 28 November 2021 and was 196 MW lower than the previous record set in Q4 2020.

Figure 7 SA minimum demand falls to 104 MW

SA monthly minimum operational demand – Oct-20 to Dec-21

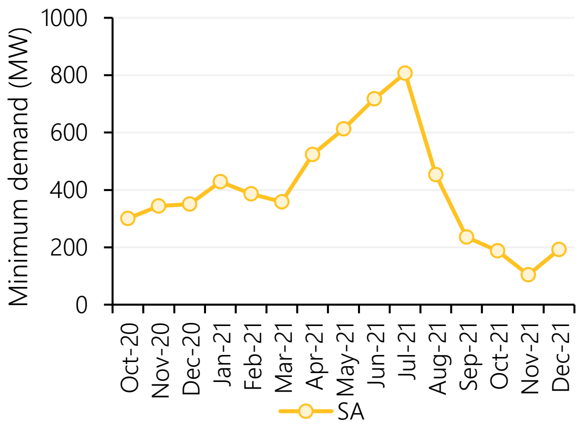
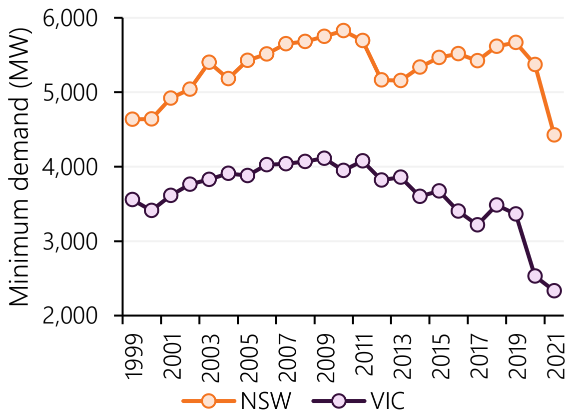


Figure 8 NSW and VIC both set new records

NSW and VIC all time minimum operational demand - annual



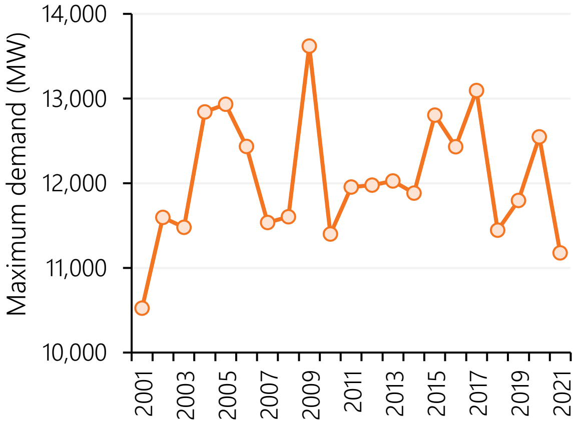
With cooler than average Q4 conditions and increased distributed PV output, quarterly maximum demands in the NEM were also down on recent fourth quarters (Figure 9). In particular, New South Wales' maximum demand of 11,176 MW was 1,370 MW (or 11%) lower than Q4 2020, representing its lowest Q4 level since 2001 (Figure 10) while Victoria's maximum demand of 7,547 MW was its lowest Q4 level since 2016.

Figure 9 Q4 maximum demand fall in mainland NEM

NEM maximum operational demands – Q4 2021 vs Q4 2020

Figure 10 Lowest NSW Q4 maximum demand since 2001

NSW maximum operational demands – Q4s



Intra-day demand swing

As minimum operational demands now typically occur in the middle of the day, an emerging dynamic in the NEM is increasing intra-day demand swing – the difference between daily maximum and minimum demands – with this swing occurring within a relatively short timeframe.

As an example, Queensland recorded its highest daytime intra-day operational demand swing for a Q4 in 2021 (Figure 11). This occurred on 4 October 2021 with a difference of 3,605 MW between daily minimum operational demand of 4,228 MW at 1030 hrs and maximum operational demand of 7,833 MW at 1900 hrs (Figure 12).

Figure 11 Record Q4 daily demand swing in Queensland

QLD maximum daytime intra-day operational demand swing (Q4s[9])

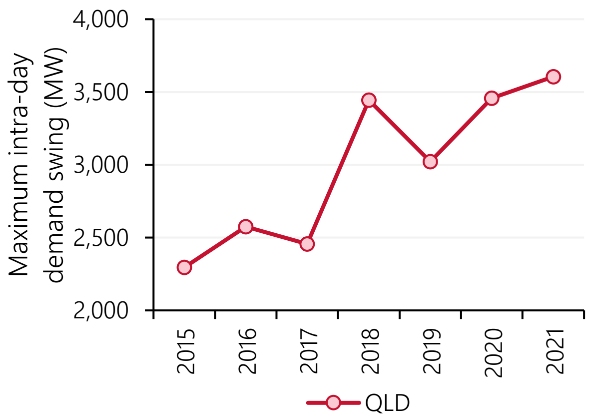
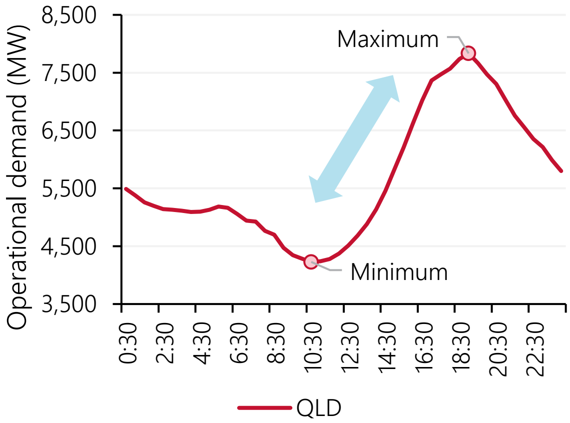


Figure 12 Operational demand swing of 3,605 MW from 1030 hrs to 1900 hrs

QLD operational demand – 4 October 2021



Efficiently dispatching generation and demand-side resources to meet large daily demand swings introduces operational challenges and places increased importance on short term forecasting accuracy. The swings in demand, driven by both distributed PV and demand-side response, plus ramps in renewable generation become increasingly important as renewable penetration increases. The forecasting, not only of these swings or ramps, but also of the associated uncertainty and variability driven by the weather systems and/or market responses are critical for short term commitment and utilisation of resources. Variability and uncertainty are two distinct operational challenges that require management, both via market structures and through deployment of enhanced forecasting techniques.

As the energy transition progresses, it is expected there will be a higher demand for flexible resources to be online and ready to be dispatched up and down to match variability and uncertainty in supply and demand. Without a new reserve service, interventions may increase due to the lack of suitable flexibility that can physically respond to increasing variability.

There is increased net demand uncertainty over operational timeframes, which supports the development of a new operating reserve product. An operating reserve product/market comprises a dispatchable service in real-time and co-optimised with other energy market services. The product could be procured 30 minutes ahead of time and align with the requirement to return the system to a secure operating state within 30 minutes.

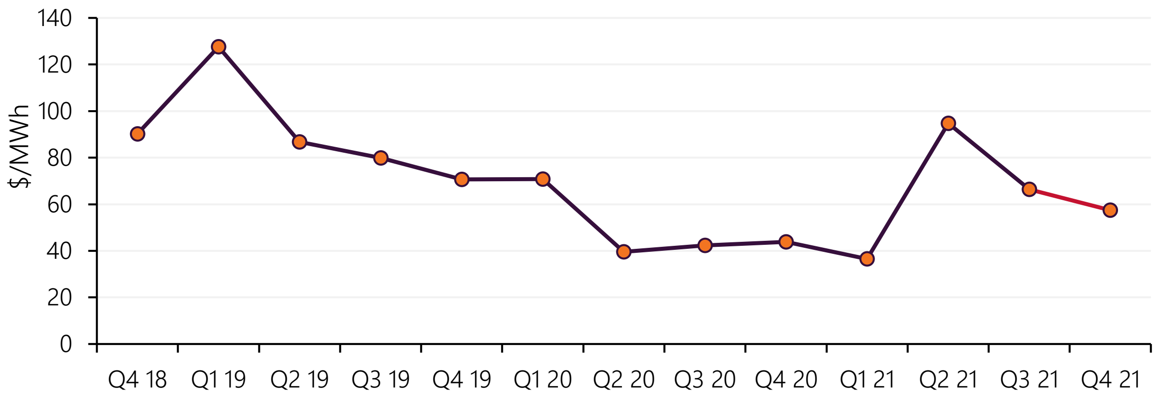
[9] Daytime intra-day operational demand swing is measured for each day as the difference between minimum and maximum operational demands recorded between 0600 hrs and 2000 hrs. Prior to high levels of distributed PV penetration, daily minimum demands typically fell outside this window, in the early overnight hours.

1.2 Wholesale electricity prices

Mainland NEM prices averaged $57/MWh for the quarter, down 13% on Q3 but 31% higher than in Q4 2020 (Figure 13). Within the quarter, monthly mainland averages increased progressively, rising from $39/MWh in October to $75/MWh in December.

Figure 13 A slowing decline in NEM prices

Mainland average wholesale electricity price

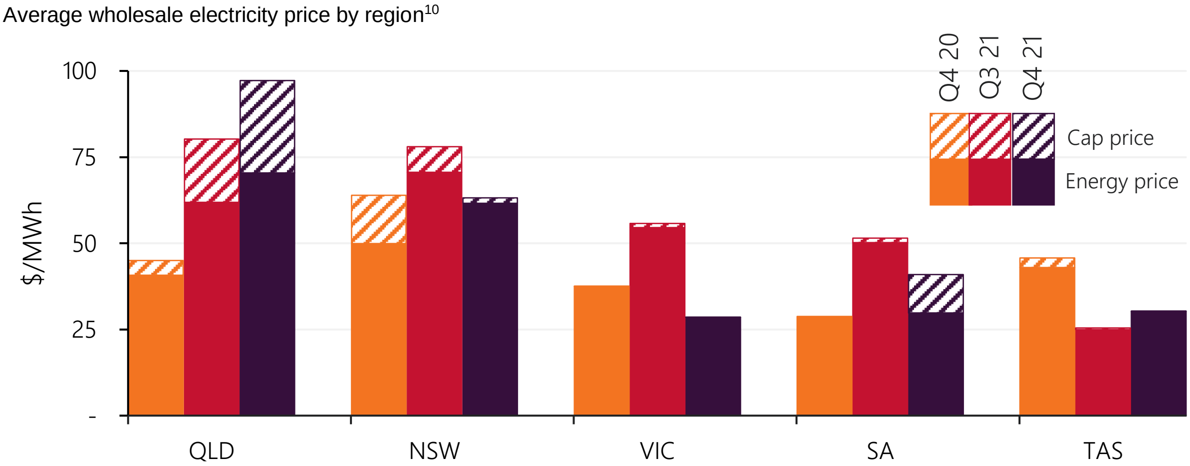


Price behaviour once again varied significantly across NEM regions (Figure 14):

- Queensland's quarterly average price of $97/MWh was its highest Q4 average on record and more than double the level of one year ago. Price volatility, particularly in November and December, was a significant factor, lifting the region's average by $27/MWh (Section 1.2.2). Conversely, Victoria's quarterly average price of $28/MWh was its lowest Q4 average since 2014.
- Underlying energy prices in other mainland NEM regions fell from Q3 levels, and price outcomes were broadly comparable with those of a year ago, although episodes of price volatility late in December raised South Australia's quarterly average relative to Q4 2020, while in New South Wales underlying prices above those of 2020 were offset by an absence of volatility in Q4 2021.

Figure 14 Queensland prices hold up the NEM average

Average wholesale electricity price by region[10]

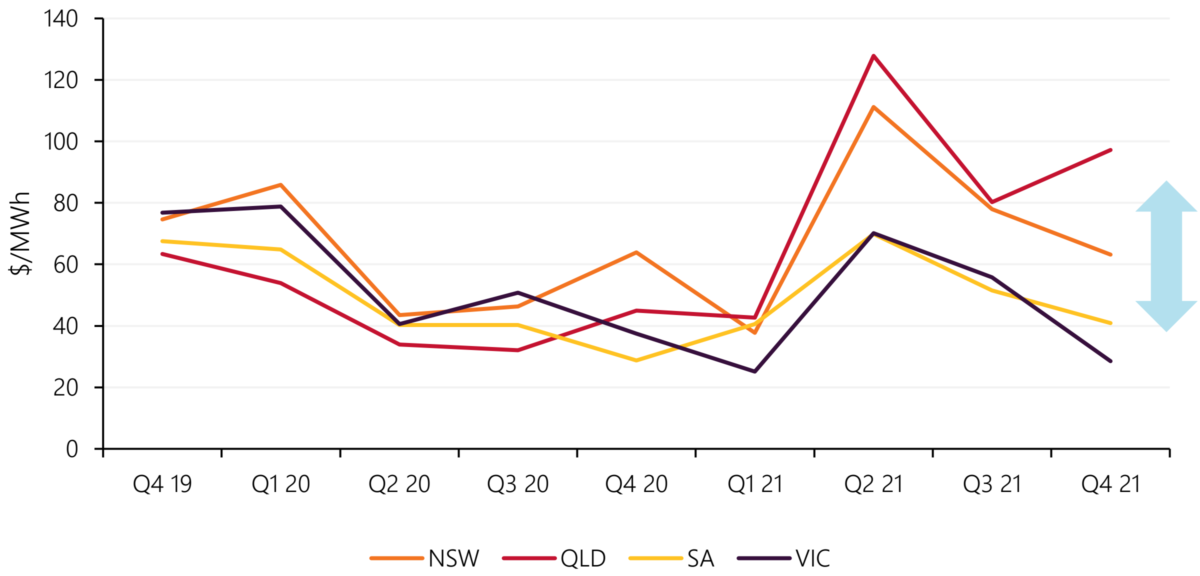


[10] 'Energy price' is used in electricity pricing to remove the impact of price volatility (that is, price above $300/MWh). Since commencement of 5MS from 1 October 2021, energy and cap prices are calculated on a 5-minute basis.

The gap between prices in the northern NEM regions of Queensland and New South Wales and the southern regions persisted through the quarter (Figure 15), with prices in Queensland and New South Wales averaging $45/MWh higher than those in Victoria and South Australia, the second largest differential after Q2 2021.

Figure 15 North-South price divide continues

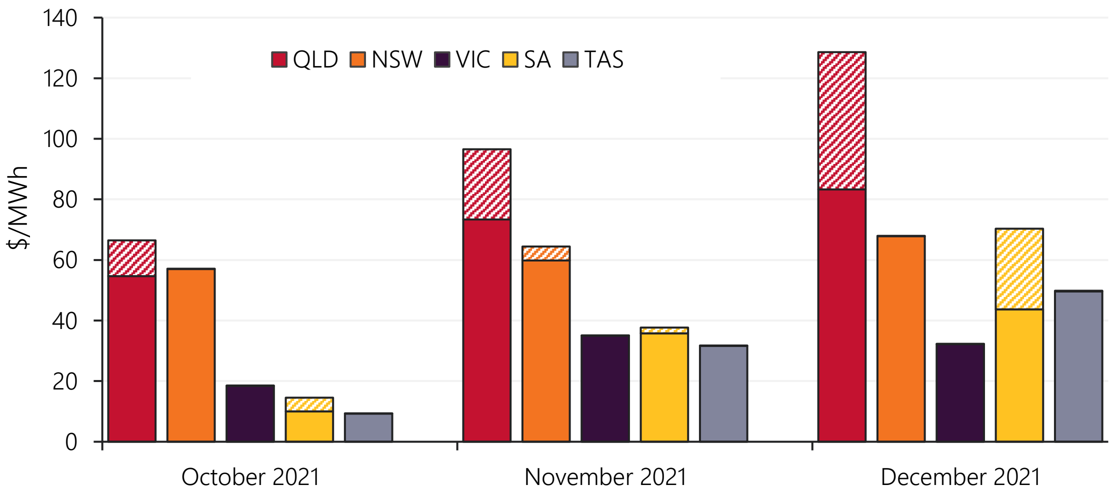
Average spot electricity price by mainland NEM region



A monthly breakdown of average prices by region (Figure 16) clearly shows the rising trend within the quarter and the impacts of volatility in Queensland and South Australia.

Figure 16 Energy prices and volatility rising through the quarter

Average wholesale monthly electricity price (energy and cap) by region and month – Q4 2021



The profile of average energy price by time of day for the mainland regions relative to Q4 2020 (Figure 17) shows a continuing trend of lower middle-of-day prices, driven by increasing solar generation capacity (grid-scale and distributed PV) and declining operational demand, but higher evening and overnight prices. In Victoria, spot price averages in Q4 2021 were negative between 0925 hrs and 1420 hrs, while the overall average between 0800 hrs and 1630 hrs was just $0.1/MWh (Figure 18).

Figure 17 Lower daytime prices, higher evening and overnight prices

Mainland NEM average Q4 energy prices by time of day

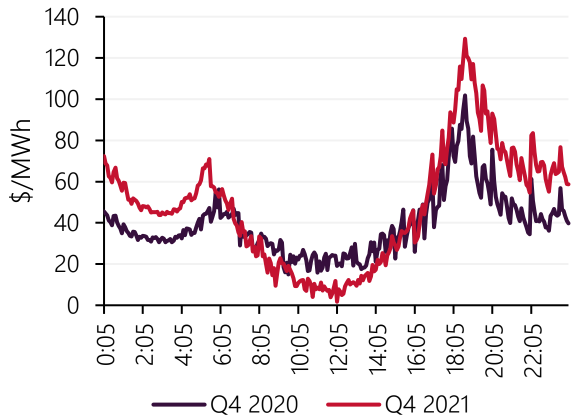
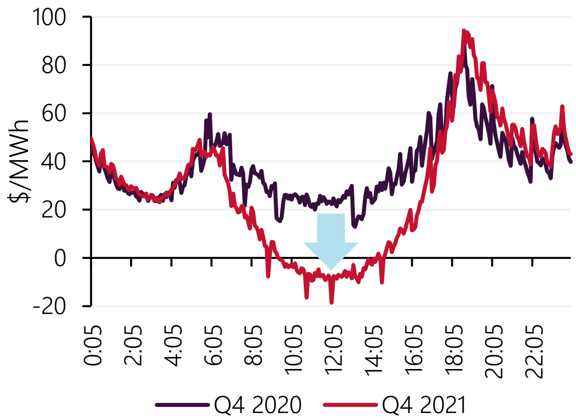


Figure 18 Victorian middle-of-day prices fall below zero

Victoria average Q4 spot prices by time of day



1.2.1 Wholesale electricity price drivers

Important influences on the level and pattern of electricity prices in Q4 2021 are summarised in Table 1 below, and discussed in more detail in subsequent sections of this report.

Table 1 Wholesale electricity price levels: Q4 2021 drivers

Price volatility	Episodes of volatility, discussed further in Section 1.2.2, significantly lifted quarterly average prices in Queensland and South Australia and added $10/MWh to the NEM mainland average, compared to $5/MWh in Q4 2020 and $7/MWh in Q3 2021.
Thermal generation	Black coal generation output was 693 MW lower than in Q4 2020, with many generators also repricing marginal offer bands upwards (Section 1.3.1). Compared with Q4 2020, average black coal volumes offered below $40/MWh fell by over 2000 MW. Rising gas prices (Section 2.2) saw reduced output from gas-fired generators (Section 1.3.2) but higher price levels at times when gas units did set the spot price (Section 1.2.4). These repricing trends particularly affected evening and overnight electricity prices when thermal generation sets price more frequently.
Variable renewable energy (VRE) supply	VRE supply increased steadily, with additional grid-solar output averaging 269 MW and wind 156 MW (Section 1.3.4). Combined with distributed PV growth (+492 MW) reducing daytime operational demands (Section 1.1.2), this saw falls in NEM daytime prices (Figure 17) and increased negative price incidence (Section 1.2.3).
Price separation	While underlying spot prices fell or were stable in the southern NEM regions, the larger share of thermal generation in Queensland and New South Wales and higher prices being set by black coal and gas (Section 1.2.4), as well as limitations on transfers of lower cost energy from the southern regions (Section 1.4) each contributed to ongoing north-south price differentials in Q4.

1.2.2 Wholesale electricity price volatility

Spot price volatility increased on Q3 levels, contributing $27/MWh to Queensland's average quarterly spot price and $11/MWh to South Australia's. Although there was minimal volatility in other regions, this yielded the highest Q4 NEM volatility since 2009 (Figure 19). As in Q2 and Q3, there was also very significant volatility in contingency FCAS prices in Queensland during the quarter, leading to high FCAS recovery costs discussed in Section 1.5.1.

Drivers of energy price volatility in Queensland and South Australia were varied, with days of very high volatility[11] summarised in Table 2.

[11] The AER publishes $5000/MWh reports which analyse the cause of these events in more detail: https://www.aer.gov.au/wholesale-markets/performance-reporting.

Figure 19 Highest Q4 cap returns since 2009

Q4 average cap returns by region - stacked[12]

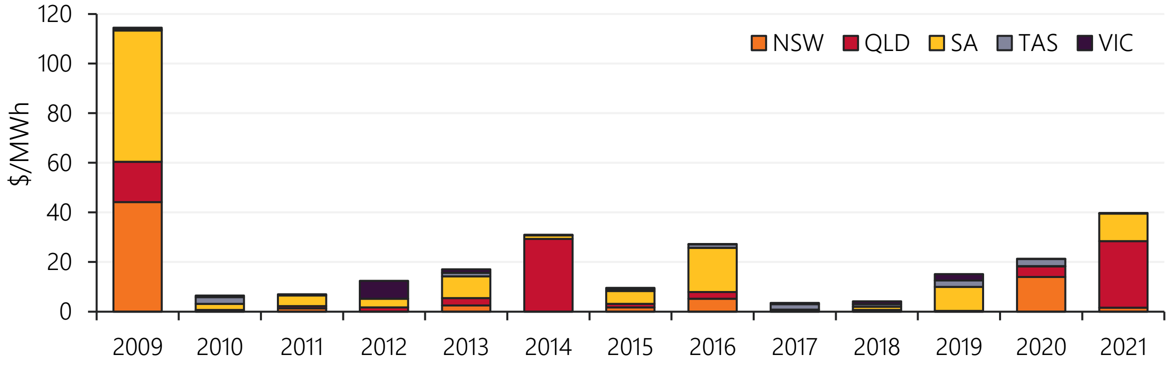


Table 2 High priced days in Q4 2021

Region	Date	Average daily price ($/MWh)	No. of DIs =>$10k/MWh	Contribution to quarterly cap returns ($/MWh)	Drivers
QLD	20 Dec	$853	16	$7.75	• High evening peak demands >9,000 MW • Declining grid-solar output • Limited NSW imports • Gas and hydro units setting price
	09 Dec	$612	13	$5.32	• High evening peak demands >8,400 MW • Declining grid-solar output • Coal-fired outages • Gas units setting price
	11 Nov	$572	5	$4.26	• Local FCAS constraints due to QNI works • Extreme FCAS volatility influencing energy price through co-optimisation and impacts on generator rebidding • Rapid changes in operational demand due to variability in distributed PV output
SA	30 Dec	$409	7	$3.08	• Evening peak volatility • Low wind and grid-solar output • Interconnector flows from Victoria at limit • Gas units and batteries setting price
	13 Dec	$308	4	$2.08	• Low wind, variable cloud cover affecting distributed PV and grid-solar • Interconnector flows from Victoria at limit • Rapid changes in supply demand balance

As an illustration of one of these varied causes of volatility, Figure 20 shows demand, generation availability and spot prices for South Australia on 13 December, when high and changing levels of cloud cover reduced distributed PV output, leading to increased and unusually variable scheduled demand[13] through the middle of the day. A more typical daily demand pattern is illustrated by the scheduled demand profile for 14 December overlaid

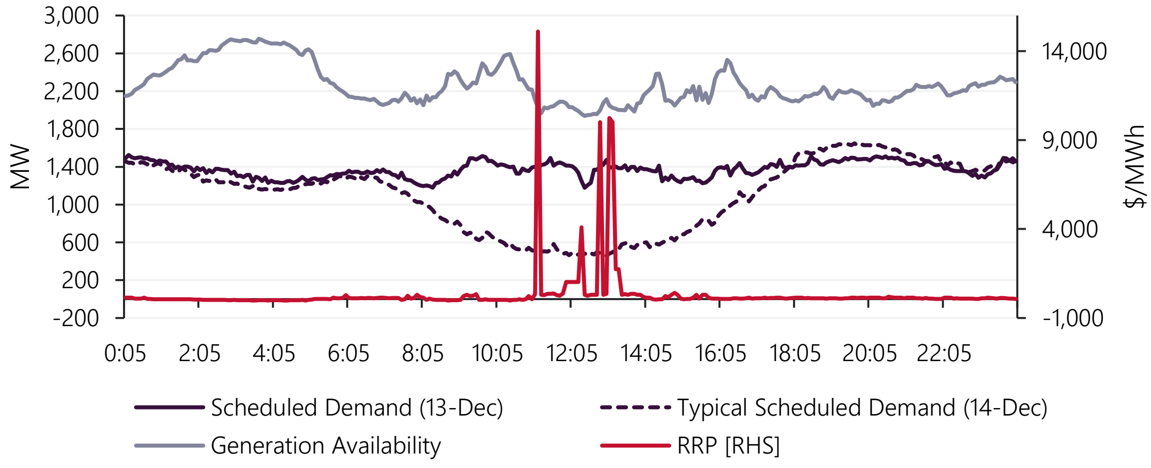
[12] A measure of volatility in electricity prices is the presence of high price events – prices above $300/MWh. This is often represented as 'quarterly cap returns', which is the sum of the NEM pool price minus the $300 cap price for every dispatch interval in the contract quarter where the pool price exceeds $300/MWh, divided by the number of dispatch intervals in the quarter. Since commencement of 5MS from 1 October 2021, cap returns are calculated on a 5-minute basis for current and previous quarters.

[13] 'Scheduled demand' refers to demand met through the market clearing process by large-scale scheduled and semi-scheduled generation and loads. It is the net supply requirement to meet the difference between underlying demand and supply from distributed PV and non-scheduled sources.

on the chart. Wind output through the middle of the day was very low and cloud cover also affected grid-solar output, both reflected in the changes seen in generation availability. The resulting variations in market supply-demand balance led directly to instances of spot price volatility, as gas and liquid-fuelled generation as well as battery storage were dispatched to manage rapid changes in the net supply requirement.

Figure 20 Weather-driven demand variability triggers volatility in South Australia

South Australian dispatch outcomes for 13 December 2021



Five-minute settlement (5MS)

An early and readily observable impact of the change to 5MS from 1 October 2021 was the effective cessation of dispatch prices regularly falling to the market price floor of -$1,000/MWh following a very high price dispatch interval (Figure 21). Previously, loads and generators had a strong financial incentive to rebid after a price spike early in a 30-minute trading interval due to the effect of the spike on the 30-minute average settlement price. Under 5MS, this incentive is removed, and in most circumstances price spikes have not been followed by price collapses to the floor over the balance of a half-hour (Figure 22).

Figure 21 Pre 5MS – Rebidding after Qld price spikes

Queensland 5-minute spot prices – 30 September 2021

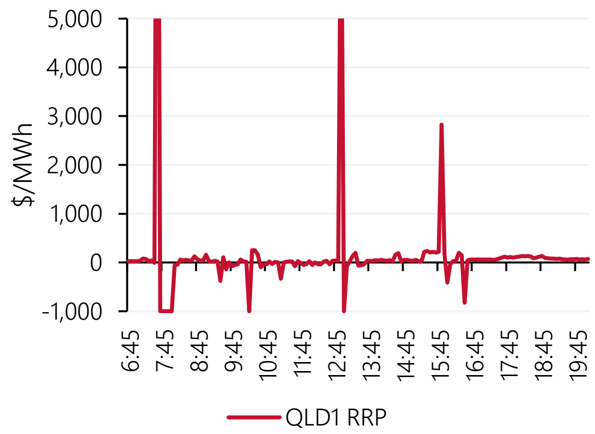
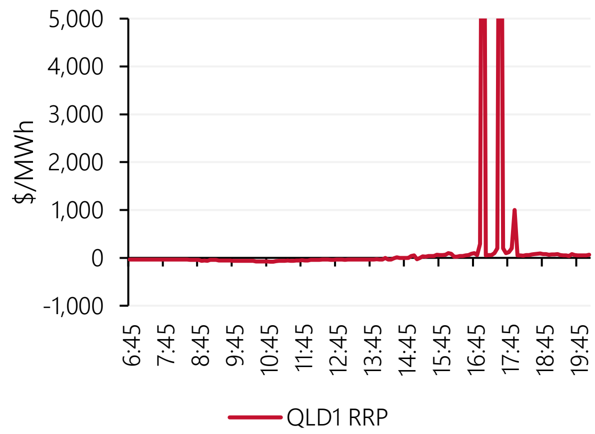


Figure 22 Post 5MS – No rebidding after price spikes

Queensland 5-minute spot prices – 4 Oct 2021

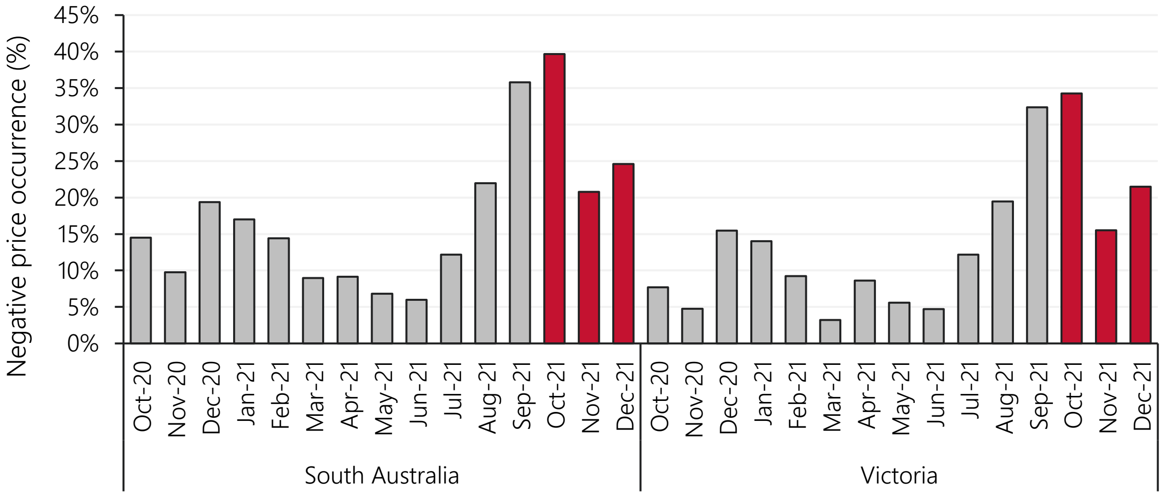


1.2.3 Negative wholesale electricity prices

Negative and zero spot price[14] incidence continued to trend upwards in 2021, occurring in 11.2% of all dispatch intervals[15], more than doubling 2020's average of 4.9%. During Q4 2021, the frequency of negative spot prices was similar to Q3 2021 at 16.6% of all dispatch intervals, with the majority of negative prices in October. Negative spot prices occurred consistently across all NEM regions, with records set in South Australia and Victoria. In South Australia, spot prices were negative 28% of the time during Q4 2021, surpassing the previous quarterly high of 23%, while Victoria reached a new record of 24% (Figure 23).

Figure 23 Negative prices declined from October highs but still set quarterly records

Frequency of negative or zero spot prices in South Australia and Victoria



These South Australian and Victorian records were driven by high incidences in October, with negative spot prices occurring in 40% and 34% of dispatch intervals respectively during the month. Drivers included:

- Reduced daytime demand – driven by very mild conditions and high distributed PV output, in October 2021, combined Victorian and South Australian daytime operational demand between 1000 hrs and 1500 hrs dropped below 4,500 MW 52% of the time compared to 14% of the time in October 2020, contributing to frequent negative spot price occurrence during the middle of the day.
- High VRE and hydro output – increased levels of VRE output particularly from Victorian grid-solar and wind, coupled with increased Tasmanian hydro offers below $0/MWh and transfers on Basslink, contributed to increased occurrence of negative prices in the southern regions.
- Interconnector constraints – transfers of energy across the Victoria – New South Wales Interconnector (VNI) were constrained to lower daytime levels in Q4 (Section 1.4), tending to suppress prices in southern regions.

Change in VRE bidding behaviour

While the overall frequency of negative spot prices remained high during the quarter, there was a notable reduction in the proportion of negative prices falling within the -$1,000 to -$100/MWh and -$15 to $0/MWh price ranges, while negative prices around the minus $35-$50/MWh range, close to the value of a Large-scale

[14] Hereafter referred to as negative prices.

[15] Since commencement of 5MS from 1 October 2021, negative and zero spot price occurrences are calculated on a 5-minute basis for current and previous quarters.

Generation Certificate (LGC)[16] have increased substantially. For example, in South Australia 40% of all negative price intervals fell within this minus $35-50/MWh price band, an increase from 16% in Q3 2021 (Figure 24).

A key driver to this increase was the change in VRE bidding behaviour since 1 October 2021. A large proportion of semi-scheduled generators across the NEM have altered their bidding behaviour. During the week prior to 1 October 2021, on average over 8,600 MW of nominal capacity was offered at market price floor of -$1,000/MWh, however since then volumes offered at this level have declined substantially, with only around 5,500 MW offered in the week after 1 October, as more VRE generators shifted their offers towards their break-even price or short run marginal cost (SRMC) within the -$100/MWh to -$35/MWh ranges (Figure 25). Typically, a VRE generator's break-even price is influenced by the value of an LGC, however other factors such as a generator's power purchase agreements (PPAs) and portfolio position are also key determinant to this price.

Figure 24 Significant increase in minus $35/MWh to $50/MWh price band in Q4 2021

South Australian negative spot price band - % of the time

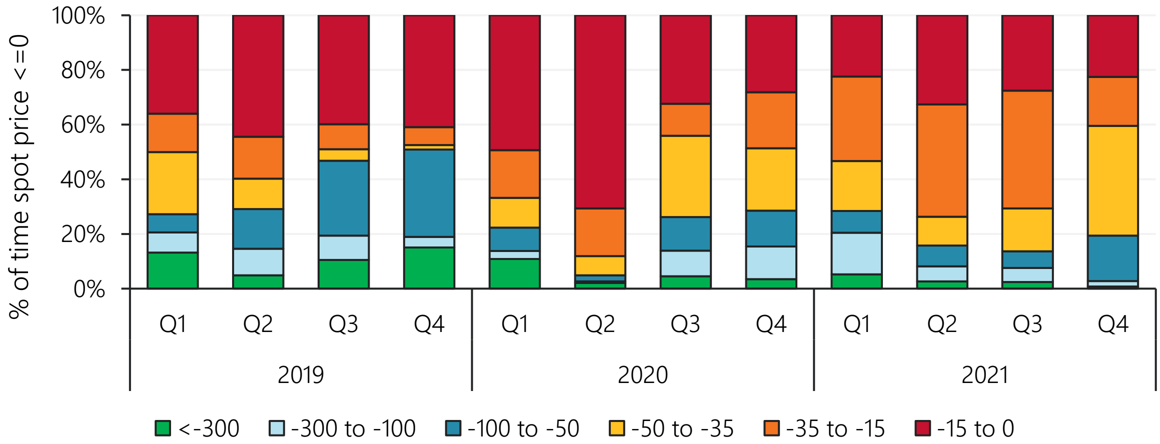
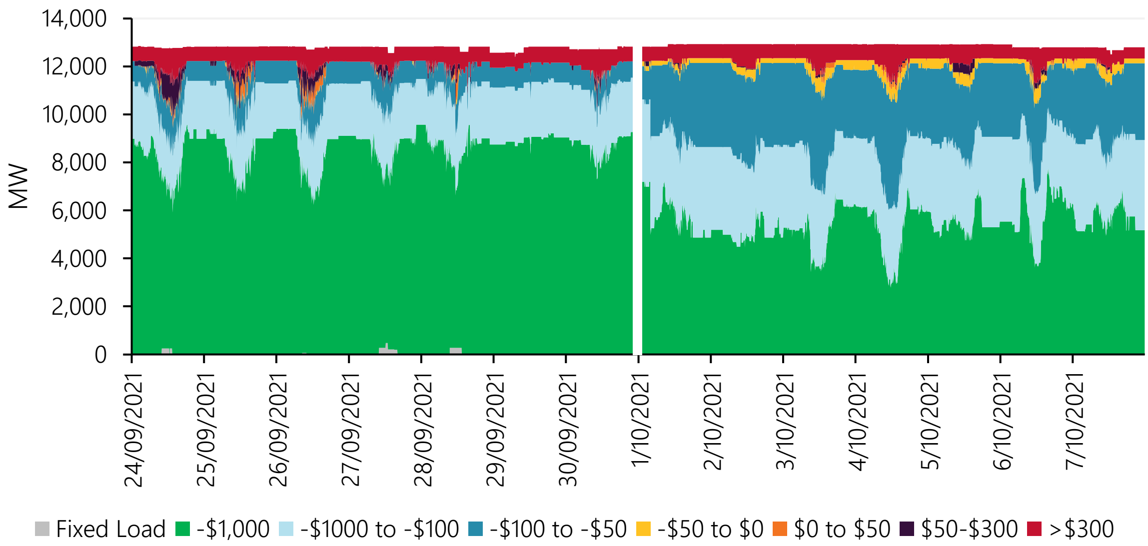


Figure 25 NEM VRE shift bid volumes from minus $1,000/MWh to less negative price bands

NEM semi-scheduled generators final bid distributions[17] – 24 September 2021 to 7 Oct 2021



[16] Mercari 2021: http://lgc.mercari.com.au/.

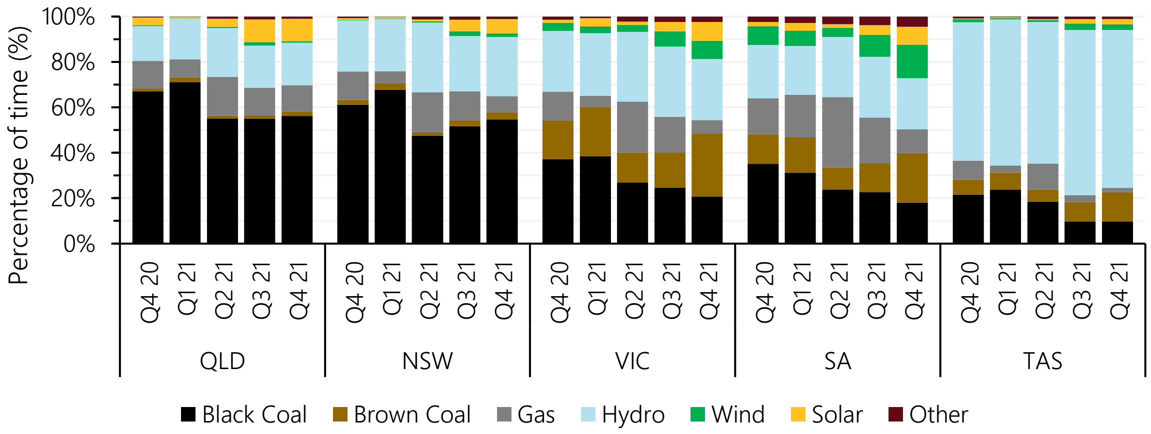
[17] Band volumes of the last bid/rebid before dispatch. Note that bid volumes charted were not truncated or constrained by actual availability.

1.2.4 Price-setting dynamics

Price-setting behaviour in Q4 2021 continued trends observed in Q3 (Figure 26). Across the NEM, the proportion of periods in which gas offers set prices declined to 7%, down from 13% in Q3 and 12% in Q4 2020. Wind and solar price-setting frequency increased to 12% in Q4 from 10% in Q3, an increase of eight percentage points since Q4 2020. Q4 2021 prices were set by these sources for 23% of the time in South Australia and 16% in Victoria. The ongoing price separation between northern and southern NEM regions noted in Section 1.2 meant that black coal set prices much less frequently in the south, with brown coal increasing its price-setting frequency in Victoria, South Australia and Tasmania.

Figure 26 Thermal price-setting frequency steady in the north, falling in the south

Price-setting by fuel type

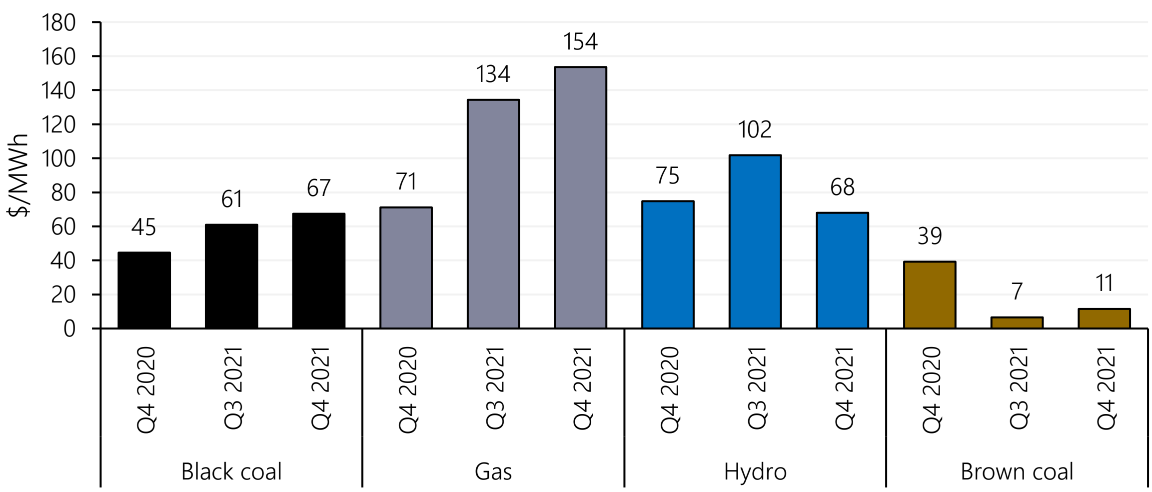


Note: price setting can occur inter-regionally; for example, Victoria's price can be set by generation offers in other NEM regions.

Black coal and gas offers set prices at higher average levels in Q4 (Figure 27), and their significant role in price-setting frequency in the northern NEM regions goes towards explaining the regional price differentials observed in the quarter (Section 1.2). Increases in underlying traded prices for black coal and gas, discussed in Section 2.2.1, were likely to have been influences on offer price levels for some of these generators.

Figure 27 Black coal and gas offers setting higher prices in Q4 2021

Average prices set by fuel type



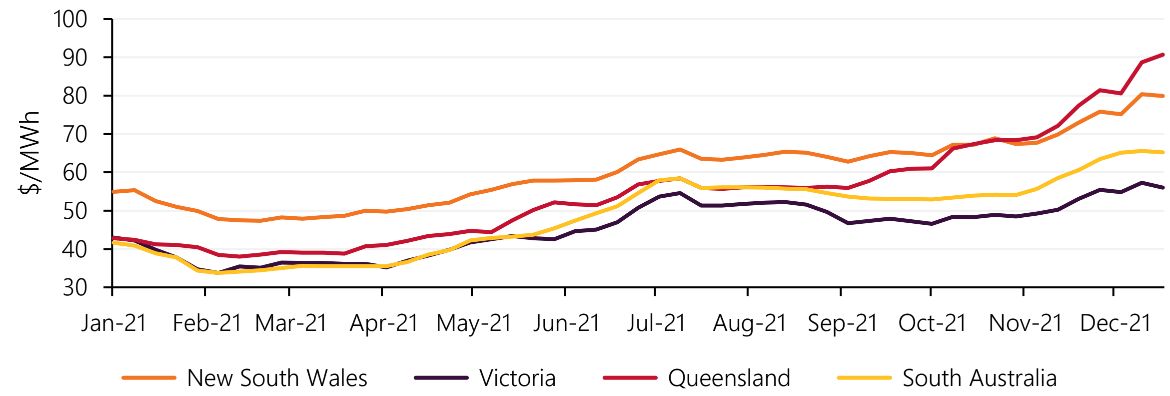
1.2.5 Electricity futures markets

During the quarter, ASX Calendar (Cal) 2022 futures prices increased across all states, from an average of $57/MWh at the end of Q3 2021 to finish the year at $73/MWh, with participants' outlooks influenced by wholesale spot price trends, possible impact from long-term generation unit outages and closures, and potentially higher fuel cost expectations in 2022.

Queensland led the rally, rising $29/MWh to $91/MWh and reversing its previous spread to New South Wales which rose $13/MWh to $79/MWh. The spread between the northern and southern states increased by $13/MWh to $25/MWh on average, with South Australia at $65/MWh while Victoria remained the lowest-priced state at $56/MWh (Figure 28).

Figure 28 Queensland Cal22 swaps rise strongly

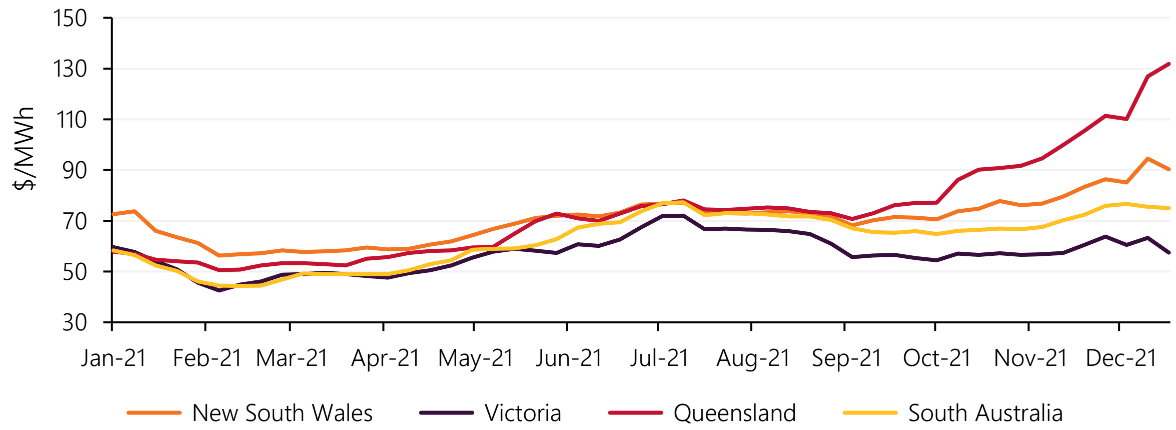
ASX Energy – Cal22 swap price by region – seven-day averages



The individual base quarters' contributions to the Calendar 2022 swap increase were most notable in the Q1 2022 price movement. Queensland led the rally from $78/MWh at the end of last quarter to finish the year at $132/MWh, followed by New South Wales (up $17/MWh to $90/MWh), while smaller increases in South Australia (to $75/MWh) and Victoria (to $57/MWh) emphasised the growing spread between northern and southern NEM regions (Figure 29).

Figure 29 Queensland Q1 2022 swaps rally

ASX Energy – Q1 2022 swap price by region – seven-day averages



1.3 Electricity generation

Figure 30 and Table 3 show the change in NEM generation mix in Q4 2021 compared to Q4 2020, while Figure 31 shows the change by time of day. Key outcomes compared to Q4 2020 include:

- NEM instantaneous renewable share of total generation reached a record 61.8%, with distributed PV output accounting for 32% of total generation during the interval, followed by wind and grid-scale solar at 28% combined.
- Hydro generation increased to its highest Q4 average since 2016, led by Tasmania where La Niña conditions filled dams to near record levels during the quarter.
- Black coal-fired generation fell to its lowest Q4 average since NEM start, with both Queensland and New South Wales contributing to the decline.
- Gas generation declined to its lowest Q4 average since 2003, with South Australia falling to its lowest Q4 average since NEM start.

Figure 30 Renewable energy leads output increase

Change in supply – Q4 2021 versus Q4 2020

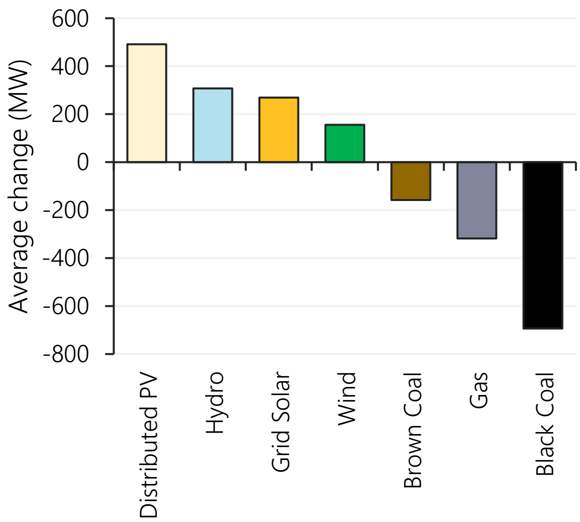
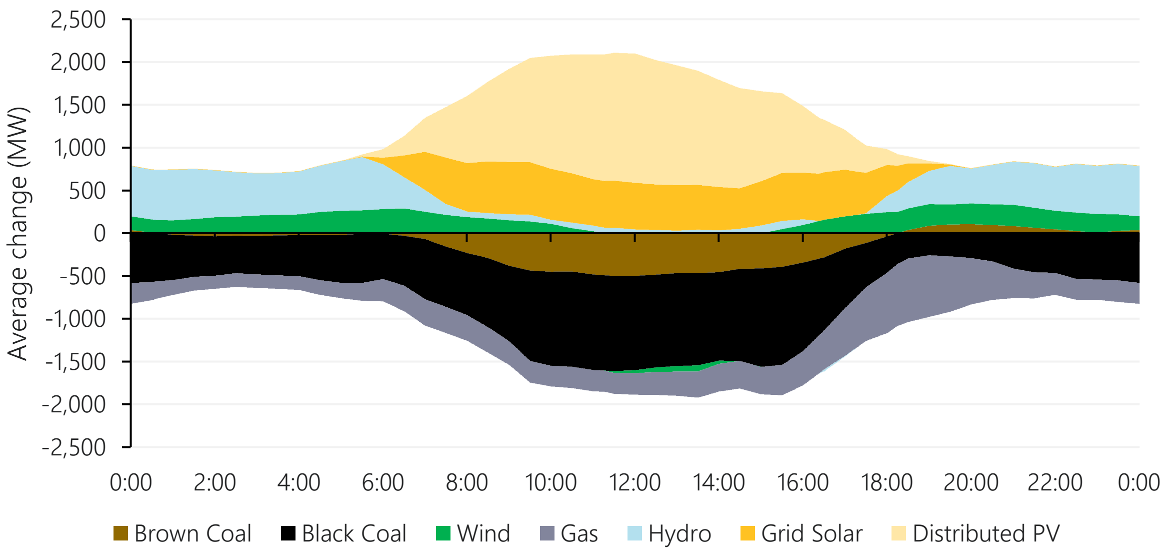


Table 3 NEM large-scale supply mix by fuel type

Quarter	Black coal	Brown coal	Gas	Hydro	Wind	Grid solar
Q4 2020	52.1%	17.8%	6.4%	6.8%	11.9%	5.0%
Q4 2021	49.8%	17.4%	5.0%	8.5%	12.9%	6.4%
Change	-2.3%	-0.4%	-1.4%	1.7%	1.0%	1.4%

Figure 31 Renewable energy displaces thermal generation in Q4 2021

Change in supply – Q4 2021 versus Q4 2020 by time of day



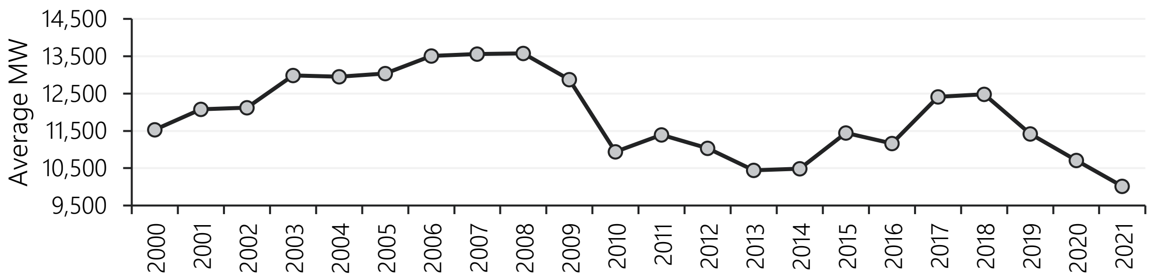
1.3.1 Coal-fired generation

Black coal-fired fleet

During Q4 2021, average black coal-fired generation declined to 10,016 MW, its lowest Q4 output since NEM start and 693 MW lower than Q4 2020 (Figure 32). Record low output was driven by both the Queensland and New South Wales fleet, with output decreasing by 406 MW and 287 MW, respectively (Figure 33).

Figure 32 Q4 NEM black coal-fired output at new lows

Average NEM black coal-fired generation – Q4s



Average Queensland black coal-fired output declined to 5,055 MW, its lowest Q4 generation since 2014. Increased outages (69% unplanned, 31% planned), coupled with units offering capacity at higher price bands and several black coal units operating at lower availability, were the key drivers of lower output. Key changes:

- Increased outages (mostly unplanned) at Callide C Power Station reduced average output by 334 MW. Higher levels of outages were largely due to Unit 4 remaining out of service since its major incident in Q2 2021[18].
- While there were almost no outages during the quarter at Tarong Power Station, average output reduced by 330 MW compared to Q4 2020, as units were offered at reduced available capacity of around 195 MW after 10 November 2021 (Figure 34).
- Fewer planned outages at Tarong North and Kogan Creek Power Stations this quarter increased average output by 224 MW and 208 MW, respectively.

Figure 33 Decline in coal generation across the NEM

Change in coal-fired generation – Q4 2021 vs Q4 2020

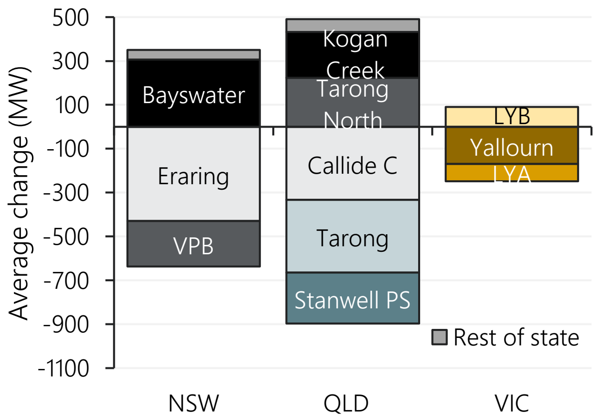
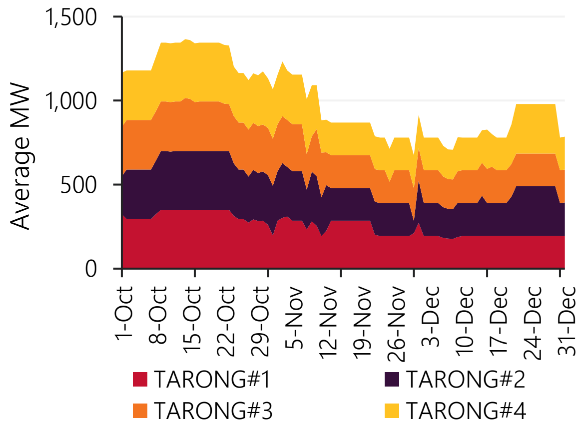


Figure 34 Reduced availability at Tarong mid-quarter

Tarong average daily availability – Q4 2021



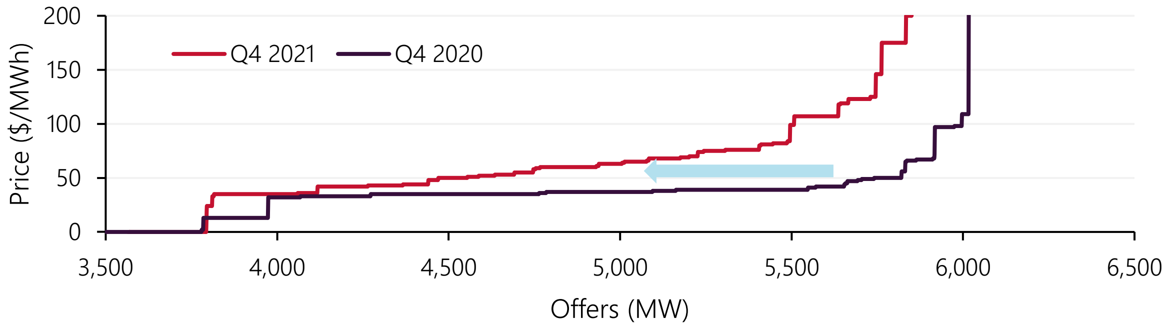
[18] Callide Unit 4 is currently scheduled to return on 7 April 2023.

In New South Wales, despite increased average availability (+466 MW), black coal-fired output declined to its lowest Q4 average on record this quarter (4,961 MW). A shift in black coal offers to higher price bands, and displacement by VRE and distributed PV, contributed to lower output. Compared to Q4 2020, an average 1,430 MW of New South Wales coal offers were shifted from lower price levels to bands above $40/MWh (Figure 35).

- Increased outages (mostly planned) at Eraring Power Station, coupled with units shifting around 920 MW of capacity on average to higher price bands (>$40/MWh), reduced average output by 430 MW to its lowest quarterly output since Q4 2016.
- Average output at Vales Point B Power Station declined by 208 MW to its lowest Q4 level since 2011. With small changes to availability (-73 MW) over Q4 2020, lower output was driven by increases in marginal offer prices and displacement by VRE output – utilisation rate[19] declined from 81% in Q4 2020 to 66% this quarter.
- Fewer outages at Bayswater Power Station increased average output by 307 MW. On average, Bayswater units were out of service 17 days compared to 29 days in Q4 2020.

Figure 35 New South Wales black coal-fired generation shifting offers to higher price bands

NSW black coal-fired generation bid supply curve – Q4 2021 vs Q4 2020



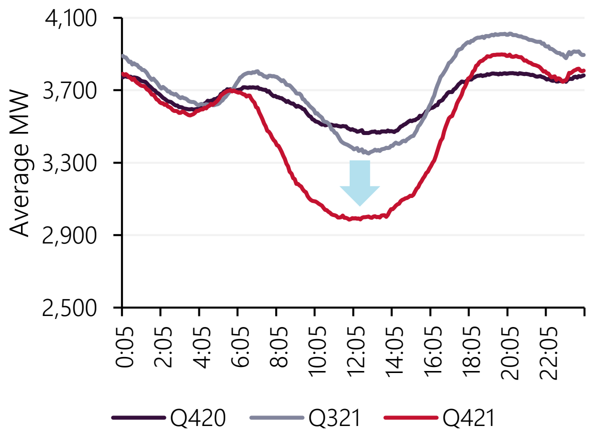
Brown coal-fired fleet

Average brown coal-fired generation decreased by 158 MW compared to Q4 2020 as reduced output from Yallourn (-170 MW) and Loy Yang A (-78 MW) more than offset increases from Loy Yang B (+91 MW).

Despite an increase in average availability compared to Q4 2020 (+115 MW), brown coal-fired output declined as low and negative daytime spot prices in Victoria induced more flexible operation, with average utilisation rate reducing from 95% in Q4 2020 to 89% in Q4 2021. While brown coal units have exhibited flexibility in previous quarters, the decline in daytime generation this quarter was even more pronounced – compared to Q4 2020 and Q3 2021, output between 1000 hrs and 1600 hrs during Q4 2021 was 448 MW and 383 MW lower, respectively (Figure 36).

Figure 36 Decline in midday brown coal output more pronounced in Q421

Brown coal average output by time of day – selected quarters



[19] Ratio of generator's average generation divided by average availability.

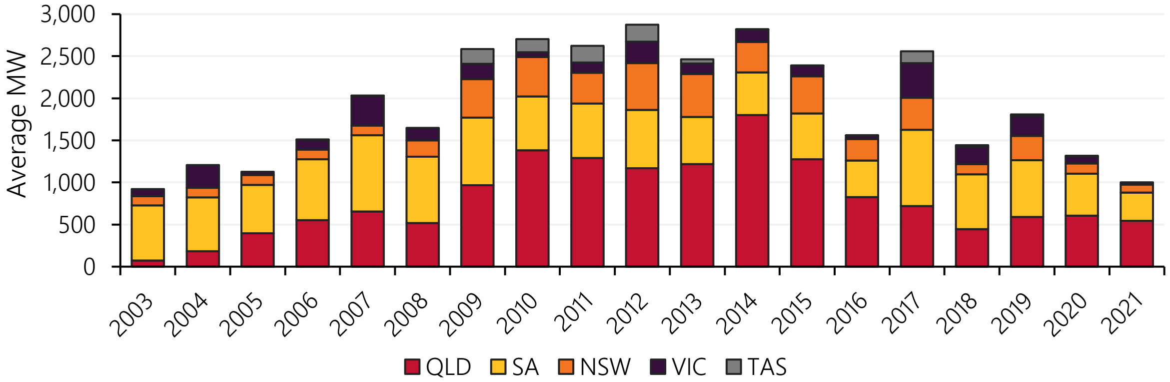
1.3.2 Gas-powered generation

During Q4 2021, NEM gas generation declined to 1,000 MW on average, 486 MW lower than the previous quarter and 318 MW less than Q4 2020, reaching its lowest Q4 average since 2003 (Figure 37).

South Australia[20] (333 MW on average) led the decline to its lowest Q4 average since NEM start (Figure 38), while Queensland (546 MW) decreased to its lowest Q4 average since 2018.

Figure 37 Gas generation declines to its lowest Q4 since 2003

Average Q4 gas generation by state



During the quarter, elevated gas prices (Section 2.1) coupled with high negative price occurrence frequently rendered gas generation subeconomic in most regions. In addition, the commissioning of all four synchronous condensers in South Australia reduced the online synchronous generation requirement to the equivalent of two large gas generation units from 25 November[21], with typical minimum output of 80 MW (Figure 39). Volumes of gas generation directed thus fell in Q4 2021 (Section 1.5.2).

Figure 38 Record low Q4 SA gas generation

Average SA gas-fired generation – Q4s

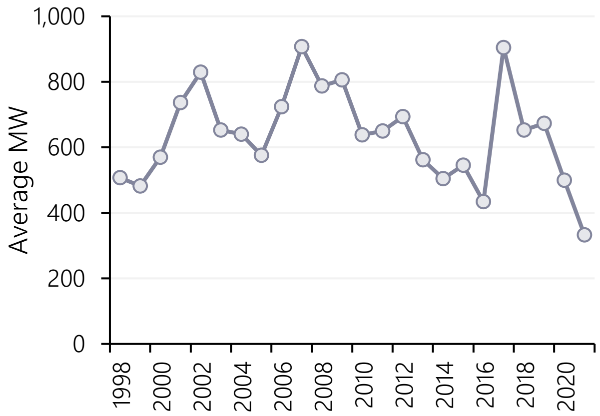
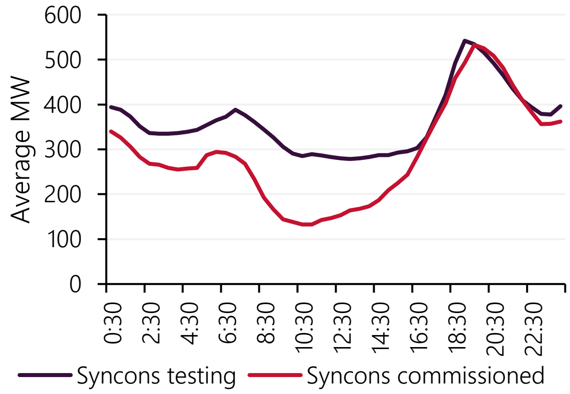


Figure 39 Syncons enable lower gas generation

Average SA Q4 2021 gas-fired generation with two and four synchronous condensers



[20] AGL Torrens Island Unit A1 was officially withdrawn on 30 September 2021 with no impact on Q4 2021 averages, as last generation was in September 2020.

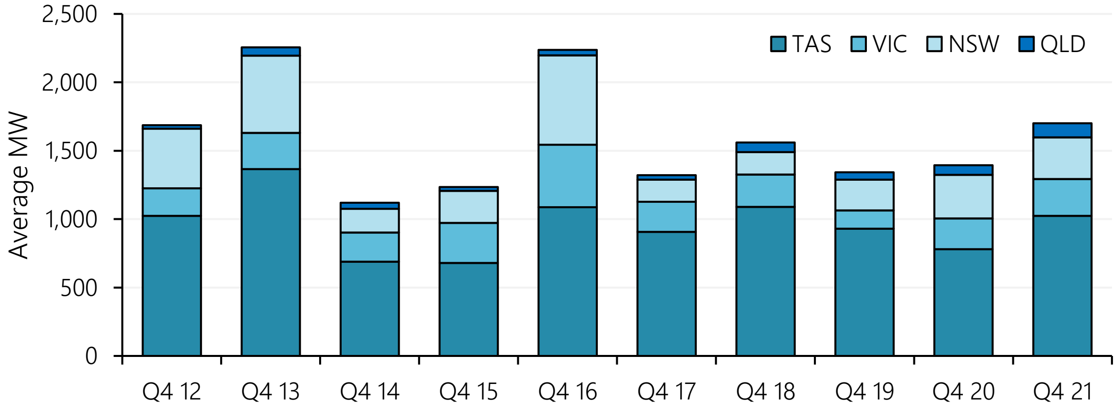
[21] AEMO moved to four synchronous condenser operation for system normal conditions as of 1900 hrs on 25 November 2021. For more information, refer to Market notice 92718 and https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/related-resources/operation-of-davenport-and-robertstown-synchronous-condensers

1.3.3 Hydro

Hydro generation increased by 307 MW on average compared to Q4 2020 (Figure 40), influenced by La Niña conditions with increased rainfall mainly in Tasmania, coupled with higher mainland prices and volatility.

Figure 40 Hydro Tasmania leads hydro generation increase

Q4 average hydro generation by state

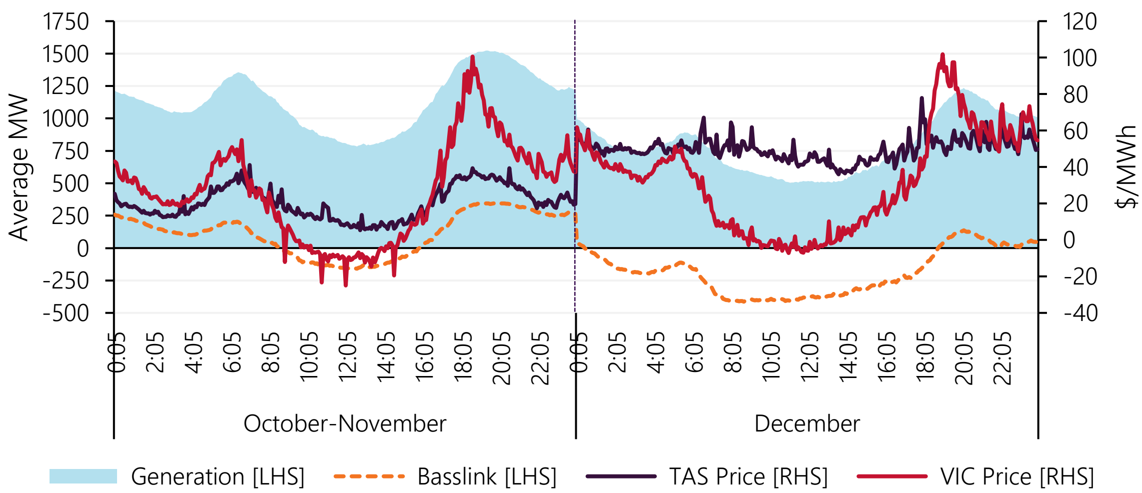


By region compared to Q4 2020:

- **Tasmania** was the main contributor to higher NEM hydro output, increasing 243 MW to 1,024 MW to its highest Q4 average since 2018, with hydro generators in the region bidding an additional 388 MW below $40/MWh, as high rainfall increased dam levels to near record levels, finishing the quarter at 49%. Generation increased especially in the first two months of the quarter, capturing higher mainland evening peak prices via Basslink exports but importing in the middle of the day, while in December generation fell and Basslink switched to higher Tasmanian imports (Figure 41).
- **Mainland** – hydro output increased by 65 MW on average to 677 MW. Victoria (+46 MW) and Queensland (+33 MW) were the main contributors to the increase, ramping up especially during the evening shoulder period to capture increasing prices, while output in New South Wales was comparable to last year.

Figure 41 Hydro Tasmania generation flex

Q4 2021 Tasmania hydro generation, regional prices, and Basslink transfer by time of day

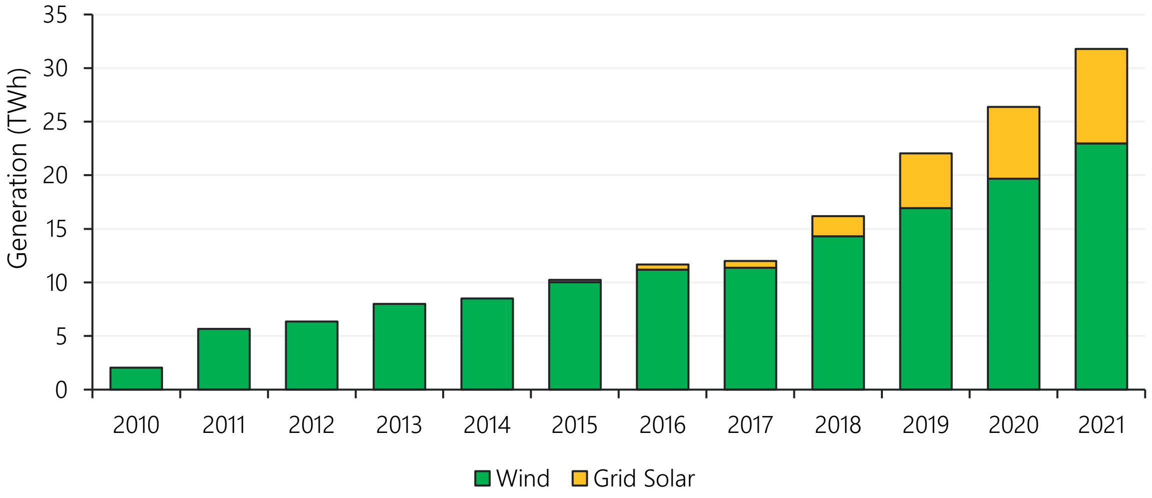


1.3.4 Wind and solar

Total VRE generation across the NEM reached 31.8 terawatt hours (TWh) by the end of 2021, representing 17% of the NEM generation mix (Figure 42). Compared to 2020, VRE output increased by 5.4 TWh in 2021, with wind and grid-solar contributing 3.3 TWh and 2.1 TWh, respectively. While VRE output continued to grow as new capacity additions commenced generation in the NEM, its annual growth rate of 20% was similar to 2020.

Figure 42 NEM VRE output increased by 20%

NEM VRE – annual generation



Compared to Q4 2020, average grid-scale VRE generation in Q4 2021 increased by 425 MW, with grid-scale solar and wind contributing 269 MW and 156 MW, respectively. Higher output was concentrated in New South Wales (+265 MW) and Victoria (+203 MW, Figure 43) due to ramping up of capacity that was still commissioning in Q4 2020[22] as well as new capacity additions over the past year.

Figure 43 NSW and VIC lead VRE output increase

Average change in VRE generation – Q4 2021 vs Q4 2020

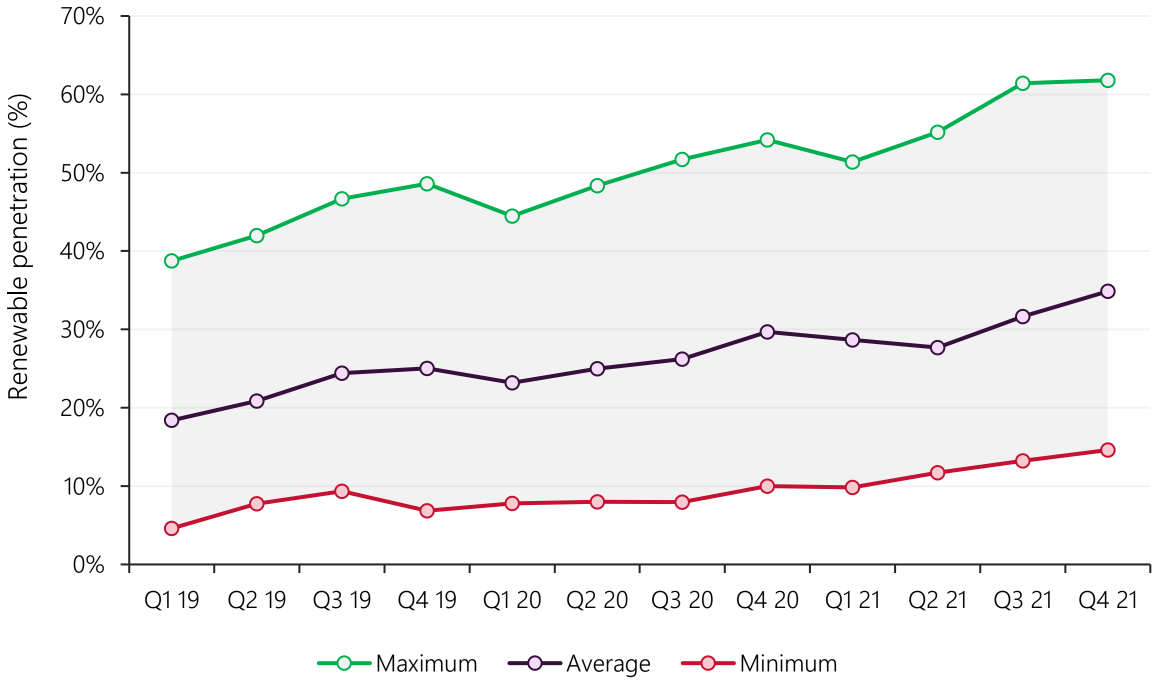
[22] Includes projects which started generating in quarter(s) earlier than the comparison period (Q4 2020) but had not reached full capacity.

Increased VRE output also resulted in several renewable generation records during the quarter, including:

- **Highest NEM instantaneous renewable share of total generation**[23] – on 15 November 2021, renewable penetration (including grid-scale wind and solar, hydro, biomass, battery discharge and distributed PV) reached a reached a record high 61.8% of total NEM generation in the half hour ending 1130 hrs (Figure 44), surpassing the previous record set in Q3 2021 of 61.4%.
  - During this interval, distributed PV output accounted for 32% of total generation, followed by VRE output (wind and grid-scale solar) at 28%.
- **Highest NEM average renewable share of total generation** – NEM average renewable share reached 34.9% of total generation during the quarter, surpassing the previous record set in Q3 2021 (31.6%).
- **Highest grid-scale solar output** – NEM grid-scale solar output reached 4,444 MW in the half-hour ending 1200 hrs on 24 December 2021, 560 MW higher than the previous record set in Q3 2021.

Figure 44 NEM instantaneous renewable penetration reached 61.8%

NEM instantaneous renewable penetration quarterly records



Average grid-scale solar generation reached a quarterly high of 1,291 MW, surpassing the previous record (set in Q1 2021) by 221 MW. A marked increase in grid-solar curtailment on Q4 2020 levels (+159 MW, Section 1.5.3) and lower solar irradiation, particularly in November due to wet conditions, were more than offset by ramping up of recently installed capacity and new capacity additions particularly in New South Wales and Victoria. During the quarter, two new solar farms commenced generation in New South Wales – Hillston Sun Farm (85MW) and Sebastopol Solar Farm (90 MW).

[23] Instantaneous renewable penetration is calculated using the NEM renewable generation share of total generation. The measure is calculated on a half-hourly basis, because this is the granularity of estimated output data for distributed PV. Renewable generation includes grid-scale wind and solar, hydro generation, biomass, battery generation and distributed PV, and excludes battery load and hydro pumping. Total generation = NEM generation + distributed PV generation.

- In New South Wales, increased output (+176 MW) was predominantly driven by ramping up of recently installed capacity (Sunraysia, Wellington, Darlington Point and Limondale 1 solar farms), which accounted for 88% of the increase. Similarly, in Victoria the continued ramp up at Kiamal and Glenrowan solar farms accounted for majority of the output increase in the region.
- Despite small capacity additions over the past year, grid-solar output in South Australia was largely unchanged (-1 MW) due to lower output in November driven by below average solar irradiation.

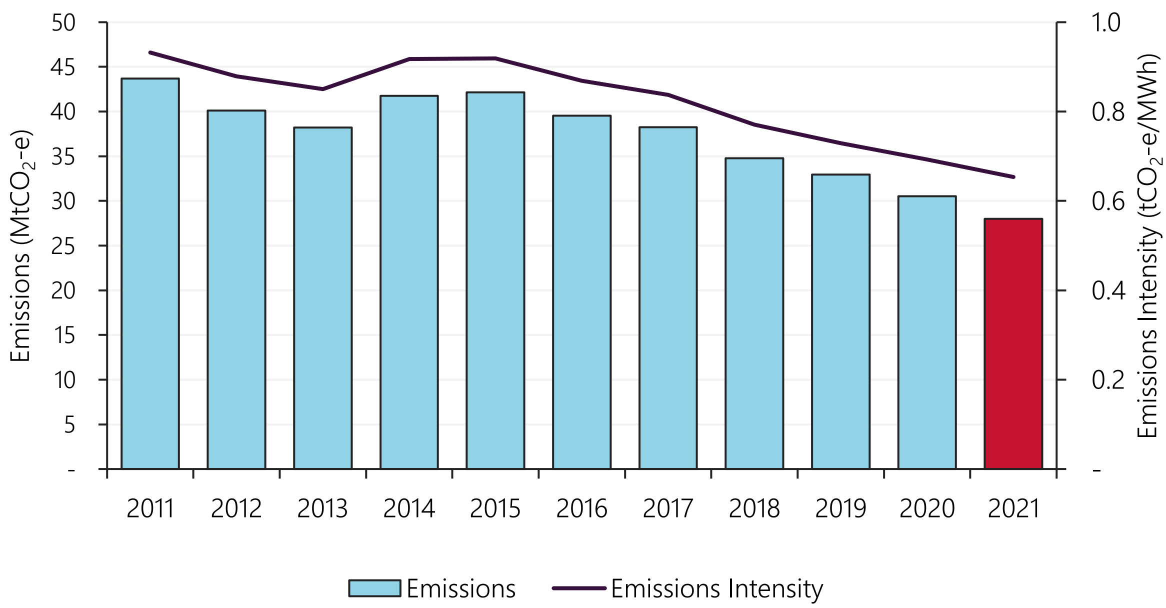
Wind output increased by 156 MW on average, with increases in Victoria and New South Wales (+211 MW combined) while output in South Australia and Tasmania declined by 37 MW and 22 MW, respectively. Drivers for increased wind output were a combination of ramping up at recently installed capacity and new capacity additions in Victoria and New South Wales, more than offsetting lower NEM wind speeds during the quarter (average wind available capacity factor[24] falling to 32% in Q4 2021 from 35% in Q4 2020) and small increases in wind curtailment (+25 MW). Two new wind farms commenced generation during the quarter, one in Victoria (Diapur Wind Farm, 7 MW) and one in South Australia (Lincoln Gap Wind Farm Stage 2, 85 MW).

1.3.5 NEM emissions

During the quarter, NEM emissions declined to the lowest quarterly total on record at 28 million tonnes carbon dioxide equivalent ($MtCO_2$-e), 8% lower than the previous quarterly low in Q4 2020 (Figure 45), driven by reduced thermal generation and demand combined with continuing growth in VRE output.

Figure 45 Record low quarterly emissions

Quarterly NEM emissions and emissions intensity (Q4s)



[24] Capacity factors of each project are weighted by maximum capacity to derive weighted average by state. Project capacity factors are calculated using the availability divided by its maximum installed capacity. The use of availability instead of generation removes the impact of curtailment.

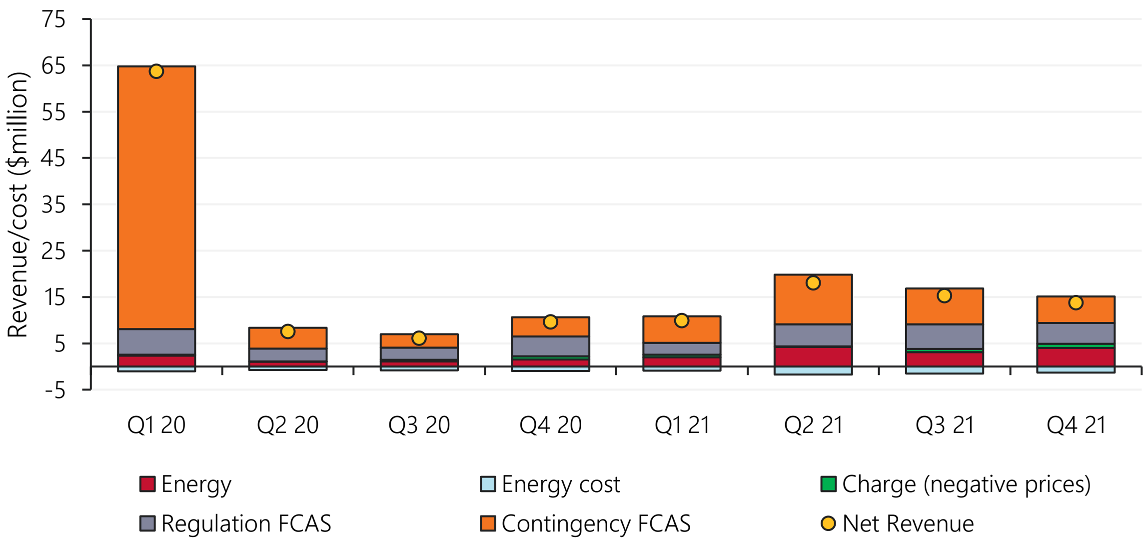
1.3.6 Storage

Batteries

During Q4 2021, estimated NEM battery net market revenue[25] was $14 million, $4 million higher than Q4 2020 (Figure 46). While FCAS markets continued to remain the largest revenue source, contributing 68% of total gross revenue, this share was lower than Q4 2020 (79%). Higher revenue compared to Q4 2020 was largely driven by South Australian (+$2.4 million) and Victorian batteries (+$1.5 million), with a smaller increase in New South Wales (+$0.3 million).

Figure 46 Battery net revenue higher than Q4 2020 but lower than Q3 2021

Battery revenue sources - quarterly



By region, compared to Q4 2020:

- In South Australia, increased net revenue was largely driven by the energy market (+$1.9 million), accounting for 80% of the increase. Higher net energy revenue was largely due to the significant increase in volume-weighted average energy arbitrage value (from $39/MWh to $138/MWh) as average dispatch was 17% lower than Q4 2020.
  - Notably, South Australian batteries also benefitted from their ability to respond quickly to price spikes under 5MS this quarter, with net revenue around $0.4 million higher than what would have been received under 30-minute settlement, assuming the same five-minute price and dispatch outcomes.
- Higher net revenue in Victoria was mainly due to increased activity from the Victorian Big Battery (VBB), accounting for 88% of the net revenue increase. During the quarter, VBB participated in both energy and FCAS markets, capturing $0.4 million and $0.9 million in each market respectively. In FCAS markets, enablement across all eight services increased since VBB registered in November, which resulted in a 73% increase in Victorian battery FCAS enablement in Q4 2021 compared to Q3 2021 (Figure 47).

[25] Since commencement of 5MS from 1 October 2021, battery and pumped hydro net market revenue for Q4 2021 was estimated using spot prices on a 5-minute basis while battery and pumped hydro energy dispatch and load were estimated using the average of initial and final MW. Estimation for battery and pumped hydro net market revenue for quarters prior to 1 October 2021 remain unchanged.

  - On 8 December 2021, AEMO confirmed that the System Integrity Protection Scheme (SIPS) service with VBB was fully operational following its successful commissioning[26]. Under the SIPS contract, AEMO will reserve up to 250 MW of the VBB's 300 MW capacity to support a control scheme to increase capability of the VNI and respond to unexpected network outages in Victoria between 1 November and 31 March of each year until 2032[27,28]. Since the SIPS commenced, VBB's availability across both energy and FCAS markets has declined as participation on a commercial basis in the NEM is limited to 50 MW (Figure 48)[29].
- Small increases in battery net revenue in New South Wales was due to Walgrove Grid Battery (50MW capacity/75MWh storage) as it was registered for both energy and FCAS markets during the quarter.

Figure 47 Increase VIC battery FCAS enablement in Q421

VIC battery FCAS enablement by market – Q1 20 to Q4 21

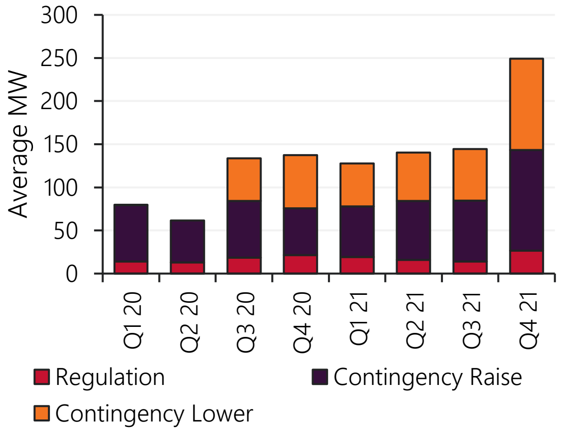
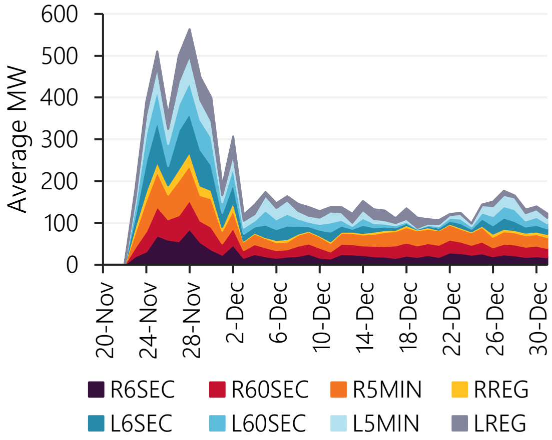


Figure 48 VBB participates in all eight FCAS markets

VBB daily average FCAS enabled - stacked



Pumped hydro

Pumped hydro spot market net revenue in Q4 2021 was $30.5 million, $26 million higher than Q4 2020. The increase was primarily driven by Wivenhoe Pumped Hydro, which accounted for 95% of total pumped hydro net revenue.

Compared to Q4 2020, by power station:

- The marked increase in net revenue from Wivenhoe Pumped Hydro (+$26 million) was a function of high Queensland price volatility during the quarter and increased utilisation (+60%). A significant proportion of revenue was captured when Queensland spot prices were high, particularly in December (Figure 49). Revenue received from generating when spot price exceeded $300/MWh accounted for 82% of total net revenue, and Wivenhoe generated in 84% of these high price dispatch intervals.
  - Notably, Wivenhoe benefitted from extreme price volatility on two separate days during the quarter, with net revenue captured on 9 and 20 December (see Section 1.2.2) accounting for 53% of its Q4 total.

[26] AEMO 2021, Victorian battery ready to deliver energy reserves this summer: https://aemo.com.au/newsroom/media-release/victorian-battery-delivering-energy-reserves-in-summer.

[27] AEMO 2020, AEMO completes System Integrity Protection Scheme procurement process: https://aemo.com.au/en/newsroom/media-release/aemo-completes-system-integrity-protection-scheme-procurement-process.

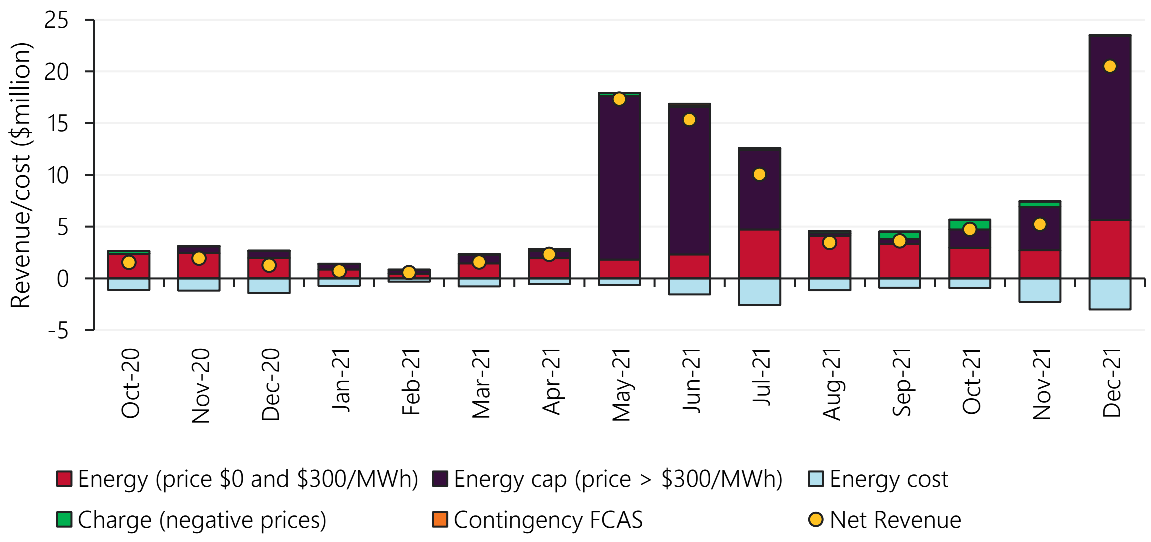
[28] Victoria Department of Environment, Land, Water and Planning (DELWP) 2020, SIPS 2020: https://www.energy.vic.gov.au/__data/assets/pdf_file/0028/495163/SIPS-2020_Executive-Summary-extract.pdf.

[29] Outside November to March each year, the full 300 MW battery will operate on a commercial basis.

- Despite increased price spreads in New South Wales and average energy arbitrage value increasing to $77/MWh, Shoalhaven Pumped Hydro's total net revenue declined by $0.2 million, mainly due to lower utilisation (-42%).

Figure 49 Majority of pumped hydro revenue captured in December

Pumped hydro revenue sources – monthly[30]



1.3.7 Wholesale demand response

Following the Australian Energy Market Commission (AEMC) final determination in June 2020, the Wholesale Demand Response (WDR) mechanism commenced operation on 24 October 2021. WDR enables demand-side (consumer) participation in the NEM spot market separately from retail energy procurement, with the mechanism typically expected to be utilised at times of high electricity prices and electricity supply scarcity. Under rules similar to those for other scheduled participants, WDR units can submit dispatch bids and, when cleared by NEM dispatch engine (NEMDE)[31], receive dispatch instructions to provide wholesale demand response to a specified level.

Following commencement of the mechanism, AEMO registered three WDR units in Q4 2021 – two in Victoria and one in New South Wales (Table 4[32]) – all of which are operated by Enel X. During Q4 2021, there was no significant market utilisation of WDR, although two units (DRXNDA01 and DRXVDJ01) were dispatched for a small number of intervals on 12 November 2021 as bidding systems for these units were being commissioned.

Table 4 Wholesale demand response units registered in Q4 2021

Facility Name	Region	WDRU DUID	Maximum response component (MRC) (MW)	Maximum ramp rate (MW/minute)
DR ENELX N1	NSW1	DRXNDA01	10	2
DR ENELX V1	VIC1	DRXVDJ01	6	1
DR ENELX V2	VIC1	DRXVQP01	4	1

[30] See footnote 25.

[31] The NEM dispatch engine (NEMDE) is software developed and used by AEMO to operate the central dispatch process and maximise the value of trade subject to various constraints.

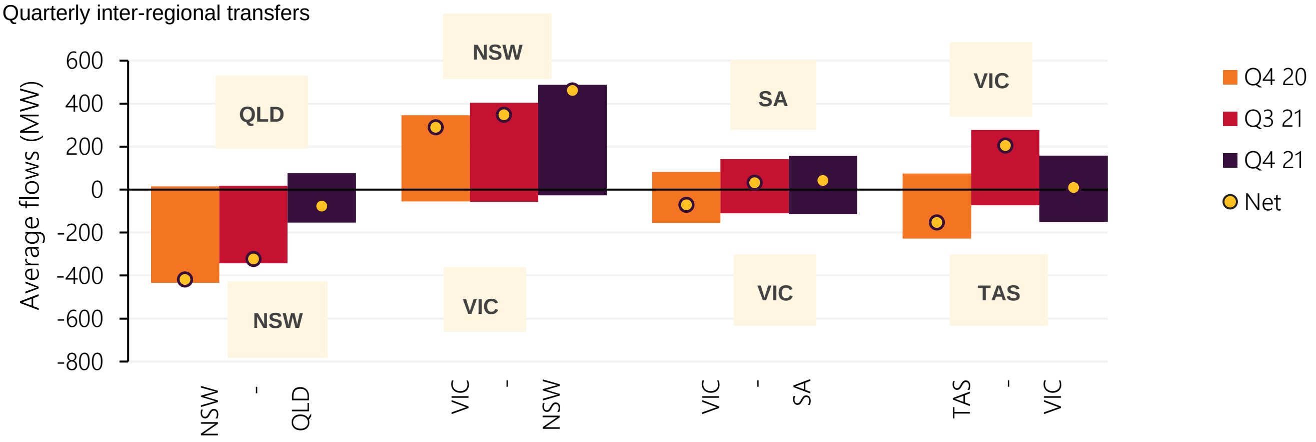
[32] AEMO 2021, NEM Registration and Exemption List: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Participant_Information/NEM-Registration-and-Exemption-List.xls.

1.4 Inter-regional transfers

Net inter-regional energy transfers fell in Q4, with net exports from Queensland to New South Wales down by 247 MW to 77 MW average and net exports from Tasmania to Victoria down by 195 MW to just 9 MW on average (Figure 50). Although Victorian exports to New South Wales increased by 113 MW, this only partially offset the reduction in flows from Queensland.

Figure 50 Exports from Queensland and Tasmania fall

Quarterly inter-regional transfers



Key outcomes by regional interconnection were:

- **Queensland to New South Wales** – transfers from Queensland to New South Wales reduced relative to both Q3 2021 (-247 MW) and Q4 2020 (-341 MW) with higher prices and lower thermal generation in Queensland, as well as outages associated with upgrades of QNI restricting flows at times[33].
- **Victoria to New South Wales** – exports from Victoria to New South Wales grew, up by 113 MW on Q3 2021 and 170 MW on Q4 2020. The percentage of time that flows reached binding limits increased from 32% a year ago and 41% in Q3 to 53% in Q4, contributing to the ongoing price differential between the southern and northern NEM regions (Section 1.2).
- **Tasmania to Victoria (Basslink)** – flows switched during the quarter from average Tasmanian exports to Victoria of 109 MW through October and November to an average Tasmanian import of 187 MW in December, as Tasmanian hydro generation reduced in that month (Section 1.3.3). December average flows were comparable to levels a year ago, when Tasmanian imports averaged 153 MW across Q4 2020.
- **Victoria to South Australia** – flows were evenly balanced between imports and exports, averaging a net flow of 42 MW into South Australia, compared with 32 MW in Q3 2021 and a net import to Victoria of 71 MW in Q4 2020. Net energy flows into South Australia over the quarter were essentially via the Murraylink DC interconnector (56 MW), driven by growing levels of renewable generation in north-west Victoria and south-west New South Wales coupled with transmission constraints tending to direct exports of this energy into South Australia via Murraylink.

[33] The AER's forthcoming Quarter 4 2021 Wholesale Markets Quarterly report will analyse the impact of outage versus system normal constraints on the QNI in more detail.

Southern to northern NEM flows and price differences

The time-of-day pattern in interconnector flows and price differences between Victoria and New South Wales shown in Figure 51 below illustrates one factor contributing to the price gap between northern and southern NEM regions noted in Section 1.2. Average exports from Victoria to New South Wales during daytime hours were substantially lower than at other times of day. Between 0600 hrs and 1800 hrs, exports averaged 350 MW, 221 MW less than the evening-overnight average of 571 MW from 1800 hrs to 0600 hrs[34] (Figure 51). During the daytime hours, New South Wales energy prices on average exceeded Victorian prices by $39/MWh, but with higher transfers in evening-overnight hours the average difference reduced to $27/MWh.

An important factor in reducing daytime exports from Victoria despite the higher inter-regional price differential was the impact of network constraints controlling flows on transmission lines in the south-west of New South Wales. To maintain secure flows with high grid-solar generation in this zone and in north-west Victoria, the dispatch algorithm scheduled reductions in overall Victoria to New South Wales transfers at times when certain of these constraints bound[35] (Figure 52).

Figure 51 VIC-NSW interconnector flows reduced during daytime hours

VNI interconnector flows and price difference[36]

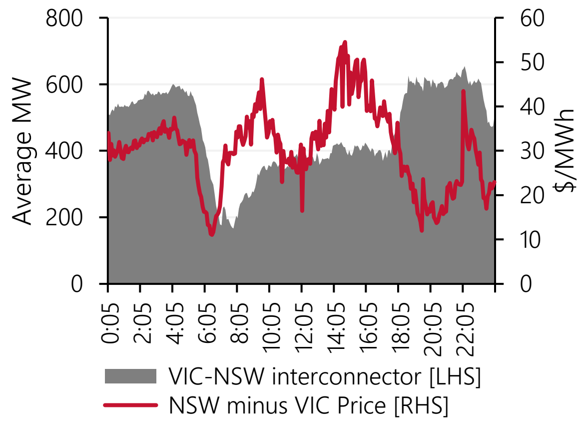
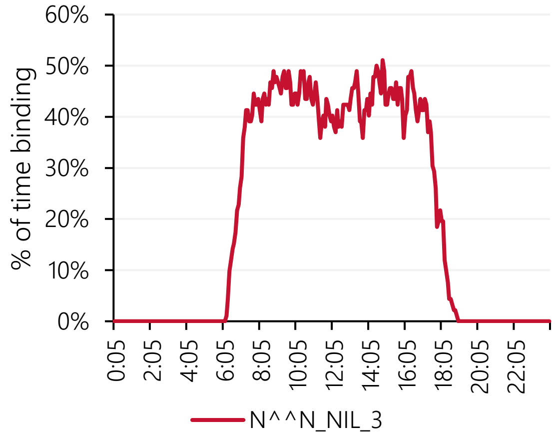


Figure 52 Constraints affecting daytime flows

% of time N^^N_NIL_3 constraint binding by time of day



1.4.1 Inter-regional settlement residue

Total positive inter-regional settlement residue (IRSR) increased to $74 million from $51 million in Q3 2021 and $59 million in Q4 2020 (Figure 53).

Isolated volatility episodes in South Australia and Queensland contributed significantly to IRSR returns of $18 million and $10 million respectively on flows into those regions. By contrast, IRSR accumulated steadily on increased average flows and persistent moderate price differences between Victoria and New South Wales, contributing $36 million of the $40 million total IRSR on flows into New South Wales. With reduced exports from Queensland to New South Wales and low price volatility in New South Wales, IRSR for that flow path fell from $15 million in Q3 to $4 million in Q4.

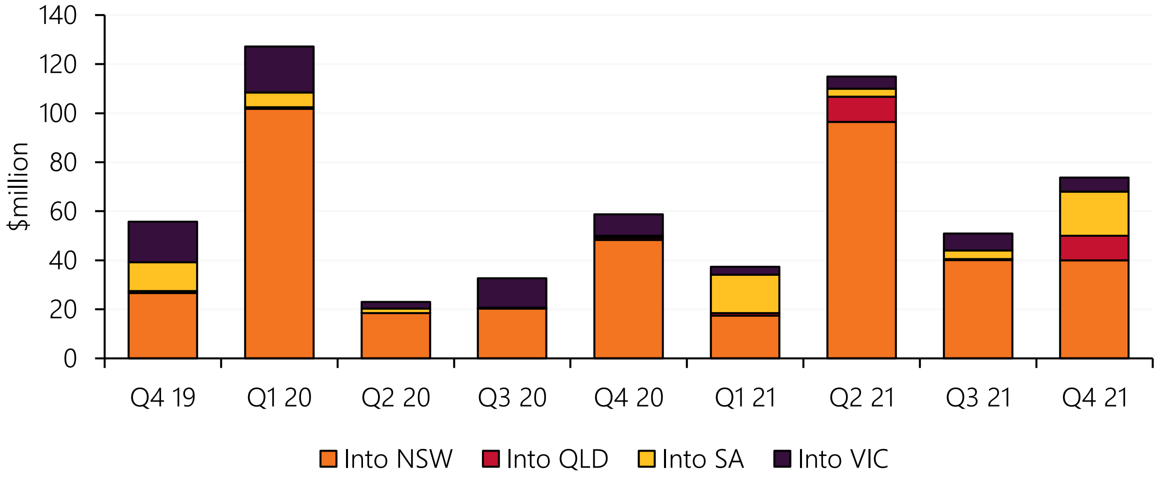
[34] The nominal limit on Victoria to New South Wales flows ranges from 700 MW to 1600 MW depending on system conditions.

[35] For further reading see https://wattclarity.com.au/articles/2020/11/casestudy-x5-constraint/.

[36] Spot prices capped at $300/MWh.

Figure 53 Volatility in South Australia and Queensland lifts IRSR returns

Quarterly positive IRSR value

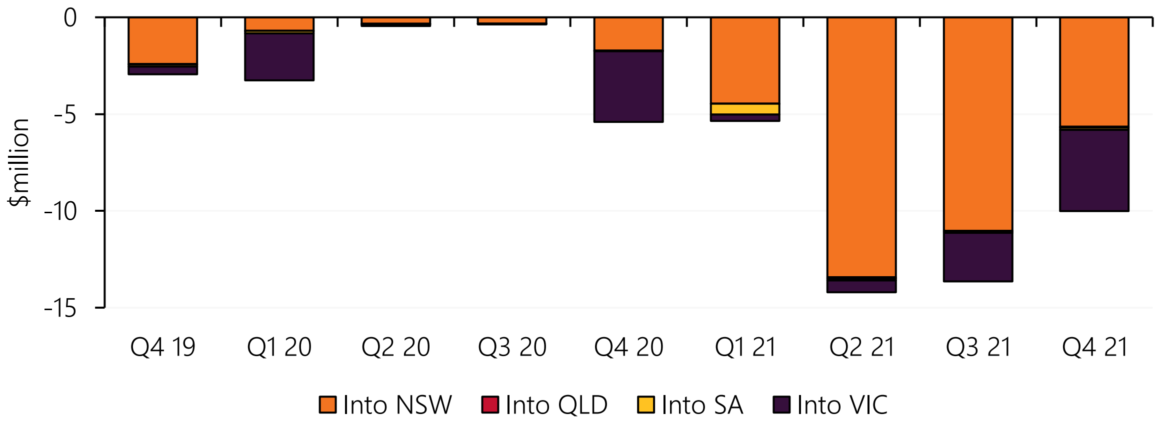


Negative residue management

Negative settlement residues totalled $10 million in Q4, a reduction of $4 million on Q3 but still significantly above levels prior to Q2 2021. Negative residue on flows into New South Wales at $6 million was down from $11 million in Q3 while negative residue on flows into Victoria rose slightly to $4 million (Figure 54).

Figure 54 Negative residues reduce but remain elevated

Quarterly negative inter-regional settlement residue

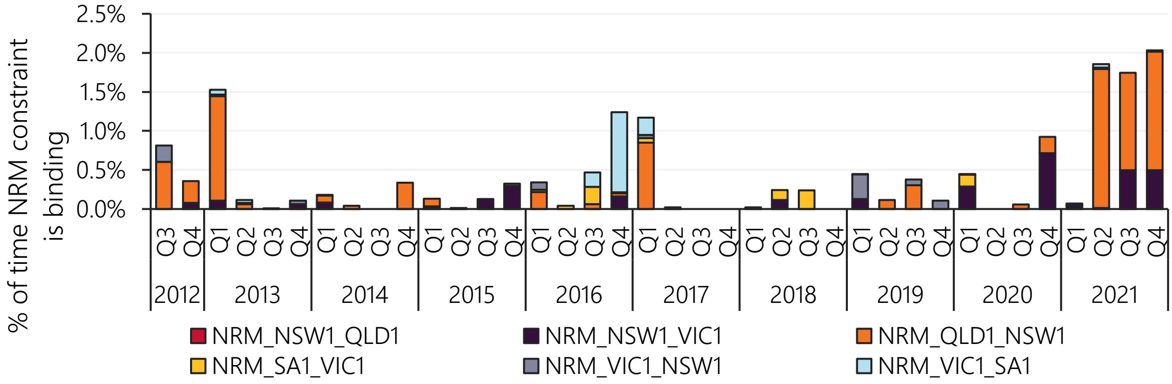


Negative residues often arise when intra-regional transmission constraints limit generation in one zone of a NEM region from flowing freely to the rest of that region, and some energy is instead "forced" across an interconnection to an adjoining region at lower prices. In Q4, different constraints on flows out of southern Queensland towards Brisbane, and from southern New South Wales towards Sydney, caused accumulation of negative residues on the Queensland – New South Wales Interconnector (QNI) and the VNI respectively.

Negative residue management (NRM) constraints operate in the dispatch process to limit the rate at which negative residues accumulate. These constraints were binding for a record proportion of the time in Q4, indicating an increased impact of relevant intra-regional constraints on the dispatch process (Figure 55).

Figure 55 Negative residue management constraints bind with record frequency

Proportion of dispatch intervals bound by NRM constraint

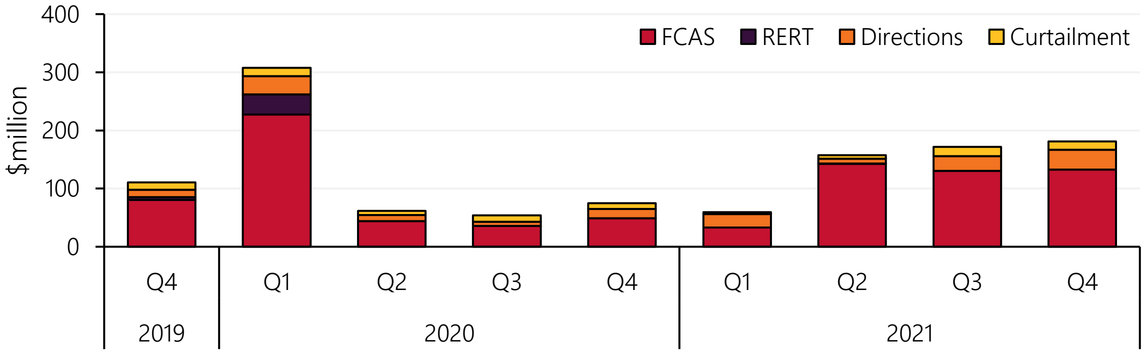


1.5 Power system management

Total NEM system costs[37] rose again to $181 million. This was $10 million higher than Q3 2021 and well above Q4 2020 (+$106 million), with FCAS costs the major contributor (as in Q2 and Q3) and direction costs significantly higher (Figure 56).

Figure 56 FCAS and directions continue to elevate NEM system costs

Quarterly system costs by category



- **FCAS costs** increased marginally on Q3 2021 to $132 million this quarter, but this was $83 million above Q4 2020 and represented 73% of quarterly system costs. Section 1.5.1 provides details on FCAS.
- High gas prices and lower South Australian spot prices meant that prior to full commissioning and testing of the four new synchronous condensers in that region, completed in late November, more frequent **direction of South Australian synchronous units** was required to maintain system strength, with the cost of directions increasing by $9 million on Q3 and by $18 million compared to Q4 2020. Section 1.5.2 provides details on system security directions.
- Estimated costs of **VRE curtailment**[38] increased by $5 million from Q4 2020 due to greater curtailment impacts from non-system strength network constraints. Section 1.5.3 covers this in detail.

[37] In this report, 'NEM system costs' refers to costs associated with market ancillary services ie FCAS, as well as directions compensation, Reliability and Emergency Trader (RERT), and curtailment. For more information on Non-market ancillary services (NMAS) costs, see https://aemo.com.au/-/media/files/electricity/nem/data/ancillary_services/2021/nmas-cost-and-quantities-report-2020-21.pdf?la=en.

[38] Excludes participants self-curtailing for economic reasons. The cost of curtailed VRE output is estimated to be $40/MWh of output curtailed.

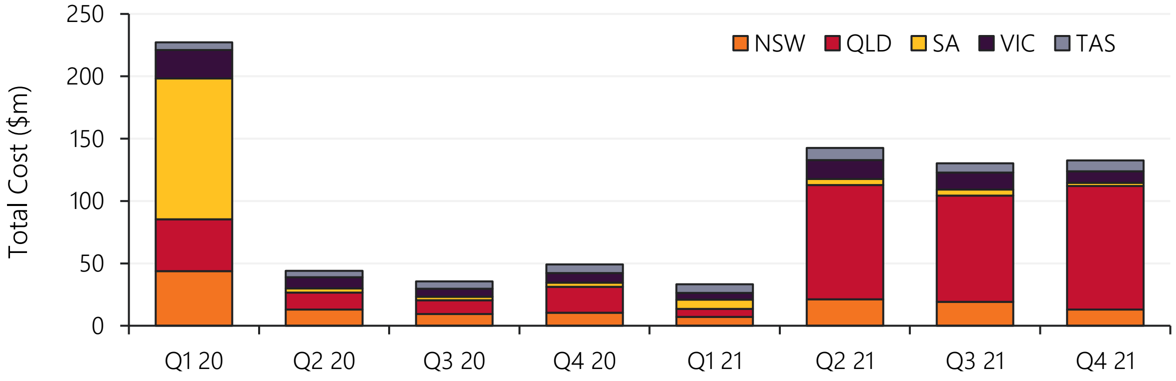
1.5.1 Frequency control ancillary services

FCAS costs of $132 million in Q4 continued the trend of elevated quarterly costs which commenced in Q2 2021. Queensland costs comprised 75% of the total at $99 million, their highest recent quarterly level, while costs in other regions fell or were stable (Figure 57).

By service type, costs for Contingency Raise at $84 million and Contingency Lower at $33 million accounted for 64% and 25% of the Q4 total respectively and essentially were responsible for the entire increase in FCAS costs since Q4 2020, with Regulation costs stable.

Figure 57 Queensland FCAS costs remain high

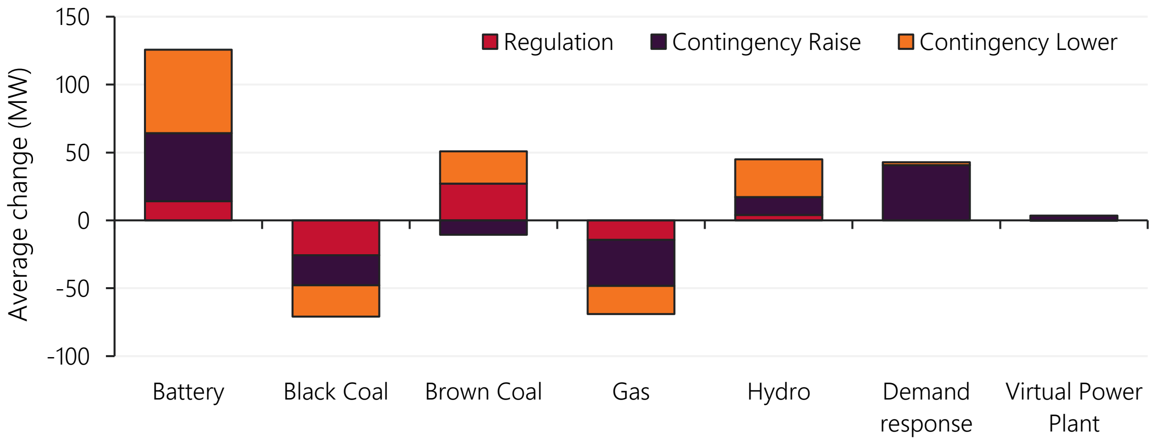
Quarterly FCAS cost by region[39]



By fuel type, grid-scale batteries and demand-side participants continued to increase their provision of FCAS services in Q4 relative to the preceding quarter (Figure 58), with a large share of the net 126 MW increase in battery provision attributable to commencement of FCAS participation by the Victorian Big Battery in late November (Section 1.3.6). Variations in provision by synchronous generators were mixed across fuel sources, in part reflecting changes in energy market dispatch.

Figure 58 Battery provision of FCAS increases with VBB commissioning

Change in FCAS supply by fuel/technology type and market – Q4 2021 versus Q3 2021



[39] Based on AEMO Settlement data and represents preliminary data that will be subject to minor revisions.

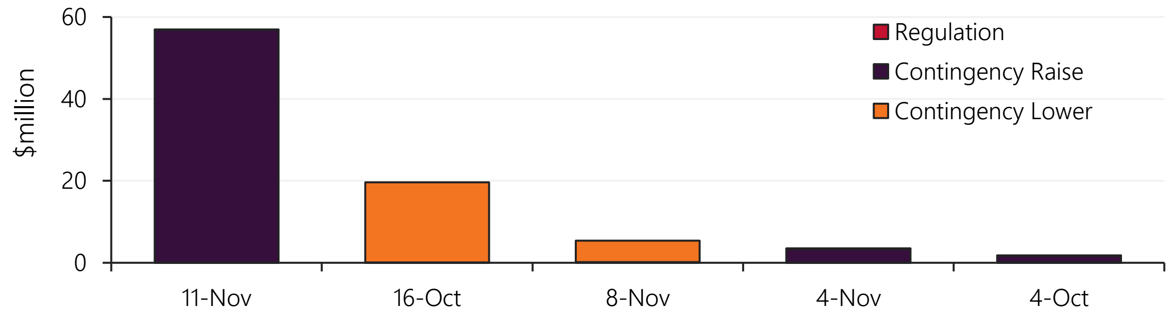
Queensland FCAS price volatility

Individual days of extreme FCAS price volatility once again drove Queensland's continued high level of FCAS costs in Q4[40]. Events on just two days – 11 November and 16 October – accounted for 77% of the region's quarterly costs and 58% of the NEM-wide total (Figure 59).

On both these days, planned transmission outages affecting the QNI required the application of local FCAS constraints, increasing supply required from Queensland providers of Contingency Raise and Lower services. On 11 November, Queensland prices for one or more of the Contingency Raise services exceeded $10,000/MWh in 84 separate dispatch intervals, while on 16 October, prices for one or more of the Contingency Lower services exceeded $10,000/MWh in 35 dispatch intervals.

Figure 59 Top two days accounted for 77% of Queensland's Q4 FCAS costs

Queensland top five highest FCAS cost days in Q4 2021

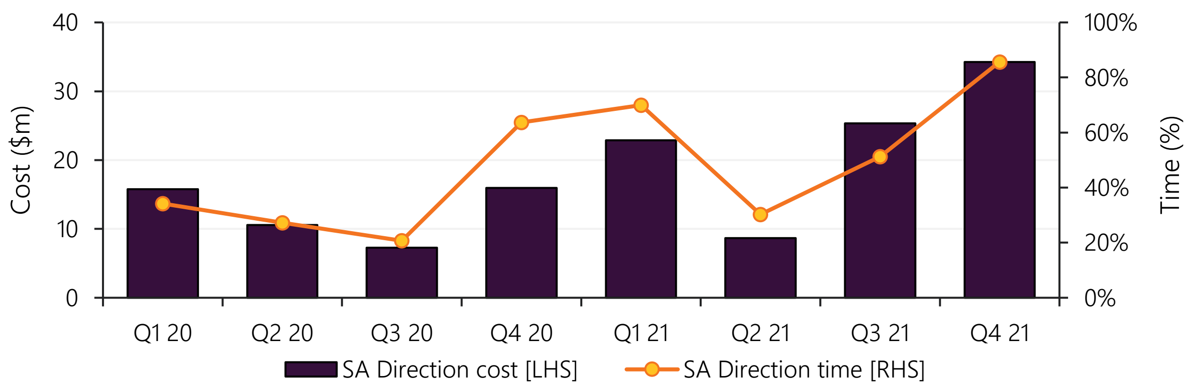


1.5.2 Directions

In 2021, total costs for directing South Australian generators for system strength reached $91 million, which was $25 million or 39% higher than 2020. During Q4, AEMO continued to issue directions to gas generators in South Australia to maintain system security in the region. This quarter, South Australian generators' time on directions reached 86%, the highest quarterly level on record, with a total 131 directions issued[41]. This resulted in South Australian system strength direction costs increasing to $34 million, from $16 million in Q4 2020 (Figure 60).

Figure 60 South Australian directions cost and time reached new highs

Time and cost of system security directions (energy only) in South Australia



Note: direction costs are preliminary costs which are subject to revision

[40] See the forthcoming Australian Energy Regulator (AER) Quarter 4 2021 Wholesale Markets Quarterly report for further detail on high Queensland FCAS prices in Q4 2021.

[41] Number of directions is preliminary and subject to revision as directions details are finalised.

With electricity spot prices below $30/MWh 52% of the time, and Adelaide average spot gas prices continuing to remain high ($10.7/GJ), South Australian gas generators frequently sought to de-commit from the market for economic reasons. Most notably, in October when the monthly spot price average in South Australian fell to its lowest October level since NEM start ($14.5/MWh), average gas generation output under direction increased to 213 MW, accounting for 58% of South Australian gas generation output (Figure 61).

Figure 61 Reduced directions since update in limits

SA gas-fired generation directed

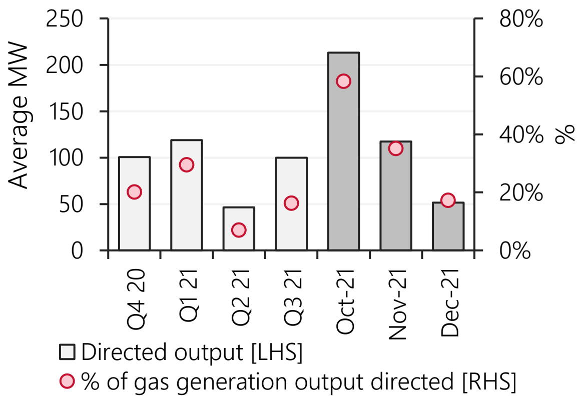
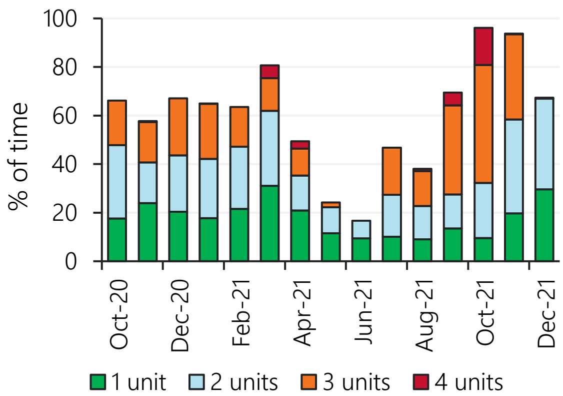


Figure 62 No of gas generation units directed reduced

% of time number of gas-fired generation units directed



While time under directions reached new highs during the quarter, the successful commissioning and testing of the four synchronous condensers meant that AEMO is now able to operate South Australia securely with a reduced number of synchronous generators. On 25 November 2021, AEMO updated its system strength limit advice to reduce the minimum number of gas generation units required to ensure power system security from the equivalent of four large units to two under most operating conditions, as well as allowing for an increased nominal limit on non-synchronous generation in the state[42]. Since the updated advice, in most circumstances only two gas generation units have been required to be online for system security purposes, resulting in a notable reduction in average gas generation output under direction and therefore directions costs (Figure 61 and Figure 62). Based on preliminary data, balance of quarter directions costs incurred after the change reduced to $3 million compared to $31 million prior to the change, although these estimates may change as directions costs and additional claims are finalised.

There is no shortfall in system strength in South Australia with the full operation of the four synchronous condensers, allowing dispatch of up to 2,500 MW of online inverter-based resources. However, at least two large synchronous thermal generators are required online to provide essential system support that may not otherwise be available in the South Australian system, including:

- Active power response required to maintain the rate of change of frequency within limits.
- Maintenance of sufficient ramping control under system normal conditions.
- Maintenance of reactive voltage support.

Despite the average 12-month 90th percentile spot price (used as the benchmark for compensating participants) increasing to $104/MWh this quarter from $77/MWh in Q4 2020, additional compensation claims[43] remained high

[42] See Market Notice 92718 and https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/related-resources/operation-of-davenport-and-robertstown-synchronous-condensers.

[43] Under National Electricity Rules (NER) clause 3.15.7B, a directed participant is entitled to make a written submission to AEMO claiming for additional compensation, equalling the sum of the aggregate of the loss of revenue and additional net direct costs incurred by the directed participant less the amount notified to that directed participant less the aggregate amount the directed participant is entitled receive.

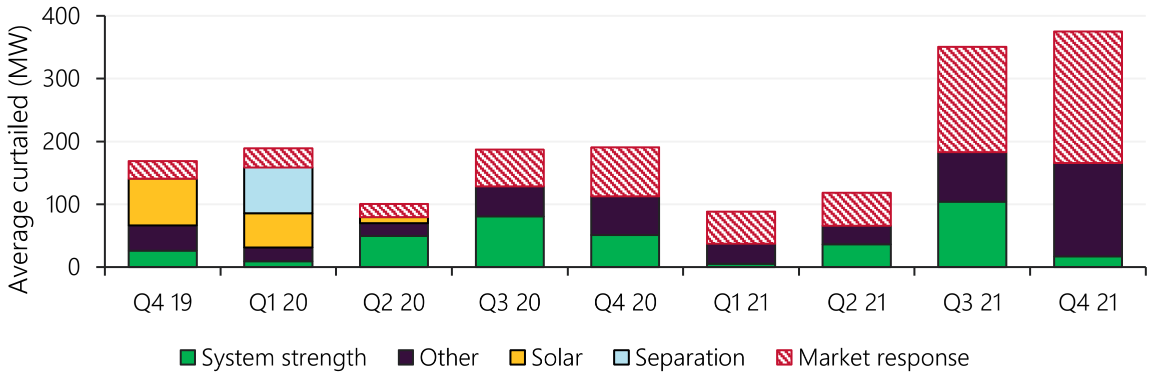
due to higher gas prices. AEMO received 53 of these claims during the quarter, accounting for 24% of total directions costs[44].

1.5.3 VRE curtailment

Curtailment of VRE rose slightly on Q3 levels to average 375 MW in Q4 2021, which represented 9.4% of potential output and was double the level of Q4 2020 (Figure 63).

Figure 63 VRE curtailment continues to rise

Average NEM VRE curtailed by curtailment type[45]

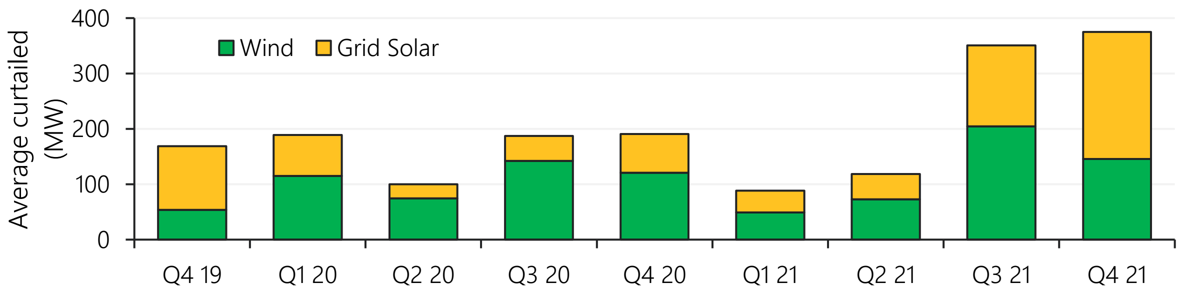


VRE generators' market response to price signals such as negative spot prices or high FCAS prices[46] continued to grow and accounted for 56% of overall curtailment in the quarter. There were sharp increases in curtailment driven by non-system strength network constraints in New South Wales (averaging 80 MW) and Victoria (41 MW), but commissioning of synchronous condensers in South Australia led to system strength curtailment in the region falling from 62 MW in Q3 2021 to zero in Q4.

By energy source, curtailment of grid-solar output (229 MW average, or 15% of potential output) exceeded that of wind (146 MW, 6%) for the first time since Q4 2019 when system strength constraints impacted solar output in the West Murray zone of Victoria and New South Wales (Figure 64). Key drivers of grid-solar curtailment in Q4 varied. In Queensland, market response comprised 83% of the 66 MW curtailed, but network constraints were the main driver in New South Wales, at 84% of that region's 95 MW grid-solar curtailment.

Figure 64 Grid-solar curtailment accounted for 61% of total

Average NEM VRE curtailed by fuel type



[44] Additional claims and additional claims that require independent expert may take up to 30 weeks to finalise.

[45] Curtailment amount is based on combination of market data and AEMO estimates. For more information on the calculation, see www.wattclarity.com.au/articles/2020/06/not-as-simple-as-it-appears-estimating-curtailment-of-renewable-generation/?utm_source=rss&utm_medium=rss&utm_campaign=not-as-simple-as-it-appears-estimating-curtailment-of-renewable-generation.

[46] Previously noted as economic curtailment

From 1 October 2021, there was a notable rise in grid-solar rebids, particularly in New South Wales and Victoria (up around 76,000 bids compared to Q3 2021, Figure 65), coinciding with the shift in VRE generators bidding closer to their break-even price (discussed in Section 1.2.3). Increases in grid-solar rebids may have been in part driven by responses to network constraints as generators were observed rebidding to the market floor price of -$1,000/MWh to manage constraint impacts. Figure 66 illustrates a correlation between monthly grid-solar curtailment levels and the changes in VRE rebid frequency.

Figure 65 NSW drives increase in grid-solar rebids

No. of grid-solar rebids by region - monthly

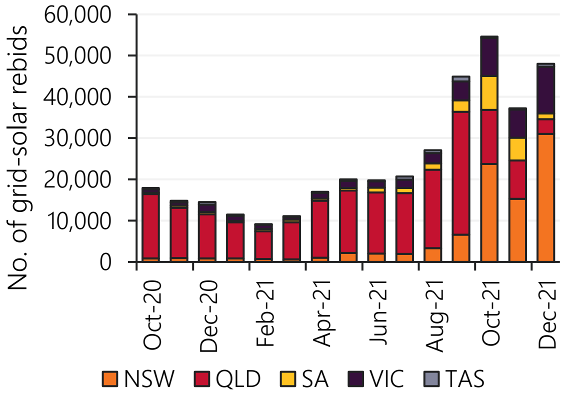
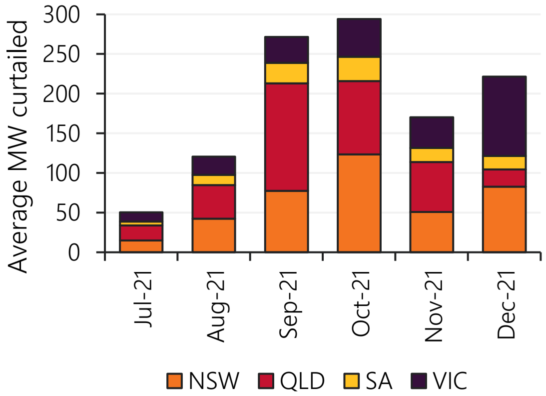


Figure 66 Increased curtailment influences rebidding

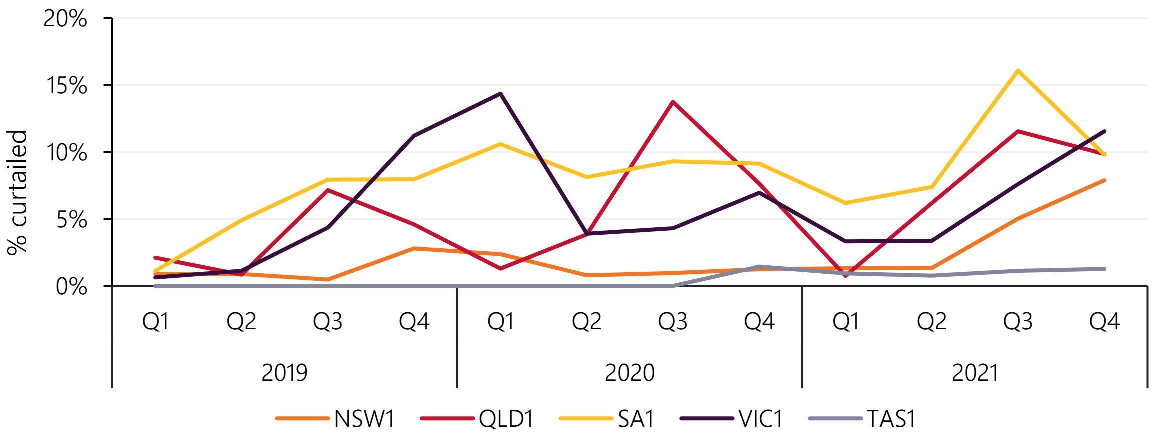
Average grid-solar curtailment by region - monthly



As percentages of potential regional VRE output, curtailment in New South Wales and Victoria continued to grow from levels in Q3 2021 and Q4 2020, driven by non-system strength constraints and greater market response (Figure 67). In the other mainland regions, rising trends seen in Q2 and Q3 2021 reversed, with the absence of system strength constraints in South Australia and lower network constraint impacts in Queensland.

Figure 67 Curtailment percentage growing in Victoria and New South Wales, moderating elsewhere

% VRE curtailed by NEM region



With increased periods of high VRE and distributed PV output, and VRE generators moving offers to higher price bands, instantaneous VRE curtailment in both South Australia and Victoria reached new highs on 14 November 2021. In South Australia, curtailment reached 1,307 MW at 1355 hrs on this day, accounting for 75% of potential semi-scheduled output in the region, while Victoria's new curtailment record of 2,181 MW at 1335 hrs accounted for 71% of potential output. During the relevant periods spot prices in South Australia were well below -$100/MWh and in Victoria below -$50/MWh, highlighting the impact of market response on renewable output.

2 Gas market dynamics

2.1 Gas demand

Total east coast gas demand decreased by 1% compared to Q4 2020, mostly driven by a decrease in gas generation demand (Table 5). Demand in AEMO markets was up 5%, primarily due to a colder spring in Victoria, New South Wales and South Australia than 2020.

East coast gas generation demand decreased by 22% compared to Q4 2020 with reductions in all states, resulting in the lowest Q4 gas generation demand since 2003 (Section 1.3.2).

Queensland LNG exports were similar to Q4 2020, down slightly by 0.5 PJ, but an increase of 23 PJ on Q3 2021. This is the second highest quarter on record, while 2021 saw record exports for any calendar year with flows of 1,407 PJ, compared to 1,338 PJ in 2020. Relative to Q4 2020, Queensland Curtis LNG (QCLNG) recorded an increase in flows for export of 5 PJ, Australia Pacific LNG (APLNG) increased by 2.5 PJ, while Gladstone Liquified Natural Gas (GLNG) decreased by 8 PJ (Figure 68).

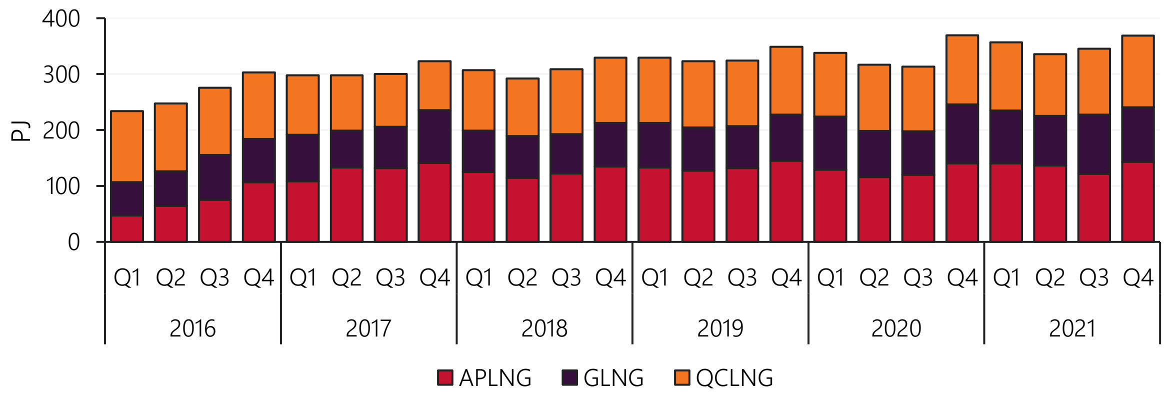
Table 5 Gas demand – quarterly comparison

Demand (PJ)	Q4 2021	Q3 2021	Q4 2020	Change from Q4 2020
AEMO Markets *	67.6	107.7	64.2	3 (5%)
Gas generation **	19.9	30.2	25.6	-6 (-22%)
QLD LNG	369	345.7	369.5	-0.5 (-)
TOTAL	456.5	483.6	459.3	-3 (-1%)

* AEMO Markets demand is the sum of customer demand in each of the Short Term Trading Markets (STTMs) and the Declared Wholesale Gas Markey (DWGM) and excludes gas powered generation in these markets.
** Includes demand for gas generation usually captured as part of total DWGM and STTM demand. Excludes Yabulu Power Station.

Figure 68 GLNG and QCLNG drive record calendar year flows to Curtis Island for LNG export

Total quarterly pipeline flows to Curtis Island



Reflecting higher flows to Curtis Island, during Q4 there were 93 LNG cargoes exported, up from 87 in Q3 2021. With a record year for Queensland LNG exports, there were 354 cargoes exported in 2021, compared to 339 cargoes in 2020. APLNG exported the most cargoes in 2021 with 125, unchanged on 2020, while QCLNG exported 120 cargoes compared to 114 in 2020, and GLNG exported 109 cargoes, up from 100 in 2020.

2.2 Wholesale gas prices

Continuing from Q3 2021, quarterly average prices were at or near record levels across all AEMO markets, averaging $10.60/gigajoule (GJ) compared to $5.95/GJ in Q4 2020 (Table 6). Brisbane and Gas Supply Hub (GSH) average prices set new records, while Victoria's Declared Wholesale Gas Market (DWGM), Adelaide and Sydney saw their second highest levels on record after Q3 2021.

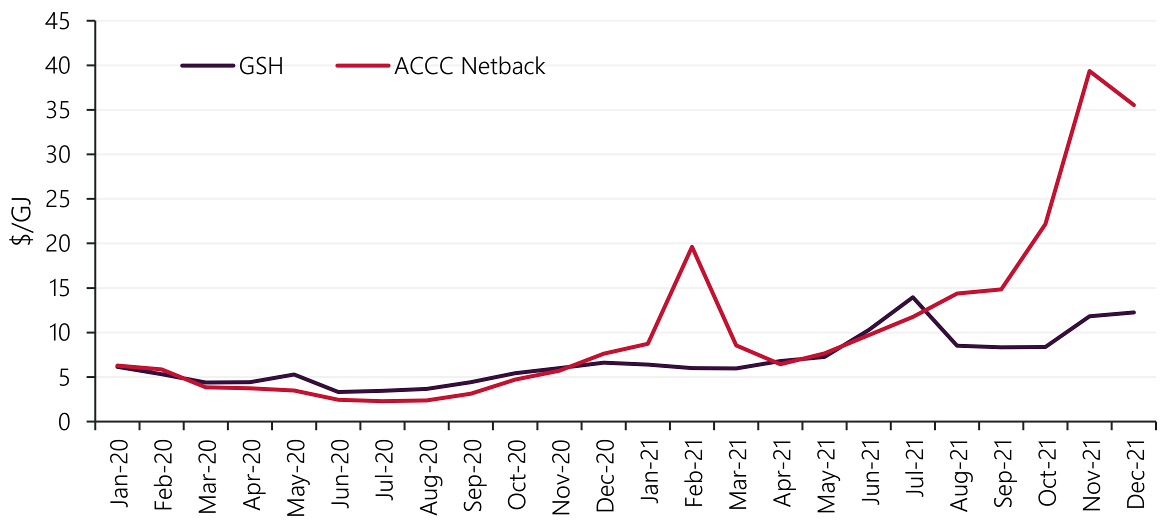
Table 6 Average gas prices – quarterly comparison

Price ($/GJ)	Q4 2021	Q4 2020	Change from Q4 2020
DWGM	10.02	5.52	+82%
Adelaide	10.67	6.00	+78%
Brisbane	10.91	6.28	+74%
Sydney	10.52	5.96	+76%
GSH	10.86	6.01	+81%

While domestic market prices increased, international prices as represented by the Australian Competition and Consumer Commission (ACCC) netback price soared to significantly higher record levels, peaking close to $40/GJ in November (Figure 69). Drivers for higher international prices are discussed in Section 2.2.1.

Figure 69 Domestic prices increase but remain well below international prices

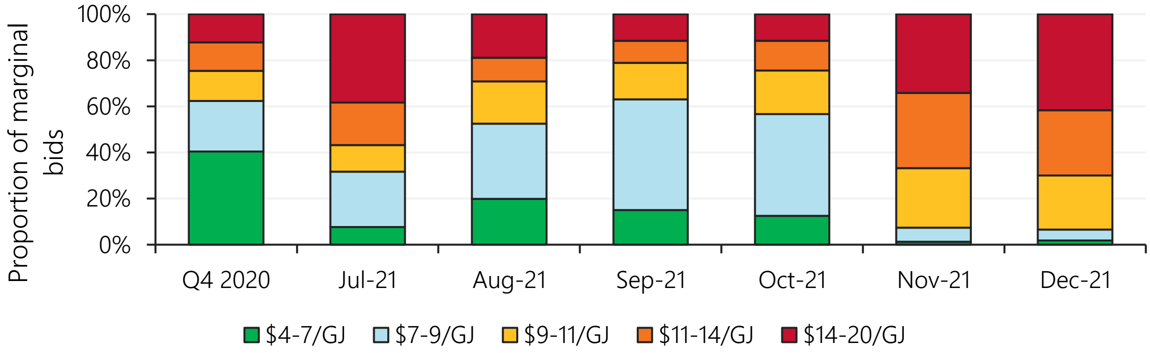
ACCC netback and GSH average gas price by month



Prices in November and December were significantly higher than in October, caused by a combination of cold weather in November (particularly in Victoria) and a reduction in supply from the Longford Gas Plant due to plant maintenance. This resulted in Iona Gas Plant storage supply being utilised to meet Victorian and interstate demand, as well as to sustain Victorian exports. In response, market participants began moving bid volumes to higher price bands, predominantly $10/GJ and above (Figure 70). Prices only dropped below $10/GJ from 24 December, due to lower demand associated with the Christmas/New Year shutdown of industrial users. November and December average prices were at record levels in all markets for those months.

Figure 70 DWGM bids driving price increases in November and December 2021

DWGM – proportion of marginal bids by price band



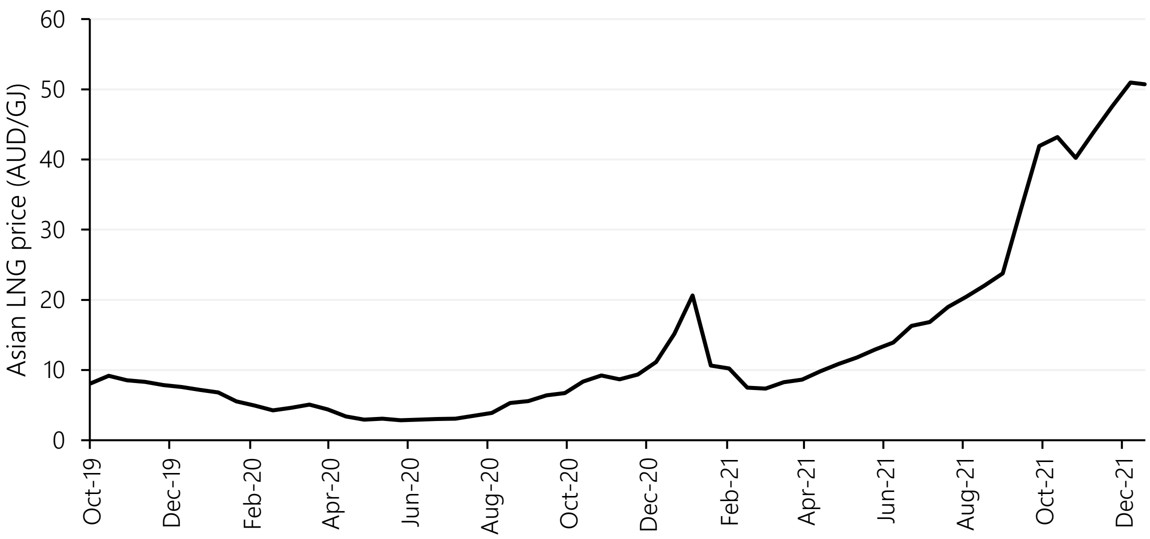
2.2.1 International energy prices

International energy prices remained volatile during the quarter, as global energy supply constraints continued, influenced by low gas storage levels, post pandemic recovery and new Covid variants[47].

While domestic gas prices remained comparable with Q3's record levels (Section 2.2), Asian LNG prices rallied to a new A$64/GJ record during the quarter, and finishing the year at A$40/GJ (Figure 71). Key drivers for extremely high international LNG prices included ongoing refilling of gas storages, which were at multiyear lows especially in Europe heading into the Northern hemisphere winter, combined with new supply delays.

Figure 71 Asian LNG price rallied to new record

Asian LNG price in A$/GJ



Source: Bloomberg ICE data in 14-day averages

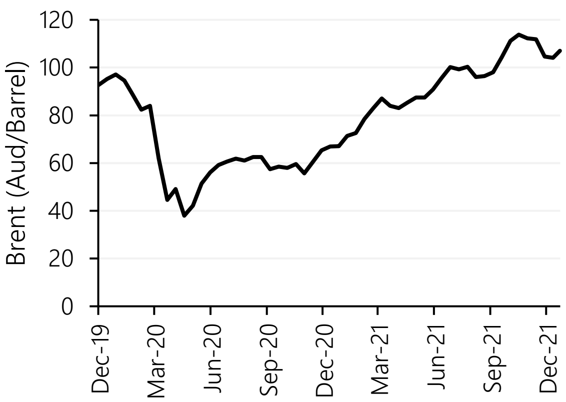
Brent Crude oil averaged A$109/Barrel during the quarter, A$10/Barrel higher than Q3 2021, but steadied towards the end of the year with the global demand recovery slowed by the emergence of the Covid Omicron variant, while Organisation of the Petroleum Exporting Countries (OPEC) maintained their month-by-month production

[47] Bloomberg 2021, Europe's energy crisis: https://www.bloomberg.com/news/articles/2021-11-28/europe-s-energy-crisis-is-about-to-get-worse-as-winter-arrives?sref=kkhkDP70

increase[48] (Figure 72). Thermal coal export prices declined sharply from a record A$332/tonne to end the quarter at A$244/tonne (Figure 73), mainly due to a rapid decline in Chinese thermal coal prices, as authorities prompted local coal producers to both raise output and lower prices to help address tight fuel supply conditions[49].

Figure 72 Brent Crude steadies late in quarter

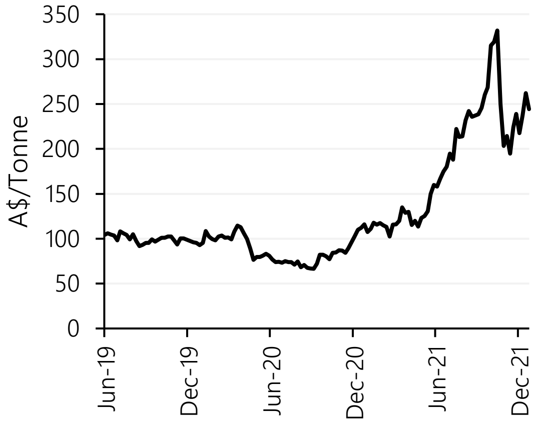
Brent Crude oil in A$/Barrel



Source: Bloomberg data in 14-day averages

Figure 73 Thermal coal decline from record high

Newcastle export thermal coal A$/Tonne



Source: Bloomberg data

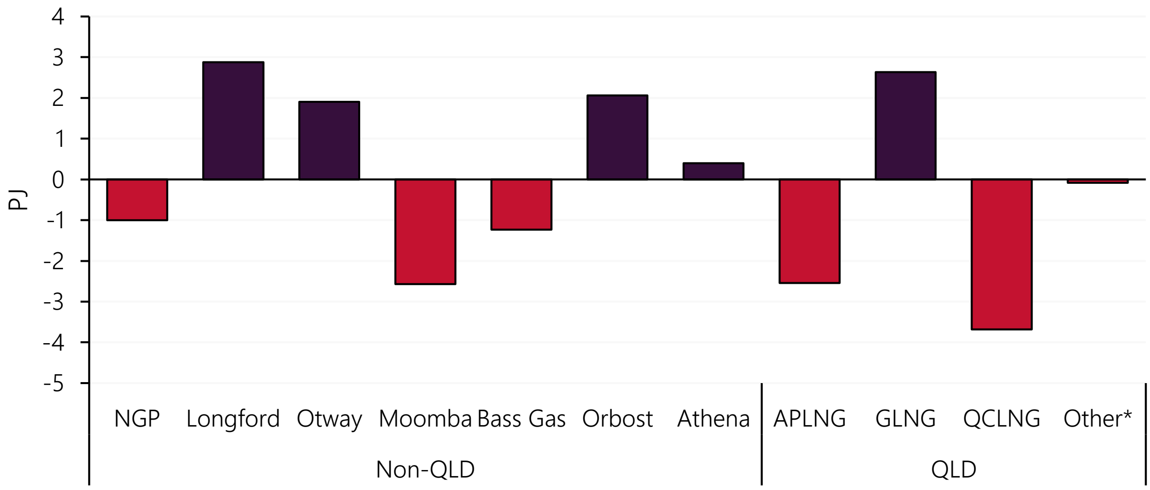
2.3 Gas supply

2.3.1 Gas production

East coast gas production decreased by 1.2 PJ on Q4 2020 levels (-0.25%, Figure 74).

Figure 74 East coast gas production down 0.25%

Change in east coast gas supply – Q4 2021 versus Q4 2020



[48] Reuters 2021, OPEC+ agrees to go ahead with oil output rise: https://www.reuters.com/markets/commodities/opec-weighs-output-policy-omicron-fears-hammer-prices-2021-12-02/

[49] Bloomberg 2021, Coal in freefall in China: https://www.bloomberg.com/news/articles/2021-10-29/china-s-economic-planning-body-says-coal-prices-could-fall-more?sref=kkhkDP70

Key changes included:

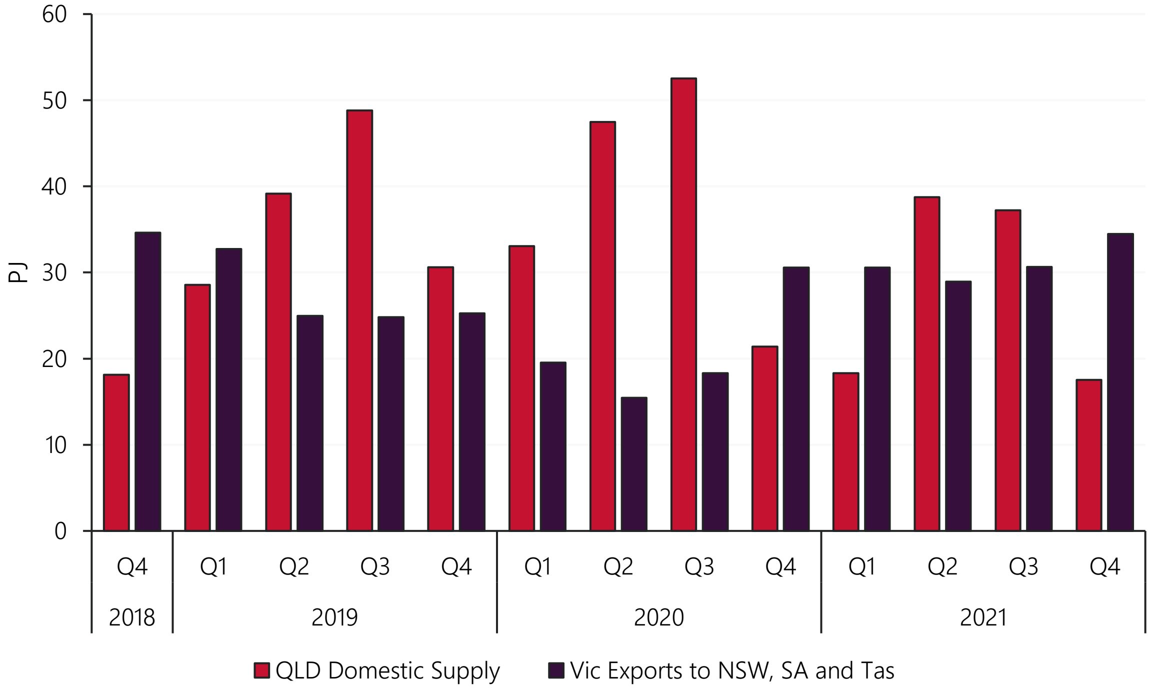
- Decreased Queensland production, particularly QCLNG (-3.7 PJ) and APLNG (-2.5 PJ) despite continued high Curtis Island flows. GLNG however increased production (+2.6 PJ).
- Decreased Moomba production (-2.6 PJ) despite increased South West Queensland Pipeline (SWQP) flows north to Queensland. On 12 December 2021, Moomba experienced an unplanned plant outage resulting in a supply decrease of 162 TJ from the previous day. The plant returned to regular production levels on the 14th.
- Higher Victorian production (+7 PJ), mainly driven by higher Longford production despite maintenance (+2.9 PJ), Orbost (+2.1 PJ) and Otway (+1.9 PJ). On 15 December, Cooper Energy began processing gas from its Athena Gas Plant (+0.4 PJ). Athena, formerly known as Minerva Gas Plant, ties in gas from the Casino, Henry and Netherby fields. Production from these fields was previously processed through the Iona Gas Plant[50].

2.3.2 Queensland net domestic production

Total net domestic supply into Queensland was 17.6 PJ in Q4 2021, down 20 PJ on Q3 2021 levels (Figure 75) as more gas was exported during the quarter. Queensland gas production decreased by 3.7 PJ, while LNG exports increased by 23.3 PJ. With only a small decrease in Queensland domestic demand (-1 PJ), this led to higher northerly flows from SWQP into Queensland (Section 2.4).

Figure 75 Victorian gas exports partially offset Queensland domestic supply

QLD domestic supply and Victorian gas exports by quarter



[50] Cooper Energy 2022, ASX announcement operations update: https://www.cooperenergy.com.au/UPLOAD/DOCUMENTS/ANNOUNCEMENTSITEM/2022.01.13---FINAL-ASX-RELEASE---OPERATIONS-UPDATE.PDF

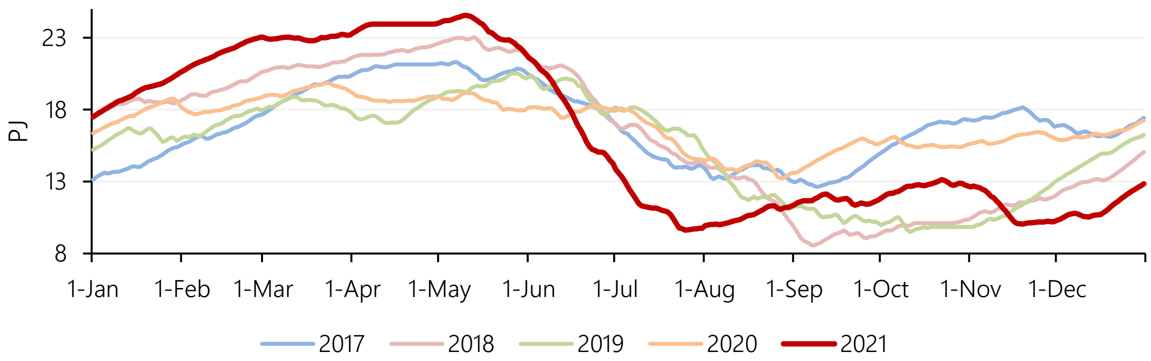
2.3.3 Gas storage

Iona began the quarter storage at storage levels lower than in Q4 2020, but higher than in Q4 2018 and Q4 2019, and saw moderate filling during October. It was, however, heavily utilised in the first half of November due to a combination of unseasonably cold weather in Victoria, reduced Longford production for maintenance, and sustained Victorian exports to New South Wales. This led to Iona emptying by 2.2 PJ in the first half of November, falling to levels close to those at the end of July 2021. This was the first significant drawdown of Iona storage in November since reporting of storage levels commenced in 2016.

Storage levels began to recover in December, particularly later in the month as market demand decreased and supply increased. Iona finished the quarter with a gas balance of 12.8 PJ, 4.4 PJ lower than Q4 2020 (Figure 76).

Figure 76 Iona heavily utilised in November before recovering

Iona storage levels

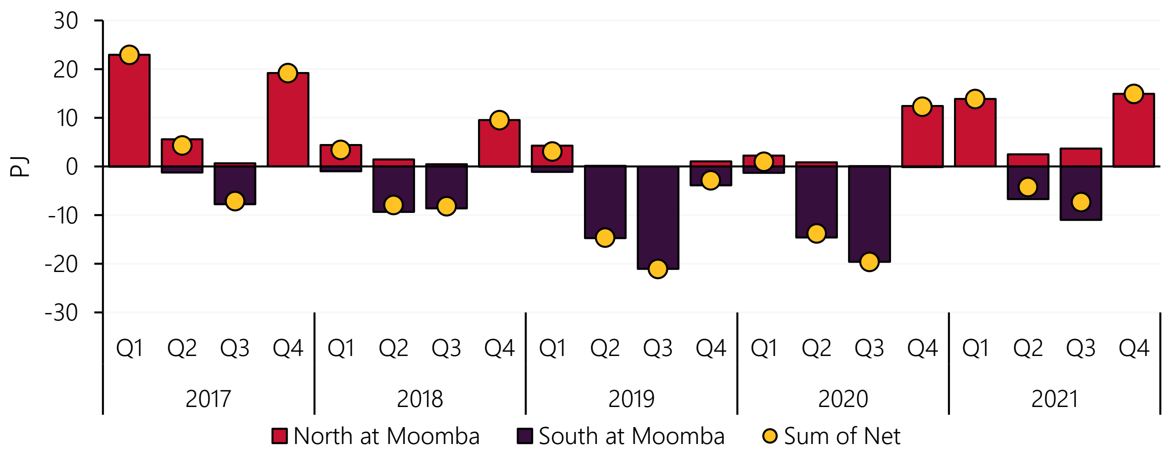


2.4 Pipeline flows

Compared to Q4 2020, there was a 2.6 PJ increase in net transfers into Queensland on SWQP (Figure 77). This represents the highest flow north from Moomba for any quarter since Q4 2017, driven by the increase in Queensland LNG export demand and a decrease in Queensland production.

Figure 77 Highest gas flows north to Queensland since 2017

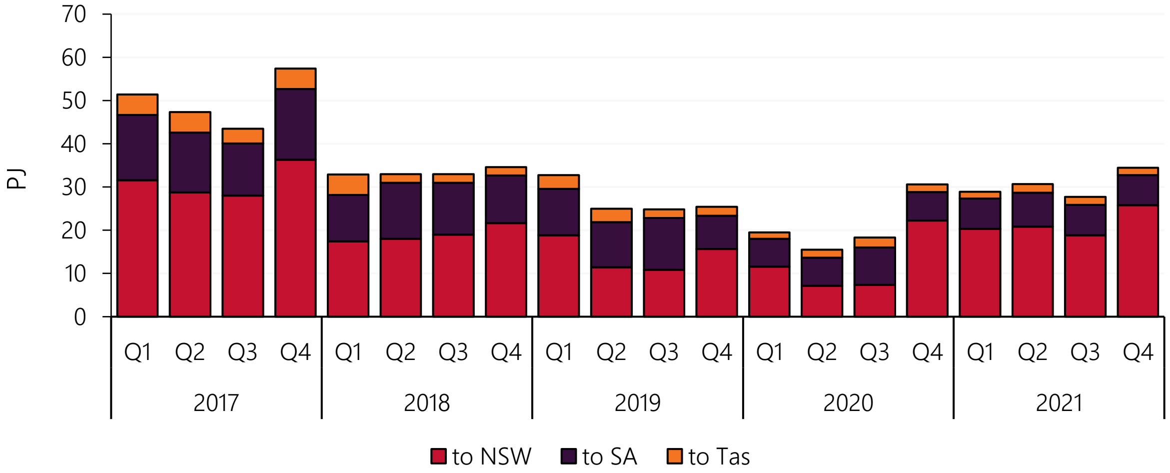
Flows on the South West Queensland Pipeline at Moomba



Victorian net gas transfers to other states increased by 3.9 PJ over Q4 2020 levels, due to increased Victorian supply. This represented the highest export volume for any quarter since Q4 2018 (Figure 78). There were increased flows from Victoria to New South Wales comprising 6.4 PJ via Culcairn, compared to 5.1 PJ in Q4 2020, and 19.5 PJ via the Eastern Gas Pipeline (EGP), up from 17.2 PJ in Q4 2020. Flows from Victoria to South Australia increased slightly by 0.4 PJ.

Figure 78 Victorian gas transfers highest for any quarter since Q4 2018

Victorian net gas transfers to other regions

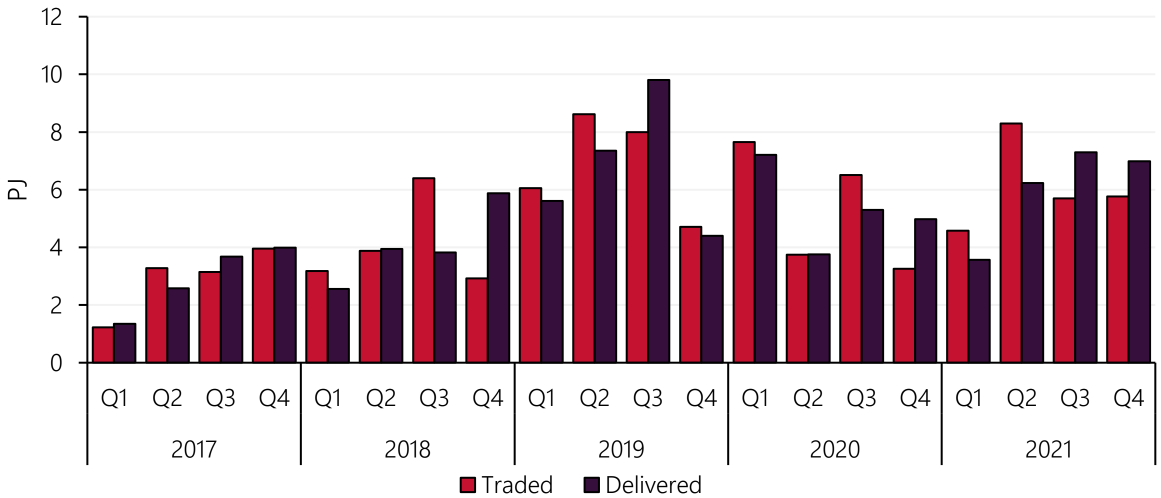


2.5 Gas Supply Hub

In Q4 2021 there were increased trading and delivered volumes on the GSH compared to Q4 2020 (Figure 79), with traded volume up by 2.5 PJ and delivered volume by 2 PJ. Overall, 2021 was the second highest volume year for the GSH, rebounding from 2020, with traded volume increasing by 3.2 PJ and delivered volume increasing by 2.8 PJ.

Figure 79 GSH records second highest trading year on record

Gas Supply Hub – quarterly trades and deliveries



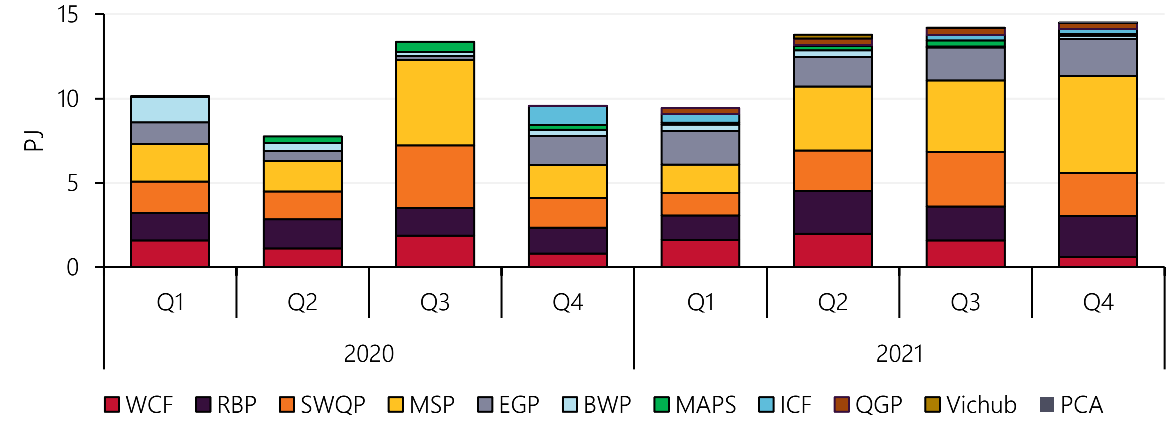
2.6 Pipeline capacity trading and day ahead auction

Day Ahead Auction (DAA) utilisation set a record in Q4 2021, 540 TJ higher than the previous record set in Q2 2021, and 4.5 PJ higher than Q4 2020 (Figure 80). The largest increases occurred on the Moomba to Sydney Pipeline (MSP, +3.8 PJ), Roma to Brisbane Pipeline (RBP, +0.9 PJ), and SWQP (+0.8 PJ). Volumes increased considerably in December, accounting for 46% of the volume for the quarter.

Average auction clearing prices remained at or close to $0/GJ on most pipelines. The exceptions to this were the EGP which averaged $0.17/GJ, RBP which averaged $0.02/GJ, and SWQP which averaged $0.02/GJ.

Figure 80 Day Ahead Auction utilisation sets a record for any quarter

Day Ahead Auction results by quarter

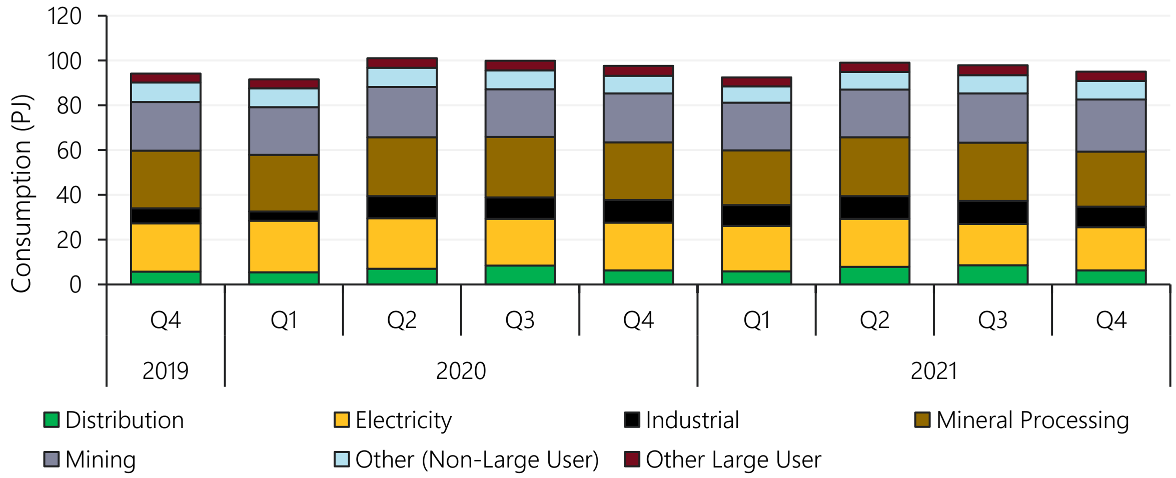


2.7 Gas – Western Australia

A total of 95.0 PJ was consumed in the Western Australian domestic gas market in in Q4 2021, which was a 2.9 PJ (-3.0%) decrease from Q3 2021 and a 2.6 PJ (-2.7%) decrease from the same quarter last year (Figure 81).

Figure 81 Western Australia domestic gas consumption drops 3.0% from Q3 2021

WA quarterly gas consumption by industry – Q4 2019 to Q4 2021



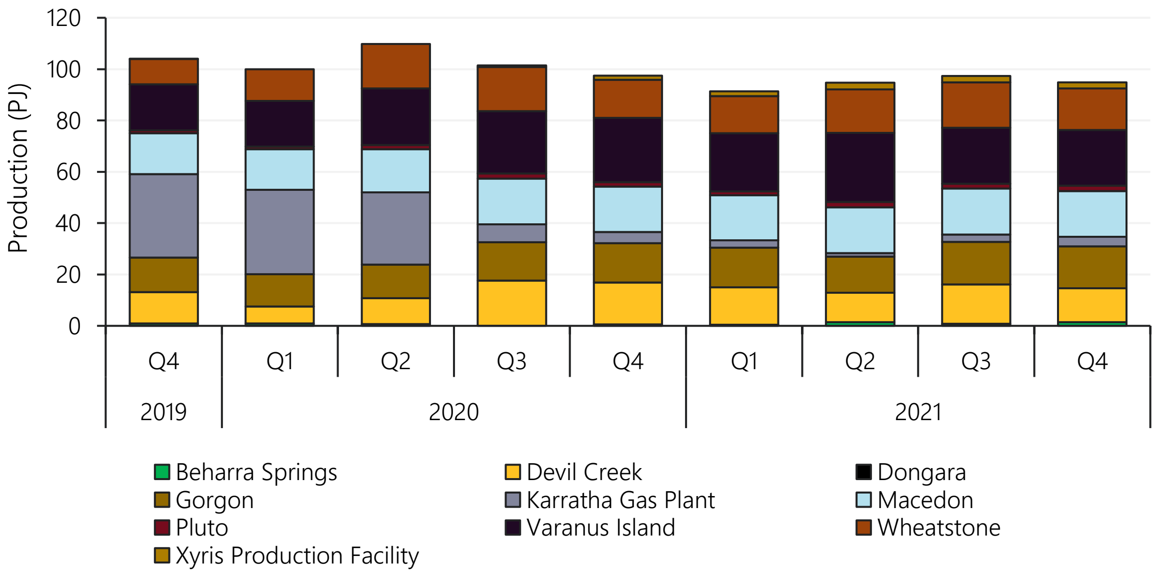
Domestic gas consumption in Western Australia decreased in most user categories compared to the same quarter last year:

- Gas consumed for electricity generation reduced by 2.0 PJ (-9.4%), which was in line with fuel mix trends observed in the Wholesale Electricity Market (WEM), with gas-fired generation reducing by 16% in Q4 2021 (see Section 3.3).
- Gas consumed for industrial use also reduced in Q4 2021, with a 1.0 PJ (-9.9%) decrease compared to the same quarter last year, primarily due to CSBP ammonia production facility reducing gas consumption by 1.0 PJ (-40.1%).
- Mineral processing consumption was 1.2 PJ (-4.6%) lower than the same quarter last year. Each large user that consumes gas for mineral processing reduced consumption in Q4 2021 by at least 2% compared to Q4 2020.
- Other large users'[51] consumption reduced by 0.3 PJ (-7.6%), primarily due to the Kwinana BP Refinery ceasing operations.
- Gas consumption for mining use increased from Q4 2020 by 1.6 PJ (+7.2%). Newman Power Station, which operates in the Pilbara primarily supplying electricity to the Roy Hill mine[52], increased its gas consumption from the Goldfields Gas Pipeline by 1.2 PJ (+127.1%). Telfer Gold Mine and Yurrali Maya Power Station also increased their gas consumption by 0.2 PJ (+11.3%) and 0.4 PJ (+22.9%), respectively.

In line with domestic gas consumption, gas production in Western Australia decreased by 2.4 PJ (-2.5%) from Q3 2021 and by 2.6 PJ (-2.7%) from the same quarter last year (Figure 82). This was primarily driven by Devil Creek Production Facility, which has reduced its gas production by 2.1 PJ (-13.9%) since Q3 2021.

Figure 82 Western Australia domestic gas production drops 2.5% from Q3 2021

WA quarterly gas production by facility – Q4 2019 to Q4 2021



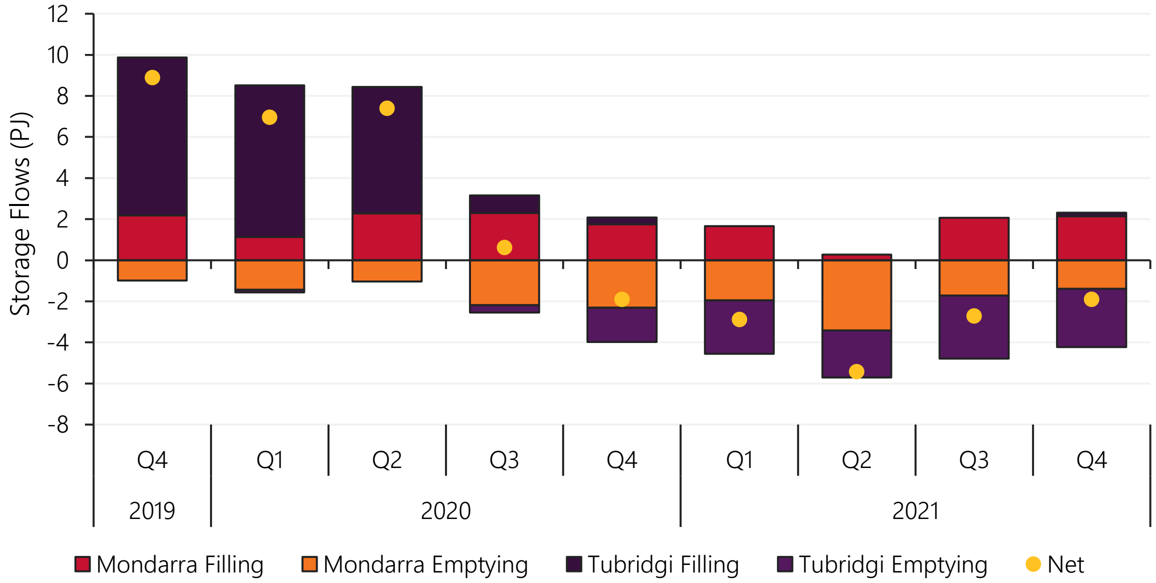
[51] Predominately comprised of large users that are liquid natural gas refineries.

[52] Alinta Energy 2021, Newman Power Station: https://www.alintaenergy.com.au/wa/about-alinta-energy/power-generation/newman-power-station/.

Injections into and withdrawals from Storage Facilities remained relatively similar in Q4 2021 compared to Q3 2021, with a net increase in gas flow into storage of 0.8 PJ (-1.9 PJ total net flows). This was due to both Tubridgi emptying an additional net 0.4 PJ compared to last quarter and Mondarra emptying an additional net 0.4 PJ (Figure 83).

Figure 83 Slight increase in net gas flows from Storage Facilities

WA gas storage facility injections and withdrawals – Q4 2019 to Q4 2021



3 WEM market dynamics

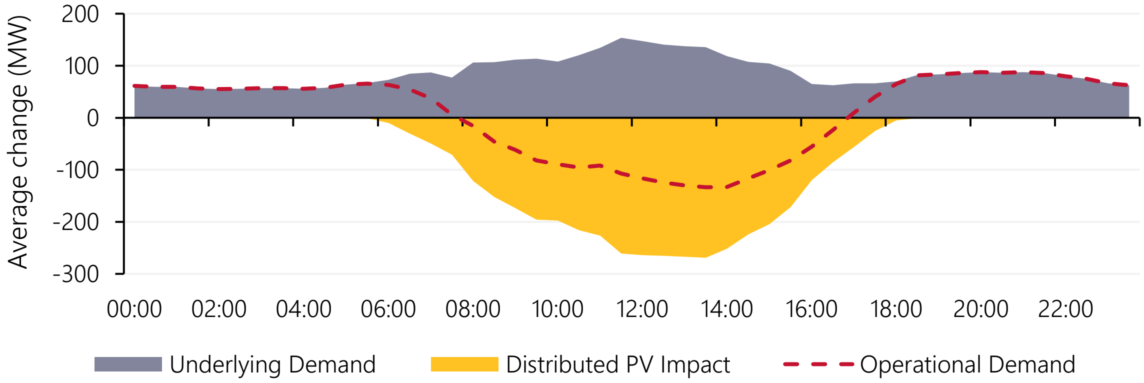
3.1 Electricity demand

Average underlying demand[53] was 87 MW (+4%) higher than the previous year and was higher across all intervals. Average operational demand[54] remained relatively similar to Q4 2020, increasing by only 5 MW (+0.3%) to 1,860 MW, but was lower during the middle of the day compared to Q4 2020 due to increased distributed PV generation offsetting underlying demand (Figure 84).

The increase in underlying demand is attributed to average temperatures in Q4 2021 being down 0.5°C from Q4 2020, resulting in increased heating load towards the start of the quarter, and the heatwave in the last week of December, which disproportionately contributed to the overall increase in demand.

Figure 84 Underlying demand increases, higher distributed PV reduces midday operational demand

Change in Q4 2021 WEM-average operational and underlying demand by time of day compared to Q4 2020



3.1.1 New minimum demand record

A new minimum operational demand record of 761 MW was set on 14 November 2021 at 1130 hrs. During this interval, distributed PV was generating an estimated 1,518 MW[55], which was 67% of the total underlying demand. This, combined with reduced consumption from a large mining load, contributed to the 12% decrease from the previously reported quarterly minimum operational demand record, which occurred in September 2021, and a 20% decrease from the record set in the previous shoulder season in March 2021. Of the total generation contributing to underlying demand, 78% was supplied by renewable energy[56] (Figure 85).

Between 2006 and 2019, the minimum operational demand of any given day occurred overnight. From 2019 onwards, minimum operational records have been set during the middle of the day due to the impact of distributed

[53] Underlying demand is an estimated measurement of the total load on the SWIS, including behind-the-meter demand. Underlying demand is measured as Operational demand adjusted to remove the impact of distributed PV output.

[54] Operational demand is the average measured total of all wholesale generation from registered facilities in the SWIS and is based on non-loss adjusted sent out SCADA data: http://data.wa.aemo.com.au/#operational-demand.

[55] Estimates are based on Clean Energy Regulator small-scale solar data installations and solar-irradiance sensors in the SWIS: http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-datafor-small-scale-installations.

[56] Renewable energy supply percentage is calculated as all generation supplied by distributed PV, wind and grid-scale solar facilities, divided by total underlying demand.

PV and lower underlying demand over the shoulder season (Figure 86). AEMO reported in the Renewable Integration Paper (2021) that in the power system's current state, as the minimum operational demand approaches 600 MW or below, dispatch options materially decrease, such that AEMO considers it a zone of 'heightened power system security threat'[57].

Figure 85 Operational demand on 14 November 2021

Supply by fuel type on day of lowest operational demand

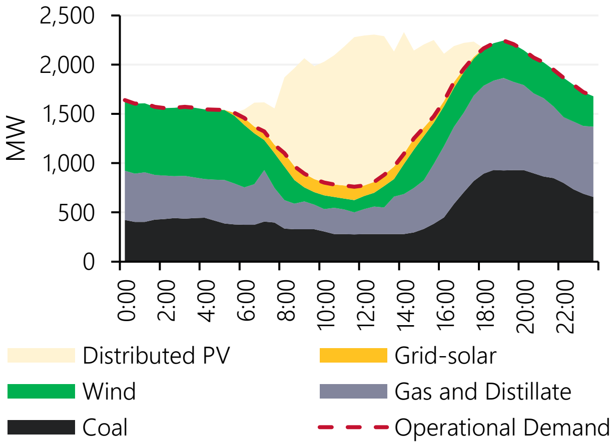
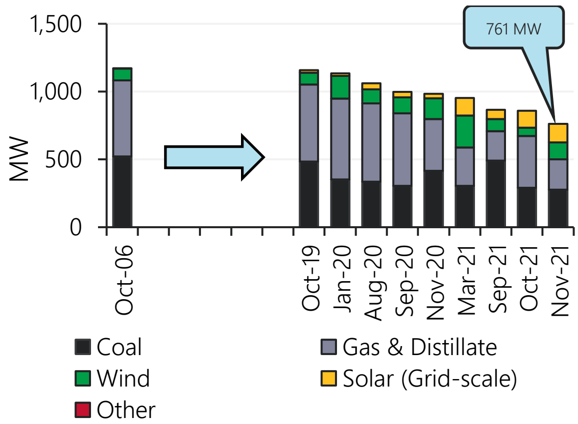


Figure 86 Minimum operational demand trends downwards in the shoulder seasons

New minimum demand records since October 2006

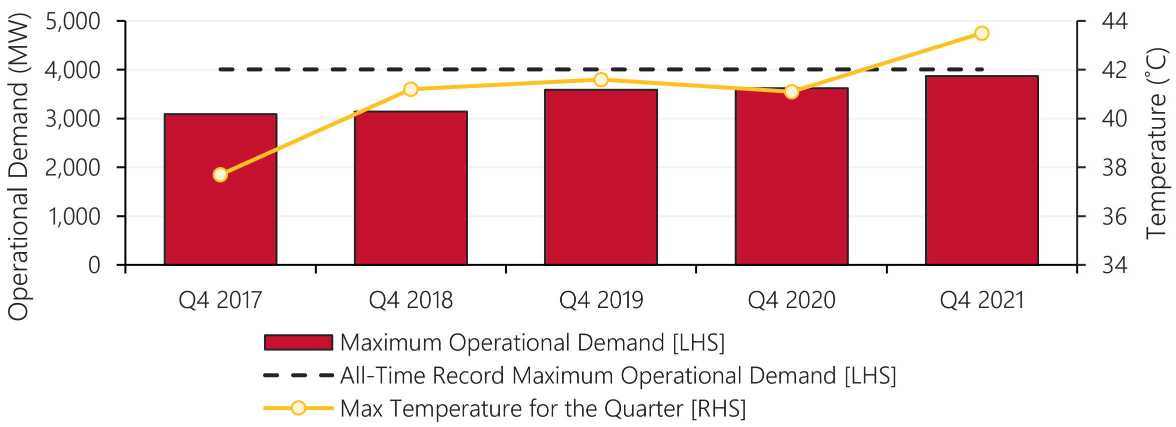


3.1.2 Q4 maximum operational demand record

This quarter saw the highest Q4 maximum operational demand in the WEM. At 1830 hrs on 27 December 2021, operational demand reached 3,869 MW (Figure 87).

Figure 87 New Q4 maximum operational demand record was driven by late December heatwave in Perth

Maximum operational demands and maximum temperatures for each Q4 since 2017



The new record occurred on the third day of a heatwave in which Perth Metro experienced four consecutive days over 40°C between Christmas Day and 28 December 2021[58], with the peak temperature reaching 43.5˚C[59] on

[57] AEMO 2021, Renewable Energy Integration Paper: https://aemo.com.au/-/media/files/electricity/wem/security_and_reliability/2021/renewable-energy-integration--swis-update.pdf?la=en.

[58] Bureau of Meteorology 2021, Perth Metro daily maximum temperature: http://www.bom.gov.au/jsp/ncc/cdio/weatherData/av?p_nccObsCode=122&p_display_type=dailyDataFile&p_startYear=&p_c=&p_stn_num=9225.

[59] Bureau of Meteorology 2021, Greater Perth in December 2021: http://www.bom.gov.au/climate/current/month/wa/perth.shtml.

Boxing Day. The last time Perth experienced four days over 40°C was in 2016, when the all-time maximum operational demand record of 4,006 MW was set at 1730 hrs on 8 February 2016.

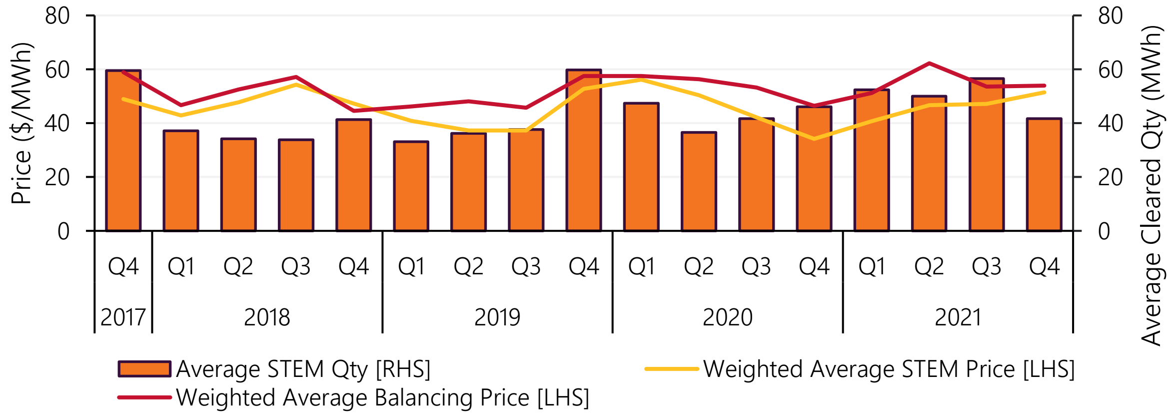
3.2 WEM prices

The weighted average Balancing Price[60] in the WEM for Q4 2021 was $54/MWh, which was similar to Q3 2021, increasing by only $0.45/MWh (Figure 88). Despite a decrease in End of Interval (EOI) demand and an increase in typically low-cost generation (wind and coal; see Section 3.3), the weighted average Balancing Price remained relatively similar due to a reduction in quantities offered by market generators into the Balancing Market between $0 and $50/MWh, with increased quantities offered between $50 and $200/MWh (see Section 3.2.3).

The weighted average Short-Term Electricity Market (STEM) Price[61] for Q4 2021 was $51/MWh, which was a $17/MWh (+51%) increase from Q4 2020. The weighted average STEM Price has been trending upwards since Q4 2020, which was low due to participants responding to the large number of negative and price floor events in the Balancing Market during that quarter.

Figure 88 Weighted average STEM price continues its upwards trend from Q4 2020

WEM weighted average Balancing Prices, STEM prices and quantity cleared in STEM – Q4 2017 to Q4 2021



3.2.1 Negative prices

The number of negatively priced and $0/MWh intervals in Q4 2021 (9% of all intervals) was down slightly on Q4 2020 (11% of all intervals) and the quarter recorded no intervals with a Balancing Price lower than -$100/MWh (Figure 89).

Despite this, the negative price impact[62] in Q4 2021 increased by 32% from last year, from $2.54/MWh in Q4 2020 to $3.35/MWh this quarter. This is due to an increase in intervals between -$100/MWh to -$50/MWh, particularly during the daytime, and a corresponding decrease in intervals between -$50/MWh to $0/MWh.

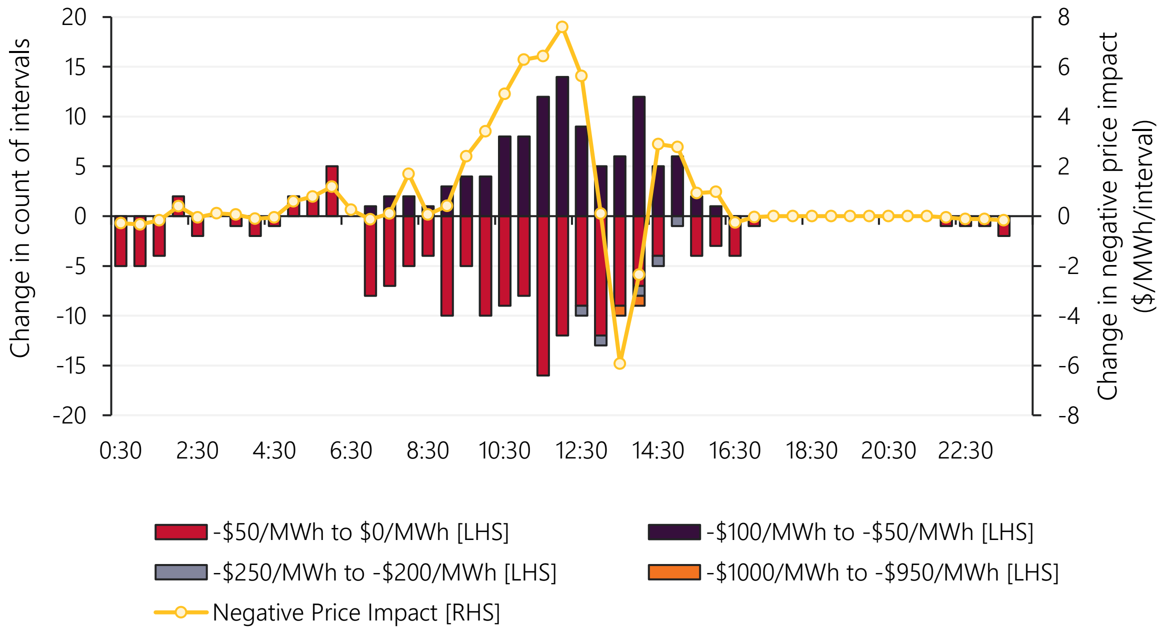
[60] The weighted average Balancing Price is a measure of the average Balancing Price that puts greater weighting on intervals where greater quantity is generated. This is to reflect the average Balancing Price more accurately against quantity of electricity generated, rather than against intervals. Weighted average Balancing Price is sum(Balancing Price * EOI Demand)/sum(EOI Demand) across the quarter.

[61] The weighted average STEM Price is a measure of the average STEM Price that puts greater weighting on intervals where greater quantity is cleared. This is to reflect the average STEM Price more accurately against quantity of electricity cleared, rather than against intervals. Weighted average STEM Price is sum(STEM Price * Qty Cleared)/sum(Qty Cleared) across the quarter.

[62] Impact of negative prices is a measure of both frequency and magnitude of negative prices. It is defined as the change from the average Balancing Price including negative intervals to the average that would result if the floor price was $0/MWh. It is calculated as the absolute sum of the Balancing Price in all negatively priced intervals, divided by the total number of intervals.

Figure 89 Lower daytime prices result in increased negative price impact

Change in count of intervals with zero or negative Balancing Price from Q4 2020 to Q4 2021, by price band



3.2.2 Maximum prices

There were 12 maximum price events in the Balancing Market in Q4 2021, which is an increase from two events in Q3 2021 and three events in Q4 2020. 10 of the 12 maximum price events occurred during the heatwave of 21-27 December 2021. During this period, the average temperature was 29.2°C, with peak temperature recorded on Boxing Day. The high temperature related demand and relatively low non-scheduled generation (NSG) resulted in more expensive gas-fired generation being required (Figure 90 and Figure 91).

Figure 90 Perth heatwave drives high demand and prices

Average quarterly demand vs demand during maximum price events

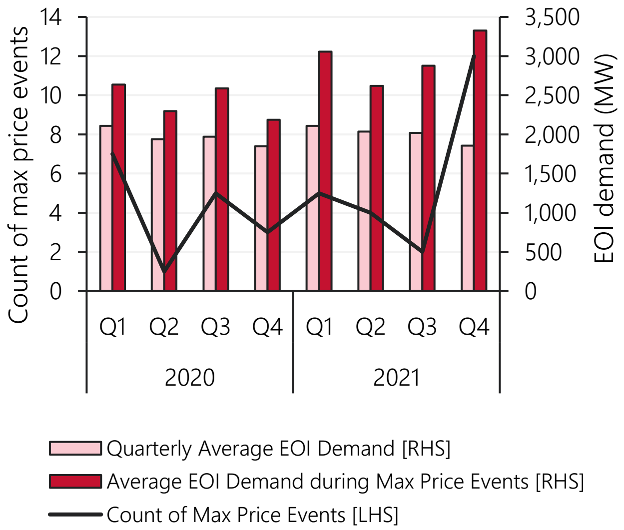
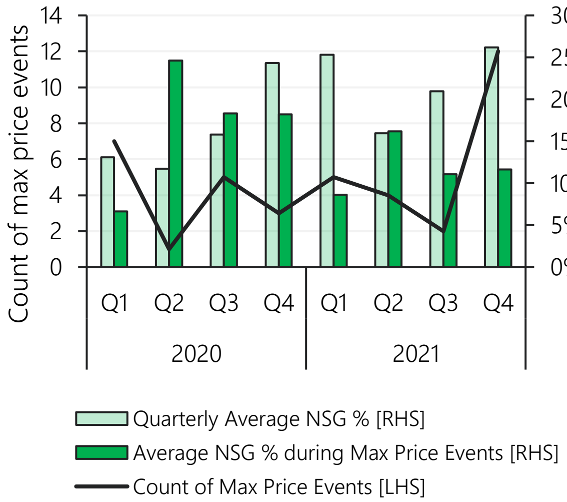


Figure 91 Reduced NSG during high demand intervals contributed to high prices

Quarterly NSG % vs NSG % during maximum price events



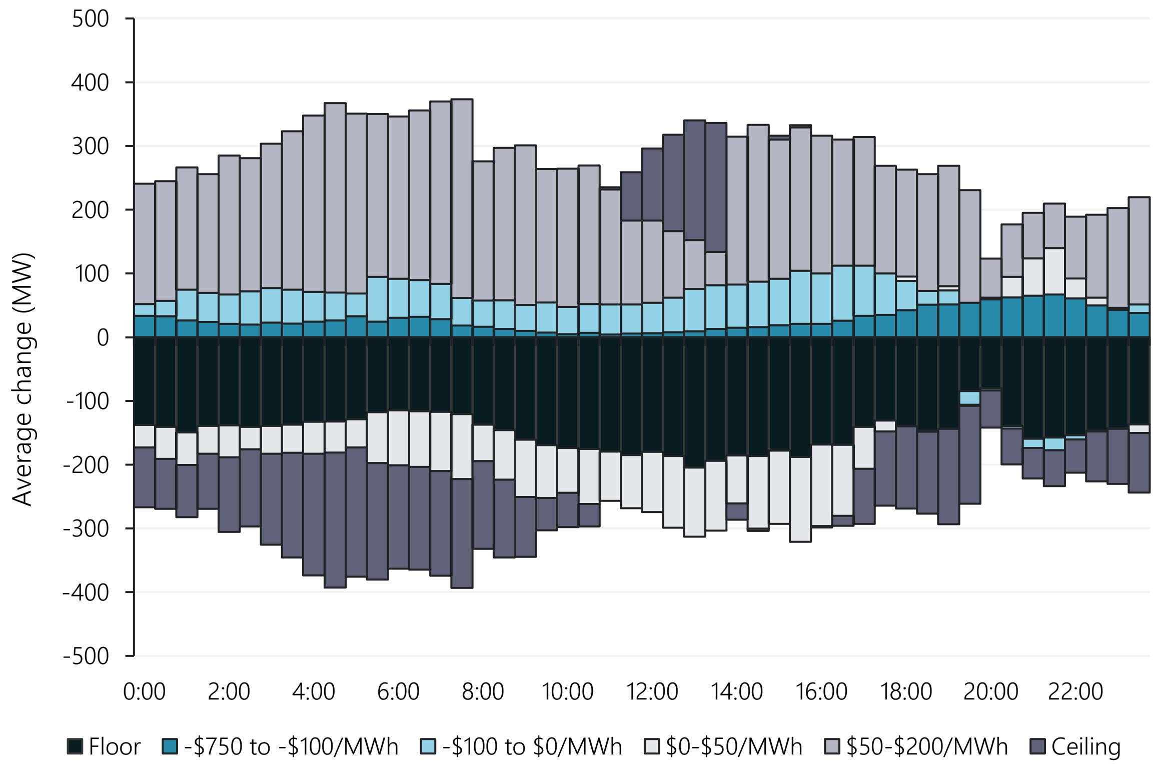
3.2.3 Balancing merit order dynamics

Participant behaviour in the Balancing Market shows a decrease in the average quantities offered at the floor price band (-$1,000/MWh to -$750/MWh) across every interval and an increase in average quantities offered in the $50 to $200/MWh price band across every interval compared to Q4 2020 (Figure 92). The key changes in Balancing Market participation were:

- Bids in the floor price band (-$1,000/MWh to -$750/MWh) decreased by 149 MW on average between Q4 2020 and Q4 2021. This represents a reduction in market generators' willingness to generate at the floor price. In Q4 2020, the Balancing Price hit the floor price band twice, but had also hit the floor price band six times in the preceding quarter. No balancing prices fell within this band in Q4 2021, despite the increased number of minimum demand events.
- There was an increase in average volumes offered in the -$750 to -$100/MWh and -$100 to $0/MWh price bands, this is linked to those Facilities which reduced quantities offered at the floor correspondingly increasing quantities offered in higher price bands.
- Between Q4 2020 and Q4 2021, greater quantities on average were offered into the $50 to $200/MWh price band across every interval. This led to an increase in offers within this price band setting the price 41.4% of the time, compared to 25.5% of the time in Q4 2020. Fewer quantities on average were offered in the $0 to $50/MWh price band and the ceiling price band (>$200/MWh) across nearly every interval.

Figure 92 Lower volumes offered at the floor and ceiling, and greater volumes at $50 to 200/MWh

Change in average forecast Balancing merit order structure by time of day – Q4 2020 versus Q4 2021



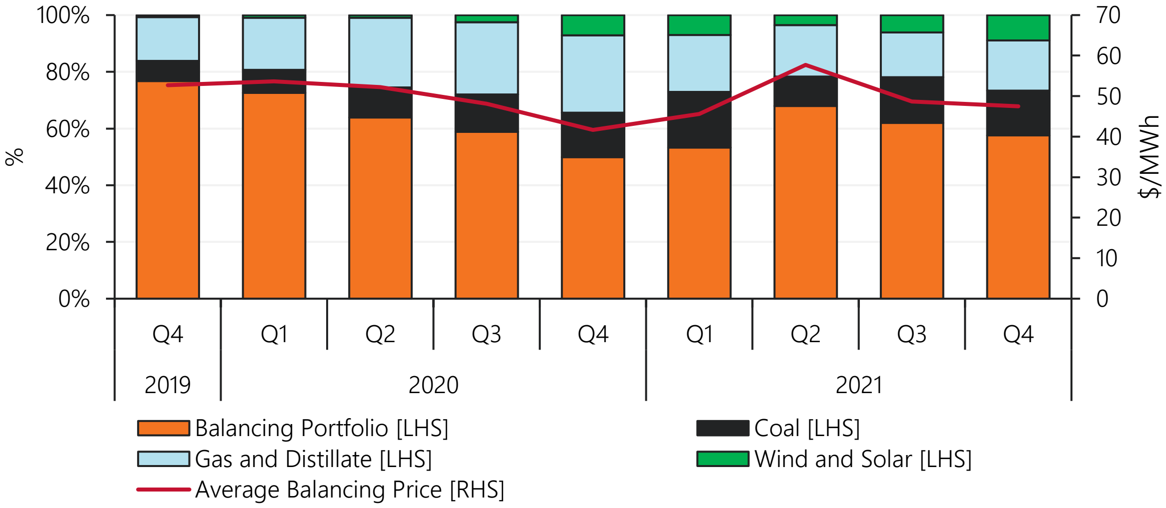
3.2.4 Price-setting dynamics

In Q4 2021, wind and solar Facilities set the price 9% of the time, a 2% increase compared to Q4 2020 (Figure 93).

- Coal remained relatively similar to Q3 2021, but the Balancing Portfolio set the Balancing Price less frequently in Q4 2021, just under 58% of the time.
- The reduction in Balancing Portfolio[63] and increase in wind and solar setting the price has put a slight downwards pressure on the Balancing Price, reducing its time-weighted average from $48.68/MWh in Q3 2021 to $47.47/MWh in Q4 2021.

Figure 93 Wind and solar facilities play their largest role yet in setting the Balancing Price

Price-setting Balancing Portfolio and fuel type of non-Balancing portfolio facilities – Q4 2019 to Q4 2021



3.3 Electricity generation

3.3.1 Change in fuel mix

Q4 2021 saw a decrease in gas and distillate powered generation with a corresponding increase in other fuel types when compared to Q4 2020 (Figure 94).

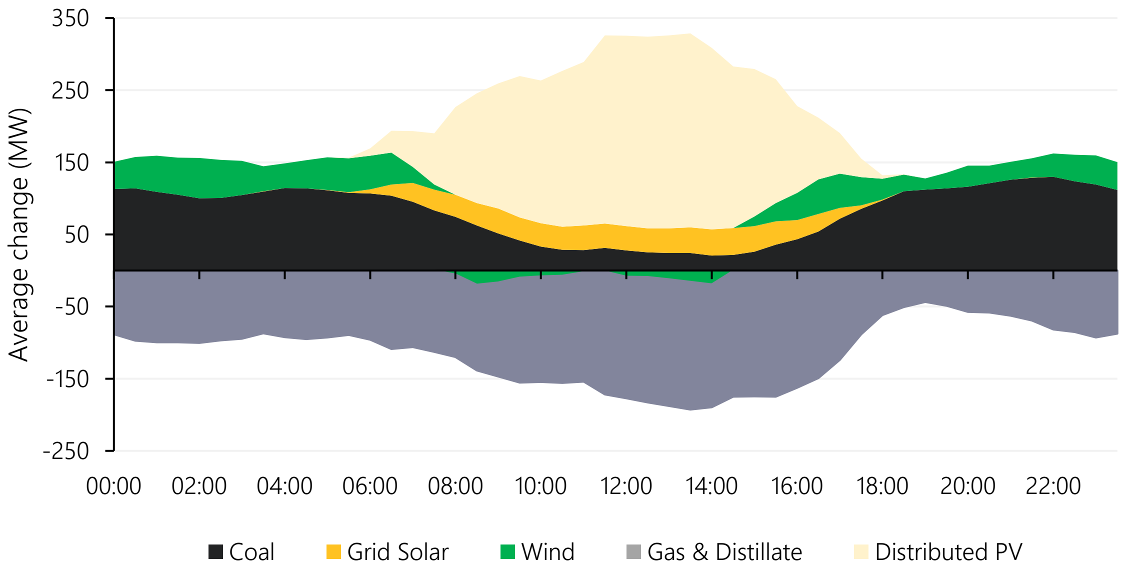
- Coal-fired generation increased by an average of 82 MW (+12%). This increase was consistent with an overall increase in availability of coal-fired generation in Q4 2021, with Muja Unit 7 and the Collie Power Station returning from outages.
- Wind increased by an average of 22 MW (+6%). The largest contribution to this change was from Yandin Wind Farm, which generated an additional 26 MW compared to Q4 2020.
- Grid-scale solar increased by an average of 14 MW (+34%). This increase was predominantly due to a 13 MW increase in the output from the Merredin Solar Farm, which was not generating at full capacity for a large part of Q4 2020.

[63] The Balancing Portfolio consists of 2,731 MW of thermal generation.

- Distributed PV output continued to grow at a rapid rate, increasing by 82 MW (+24%) on average compared to Q4 2020. This increase was due to an estimated 376 MW of additional distributed PV capacity installed in the South West Interconnected System (SWIS) compared to Q4 2020.
- Gas and distillate generation decreased by 112 MW (-16%) compared to Q4 2020, as it was displaced by lower cost generation.

Figure 94 Solar, wind and coal generation displaces gas generation throughout the day

Average change in WEM generation – Q4 2021 versus Q4 2020

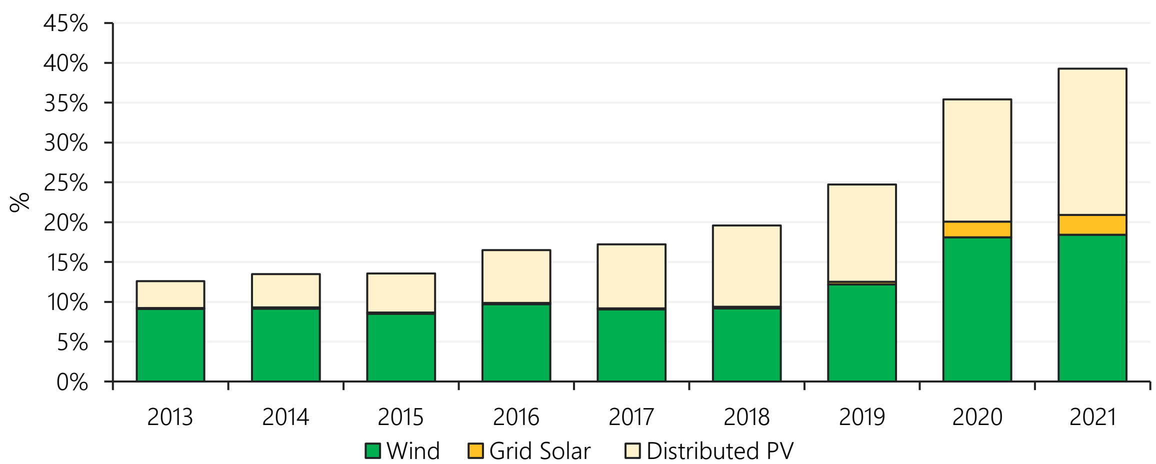


3.3.2 Renewable generation records

During 1130 hrs on 14 November 2021, renewable generation (including distributed PV) supplied 78% of the underlying demand, marginally below the all-time record of 78.6%, which was set during the 1200 hrs interval on 7 September 2021. Over Q4 2021, nearly 40% of total underlying demand was supplied by renewable generation. This is an increase of 4 percentage points on Q4 2020 and a 23% increase from Q4 2016 (Figure 95).

Figure 95 Renewable energy meets a record share of underlying demand in the WEM

Q4 renewable energy generation share – 2013 to 2021



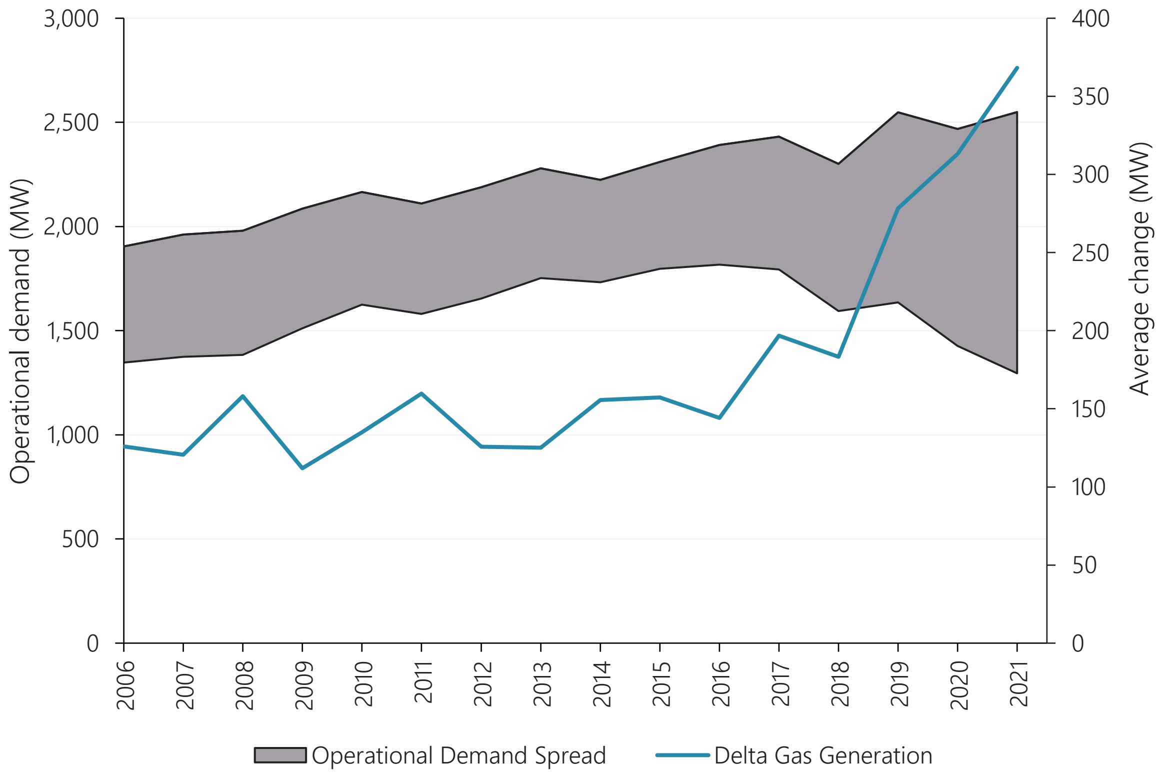
3.3.3 Ramping and changes in demand

Minimum and maximum demand events are occurring more frequently, and each year the difference between the average daily minimum operational demand and average daily maximum operational demand increases (Figure 96).

In Q4 2021, the average daily minimum operational demand was 1,295 MW and the average daily maximum operational demand was 2,549 MW (a 1,254 MW difference). Just five years ago, in Q4 2016, the difference between the two averages was 575 MW. The widening gap – average daily maximum demand increasing approximately in line with economic and population growth, combined with the decreases in average daily minimum operational demand associated with increased distributed energy resources (DER) – results in increased utilisation of fast-ramping scheduled generation, which is typically supplied by gas-fired generation (Figure 96).

Figure 96 Greater variance between daily minimum and maximum operational demand is resulting in increases in average daily ramp rates and gas generation

Q4 average maximum and minimum demand since 2006 and average change in gas generation between those intervals



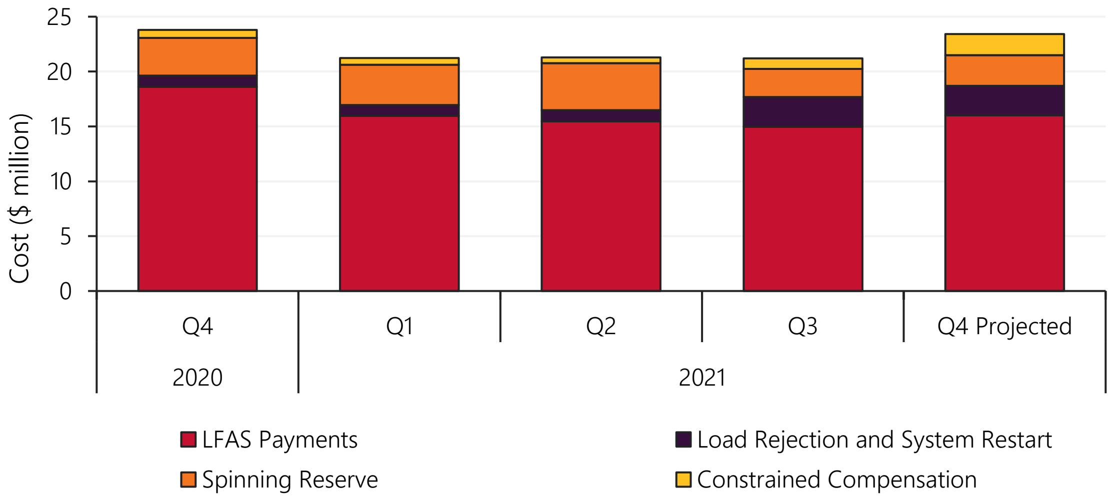
3.4 Power system management

Q4 2021 saw the following changes in cost associated with managing the power system.

- Estimated load following ancillary service (LFAS) costs for Q4 2021 was $16 million[64] and accounted for 75% of all costs of operating the power system[65] for the quarter (Figure 97).
  - The cost of LFAS increased for the first time in four quarters, with a $1 million increase (+7%) from Q3 2021. Higher LFAS costs can be attributed to higher average LFAS prices in both LFAS Upwards and LFAS Downwards markets.
  - Compared to Q4 2020, LFAS costs decreased by $2.6 million (-14%). The reduction was due to lower average LFAS prices this Q4 than in Q4 2020.
- Estimated spinning reserve costs increased by 8% compared to Q3 2021, driven by higher average Balancing Prices during off-peak periods (+$1.8/MWh during off-peak) and the additional trading day in Q4 compared to Q3. Estimated spinning reserve costs decreased by 20% compared to Q4 2020 due to a lower margin value applying during peak periods this financial year (12.6% in 2021-22 compared to 25.46% in 2020-21)[66].
- Estimated load rejection and system restart costs remained the same in Q4 2021 as for Q3 2021, as the COST_LR[67] parameter is set annually in line with financial year[68]. The newly determined COST_LR value for 2021-22 is the driver of increased load rejection and system restart costs compared to Q4 2020 (+167%).
- The cost of constrained compensation doubled in Q4 2021 from last quarter (+$1 million). See Section 3.4.2 for further insights.

Figure 97 Total projected cost of operating the power system increased by 10.4% in Q4 2021

Ancillary services costs and constrained compensation by quarter – Q4 2020 to Q4 2021



[64] Total projected LFAS costs in 2021 were $62 million.

[65] Power system management costs is considered as the cost of all ancillary services and constrained payments.

[66] Spinning Reserve margin values and requirements are determined by the ERA: Ancillary Service Parameters published for 2021/22 are available here on the ERA website - https://www.erawa.com.au/electricity/wholesale-electricity-market/ancillary-services-parameters/spinning-reserve-margin-peak-andoff-peak-load-rejection-reserve-and-system-restart-cost_lr.

[67] COST_LR refers to the total cost of Load Rejection Reserve and System Restart, as determined by the ERA.

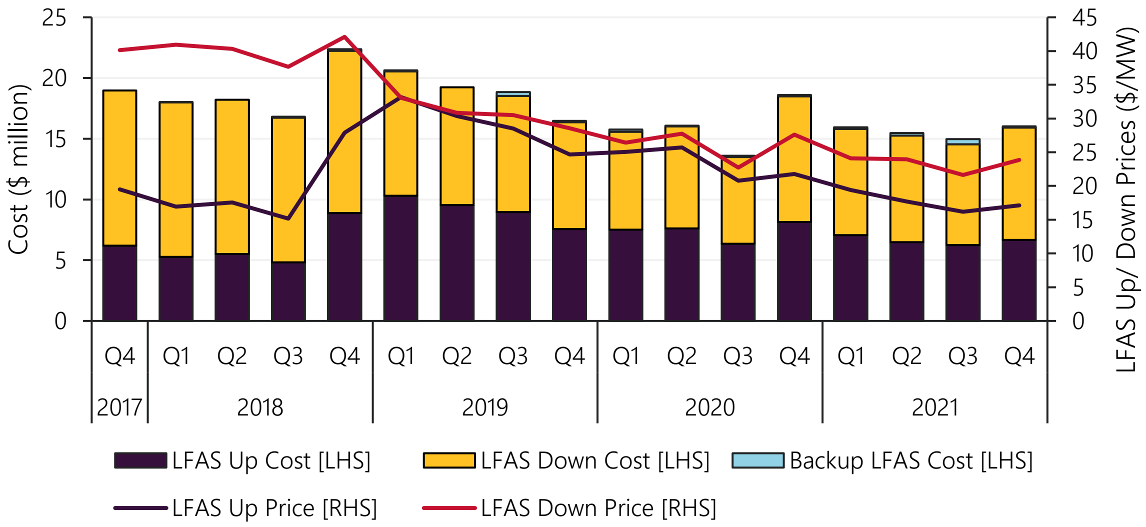
[68] Load Rejection and System Restart costs determined by the ERA are at https://www.erawa.com.au/electricity/wholesale-electricitymarket/ancillary-services-parameters/load-rejection-cost_lr.

3.4.1 LFAS market

In Q4 2021, the cost of LFAS increased by 7% from last quarter, driven by higher LFAS Up Prices (+$0.94/MWh) and LFAS Down Prices (+$2.21/MWh, Figure 98).

Figure 98 Average LFAS prices increased this quarter for the first time since Q4 2020

LFAS costs and prices – Q4 2017 to Q4 2021

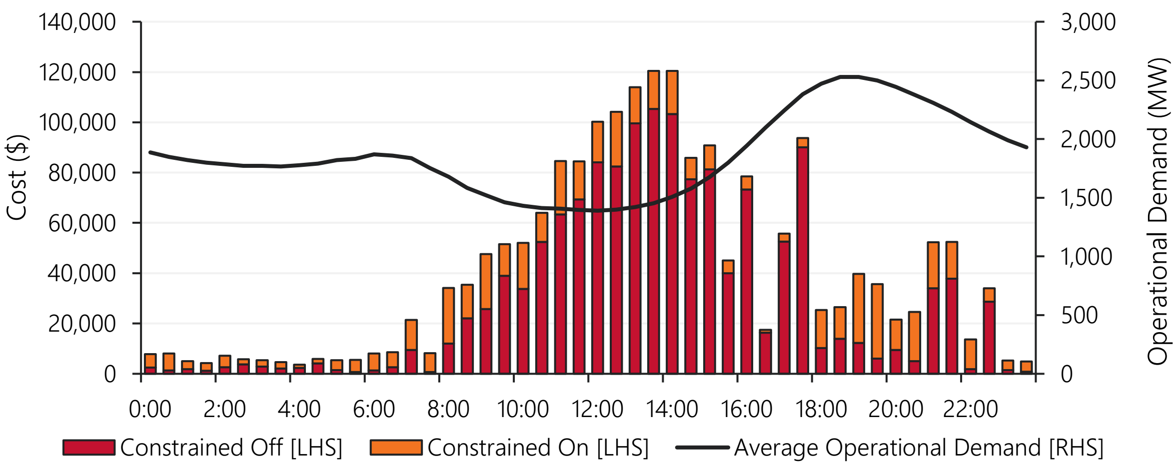


3.4.2 Constrained compensation

Constrained compensation was notably higher in Q4 2021 when compared to previous quarters. Constrained off compensation in November 2021 was $0.9 million, accounting for 48% of total compensation in Q4 2021 ($1.9 million). The high value in November 2021 was driven by intervention required during low load events. AEMO is required to limit the output of a number of generators to manage credible contingences and maintain power system security. As seen in Figure 99, constrained off compensation was highest during the middle of the day, which correlates with low operational demand due to distributed PV generation.

Figure 99 Constrained off compensation in Q4 2021 driven by several low load events in November

Constrained payments by time of day and average operational demand for Q4 2021



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Abbreviations

Abbreviation	Expanded term
5MS	Five minute settlement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Securities Exchange
APLNG	Australia Pacific LNG
AWST	Australian Western Standard Time
BoM	Bureau of Meteorology
Cal	Calendar year
DAA	Day Ahead Auction
DER	Distributed Energy Resources
DWGM	Declared Wholesale Gas Market
EOI Demand	End of interval demand
EGP	Eastern Gas Pipeline
FCAS	Frequency control ancillary services
GJ	Gigajoule
GW	Gigawatts
GLNG	Gladstone LNG
GSH	Gas Supply Hub
IRSR	Inter-regional settlement residue
LGC	Large-scale generation certificate
LFAS	Load Following Ancillary Services
LNG	Liquefied natural gas
MSP	Moomba to Sydney Pipeline
$MtCO_2$-e	Million tonnes of carbon dioxide equivalents
MW	Megawatts
MWh	Megawatt hours
NEM	National Electricity Market
NEMDE	NEM dispatch engine
NGP	Northern Gas Pipeline
NRM	Negative residue management
NSG	Non-scheduled generation
OPEC	Organisation of Petroleum Exporting Countries
PJ	Petajoule
PPA	Power purchase agreement
PV	Photovoltaic
QCLNG	Queensland Curtis LNG
QNI	Queensland to New South Wales Interconnector

Abbreviation	Expanded term
RBP	Roma Brisbane Pipeline
RERT	Reliability and Emergency Reserve Trader
SIPS	System Integrity Protection Scheme
SRMC	Short run marginal cost
STEM	Short Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System
SWQP	South West Queensland Pipeline
TJ	Terajoule
TWh	Terawatt hours
VBB	Victoria Big Battery
VRE	Variable renewable energy
VNI	Victoria to New South Wales Interconnector
WEM	Wholesale Electricity Market
WDR	Wholesale demand response