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AUSTRALIAN ENERGY REGULATOR

State of the energy market

Wholesale gas performance report 2026

Appendices

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Contents

A Liquidity in the facilitated markets

Key points

- Liquidity has improved across most measures in most facilitated markets.
- Where liquidity has worsened, there are mitigating factors which reduce our concern.
- Reduced volume of trade in the Victorian DWGM is a consequence of reduced demand in the market more generally and the trade volume remains significantly higher than any other facilitated market.
- Similarly, while some markets have become more concentrated (measured by HHI), we have observed (chapter 3) that concentration in net trade, being gas actually and substantively traded in the facilitated market, has improved across all markets.
- As set out in chapter 4, growth in liquidity would further improve the facilitated markets' contribution to competition and efficiency in east coast gas markets.

Liquidity refers to the ability of a market participant to undertake transactions without moving the price excessively and with ease. Improving liquidity leads to a more efficient market. It supports gas being supplied to those consumers who value it the highest, at the lowest possible cost, over time.[1]

In 2025, Energy Ministers requested that the AER commence reporting on liquidity metrics, taking over a role previously done by the AEMC. The AEMC previously published biennial reviews on liquidity in facilitated markets. Its most recent review was published in 2020. Its reporting on liquidity of facilitated markets included both quantitative measures from market data and qualitative measures, sourced from stakeholder surveys.

Elsewhere in this report we have evaluated the broader performance of the facilitated markets in context of their overall contribution to the east coast gas market. Our analysis is informed by inquiries with market participants. In our view, this captures effectively the overall perspective gained from the previously reported qualitative measures.

In this appendix, we have set out analysis of 7 key quantitative measures of market liquidity. These mirror the measures reported by the AEMC in its most recent Biennial review of liquidity in gas markets. Specifically, we analyse for all relevant facilitated markets:

- total traded volumes
- numbers of active participants
- numbers of trades per product
- churn rate
- bid-offer spread

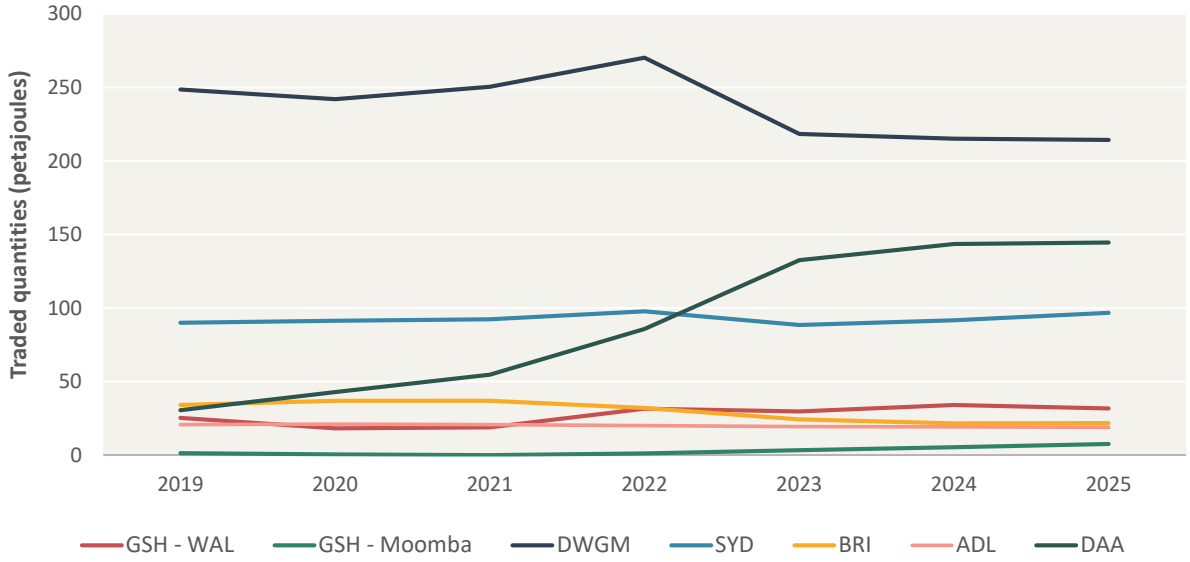
[1] AEMC, Final report published on liquidity review of Australian gas markets, Australian Energy Market Commission, 17 July 2020.

- concentration of trade on the selling-side of the market
- concentration of trade on the buying side of the market.

A.1 Total traded volumes

Total traded volume within a market is a simple and readily observable measure of participation and an indicator of market liquidity. We expect that a market with higher volume of trade is more likely to be liquid, since it should decrease the likelihood that any individual bid can materially impact market price.

Figure A.1 Total traded volumes across the facilitated markets



Note: For the day ahead auction, traded volume is the total quantity won at auction.
Source: AER analysis of AEMO data.

Considering overall trends in traded volumes between 2019 and 2025, we observe that:

- liquidity has increased markedly on the day ahead auction, which has supported broader facilitated market performance by reducing barriers to accessing short-term transportation. A substantial proportion of growth in day ahead auction volume has come from a specific facility (Wallumbilla Compression Facility B), but even without the capacity won on this facility the volume traded has grown materially.
- GSH trade volumes have increased both at the larger Wallumbilla Hub and the smaller Moomba Hub, however they still remain a relatively low proportion of overall market demand
- trade volumes have remained relatively steady in the Sydney and Adelaide STTMs, with a slight overall increase in Sydney.
- trade volumes have declined in the DWGM and Brisbane STTM hub, but:
  - The decline in the DWGM is a result of lower demand overall in Victoria. The volume of offers into the DWGM has increased over the same period, albeit much of the increase is in higher volume bands.

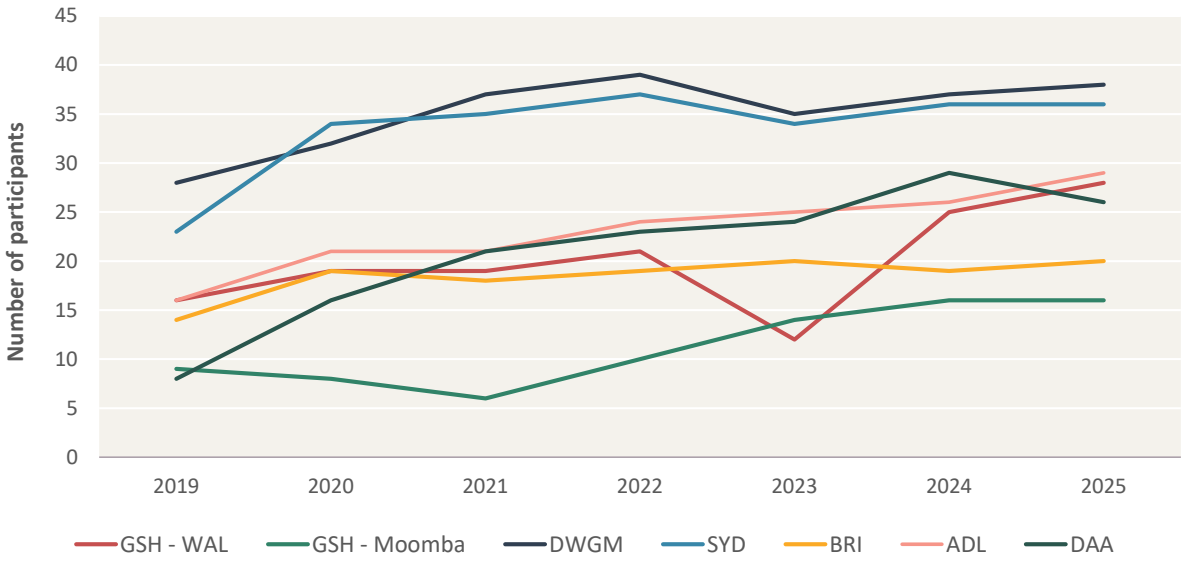
– the decline in Brisbane is primarily due to the exit of Incitec Pivot (a large participant and fertiliser producer) from the relatively small Brisbane market due to closure of its Gibson Island Fertiliser Facility in 2022.[2]

A.2 Numbers of active participants

A higher numbers of active participants in a market indicates higher liquidity because it increases the likelihood that:

- there are diverse price points for offers and bids, reflecting the different circumstances of a greater range of buyers and sellers; and
- as a result, it is less likely that any specific change in bids or offers will materially change the overall price outcomes.

Figure A.2 Total number of active participants (buy and sell side) in all facilitated markets



Note: For the day ahead auction, there are only 'buy-side' participants and we have only included auction facilities on which capacity was won.
Source: AER analysis of GSH, DWGM, STTM and DAA data.

Considering the overall trends in active participation between 2019 and 2025, we observe that:

- the total number of active participants has increased in every facilitated market, with growth even in relatively more established and mature markets such as the DWGM
- there are more active buyers than sellers in all markets other than the GSH.

[2] Australian Manufacturing, Incitec Pivot to close its Gibson Island manufacturing operations, accessed 19 March 2026.

A.3 Numbers of trade per product

Some of the facilitated markets offer a range of traded products. Specifically:

- the GSH includes end of day or balance of day, daily, day ahead, weekly and monthly products
- on the DAA, capacity can be won on a growing number of auction routes. Consistent with the AEMC's methodology, for this analysis, we have treated auction routes as individual products and then summed those products to pipeline level.

Numbers of unique trade per product is a useful complement to overall measures of trade volumes, because:

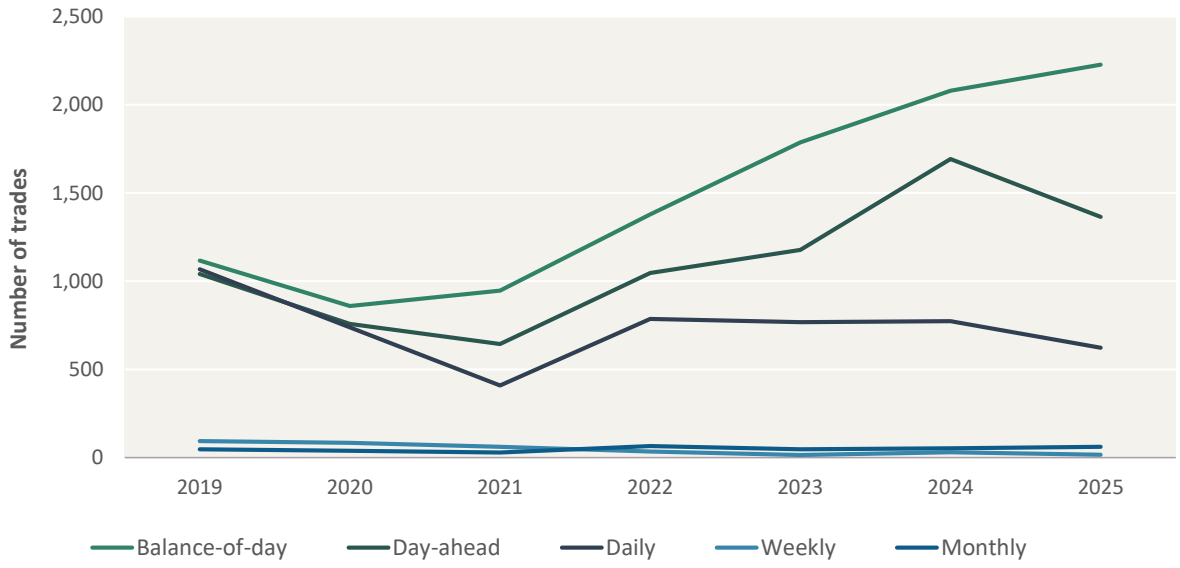
- a higher number of trades suggests that an individual change to offers or bids is unlikely to materially change overall price outcomes. In contrast, if a market is made up of infrequent but large trades, it might suggest a lack of liquidity even if overall trade volumes are high
- the measure of number of trades across the range of products highlights whether there are more or less liquid individual products within the relevant markets.

A.3.1 Gas Supply Hub

Overall, on the GSH, we observe that:

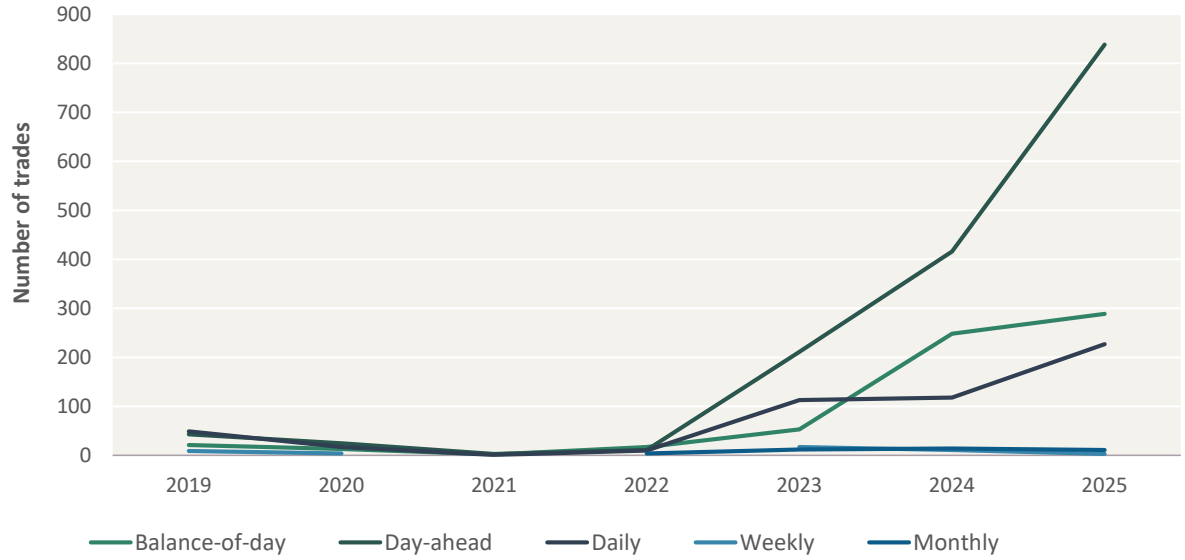
- there has been growth in the number of trades in shorter duration products, with balance-of-day, daily or day ahead products either growing or remaining relatively steady in numbers of trades
- monthly and weekly products have and continued to trade infrequently, albeit they typically trade at higher volumes per trade when they do occur.

Figure A.3 Number of trades per product - Gas Supply Hub (Wallumbilla)



Source: AER analysis of GSH data.

Figure A.4 Number of trades per product - Gas Supply Hub (Moomba)



Note: Monthly and weekly products are not traded in each year.
Source: AER analysis of GSH data.

The availability of longer duration products is a distinguishing feature of the GSH compared to the other facilitated markets. However, growth has been subdued in numbers of trades for these longer duration products. This likely reflects a preference for bespoke bilateral contracts for longer-term products, reducing the relative appeal of standardised GSH offerings.

A.3.2 Day Ahead Auction

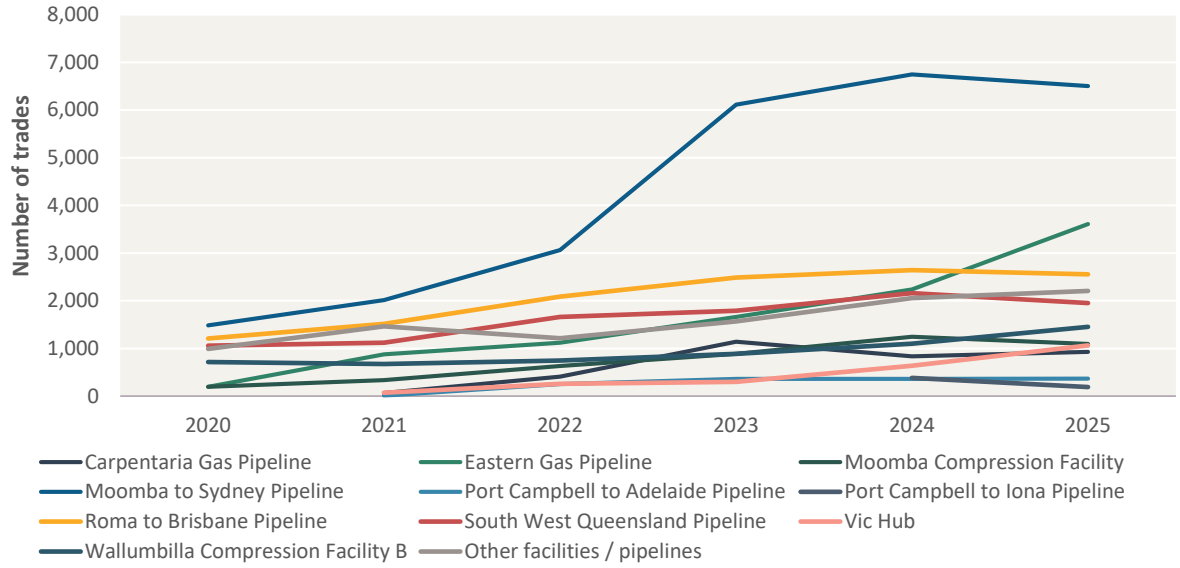
Participants can bid and win capacity on multiple different auction routes through the DAA. For this analysis, we have treated these routes as distinct products.

The number of 'trades', or instances in which capacity is successfully won on auction routes, is highest on key north to south transmission pipelines. Capacity on the Moomba to Sydney Pipeline by far the most traded.

This is consistent with capacity on key north to south pipelines being:

- in high demand from a significant number of shippers
- contracted to a high proportion of nameplate capacity but in most cases, utilised to a lower proportion, meaning capacity is typically available to be won via the auction. More on this is set out in chapter 7.

Figure A.5 Numbers of trades by facility - Day Ahead Auction



Note: Auction capacity can be won on numerous different auction routes within individual pipelines. For simpler presentation, we have summed the numbers of instances in which capacity is won on smaller auction routes on non-listed pipelines as 'Other facilities/ pipelines'.
Source: AER analysis of DAA data.

A.4 Churn rate

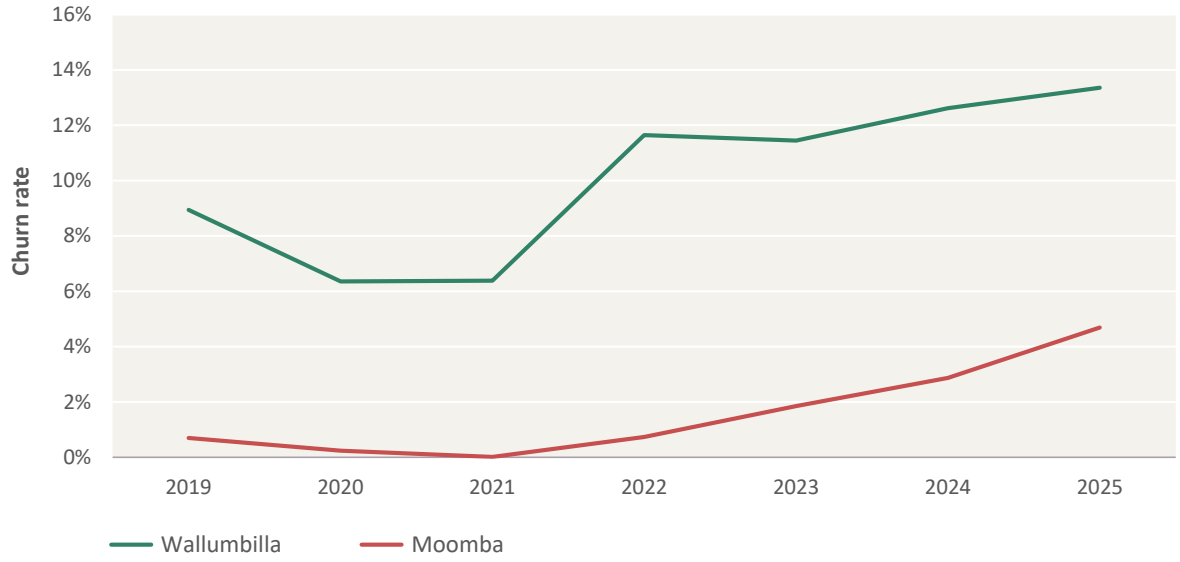
Churn rates show the volume of trade in a market relative to the size of the market for the underlying asset. In some particularly liquid markets, churn rates for (for example) hedging contracts may be multiples of trade in the underlying product markets. Higher churn rates indicate higher liquidity.

In line with the AEMC's methodology, we have calculated churn rates for the gas supply hubs as the volume traded on the hubs as a proportion of total gas flows through that location.

Overall, from 2019 to 2025, we observe that:

- Churn rate at both GSH Wallumbilla and GSH Moomba remains a relatively low proportion of overall gas flows but has grown markedly in both cases.
- Consistent with other indicators of trade, GSH Wallumbilla appears materially more liquid.

Figure A.6 Churn rates on the gas supply hubs



Source: AER analysis of GSH data.

The equivalent measure is not informative for downstream markets because all demand downstream of the hubs must be traded through the Hub, meaning the churn rate is by definition 100%.

A.5 Bid-offer spread

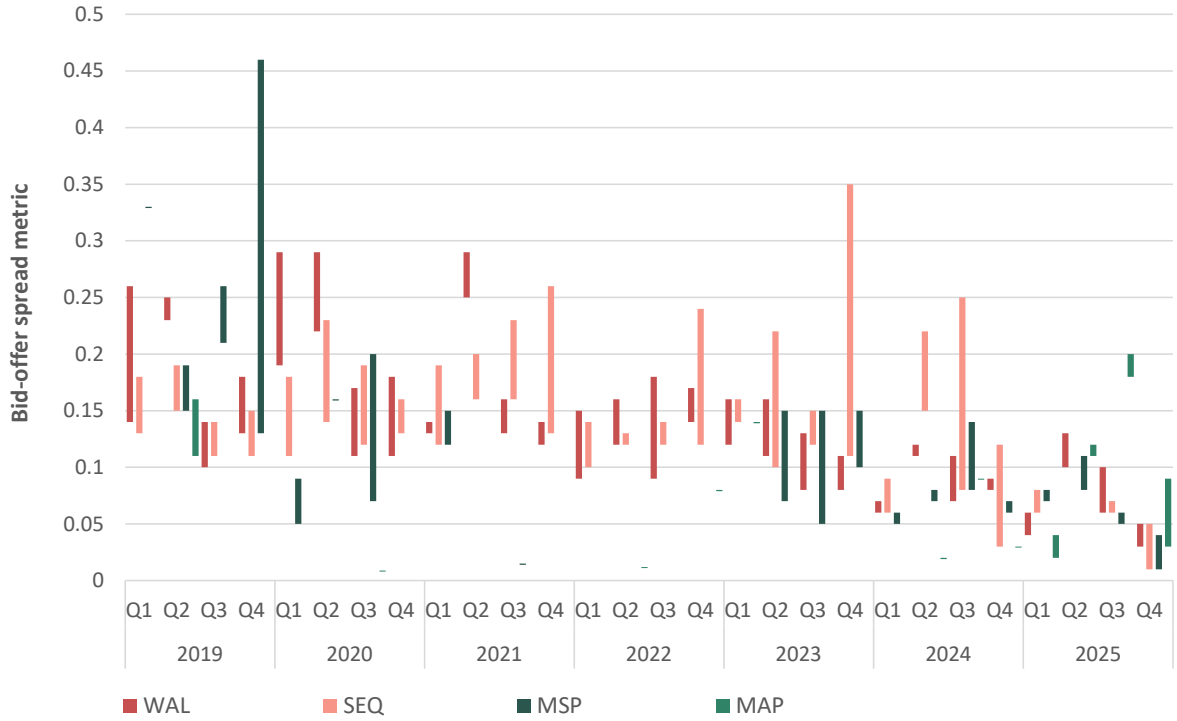
The bid-offer spread shows the difference between the highest bids (buy) and lowest offers (sell) price of gas commodity/service products on the GSH exchange. A lower spread (i.e. the closer the metric is to zero) indicates a higher level of liquidity.

We have calculated bid-offer spreads where data is available to do so, specifically for on-screen trade via the GSH. As discussed in chapter 3, most GSH trade continues to be off-screen where bids and offers are negotiated directly between participants (or with the aid of a broker) and lodged as a final transaction without access to underlying bids or offers.

Overall, on bid-offer spreads from 2019 to 2025, we observe that:

- bid-offer spreads have markedly decreased at both Wallumbilla and Moomba locations
- this is consistent with the relatively low churn rates observed in these market locations, suggesting that liquidity has improved on the gas supply hub but that there is potential for material further improvement.

Figure A.7 Bid-offer spreads on the GSH



Note: Bid-offer spread metrics represent a time-weighted ratio[3] of the difference between the highest unmatched active bid (to buy) and offer (to sell) on the Trayport trading exchange. Where gaps exist in each time-series, it indicates there were no matching orders over that quarter. The bid-offer spread has been shown for balance-of-day, day-ahead and daily commodity products at the Moomba and Wallumbilla trading locations. Ranges shown represent the minimum and maximum spread metric values for the 3 commodity product types.
Source: AER analysis of GSH data.

A.6 Concentration of trade

Highly concentrated markets are less likely to be liquid, because they suggest either the sell or buy sides of a market are influenced significantly by a small number of participants.

In chapter 3, we have detailed trends in concentration of offers using the Hirfendal-Hirschman Index (HHI). We analysed concentration in both offers and net-trade, focussing on the selling side of the downstream facilitated markets.

In this section, we focus on HHI of net-trade as the most informative measure of liquidity for trade substantively traded via the facilitated markets (rather than bilateral contract trade passed through gas supply hubs or offers on the downstream hubs).

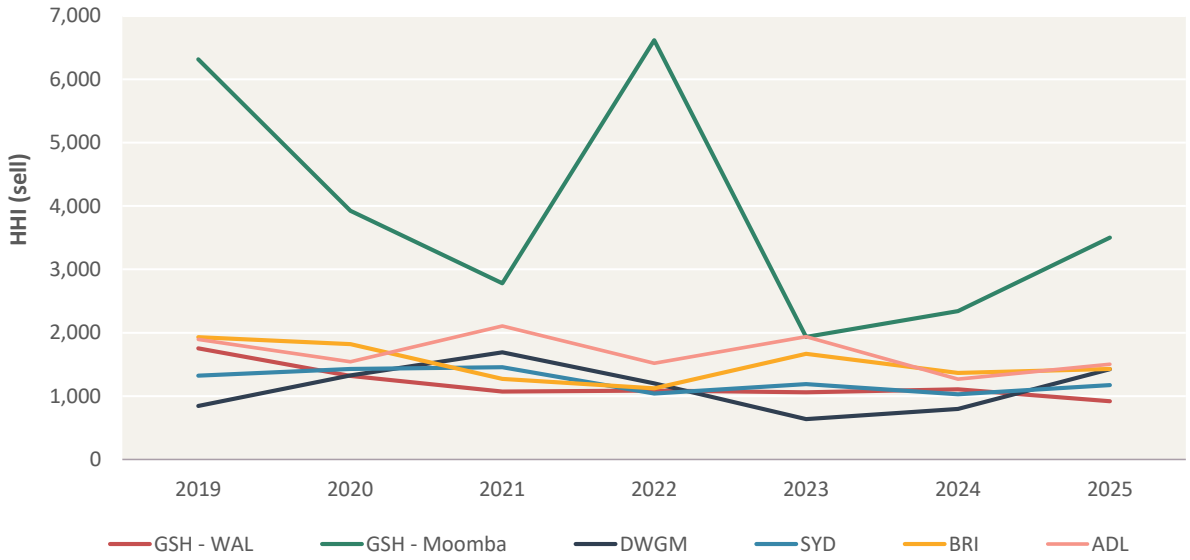
Overall, on concentration in net trade from 2019 to 2025, we observe that:

- buy and sell side trade in most markets has decreased and sits well below 2000, which is the threshold level of concern we use for concentrated markets

[3] The spread metric is the difference between the sum of time-weighted offer prices and the sum of the time-weighted bid prices, divided by the sum of time-weighted bid prices. Lower metric values represent closer alignment between uncleared bids and offers available to trade on the exchange.

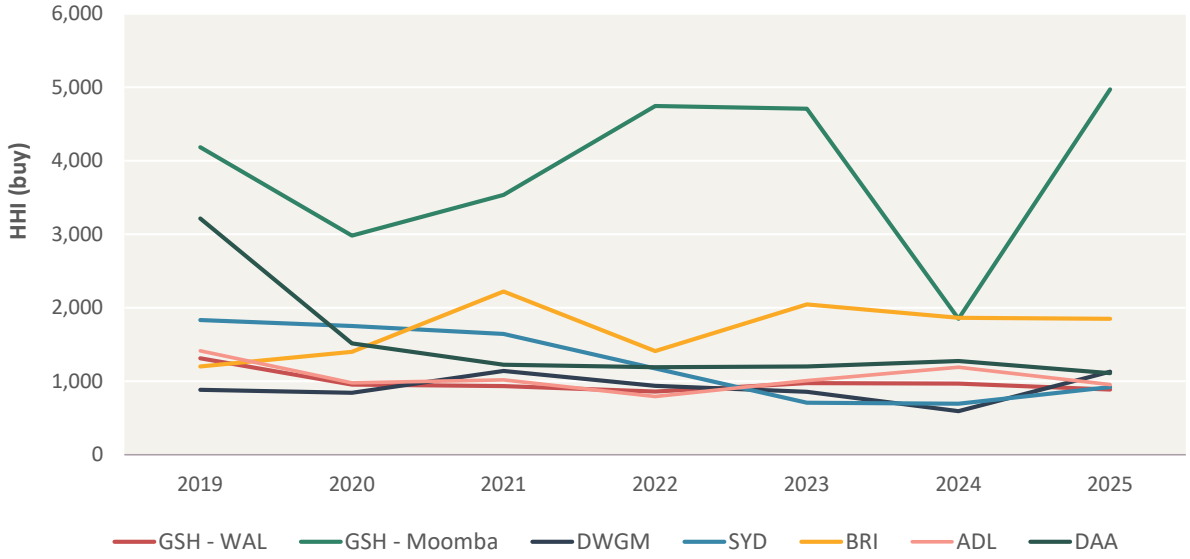
- the exception is GSH trade at Moomba which is highly concentrated, but this is consistent with the general low liquidity and low levels of trade observed in this market.

Figure A.8 HHI of net-trade (sell-side)



Source: AER analysis of GSH, DWGM and STTM data.

Figure A.9 HHI of net-trade (buy-side)



Source: AER analysis of GSH, DWGM, STTM and DAA data.

B Pipeline behaviour and compliance

Key points

- Prices charged by pipeline owners for transportation on non-scheme pipelines appear significantly higher than required to cover underlying costs. Standing prices for analysed non-scheme pipelines were 49% ($0.46) to 67% ($0.66) higher than cost-based pricing benchmarks in 2025.
- We found little evidence of negotiation between pipeline owners and user away from standing offers. This suggests users may be unable to negotiate on terms and conditions of access to pipelines due to lack of countervailing power despite transparency measures.
- Transportation contract lengths have decreased to an average of around 2 years in 2025, which aligns with a similar decrease in supply contract lengths. A reduced ability for pipeline owners to lock in long-term revenue may discourage new investment.
- The 2023 reforms have now fully taken effect and service providers have generally been compliant with obligations. However, there are opportunities to improve transparency and accessibility that we will explore when we re-open aspects of the *Pipeline information disclosure guideline* in mid-2026.

Gas pipelines exhibit natural monopoly characteristics. This is because pipelines are capital intensive and rarely, if ever, have natural competitors across similar transportation routes. This increases the potential for service providers to hold market power in the provision of access to the pipelines

Sustained market power may create inefficiencies in the gas markets, including impacting the supply of gas to the markets. The regulatory framework under the NGL includes two tiers of regulation, ranging from:

- measures to promote transparency and competition under non-scheme regulation; to
- more intensive scheme regulation under which reference tariffs are set for key services on scheme pipelines by reference to underlying costs.

This appendix forms part of our monitoring and reporting under section 63B(4) of the NGL on the behaviour of service providers and adherence to regulatory obligations. The key areas we are required to monitor and report on are found under section 63A(a)-(g) of the NGL and are the focus of this appendix:

- the prices charged by service providers for pipeline services
- the non-price terms and conditions for pipeline services
- the financial information reported by service providers
- the outcomes of access negotiations
- service providers' dealings with associates
- service providers' compliance with ring fencing requirements

- the compliance of service providers with other requirements of this NGL and the NGR.

There are currently 72 service providers for 118 gas pipelines in Australia (excluding Western Australia). We monitor most of these service providers, however, some service providers hold an exemption to not publish some or all information or respond to the ACO for pipelines that are single user, small (<10 TJ per day) or do not offer third-party access. For this appendix we have aggregated and summarised the information reported under Part 10 of the NGR for several service providers and pipelines.

B.1 Prices charged by service providers for pipeline services

Service providers are required across 63 pipelines to publish actual prices payable information for each service that a user has procured unless all users are on the reference service. In this case, service providers must specify how many users or prospective users are using the reference service. The actual prices payable information includes:

- the names of pipelines used to provide the service
- the date the contract was entered into or varied
- the service term (start and end dates)
- the service type (such as forward haul, backhaul, interconnection, park and loan)
- the priority of service (such as firm, as-available or interruptible)
- the contracted quantity (GJ/day or GJ per hour)
- the direction of the service (if a forward haul or backhaul service) (for transmission pipelines only)
- receipt and delivery points (for transmission pipelines only)
- imbalance allowances[4] (for transmission pipelines only)
- overrun allowances[5] (for transmission pipelines only)
- whether the service is provided on the same or substantially the same non-price terms as those set out in the standing terms
- the pricing structure (such as fixed, variable or a combination)
- the price payable (excluding GST)
- the price escalation mechanism.

The service providers of 72 pipelines are also required to publish standing prices for each service offered.

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4 An imbalance allowance is the allowed difference between the quantity of gas taken from the pipeline and the quantity of gas delivered into the pipeline at a particular time.

5 An overrun allowance is the allowed quantity of gas taken from the pipeline that is greater than originally scheduled at a particular time.

We have found little standardisation in how service providers publish actual prices payable information and standing prices. The presentation of information is inconsistent and places a burden on users to process the information. This limits the accessibility and transparency of the information and thus the assistance it can provide to users in negotiations. To mitigate this issue, we will re-open the *Pipeline information disclosure guideline* in mid-2026 to require service providers use and publish a standard actual prices payable template.

B.1.1 There is little evidence of negotiation away from standing offers

For this report, we focused our analysis on several pipelines' actual prices payable information and standing prices for firm forward transportation.

We found minimal variation in the actual prices payable by users on the analysed pipelines as most users pay substantially the same as the standing price offered by the service provider. As of December 2025, the average difference between the standing price and median price across the analysed pipelines was only $0.03. Given the pipelines have natural monopoly characteristics and users do not have competitive alternatives to pipeline transportation, this absence of bespoke pricing suggests minimal ability for users to negotiate away from standing offers.

Most variation from standing prices was evident in older contracts with large volumes. These services likely derive from legacy foundation contracts between service providers and large users that underwrote pipeline investment. It is likely the users held some level of countervailing bargaining power in the legacy negotiations to underwrite pipeline investment that is not present during more recent negotiations.

Where the analysed pipelines have these legacy services with lower prices, the volume weighted average prices are heavily biased toward larger users due to the large associated volumes. This means the volume weighted average prices do not provide an accurate indication of the price most users can expect to pay for a service. Under the previous regulatory framework, service providers were only required to publish these volume weighted average prices. To address this bias, the introduction of actual prices payable information under Part 10 of the NGR was expected to provide better transparency to users on the prices and terms actually obtainable on a pipeline.

B.1.2 Service providers are protected from inflation through CPI-linked prices

Prices for pipeline services are almost always inflation-linked, meaning prices increase with inflation. In most cases, the prices are escalated by the Consumer Price Index (CPI) with 85% of the services analysed on the analysed pipelines increased by 100% of CPI. The remaining services increased by a lower proportion of CPI, such as 75%. Inflation is also almost always applied annually.

B.1.3 Prices appear higher than required to cover underlying costs, including required profit levels

Part 10 of the NGR introduced a pricing template, which was published by the AER under rule 103A of the NGR. This pricing template provides a mechanism for users and prospective users to transform a pipeline's financial and historical demand information into cost-based

pricing benchmarks that are reflective of the pipeline's underlying costs. The cost-based pricing benchmarks are calculated using a building block methodology comprising the following costs:

- operating expenses (total costs less depreciation)
- return of capital (depreciation)
- return on capital (rate of return on the asset base)
- tax (using a statutory tax rate of 30%).

'Low' and 'high' benchmarks are calculated to form an estimated range using combinations of the minimum and maximum underlying costs. For example, the asset base may be determined using the depreciated book value method (DBVM), regulatory asset base (RAB) or recovered capital method (RCM) valuation methodology depending on which produces the lowest and the highest value. These cost-based pricing benchmarks were intended to increase transparency by easing comparison with and evaluation of service provider's offers, standing prices and actual prices payable. However, multiple users were not aware of the cost-based pricing benchmarks or considered they would not provide any leverage to aid negotiations with service providers. The cost-based pricing benchmarks may also highlight potential misuses of market power, and the potential for inefficient pricing for users.

In 2025, standing prices (and thus the actual prices payable by most users) were significantly higher than cost-based pricing benchmarks on every non-scheme pipeline we analysed. As of December 2025, standing prices for the non-scheme pipelines were on average 49% ($0.46) to 67% ($0.66) higher than the respective high and low cost-based pricing benchmarks.

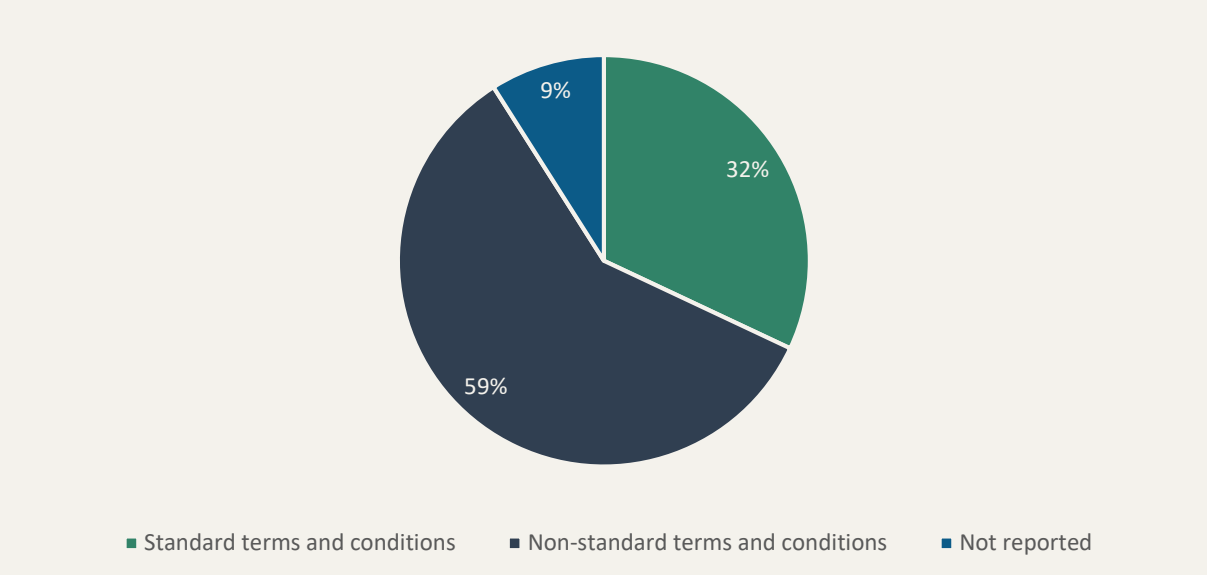
B.2 Non-price terms and conditions for pipeline services

In addition to the requirement to publish actual prices payable a discussed in 1.1 above, the service providers of 63 pipelines are also required to publish actual non-price terms for each service that a user has procured as part of the actual prices payable information. Further, the service providers of 72 pipelines are required to publish standing terms and conditions for each service offered.

B.2.1 Transparency of non-price terms and conditions is limited

Service providers must publish standing terms and information on whether each service procured is provided on 'substantially the same as' the standing terms as part of the actual prices payable information. As of December 2025, the analysed pipelines reported providing 59% of services on terms that are not substantially the same as the standing terms. However, analysis of the specific non-price terms reported as part of the actual prices payable information did not reveal significant variation between the non-price terms offered to users. It is possible that other non-price terms and conditions that are not included in the actual prices payable information may better reveal points of variation. However, it is also possible that service providers have overstated the extent to which services are provided on terms that are not substantially the same as the standing terms. As reported in the March 2025 *Gas pipeline monitoring and transparency report*, users have reported little ability to negotiate with service providers on terms and stated flexibility has decreased in recent years.

Figure B.1 Proportion of services with substantially similar to standard vs non-standard terms and conditions



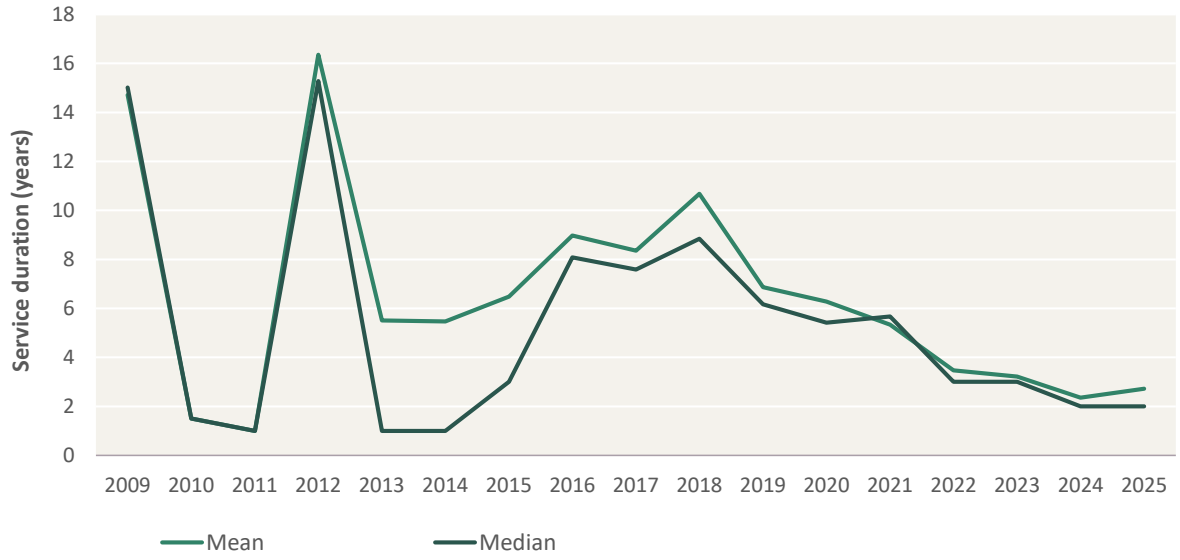
Source: AER analysis of Part 10 of the NGR actual prices payable information.

B.2.2 Users appear less willing to contract longer term

As of December 2025, the median duration of a contracted service had decreased to around 2 years. In the 2000s and early 2010s, longer contracts of up to 16 years likely underwrote investment in the analysed pipelines. This reduction in pipeline service duration is likely due to a similar decrease in the average contract length of gas supply agreements as users generally seek to align supply and transportation contracts.[6] Shorter-term transportation contracts increase the demand risk for service providers who do not have the guaranteed capacity and revenue they would under longer-term contracts. Users have reported taking longer-term transportation contracts to negotiate on other terms of the contract, which may indicate this is a key concern for service providers.

6 ACCC, *Gas Inquiry 2017-2030 Interim update on east coast gas market*, Australian Competition and Consumer Commission, September 2025.

Figure B.2 Average service duration by service start date



Source: AER analysis of Part 10 of the NGR actual prices payable information.
Note: Only services in effect as of December 2023 are included in the actual prices payable information and so this analysis is not conclusive for the service duration between 2009 and 2022.

B.3 Financial information reported by service providers

The service providers of 34 pipelines were required to publish financial information under Part 10 of the NGR for the first time in either June 2025 and December 2025.[7] This financial information replaced the financial information previously required to be published by service providers under Parts 7 and 23 of the NGR. As this is the first tranche of reported financial information under the 2023 *Pipeline information disclosure guideline*, we have prioritised monitoring of this information.

B.3.1 New Part 10 information is substantially the same as Part 23, but marks a large shift from Part 7

The Part 10 financial information is similar to the information previously published under Parts 7 and 23 of the NGR, however, it:

- consolidates the financial reporting into a single template
- must also be published by scheme pipelines
- includes a pricing template, cost allocation methodology and historical demand information
- must comply with the AER's Pipeline information disclosure guidelines published in 2023.

[7] Pipelines publish financial information on either a calendar year basis or a financial year basis, which results in a 6-month difference between the reporting periods.

Most of the Part 10 financial information reported by service providers exactly matches the information previously published under Parts 7 and 23 of the NGR for the same reporting period. The key differences between Parts 7 and 23 of the NGR financial information ending December 2023 or June 2024 and the equivalent Part 10 financial information for the same periods include:

- asset bases dropped by 1.40% ($82.6 million) compared to data reported under Part 23 of the NGR
- asset bases dropped by 63% ($1,350 million) compared to Part 7 of the NGR
- revenue differed by only 0.01% ($93,077) compared to Parts 7 and 23 of the NGR
- expenses increased by 0.44% ($2 million) compared to Part 23 of the NGR
- expenses increased by 1415% ($240 million) compared to Part 7 of the NGR.

B.3.2 Analysed pipelines earnt between $468 and $609 million more than required to cover costs

We analysed the information provided in the pricing template to compare pipelines' reported revenues to cost-based revenue benchmarks.[8] The revenue benchmarks are calculated by summing the product of the cost-based pricing benchmarks and equivalent capacities. This approach provides a higher-level view of a pipeline's financial performance and reduces the number of assumptions required when using service specific pricing estimates. All of the pipelines analysed for this report reported revenue higher than the cost-based benchmark revenue. The sum of all the pipelines' revenues was 116% ($468 million) to 233% ($609 million) higher than the sum of the respective low and high benchmark estimates.

B.3.3 Analysed pipeline revenue increased to $1,014 million per year

The total revenue of the analysed pipelines increased by 6% ($62 million) up to $1,014 million for the reporting period from 2024 to 2025.

The majority of gas pipelines' revenue is typically earned from firm forward transportation services. As such, a pipeline's revenue is highly dependent on the demand for the pipeline services (how much capacity it can contract out) and the price set for those services. Because prices are CPI-linked, real changes in revenue are typically driven by fluctuations in demand and/or changes in the way a service provider has contracted new capacity. Firm forward haul transportation services remained the main source of revenue for the analysed pipelines (79% of total revenue). Compression services and storage services were the next most prominent sources of revenue.

B.3.4 Analysed pipelines are depreciating despite large capital investments

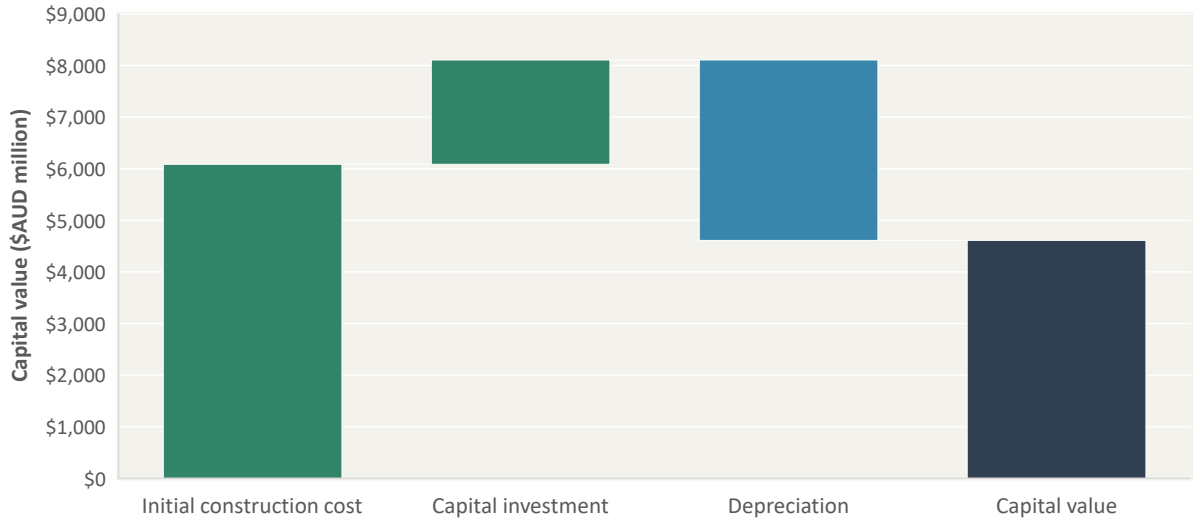
Pipelines are capital-intensive assets, meaning that a large portion of a pipeline's cost is the up-front capital investment. Except where pipelines undertake major capital expenditure to

[8] Due to issues with service provider's reporting of historical demand information under Part 10 of the NGR, we used the revised cost-based pricing benchmarks based on the Gas Bulletin Board contracted capacity data.

fund expansions or other augmentations, we expect to see pipelines having a large initial asset base which depreciates over the life span of the pipeline. This means operating expenses tend to be relatively low as a proportion of overall expenditure as the largest ongoing expense a pipeline incurs is generally depreciation of its asset base. In the 2025 reporting period, depreciation comprised 41% ($208 million) of total expenses.

Excluding 'other non-depreciable pipeline assets' and 'other assets', the total asset base (DBVM and RAB) of the analysed pipelines decreased by 5% from the previous reporting period and amounted to $4,609 million. This valuation is lower than the initial RAB, construction and acquisition costs of the pipelines ($5,726 million) and is the result of depreciation ($3,496 million) exceeding capital investment ($2,021 million). Significant depreciation is expected as the average age of the pipelines was 42 years in 2025.

Figure B.3 Depreciation vs capital expenditure (CY2024 and FY2024-25)

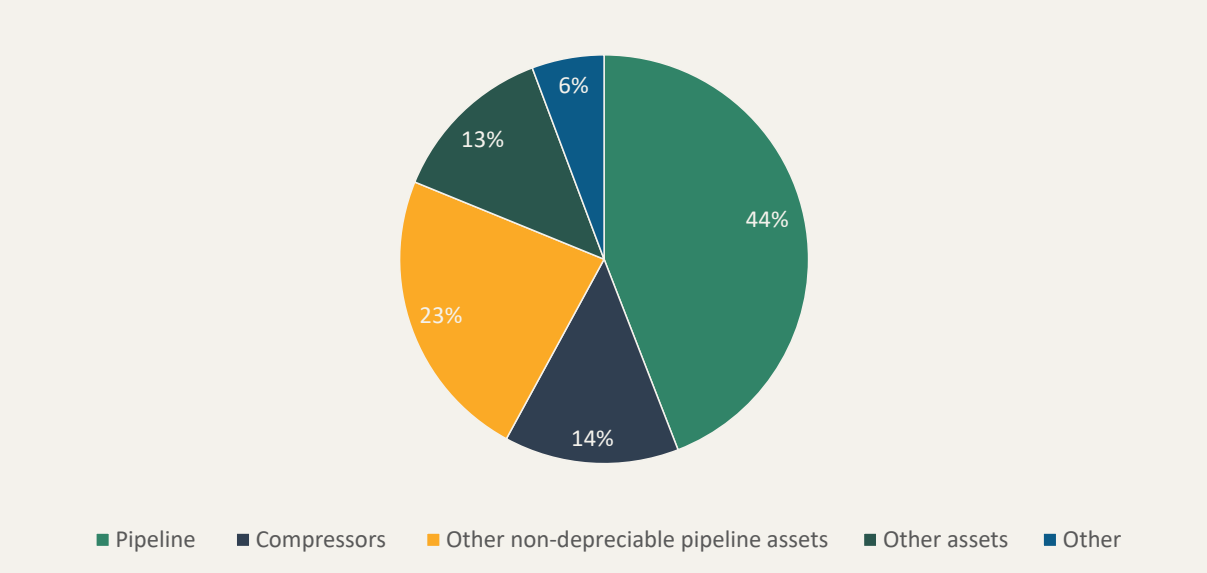


Source: AER analysis of Part 10 of the NGR financial information.
Note: Asset values exclude 'other non-depreciable pipeline assets' and shared assets.

B.3.5 Goodwill is a major component of the reported pipeline asset bases, but would not be included under scheme regulation

As expected, the pipelines' asset bases primarily included the cost of the pipeline itself, with compressors also adding a significant portion of the capital expenditure. However, a substantial proportion of capital for the analysed pipelines was also due to 'other assets' ($972 million) and 'other non-depreciable pipeline assets' ($1,721 million).

Figure B.4 Composition of asset base into categories (CY2024 and FY2024-25)



Source: AER analysis of Part 10 financial information.

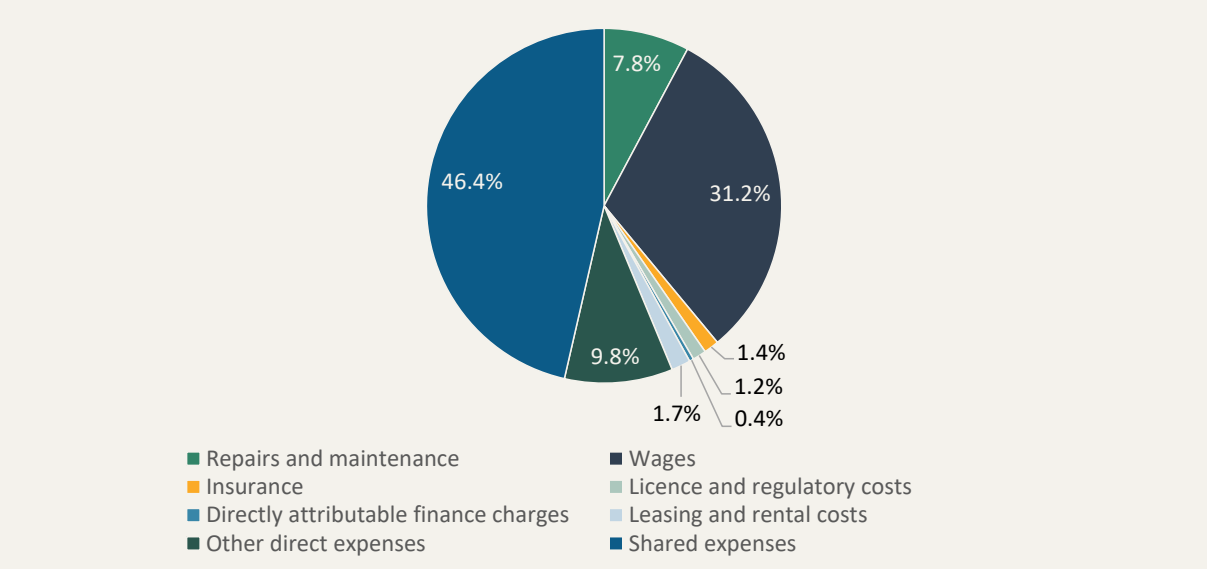
'Other non-depreciable pipeline assets' and 'other assets' includes intangible assets such as goodwill and receivables. Goodwill occurs when the purchase price of an asset exceeds its fair value. This may arise due to intangible factors such as brand reputation, which would not reflect the pipeline's debt and equity costs. As such, goodwill would not be included in the asset base for a pipeline under a cost-based approach as would be the case if a pipeline was subject to scheme regulation. Further, if a pipeline was subject to substantial competition, we expect it is unlikely they would continue to price to recover goodwill as a material component of its asset base. Facing competition, the long-run marginal cost of a depreciating capital-intensive asset should, absent further investments, approach the operating costs of the pipeline. The high inclusion of goodwill suggests the asset bases reported under Part 10 of the NGR are likely inflated which reduces the transparency of the Part 10 information. The higher asset base resulting from this approach reduces estimated profitability metrics such as the return on assets.

B.3.6 Corporate expenses and wages were the main operating expense for pipelines (excluding depreciation)

Total operating expenses for the pipelines were $299 million in the 2025 reporting period, a 35% ($162 million) decrease from the 2024 reporting period.

Shared expenses were the largest reported component accounting for 46% ($139 million) of total expenses excluding depreciation across the pipelines analysed for this report. Shared expenses include corporate level overheads and wages shared across multiple assets within an operating group. Direct wages were another primary expense accounting for 31% ($93 million). This appears consistent with most pipelines being owned by operating groups alongside multiple other pipelines and, in some cases, by other related parties. Pipelines must have separate marketing staff and accounts unless they hold a ring-fencing exemption under Part 5 of the NGR.

Figure B.5 Operating expenses (excluding depreciation) (CY2024 and FY2024-25)



Source: AER analysis of Part 10 of the NGR financial information.

B.4 Service providers' compliance with Part 10

Since our March 2025 *Gas pipeline monitoring and transparency report*, we identified 12 service providers possibly in breach of their obligation to publish Part 10 transparency information on its websites:

- 3 service providers did not publish actual prices payable information for 5 of its pipelines
- 13 service providers self-reported failure to publish service and access information on its websites for 13 pipelines
- 8 of the 13 service providers also self-reported failure to publish actual prices payable information on its websites for 8 lateral pipelines and facilities since July 2024.

B.4.1 New pricing template may require further engagement with service providers

In 2025, service providers published the Part 10 financial information including the new pricing template for the first time. We identified a discrepancy between a service provider's, reporting of historical demand information under Part 10 of the NGR and capacity information reported to the Gas Bulletin Board. The service provider chose to report only one direction for its bidirectional pipelines. This had the effect of significantly under-stating historical demand and inflating the reported Part 10 cost-based pricing benchmarks.[9] We have recalculated the cost-based pricing benchmarks using the Gas Bulletin Board information for the purposes of analysis for this report for each of the pipelines analysed.

We also observed some anomalies in the way some service providers completed the pricing template. These issues may indicate a need for us to engage with service providers regarding use of the pricing template and include the historical demand information and the asset, revenue and expense allocations assigned to specific services:

[9] The cost-based pricing benchmarks are equal to total costs divided by historical demand.

- almost all pipelines analysed reported services earned a revenue from no contracted capacity which resulted in no cost-based pricing benchmark being calculated for these services
- there was unexpected variation in the average regulatory return on debt, gearing, gamma and average regulatory rate of return used by service providers in the pricing template.

Under rule 101A(3)(b) of the NGR, we cannot require service providers to include historical demand information if the information is also required to be provided by the service provider to AEMO for publication on a Gas Bulletin Board. This has the effect of limiting the usefulness of the cost-based pricing benchmarks, especially for services other than forward haul transportation. We will continue to encourage service providers to enter this value but preferably would be able to require it.

1.1 Outcomes of access negotiations

Under the NGR, service providers must:

- comply with the access information standard set out in rule 105B of the NGR
- develop and maintain a user access guide set out in rule 105C of the NGR
- develop and maintain an interconnection policy set out in Part 6 of the NGR and publish the interconnection policy as part of a user access guide under Part 11 of the NGR
- comply with the access request and offer process set out in rules 105D and 105E of the NGR
- comply with the access dispute processes set out in Part 12 of the NGR.

For this report, we did not identify any concerns with service providers' behaviour in providing access to the pipelines, nor did we receive notification of any access disputes. Through the 2025 ACO, service providers reported 82 new or varied access agreements across 14 pipelines.[10] Also, through the 2025 ACO, 13 service providers reported receiving 15 interconnection requests for 12 pipelines. No service providers reported rejecting an interconnection request, but several responded that negotiations were still in process.

Based on the 2025 ACO responses, 6 service providers may have breached at least one obligation to develop and maintain an interconnection policy and a user access guide. We would like to highlight that while service providers may be exempt from publishing user access guides and interconnection policies, they are required to develop and maintain them. We have contacted several service providers to remind them of this obligation.

[10] The number of instances of new or varied access arrangements in this report are not comprehensive because the ACO responses also only capture access arrangements under NGR rule 105E and not access arrangements under NGR rule 105D(3). The number is also materially higher than the number reported via the Voluntary Information Requests (VIR) in 2023 and 2024. This is because a different set of service providers responded due to the class exemption in 2025 and the voluntary nature of the information request in 2024. Further, several service providers did not provide their contracts in response to the voluntary request in 2024 due to confidentiality. This means we did not have complete visibility of the actual number of contracts per pipeline. Therefore, the actual figures for 2023–24 were likely higher.

1.2 Service providers' dealings with associates

Through the 2025 ACO, 2 service providers reported entering a new or varied associate contract. In accordance with rule 33 of the NGR, the service providers had previously notified us of these contracts, and we did not identify any concerns with service providers' compliance with obligations that prohibit service providers from entering, varying or giving effect to associate contracts that have an anti-competitive effect or are inconsistent with the competitive parity rule:[11]

- may request the AER's approval of a new or varied associate contract as outlined in NGR rule 32
- must provide the AER with advance written notice of at least 20 business days before entering or varying a specified associate contract[12] as outlined in NGR rule 32A
- must provide the AER with written notification within 5 business days of entering or varying an associate contract as outlined in NGR rule 33.

1.3 Service providers' compliance with ring-fencing requirements

Unless they have received an exemption from the AER, service providers are required to adhere to the minimum ring-fencing requirements, which require the service provider to:

- not carry on a related business, including carrying on a business in activities related to processing, producing and trading gas
- not share its marketing staff[13] with an associate that takes part in a related business (and conversely, an associate in a related business cannot share marketing staff with the service provider)
- prepare, maintain and keep separate accounts for pipeline services provided by means of every pipeline owned, operated or controlled by the service provider, as well as a consolidated set of accounts for the whole of the business of the service provider.

In the 2025 ACO, all service providers indicated they had complied with their requirements under sections 143, 147 and 148 of the NGL and we did not identify any non-compliance in relation to ring-fencing requirements. However, in May 2025, one service provider self-reported a potential breach of their obligation not to carry on a related business under section 139 of the NGL. The potential non-compliance occurred in the 14-month period following the March 2023 amendments to the NGL and NGR that expanded the scope of the obligations under Chapter 4 of the NGL.

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11 The competitive parity rule states that a service provider must ensure any pipeline service that the service provider provides to an associate of the service provider is provided to that associate as if that associate were a separate unrelated entity.

12 Specified associate contracts are any contracts with an associate that carries on a related business.

13 Marketing staff is any officer, employee, consultant or independent contractor/agent of the service provider who is also directly involved in the sale, marketing or advertising of pipeline services.

1.3.1 Ring-fencing exemptions

A service provider may apply for an exemption from one or more of the minimum ring-fencing requirements or associate contract requirements. We publish these exemption decisions on the AER website.

There are currently 3 ring-fencing exemptions in place where we considered that the costs of complying with the ring-fencing obligations outweighed any associated public benefit:

- 10 of Jemena's businesses are exempt from ring-fencing obligations under section 140 of the NGL in relation to Jemena Northern Gas Pipeline Pty Ltd's operation of the Phillip Creek Compressor Station[14]
- SeamGas Joint Venture and WestSide Corporation Limited are exempt from their ring-fencing obligations under sections 139 and 140 of the NGL from July 2012[15]
- Power and Water Corporation is exempt from its ring-fencing obligations under sections 139,140 and 141 of the NGL from November 2024 in respect of the McArthur River Mining Pipeline.[16]

Since March 2025, we made final decisions for 2 ring-fencing exemption applications:

- In March 2025, we made a final decision to grant exemptions to 10 Jemena businesses from ring-fencing obligations under section 140 of the NGL in relation to Jemena Northern Gas Pipeline Pty Ltd's operation of the Phillip Creek Compressor Station.[17]
- In May 2025, we made a final decision to revoke the exemption from ring-fencing obligations under section 140 of the NGL granted to APT Pipelines NT Pty Ltd, a subsidiary of APA, in respect of the Darwin Distribution System.[18] This followed an application submitted by APA to the AER to revoke the exemption. In its application, APA stated that NT Gas Distribution was no longer involved in the purchase or sale of natural gas for delivery on the Darwin Distribution System and was therefore no longer taking part in a related business.

1.4 Service providers' compliance with other requirements

In addition to the obligations already discussed, service providers are obligated to comply with the following requirements under the NGL and NGR.

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14 AER, Final decision to grant ring-fencing exemptions to Jemena Pipeline Businesses, Australian Energy Regulator, March 2025.

15 AER, Final decision on ring-fencing exemption application for Meridian SeamGas Joint Venture and WestSide Corporation, Australian Energy Regulator, July 2012.

16 AER, Final decision - Ring-fencing exemption - Power and Water - McArthur River Mine Pipeline, Australian Energy Regulator, November 2024.

17 AER, Final decision to grant ring-fencing exemptions to Jemena Pipeline Businesses, Australian Energy Regulator, March 2025.

18 AER, Final decision on revocation of APTNT's ring-fencing exemption application, Australian Energy Regulator, May 2025.

1.4.1 Compliance audits

Under NGL section 64C, a service provider must, if required by us, carry out a compliance audit in connection with the service provider's compliance with the requirements of the NGL and NGR. We published the Compliance Procedures and Guidelines for gas pipeline service providers in December 2024 to set out how compliance audits will be undertaken. Since the March 2025 *Gas pipeline monitoring and transparency report*, we have not conducted any compliance audits.

A key purpose of the compliance audits is to verify compliance with our monitoring and other information gathering tools. We received responses to the first mandatory ACO under the new framework in October 2025. There were 3 instances of minor non-compliance with the 2025 ACO, where 3 service providers did not provide a statutory declaration in line with requirements outlined in the 2025 ACO instruction. These service providers have since provided the required statutory declaration.

1.4.2 Regulatory determinations and elections

Under Chapter 3 of the NGL and Part 4 of the NGR, our role is to make scheme pipeline determinations, scheme pipeline revocation determinations, Greenfields incentive and price protection determinations and classification and reclassification decisions. Service providers may be obligated to comply with the AER's decision process; for example, by complying with information gathering requests. We did not have any concerns with service providers' compliance with our actions over the reporting period during which we made:

- no scheme pipeline determinations or scheme pipeline revocation determinations
- one Greenfields incentive determination, with no price protection determination
- 3 classification decisions
- no reclassification decisions.

The Greenfields incentive determination was for APA's Bulloo Interlink Pipeline (final decision published on 18 December 2025). The determination means the Bulloo Interlink is exempt from becoming a scheme pipeline for 10 years from the pipeline commissioning date, after which, the Bulloo Interlink will continue to be a non-scheme pipeline unless we make a scheme pipeline determination at that time. APA sought a 15-year period; however, we found a 10-year period from when the Bulloo Interlink is commissioned is most likely to promote the achievement of the National Gas Objective. Our determination aims to encourage efficient investment in pipeline infrastructure by improving investment certainty, but these benefits were weighed against the potential risks arising from APA's market power on the pipeline. The Bulloo Interlink is proposed to be commissioned in 2028 and will connect the SWQP and MSP.

1.4.3 Information protection and use

Service providers must supply information and maintain confidentiality in accordance with Part 16 of the NGR. Through the 2025 ACO, we identified several compliance concerns related to service providers' obligations to maintain confidentiality:

- 2 service providers self-reported potential non-compliance with the confidentiality requirements under rule 137 of the NGR.

- 4 service providers did not provide any internal policy documents that cover the handling of confidential information as part of their response.
- 3 service providers provided privacy policies with minimal coverage of confidential information. While this does not necessarily constitute a breach of their obligations, we have written to these service providers to recommend reviewing their internal processes to help ensure that they are meeting their requirement to take all practicable steps to protect the confidential information in their possession.