Final decision

Australian Gas Networks (Victoria & Albury)
Gas distribution access arrangement
1 July 2023 to 30 June 2028

Overview

June 2023

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Contents

Note

This Overview forms part of the AER's final decision on the access arrangement that will apply to Australian Gas Networks (Victoria and Albury) (**AGN**) for the 2023–28 access arrangement period. It should be read with all other parts of the final decision.

As a number of issues were settled at the draft decision stage or required only minor updates, we have not prepared all Attachments. The final decision Attachments have been numbered consistently with the equivalent Attachments to our draft decision. In these circumstances, our draft decision reasons form part of this final decision.

This final decision includes the following attachments:

Attachment 2 – Capital base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 9 – Reference tariff setting

Attachment 10 – Reference tariff variation mechanism

Attachment 11 – Non-tariff components

Attachment 12 – Demand

Attachment 13 – Capital expenditure sharing scheme

Executive summary

The Australian Energy Regulator (AER) exists to ensure energy consumers are better off, now and in the future. Consumers are at the heart of our work, and we focus on ensuring a secure, reliable, and affordable energy future for Australia. The regulatory framework governing gas transmission and distribution networks is the National Gas Law and Rules (NGL and NGR). Our work is guided by the National Gas Objective (NGO).

A regulated gas network business must periodically apply to us for a ruling on network charges, in the form of an access arrangement specifying the services it will provide, the tariffs for those services, and the other terms and conditions on which they will be provided. On 1 July 2022, Australian Gas Networks (AGN) submitted a proposal for its Victorian and Albury gas distribution networks for the 1 July 2023 to 30 June 2028 access arrangement period (2023–28 period). Having consulted on that initial proposal, our December 2022 draft decision, and AGN's January 2023 revised proposal, this final decision allows AGN to set gas network charges resulting in the expected recovery of $1,362.1 million ($ nominal, smoothed) in revenues from consumers over the 2023–28 period. This is $86.5 million (6.8%) more than AGN's revised proposal, and $63.8 million (4.9%) more than our draft decision.

As in our draft decision, our final decision accepts much of AGN's revised proposal. We commend AGN and its Victorian gas distribution colleagues from Multinet Gas Networks and AusNet Gas Services on the genuine and high-quality consumer engagement they have undertaken on their 2023–28 access arrangement reviews. The residual issues post draft decision, including the allocation of gas connection abolishment costs and the appropriate level of accelerated depreciation as detailed below, are not trivial issues that can be easily resolved with unanimous stakeholder support. We also thank the many consumers, consumer advocates and representatives, and retailers for their extensive time commitment on these reviews and valued submissions made under our consultation processes.

Future gas demand uncertainty

Transformation in the energy system and the explicit policy goal of reaching net zero emissions by 2050 create considerable uncertainties in future gas demand expectations. The decline of gas demand is expected to accelerate, but there is uncertainty as to how quickly that will happen, what the path to small customer 'electrification' will look like, and whether gas networks will have any ongoing role in transporting hydrogen or biogas. We can't resolve that uncertainty in these decisions, but we are taking steps to manage the risks it creates for consumers and for the networks in this access arrangement decision.

The demand forecast approved in our draft decision was informed by the Australian Energy Market Operator's (AEMO) March 2022 Gas Statement of Opportunities (GSOO) and the Victorian Government's July 2022 Gas Substitution Roadmap (Roadmap). They projected a significant reduction in new connections compared to previous periods, and an increase in disconnections as customers choose to leave the network. They also anticipated a fall in usage for customers that continue to rely on gas as part of their energy supply.

At the time of our draft decision, discussion of forecast demand was focussed on two bookend scenarios from the 2022 GSOO: a relatively flat 'progressive change' scenario, and a more dramatic ‘step change’ scenario that assumed significant policy intervention would lead to a material decline in demand over the 2023–28 period. The demand forecasts in our draft decision sat closer to the progressive change scenario, even after the Roadmap was taken into account. AGN’s revised proposal maintained that forecast, pending consideration of updated demand outlooks in the March 2023 GSOO.

The central scenario in the 2023 GSOO is a new ‘orchestrated step change’. In the 2023–28 period, it is close to the 2022 progressive change scenario and has informed the demand forecast used in this final decision. That forecast is slightly higher than AGN’s, resulting in slightly lower tariffs over the period than would have been had we accepted its revised proposal.

The changes we have made to projected demand are driven largely by declining consumption for remaining customers, not the number of new customers connecting to the network. This means there has been no material change to forecast capital expenditure (capex) for new connections since our draft decision. It also means no material change to forecast operating expenditure (opex), given the limited impact changes in consumption have on output growth.

We have closely scrutinised the capex and opex proposals to ensure customers still reliant on gas are paying no more than necessary for safe, reliable and secure supply. While declining demand is already having an impact on growth driven elements of forecast expenditure, its impact on other drivers will be slower. The obligation on the networks to continue to offer the same services at the same regulated standards mean many costs won’t fall with demand. AGN’s capex in the 2023–28 period will decrease from the current period. Its opex, however, is materially higher than for the current period, most significantly as a result the inclusion of previously capitalised overheads as opex, the reclassification of certain capex activities as opex, and the inclusion of small customer connection abolishment costs. Our final decision to move the majority of these costs from ancillary reference services to haulage tariffs means those costs, and the expected increase in the number of connection abolishments, are now reflected in the forecast revenue requirement.

Looking beyond the period covered by this decision, the 2023 GSOO suggests that the rate of decline in demand in the medium term will be slower than expected last year. From around 2035, the rate of decline is projected to increase. This longer term outlook creates some challenges for this decision. While we can’t predict medium to long term demand with any real certainty, we can begin to manage some of the risks that it presents and mitigate their potential impact. We are looking for outcomes with sufficient flexibility to balance affordability with the ongoing need for safe, reliable and secure delivery of essential energy services, so that consumers are better off both now and in the future.

Part of the declining demand outlook for gas distribution network businesses is that the number of customers expected to significantly reduce their reliance on gas appliances, or to leave the gas network completely, is increasing. This raises important issues of cost, equity and safety, and takes us to two of the more contentious issues we have had to consider in this final decision.

Temporary disconnection versus permanent abolishment of gas connections

Victoria's energy safety regulator, Energy Safe Victoria (ESV), considers that when a customer chooses to stop using gas at their premises, permanent abolishment of the connection is required for gas distributors to meet their obligations to minimise the safety risks of permanent disconnection as far as practicable. Permanent abolishment of a connection (by removing the network assets and closing off the connection or premises to the mains) is more costly to deliver than temporary measures that simply stop withdrawal of gas through the meter. To date, it has therefore come at a much higher price for customers.

In the course of this review, we have become aware that some customers who are choosing to move away from gas are avoiding the higher charge by seeking temporary disconnection measures designed for short term pause of supply over the safer, permanent removal of connection assets. Over time, changes in property ownership will further increase the risk, as the new owners may be unaware of the live gas assets within the premises. As the number of customers moving away from gas increases over time, we are concerned about the incentives a continued difference in price between temporary disconnection versus permanent abolishment measures may create. In our draft decision, we therefore considered the costs of abolishing connections and the broader question of how these costs are recovered from consumers. That is, to continue to recover costs from individual customers at the time of disconnection, or to socialise them across all customers in the network.

In the short term, while paths to electrification are still uncertain, our final decision is a hybrid of these two options. To reduce the price difference between the two disconnection services, and the safety risks it appears to be creating, this final decision retains an upfront cost of $220 for connection abolishment and shares the remainder between all customers. This means the shared portion of abolishment costs needs to be added to the regulated revenue we use to set haulage tariffs. This is not a change to the total costs that AGN will be allowed to recover for connection abolishment services. It only changes the way in which costs are recovered. Projected costs for the shared portion of abolishment costs ($29.1 million ($2022–23)) are removed from the charges for ancillary reference services and, instead, transferred to forecast opex and the revenue requirement recovered from all AGN customers through its haulage reference services. The revenue recovered through ancillary reference service tariffs will decrease by a corresponding amount.

This is not a long-term solution. Combined with declining throughput on remaining connections, it will put upward pressure on haulage tariffs in the 2023–28 period until a more sustainable solution is identified. If, in future periods, we see further decline in demand and an increase in customers leaving the network, the upwards pressure on tariffs for remaining customers will only grow. ESV is committed to working with the gas distribution network businesses to understand whether other methods may be more appropriate than permanent abolishment in the context of the large number of disconnections that have been forecast as a result of the Victorian Government's policy to support electrification, or whether there are any new technologies that may reduce the safety risk. In the interim, our final decision includes an annual tariff variation mechanism that will ensure that only actual, efficient costs of providing abolishment services are recovered, and that any difference between forecast and actual abolishment numbers and costs will be returned to customers.

Accelerated depreciation of gas network assets

As fewer customers seek connection to the gas distribution network and usage by remaining customers falls, the ongoing costs of maintaining the network are shared by a smaller number of customers over time. As long as there is demand from consumers and businesses for gas distribution services, and regulated distribution networks are required by law to provide those services, a level of investment in the networks that provide those services is necessary to ensure safe, reliable and secure gas supply. Growth-driven expenditure is already falling with demand. However, declining throughput and slower growth in customer numbers are not yet having the same impact on the costs of maintaining the network for remaining customers. Capex, in particular, mostly relates to assets with long lives, the costs of which are recovered (depreciated) over several access arrangement periods. This poses a number of challenges, including that the cost burden of past investments may be disproportionately borne by future gas customers and that assets may be economically stranded.

It is important to start taking small steps now to manage the equitable recovery of those costs from what will be a declining, and sometimes vulnerable, customer base over time. It is clear that demand will continue to fall in the short, medium and long term. We are already seeing material reductions in demand-driven expenditure. The impact of declining use of the gas networks on investment to maintain safety, security and reliability will take longer, but we consider there is sufficient evidence now, backed up by a convincing business narrative, to support some accelerated depreciation of network assets.

We want to do this in a measured way that balances the impact increased depreciation will have on prices in 2023–28 with the longer term price outlook. Our final decision confirms our full draft decision amount of $175 million ($2022–23) in accelerated depreciation, which AGN adopted in its revised proposal. We are satisfied this small start balances price impacts in the short term with the need for longer term price stability.

The energy market transition is ongoing

The issues being raised through this review will continue to create challenges as the transition to net zero emissions progresses. If future access arrangement periods see a winding down of gas networks, there could be fewer customers to share fixed costs of the network over time. This could result in customers that cannot afford to electrify facing higher bills, raising equity concerns. If the costs of permanent disconnection remain socialised amongst existing gas customers beyond the period of this decision, and the number of customers permanently disconnected were to increase, it would exacerbate this. A potential winding down of networks could also lead to risks of asset stranding for AGN and other gas distribution networks, and deter important investment in maintaining the safety, security and reliability of those networks while they remain in use.

The economic regulatory framework is flexible, and allows us to take the steps we have taken in this decision to manage the risk of this uncertainty over the next five years. In the longer term, it may be that the gas access arrangement review process is not enough, or not the best avenue, to deal with the related safety and equity issues that may arise. There is an important role for governments to continue to set clear policy direction on the future use of gas in order to facilitate a safe, reliable and affordable transition.

1 Our final decision

AGN's access arrangement sets out the services it will provide in the five years from 1 July 2023 to 30 June 2028 (2023–28 period), the tariffs for those services, and the other terms and conditions on which they will be provided.

An access arrangement final decision is a decision to approve, or to refuse to approve, an access arrangement proposal.[1] If, in its final decision, the AER refuses to approve a proposal, the AER must itself propose an access arrangement or revisions to the access arrangement (as the case requires) for the relevant pipeline.[2] As we have not approved AGN's revised proposal, this final decision is accompanied by a revised access arrangement and tariff schedule.

At the centre of our decision is the forecast total revenue requirement for the provision of the regulated haulage reference service over the next five years. Our final decision includes total revenue of $1,362.1 million ($ nominal, smoothed) compared to AGN's revised proposal of $1,275.6 million. This is $86.5 million (6.8%) more than AGN's revised proposal, and $63.8 million (4.9%) more than our draft decision.

As in our draft decision, our final decision accepts much of AGN's revised proposal. The main areas of difference in building block revenues in nominal terms are:

- An increase in regulatory depreciation of $41.5 million (16.9%). As our final decision accepts the full amount of AGN's proposed accelerated depreciation, the increase in regulatory depreciation is driven primarily by a lower expected inflation rate which reduces the adjustment for indexation of the capital base.[3] On balance, we consider this to be a measured start to accelerated depreciation of AGN's network whilst maintaining price affordability for consumers.
- An increase to forecast opex of $25.2 million[4] (4.8%), which includes forecast costs of a growing number of small customer connection abolishments over the next five years.

While not areas of disagreement between us and AGN, updates to the following building blocks are also contributing to the difference in our calculation of total revenue:

- An increase to the return on capital of $15.9 million (2.8%), driven primarily by our higher rate of return using updated market data.
- A decrease in revenue adjustments of $7.1 million (8.3%), driven primarily by our reallocation of the true-up for the half year period from 1 January 2023 to 30 June 2023.[5]

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1 NGR, r. 62(2).

2 NGR, r. 64(1).

3 Regulatory depreciation is the net total of straight-line depreciation and inflation indexation of the capital base.

4 This reflects $29.1 million ($2022–23) for abolishments, and excludes ancillary reference services.

5 AGN has proposed the true-up of $53.4 million ($2022–23) spread over five years. We, instead, determine the true-up of $57.4 million at the final year. This value is scaled by WACC and results in the same net present value of forecast revenue compared to a scenario where the true-up is spread over five years.

- An increase in the cost of corporate income tax of $6.8 million (31.7%), driven primarily by a higher regulatory depreciation amount which increases revenue for tax purposes.

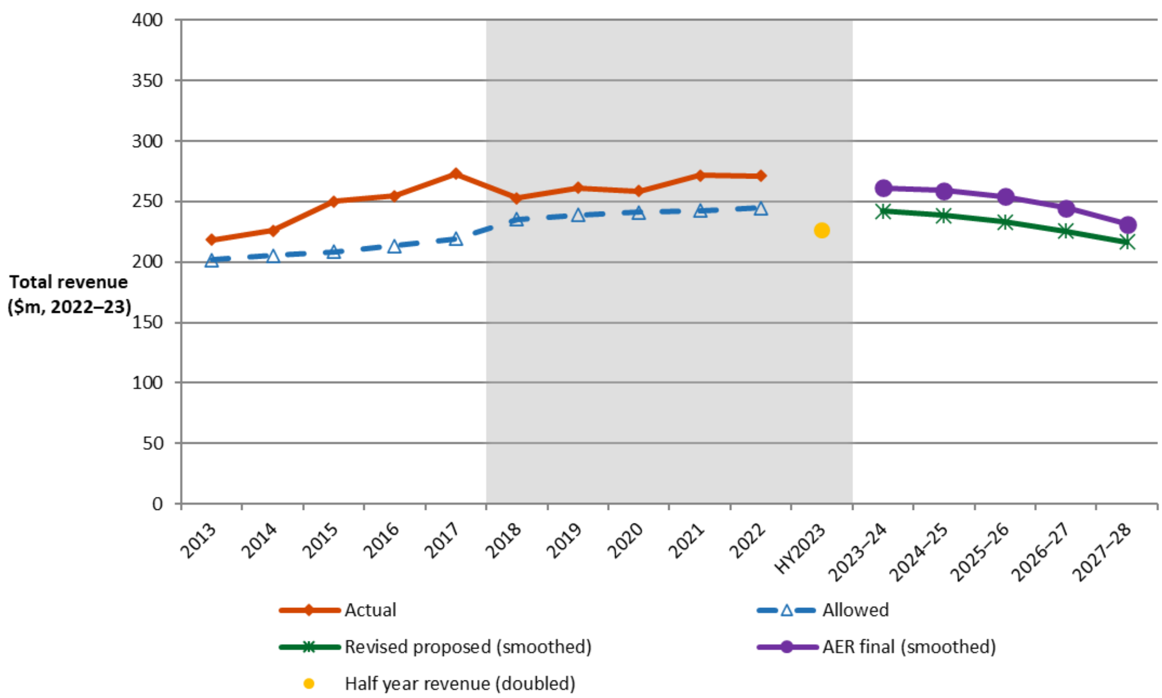
1.1 What is driving revenue?

Over time, inflation impacts the spending power of money. To compare revenue from one period to the next on a like-for-like basis, in this section, we use 'real' values based on a common year (2022–23) that have been adjusted for the impact of inflation, instead of the nominal values above.

Where the assumptions in AGN's revised proposal would have resulted in total smoothed real revenue that was $47.1 million (3.9%) lower than approved for the current period, the modelled impact of our final decision is an increase of $47.8 million (4.0%).

Figure 1 shows how real revenue would change over the next five years under this final decision, compared to AGN's revised proposal.

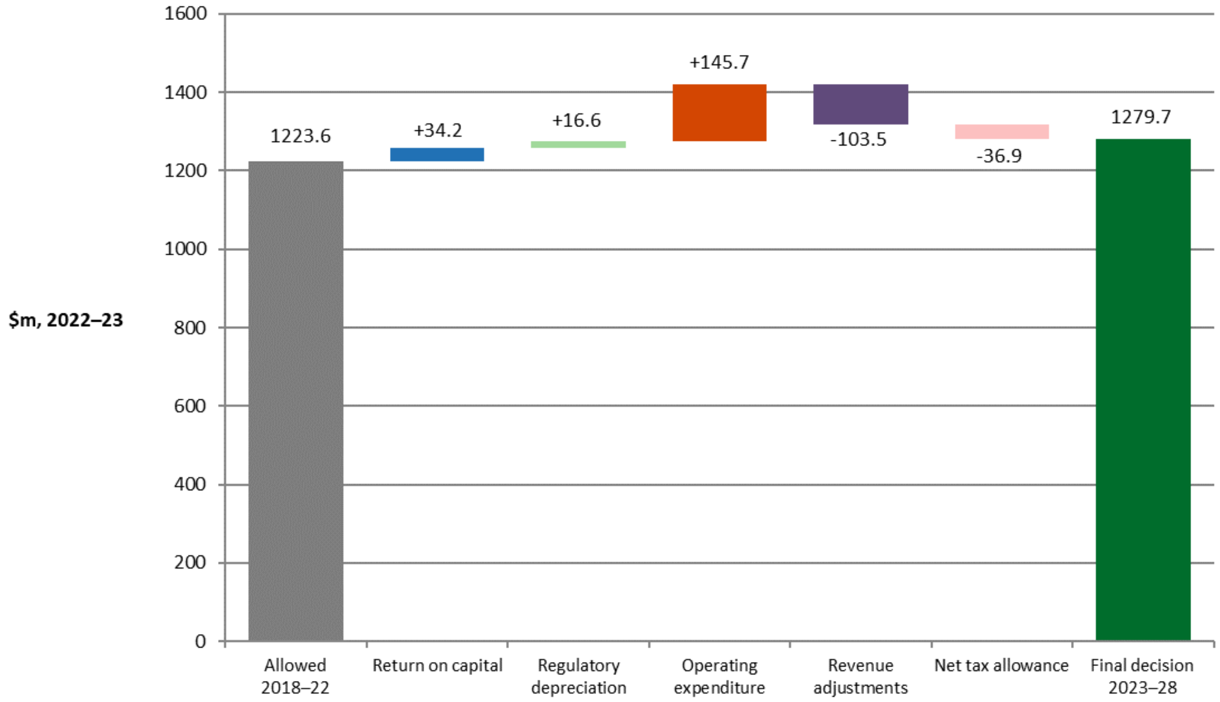
Figure 1 Changes in regulated revenue over time ($million, 2022–23)



Source: AER analysis

There are a number of reasons for this increase in revenue. Figure 2 highlights the key drivers of the change between the expected real revenue approved for AGN's 2018–22 period and that approved for the 2023–28 period.

Figure 2 Change in building block revenue 2018–22 to 2023–28 ($million, 2022–23; unsmoothed)



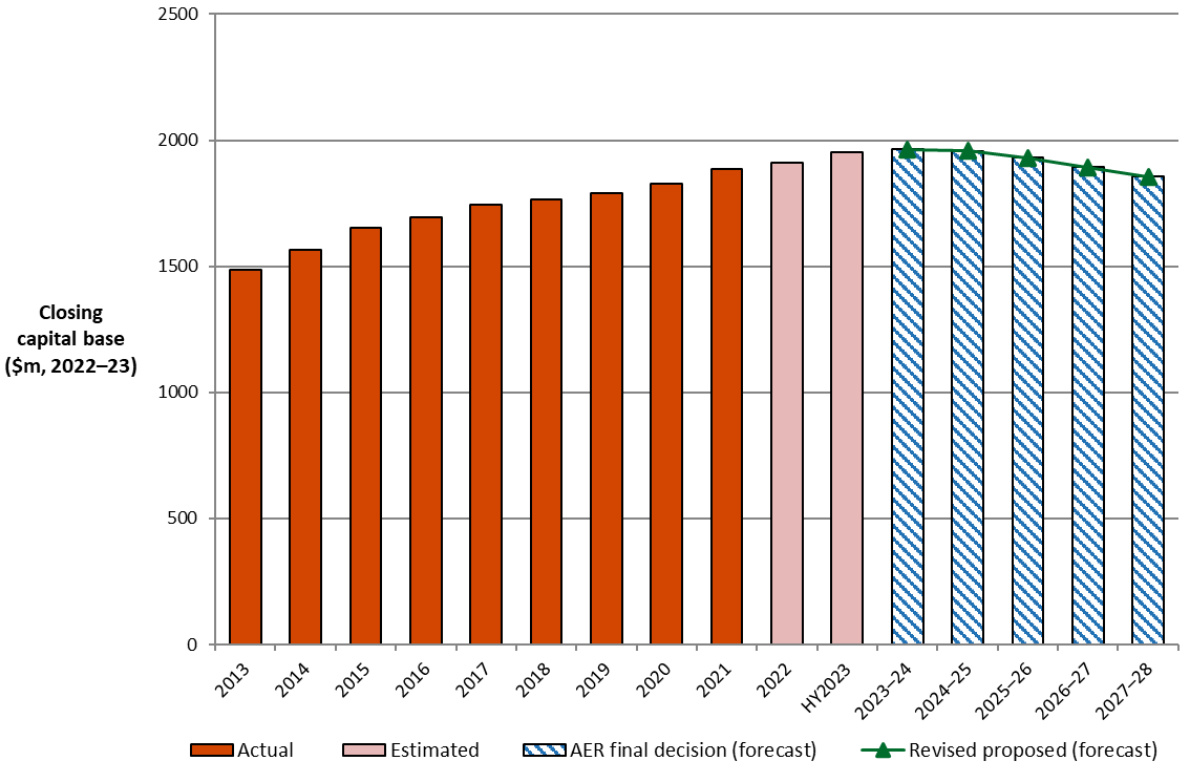
Source: AER Analysis

Note: The opex building block is inclusive of ancillary reference services. This comparison is based on converting 2018–22 forecast opex for inflation to 2022–23 dollar terms using lagged CPI.

The return on capital in this final decision is higher than in the current period. As shown in Figure 3, the real value of AGN's capital base is projected to decline over the 2023–28 period. Forecast capex is significantly lower than in previous periods as the amount of capex required to meet growth in demand and new customer connections declines. Also contributing to the declining capital base is the measured start to accelerated depreciation of assets under this final decision, which will increase the rate at which assets are 'removed' from the capital base, balancing recovery of asset costs between current customers while the customer base is still relatively high and an expected smaller number of customers in the future. However, the rate of return for the 2023–28 period is higher than for the 2018–22 period, offsetting what would otherwise be a downward impact on revenue.

The return of capital (regulatory depreciation) for the 2023–28 period is higher than for the current period. Regulatory depreciation is a method used in our decision to allocate the cost of an asset over its useful life, rather than allocating the full cost to the period in which it is incurred. AGN's 'price cap' form of control means that declining demand will drive the prices it charges to recover its revenue requirement upwards. Our final decision allows for accelerated depreciation of AGN's capital base as a way to balance the recovery of investment between current users of the network and a declining number of future users. The higher inflation rates we're currently seeing would (all else held constant) be reducing regulatory depreciation. Here, that effect is partially offsetting the impact of accelerated depreciation, noting there was also accelerated depreciation approved in our decision for the current period for mains replacement.

Figure 3 Value of AGN's capital base over time – Actual, revised proposal forecast, and final decision ($ million, 2022–23)



Source: AER Analysis

The forecast opex we have included in our forecast revenue for the 2023–28 period is materially higher than for the current period, most significantly as a result the inclusion of previously capitalised overheads as opex, the reclassification of certain capex activities as opex, and the inclusion of small customer connection abolishment costs. Our final decision to move the majority of these costs from ancillary reference services to haulage tariffs means those costs, and the expected increase in the number of connection abolishments, are now reflected in the forecast revenue requirement.

The cost of corporate income tax for the 2023–28 period is lower than for the current period. This is primarily due to applying a different regulatory tax approach for 2023–28, following our 2018 tax review.

Revenue adjustments for the 2023–28 period are lower than for the current period. This is primarily driven by the inclusion of a one-off reduction (or 'true-up') of $57.4 million to complete the transition of the access arrangement from a calendar year to a financial year cycle. It is also driven by a negative revenue adjustment resulting from the opex Efficiency Carryover Mechanism (ECM) for the 2023–28 period, and a negative revenue adjustment resulting from the introduction of the Capital Expenditure Sharing Scheme (CESS).

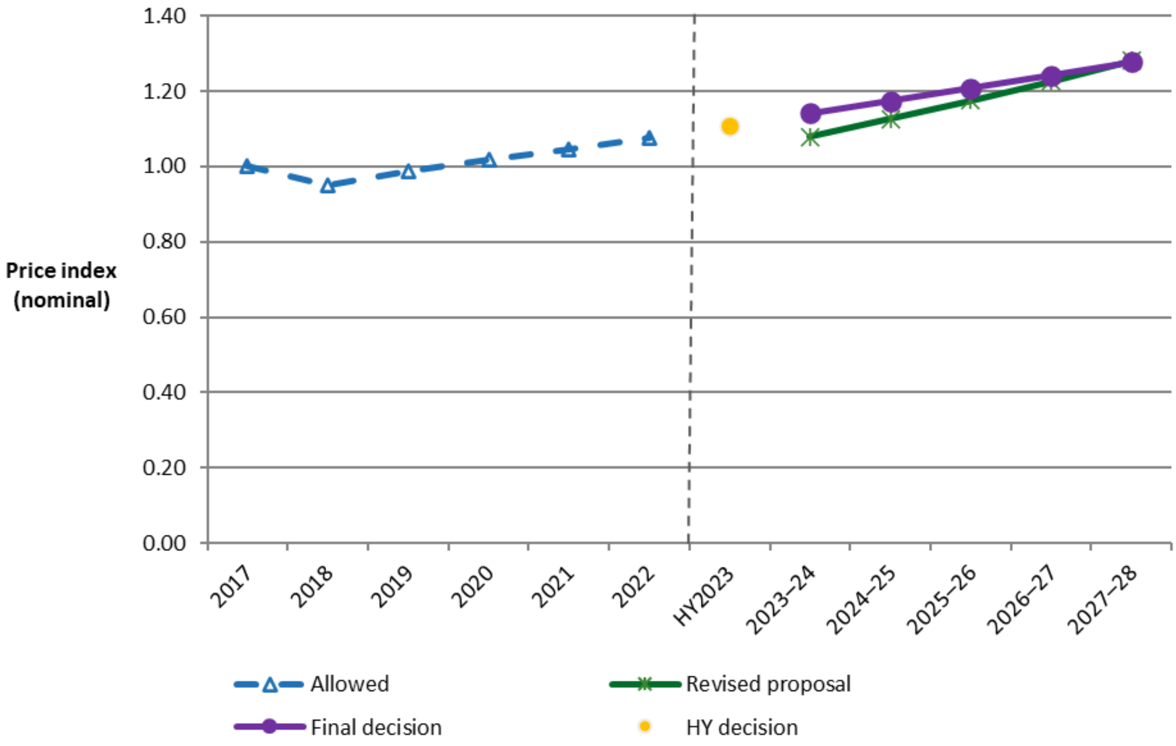
1.2 Estimated impact of our final decision on tariffs

We combine our forecast revenue requirement for AGN with forecast demand to determine its network tariffs. The forecast demand in this final decision, which reflects the latest data from AEMO's 2023 GSOO, is declining. In simple terms, tariffs are determined by dividing cost (a forecast total revenue requirement) by total demand. This means that for the same revenue amount a decrease in forecast demand leads to an increase in tariffs.

The combined effect of rising revenue and declining demand over the 2023–28 period is that this final decision will increase AGN's tariffs relative to the current period. For illustrative purposes, the modelled impact of this final decision is an estimated increase of around 15.3% by the end of the 2023–28 period.[6] This translates to an estimated nominal increase of around 2.9% per annum.

Figure 4 shows indicative tariff paths for AGN's haulage reference service across the 2023–28 period. It compares the tariff path under this final decision with that approved previously for the 2018–22 period, and with AGN's revised proposal. These are simple estimates only, calculated based on an aggregate level rather than individual zone level tariffs. While our decision establishes tariffs for year 1 (2023–24) directly, tariffs for years 2 to 5 will be set as part of the annual reference tariff variation mechanism reflecting actual inflation, updated return on debt and any cost pass throughs.[7]

Figure 4 Indicative reference tariffs paths for AGN's reference services from 2018 to 2028 ($/GJ, nominal)



Source: AER analysis.

6 In real ($2022–23) terms, the impact of this final decision on AGN's tariffs is a decrease of around 0.1% by the end of the 2023–28 period.

7 The annual reference tariff variation mechanism is discussed in Attachment 10.

AGN's distribution charges make up around 24.6% of its residential customers' gas bills and 14.9% of its small business consumers' gas bills.[8] Other components of the supply chain—the cost of purchasing energy from the wholesale market, transmission charges, and the costs and margins applied by electricity retailers in determining the prices they will charge consumers for supply—make up a larger portion in aggregate of the prices ultimately paid by consumers. These sit outside the decision we are making here, but will also continue to change throughout the period.

In nominal terms, which include the impact of expected inflation, the impact of this final decision would be an increase to the distribution component of energy bills for AGN's customers. For illustrative purposes only, holding other components constant, we estimate the modelled impact of this final decision on the average annual gas bill, as it is today, for a residential customer[9] would be an increase of $63 (3.8%) by 2027–28, or an average increase of $13 (0.7%) per annum over the 2023–28 period. For average small business customers[10], the increase would be $217 (2.5%) by 2027–28, or an average increase of $43 (0.5%) per annum over the 2023–28 period. For high usage small business customers[11], the increase would be $292 (2.3%) by 2027–28, or an average increase of $58 (0.5%) per annum over the 2023–28 period.

1.3 AGN's consumer engagement

Genuine, high quality consumer engagement by AGN is essential to ensuring that its proposal is driven by consumer preferences, supports the delivery of services that meet the needs of its consumers, and does so at a price that is affordable and efficient. We've seen through experience that a regulatory proposal developed through genuine engagement with consumers is more likely to be largely, or wholly, accepted in our decisions. Our framework for considering consumer engagement in access arrangement determinations for gas network businesses is set out in the Better Resets Handbook.[12]

Our draft decision commended the extensive and industry award-winning joint engagement program undertaken by AGN, Multinet Gas Networks (MGN) and AusNet Gas Services (AusNet) in developing their 2023–28 proposals. We also identified a number of areas that warranted further engagement with consumer and industry stakeholders in the preparation of the revised proposals. These included unresolved matters relating to the proposed Priority

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8 This is based on a residential and small business consumption of 54.4 GJ and 500 GJ being charged at AGN's 'Tariff V Domestic Central' and 'Tariff V Non-Domestic Central' approved 2022–23 tariffs, respectively, to calculate the distribution component as a proportion of our total base bill assumption.

9 Based on typical gas consumption of 54.4 GJ. Bill impact is compared to a nominal annual residential gas bill of $1,674 as at 30 June 2023. The base bill is sourced from the Essential Services Commission's, *Victorian Energy Market Report*, September 2022, Figure 38, p. 56, and indexed by expected inflation from the Reserve Bank of Australia's (RBA) May 2023 Statement on Monetary Policy (SoMP).

10 Based on typical gas consumption of 340 GJ. Bill impact is compared to a nominal annual small business gas bill of $8,674 as at 30 June 2023. This base bill is proportional to the base bill assumption of $12,756 for a 500 GJ consumption.

11 Based on typical gas consumption of 500 GJ. Bill impact is compared to a nominal annual small business gas bill of $12,756 as at 30 June 2023. The base bill is sourced from the Essential Services Commission, *Victorian Energy Market Report*, September 2022, Figure 75, p. 80., and indexed by expected inflation from the RBA's May 2023 SoMP.

12 AER, *Better Resets Handbook*, December 2021.

Services Program (PSP) for consumers, safety and equity issues to be addressed in considering cost recovery for small customer connection abolishment, and credit support arrangements for retailers.

In responding to our draft decision, AGN’s revised proposal set out the further engagement it and MGN had undertaken (and jointly with AusNet) with stakeholders to understand and respond to these residual concerns. In the months leading up to our draft decision, the six weeks between the draft decision and revised proposal, AGN’s engagement on its revised proposal included:

- Re-convening the PSP Advisory Panel prior to release of our draft decision, to re-visit the PSP and discuss outstanding implementation issues. Concerns raised in that discussion included that funding the PSP will increase prices for all customers, including beneficiaries of the program, the need for close coordination with programs offered by electricity and water companies and the existing emergency management network, how customers would access the program, and whether the program was consistent with the Victorian Government’s electrification agenda.
- Four online AGN/MGN customer workshops in January 2023 to seek input from 91 customers from both networks, focussing on accelerated depreciation and gas connection abolishment issues.
- Two joint meetings with MGN and AusNet of the Victorian Gas Networks Stakeholder Roundtable (VGNSR) and Retailer Reference Group (RRG); one before, and one after, the release of our draft decision:
  - On 10 November 2022, to explore updates in customer sentiment, new developments (related to the Victorian State Election, monetary statements and safeguards), stakeholder submissions on initial proposals, and further engagement.
  - On 15 December 2022, to discuss the draft decision and intended responses to areas of disagreement. Specific topics discussed included customer research (including the outcomes of the AGN/MGN gas customer workshops and AusNet’s survey of 800 gas customers), cost recovery challenges associated with small customer connection abolishment, demand forecasting, accelerated depreciation, the rate of return, and non-tariff terms and conditions.

A further joint VGNSR / RRG meeting was held on 6 February 2023, after the revised proposal was submitted, to ‘recap’ the revised proposal and help stakeholders with any questions as they finalised their submissions. Discussion at this meeting focussed on accelerated depreciation and connection abolishment, a focus we have seen continued in submissions to us on the draft decision and revised proposal.

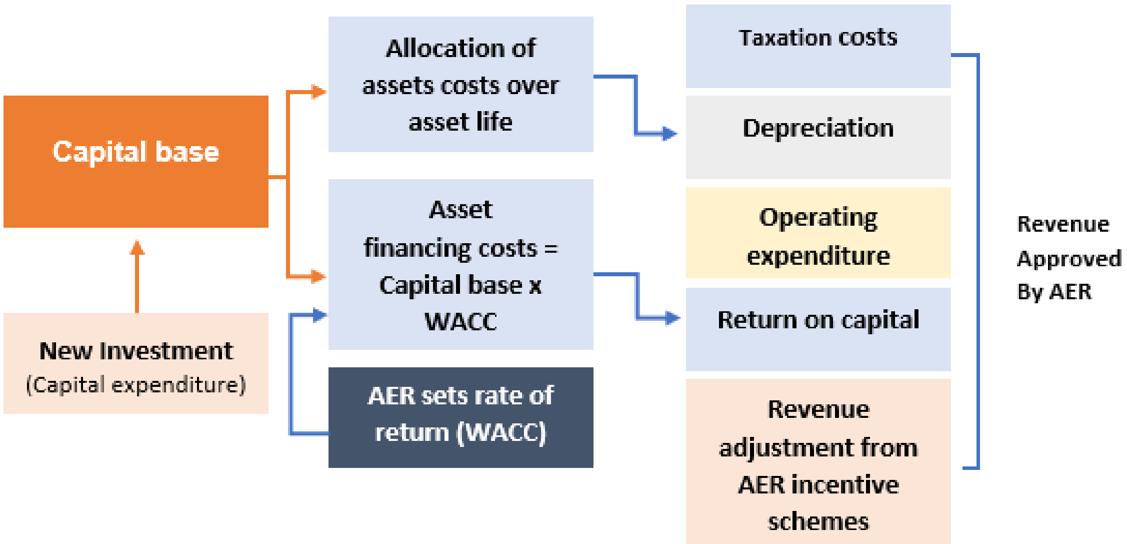
2 Total revenue requirement

The foundation of our regulatory approach is a benchmark incentive framework to setting revenues: once regulated revenues are set for the five-year period, a network that keeps its actual costs below the regulatory forecast of costs retains part of the benefit. Service providers have an incentive to become more efficient over time, as they retain part of the financial benefit from improved efficiency. Consumers also benefit when efficient costs are revealed, and a lower cost benchmark is set in subsequent access arrangement periods.

AGN's proposed revenue requirement, and our assessment of it under the NGL and NGR, is based on the six cost components, or 'building blocks', illustrated in Figure 5:

- return on the capital base – to compensate investors for the opportunity cost of funds invested in this business
- depreciation of the capital base – or return of capital, to return the initial investment to investors over time
- capex – the capital costs and expenditure incurred in the provision of network services, which directly affects the size of the capital base and, therefore, the revenue generated from the return on capital and depreciation building blocks
- forecast opex – the operating, maintenance and other non-capital expenses, incurred in the provision of network services
- revenue increments/decrements resulting from the application of incentive schemes, such as the Efficiency Carryover Mechanism and Capital Expenditure Sharing Scheme
- estimated cost of corporate income tax.

Figure 5 The building block approach to determining total revenue



Source: AER.

2.1 Final decision on total revenue

The total revenue requirement is a forecast of the efficient cost of providing gas distribution services over the access arrangement period. We determine annual revenue, and the total revenue requirement, in nominal terms that take expected future inflation into account. We use five-year inflation expectations to convert revenues to nominal values.

Our final decision on AGN's total revenue requirement is $1,362.1 million ($ nominal, smoothed). This is $86.5 million (6.8%) more than AGN's proposal, and $63.8 million (4.9%) more than our draft decision.

Table 1 sets out our final decision on AGN's total revenue requirement (by building block) for each year of the 2023–28 period, the total revenue after equalisation (smoothing), and the X factors that we have determined for use in the tariff variation mechanism.

Table 1 Final decision: AGN's smoothed total revenue and X factors for the 2023–28 period ($ million, nominal)

Building block	2023–24	2024–25	2025–26	2026–27	2027–28	Total
Return on capital	107.9	113.8	118.9	122.9	126.1	589.6
Regulatory depreciation	44.1	49.9	56.6	64.3	72.6	287.5
Operating expenditure	103.7	110.6	115.1	124.2	130.0	583.7
Revenue adjustments	–4.4	–7.9	–7.1	–4.4	–69.3	–93.0
Net tax allowance	3.5	5.6	5.3	6.8	6.8	28.0
Building block revenue – unsmoothed (including ancillary reference services (ARS))	254.8	272.0	288.9	313.8	266.3	1,395.8
Less ancillary reference services revenue	4.5	5.1	5.7	6.9	8.1	30.3
Total revenue – unsmoothed (excluding ARS)	250.3	266.9	283.2	307.0	258.2	1,365.5
Building block revenue – smoothed	**269.0**	**274.4**	**276.9**	**274.5**	**267.2**	**1,362.1**
X factors[a]	0.02%	0.02%	0.02%	0.02%	0.02%	n/a

Source: AER analysis.
n/a: not applicable.
(a) Under the CPI–X form of control, a negative X factor is an increase in price (and therefore, in revenue). The X factor for 2023–24 is indicative only. Our decision establishes 2023–24 tariffs directly, rather than referencing a change from tariffs for 1 January to 30 June 2023. The 2024–25 to 2027–28 X factors will be revised to reflect the annual return on debt update.

2.2 Revenue smoothing and tariffs

AGN operates under a weighted average price cap as its tariff variation mechanism. This means we must determine the weighted average tariff change each year such that the net present value (NPV) of unsmoothed and smoothed revenue is equal across the 2023–28 period. This average tariff change is known as the 'X factor'.

Our decision on AGN's access arrangement proposal includes a determination of AGN's total building block revenue (unsmoothed revenue), and a smoothed revenue profile across the 2023–28 period.

The X factors represent the weighted average *real* change in tariffs. As part of the annual reference tariff variation process applying from 2024, we combine the X factors we have determined in our decision with actual inflation to create *nominal* reference tariffs for the coming year. This means that the prices paid by consumers, and therefore the revenues received, change with actual inflation plus the annual X factor rate.

By smoothing revenue, we also aim to minimise price volatility between, and within, access arrangement periods by keeping the difference between smoothed and unsmoothed revenue in the final year of each period as close as possible, and to provide price signals across tariffs that reflect AGN's underlying, efficient costs of providing services. For this final decision, we set a final year divergence of 3.5%, which is slightly above our preferred target range of +-3%. We note that if there are significant changes in costs or demand at the start of the 2028–33 period, this would affect the required tariff change at that time. We are satisfied that the final decision tariff path effectively balances the aims of price path stability within the 2023–28 period and across periods.

The higher revenue we have arrived at in this final decision, combined with our revision of AGN's proposed demand forecasts, mean that revenue smoothing has also changed.[13] Further, our smoothing achieves price stability, which was a key consideration in our decision to adopt AGN's proposed accelerated depreciation amount. As a result, average annual tariffs in year 1 (2023–24) are 2.90% higher, in nominal terms, than those for the six-month extension period. While our decision establishes tariffs for year 1 (2023–24) directly, tariffs for years 2 to 5 will be set as part of the annual reference tariff variation mechanism reflecting actual inflation, updated return on debt and any cost pass throughs.[14]

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[13] Our revenue smoothing for the 2023–28 period will also smooth the return of AGN's over-recovered revenue of $57.4 million ($2022–23) from the six-month extension period. This return will reflect interest to be calculated at the regulatory WACC to maintain the time value of money. This true-up is net present value (NPV) neutral and so should ensure that both AGN and consumers are not materially better (or worse) off as a result of continuing the 2022 tariffs (extended for actual inflation) throughout the applicable access arrangement extension period.

[14] The annual reference tariff variation mechanism is discussed in Attachment 10.

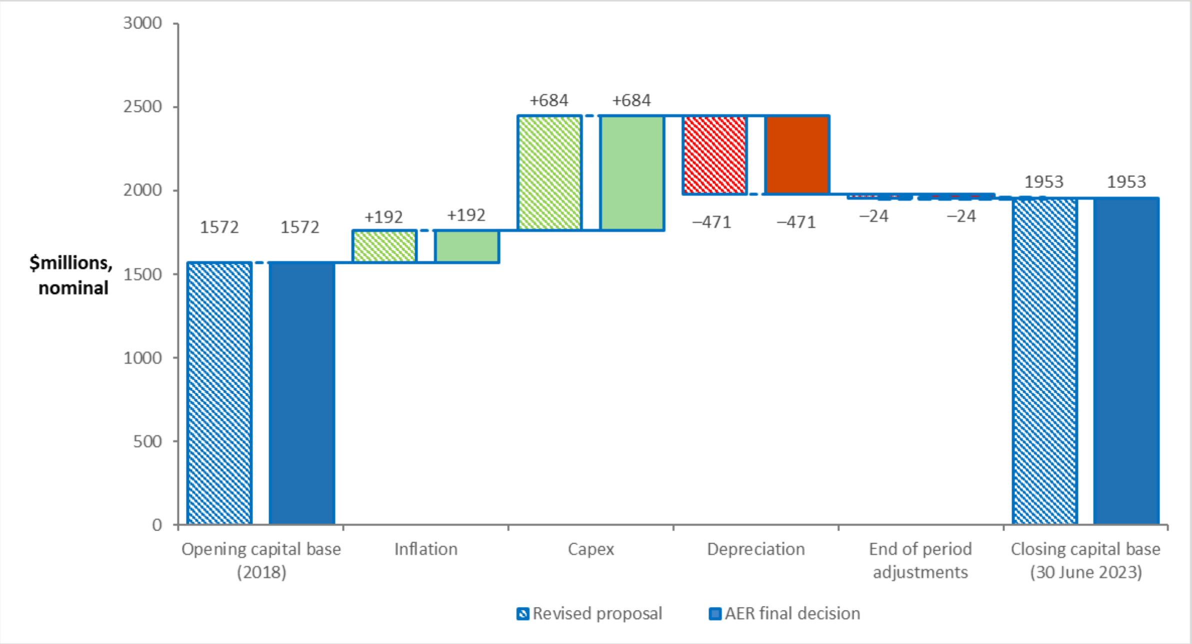
3 Key components of our final decision on revenue

3.1 Capital base

The capital base accounts for the value of regulated assets over time. To set revenue for a new access arrangement period, we take the opening value of the capital base from the end of the last period, and roll it forward year-by-year by indexing it for inflation, adding new capex and subtracting depreciation and other possible factors (such as disposals). This gives us a closing value for the capital base at the end of each year of the access arrangement period. The value of the capital base is used to determine the return on capital and depreciation building blocks. It substantially impacts AGN's revenue requirement and the price consumers ultimately pay. Other things being equal, a higher capital base would increase both the return on capital and depreciation components of the revenue determination.

For this final decision, we have accepted AGN's revised proposed opening capital base value of $1,953.1 million ($ nominal) as at 1 July 2023. Figure 6 shows the key drivers of the change in AGN's capital base over the 2018–23 period under this final decision compared to its revised proposal.

Figure 6 Key drivers of changes in capital base over the 2018–23 period – AGN's revised proposal compared with the AER's final decision ($ million, nominal)



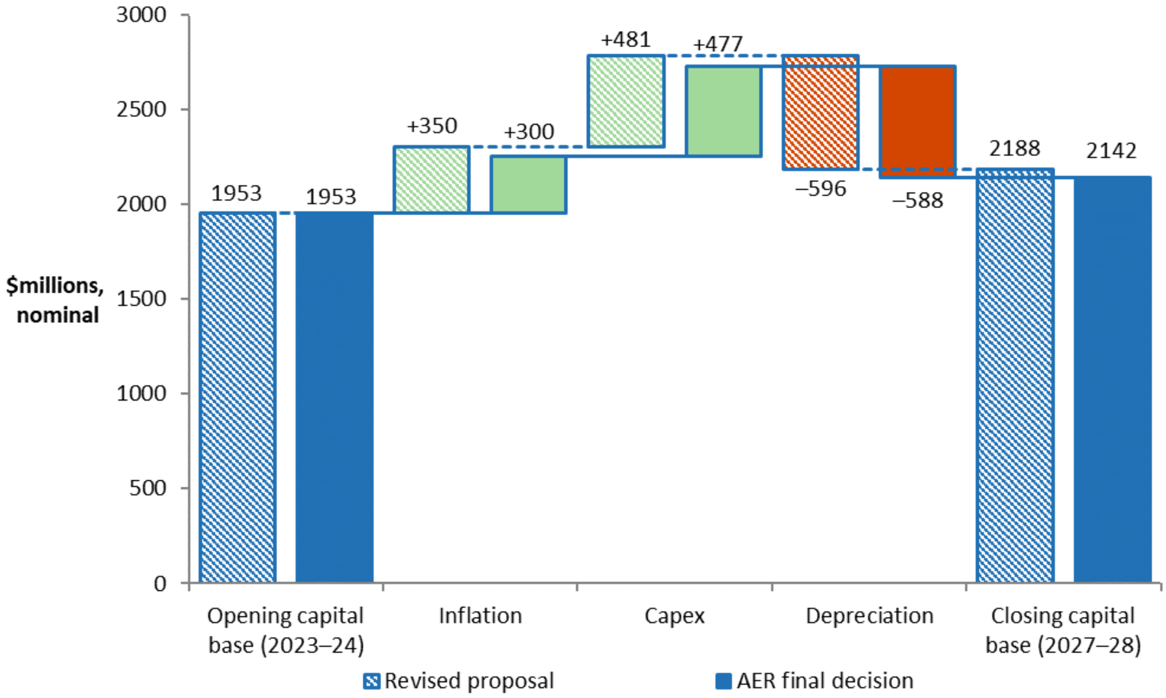
Source: AER analysis.

Note: Capex is net of disposals. It is inclusive of the half-year weighted average cost of capital (WACC) to account for the timing assumptions in the roll forward model (RFM).

Figure 7, likewise, shows the key drivers of the change in AGN's capital base over the 2023–28 period compared to its revised proposal. Our final decision projects an increase of $189.2 million (9.7%) to the capital base by the end of the 2023–28 period compared to the

$235.2 million (12.0%) increase in AGN's revised proposal. We have determined a projected closing capital base of $2,142.3 million ($ nominal) as at 30 June 2028, which is $46.0 million (2.1%) lower than AGN's proposed $2,188.3 million. This decrease is mainly due to a lower expected inflation rate applied in our final decision. It also reflects our final decision on the opening capital base as at 1 July 2023, forecast depreciation and forecast capex (discussed in the sections below).

Figure 7 Key drivers of changes in the capital base over the 2023–28 period – AGN's revised proposal compared with the AER's final decision ($ million, nominal)



Source: AER analysis.
Note: Capex is net of forecast disposals. It is inclusive of the half-year WACC to account for the timing assumptions in the PTRM. Our final decision accepts AGN's revised proposed forecast capex, the difference shown reflects updated WACC and inflation figures.

3.2 Rate of return and value of imputation credits

The return each business is to receive on its capital base (the 'return on capital') is a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the capital base.

We estimate the rate of return by combining the returns of two sources of funds for investment – equity and debt. The allowed rate of return provides the business with a return on capital to service the interest rate on its loans and gives a return on equity to investors. Our draft decision and AGN's revised proposal applied our 2018 Rate of Return Instrument

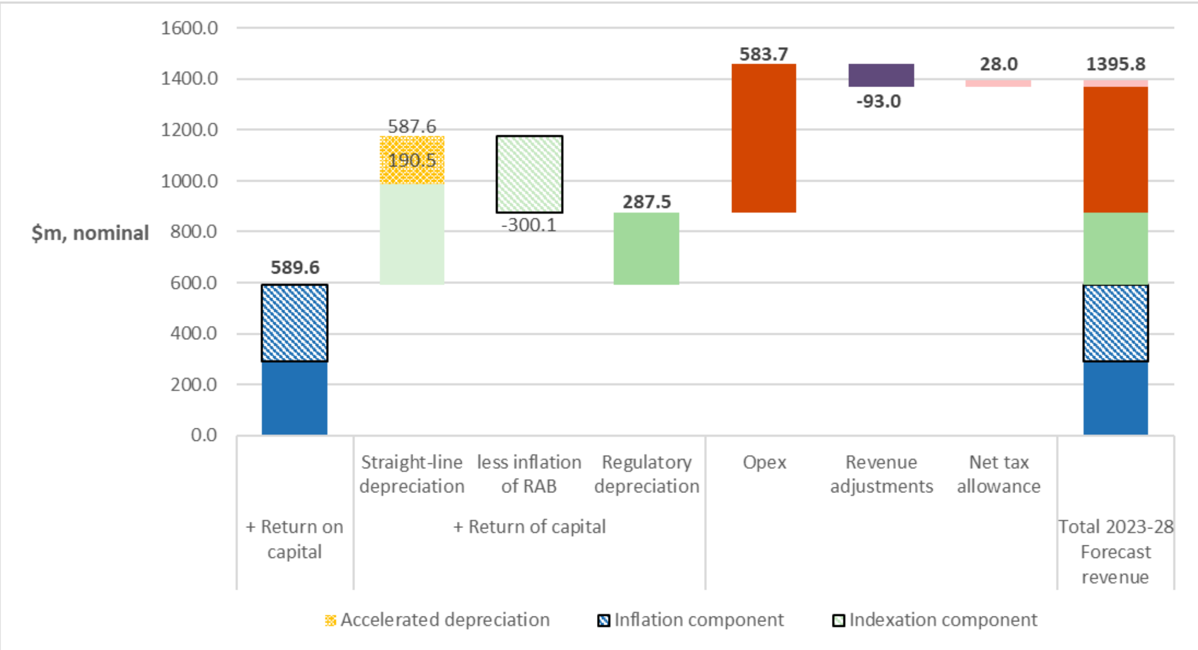
(RORI) to estimate the rate of return.[15] This final decision applies the new 2022 RORI published in February 2023:[16]

- Our final decision applies a rate of return of 5.52% for the first year of the access arrangement period, compared to the placeholder rate of return of 5.65% used in our draft decision and 5.45% in AGN's revised proposal.
- Our final decision applies a value of imputation credits (gamma) of 0.57 as set out in the 2022 RORI,[17] compared to 0.585 in the 2018 RORI.[18]

Our estimate of expected inflation for the purposes of this final decision is 2.92% per annum. It is an estimate of the average annual rate of inflation expected over a five-year period based on the approach adopted in our 2020 inflation review[19] and the forecast from the Reserve Bank of Australia's (RBA) May 2023 Statement on Monetary Policy (SoMP).[20] This is lower than the estimate of 3.37% used in our draft decision and AGN's revised proposal, which were taken from an earlier SoMP.

Figure 8 isolates the impact of expected inflation from other parts of our final decision, to illustrate its impact on the return on capital and regulatory depreciation building blocks, and the total revenue allowance. Other elements held constant, lower inflation reduces the return on capital but increases regulatory depreciation.

Figure 8 Inflation components in final decision revenue building blocks



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15 AER, *Rate of return Instrument*, December 2018. See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-guideline-2018/final-decision

16 AER, *Rate of return Instrument*, February 2023. See https://www.aer.gov.au/publications/guidelines-schemes-models/rate-of-return-instrument-2022/final-decision

17 AER, *Rate of return Instrument, Explanatory Statement*, February 2023, pp. 240–250.

18 AER, *Rate of return Instrument, Explanatory Statement*, December 2018, pp. 307–382.

19 AER, *Final position – Regulatory treatment of inflation*, December 2020.

20 RBA, *Statement on Monetary Policy,* May 2023, Table 1: Forecast Table. See https://www.rba.gov.au/publications/smp/2023/may/forecasts.html

Source: AER Analysis.
Note: The opex building block and total 2023-28 forecast building block revenue are inclusive of ARS revenue

3.3 Regulatory depreciation

Depreciation is a method used in our determination to allocate the cost of an asset over its useful life. It is the amount provided so capital investors recover their investment over the economic life of the asset (otherwise referred to as 'return of capital'). When determining the total revenue for AGN, we include an amount for the depreciation of the projected capital base.[21] Under the building block framework, regulatory depreciation consists of the net total of the straight-line depreciation less the indexation of the capital base.

Our final decision includes $287.5 million ($ nominal) of regulatory depreciation for AGN for the 2023–28 period. This is $41.5 million (16.9%) higher than AGN's revised proposal of $246.0 million.

The key reason for the increase compared to AGN's revised proposal is the lower expected inflation rate for the 2023–28 period. Our final decision includes a more recent forecast of expected inflation which is lower than the placeholder in our draft decision and AGN's revised proposal. This reduces the adjustment for indexation of the capital base that is offset against straight-line depreciation in determining regulatory depreciation. Updates to inflation are a standard part of our process, and this is not an area of disagreement between us and AGN. The reduction in indexation results in a higher regulatory depreciation amount compared to the revised proposal.

In our assessment of accelerated depreciation, our final decision accepts the $175 million in AGN's revised proposal, which is consistent with the amount in its initial proposal addendum (which reflected updates for the Roadmap).

In our draft decision, we adopted AGN's proposed accelerated depreciation of $175 million because it resulted in real price decreases and, therefore, met our 0% per annum real price path constraint.

We noted that consumers would need to be further consulted on this topic and that the final decision outcome on accelerated depreciation may differ from the draft decision. We stated that in undertaking this consultation and considering its response to the draft decision, we expected AGN to look at accelerated depreciation in the context of other components of its total revenue requirement, including the potential impact of inflation and the weighted average cost of capital (WACC) values on revenue and prices.

We acknowledge that AGN has undertaken further engagement with its consumers, including through online consumer workshops and meeting with key consumer advocates.

For this final decision, we remain of the view that employing a price path approach is appropriate. This is because it allows the AER to balance accelerated depreciation price impacts on consumers and uncertainty around demand forecasts and policy developments.

However, we have amended our price path constraint approach from the draft decision in order to preserve the intended objectives of the CESS and ECM incentive schemes applying

[21] NGR, r. 76(b).

to expenditures in the 2018–22 access arrangement period. Under these incentive schemes, networks are rewarded for efficient expenditure and penalised for inefficient expenditure. We consider our amended approach for the final decision addresses an issue raised by AusNet in its revised proposal that under the draft decision price path constraint approach, the allowed accelerated depreciation was affected by 2023–28 amounts for CESS and ECM which effectively removed the incentive properties of these schemes.

For this final decision, our approach for accelerated depreciation is to:

- Set a base real price path constraint of 1.5% per annum. for all 3 Victorian gas distributors, which excludes the impact of the 2023–28 revenue adjustments for CESS and ECM.
- Add back in the 2023–28 revenue adjustments relating to the CESS and ECM to provide the building block revenue allowance, and resmooth for the resulting real price path (which will, therefore, be different from the base price path constraint).

Based on our approach, we have accepted AGN's accelerated depreciation of $175 million since it results in a real price path below the 1.5% per annum real price constraint before the inclusion of incentive scheme penalties. Including these incentives amounts results in a 0.1% per annum real price path for AGN.

The base price path constraint of 1.5% per annum applies to all 3 Victorian gas distributors is higher than the 0% per annum real price path constraint we set in the draft decision. It reflects their respective updates since the draft decisions, including for opex (abolishments), forecast demand, WACC and inflation. It also reflects that AGN's engagement with consumers subsequent to the draft decision, showed a willingness to pay a higher price now if it would mitigate the risk of price increases in the long-term. The Energy Users' Association of Australia also submitted that modest real increases to network charges from accelerated depreciation would be appropriate.

In accepting AGN's proposed accelerated depreciation, we recognise that the publication of the Roadmap indicates that the Victorian Government is committed to the net zero emissions target by 2050.[22] This will likely mean a limited role for gas beyond this date. The 2023 GSOO shows a material decline in gas volumes over the next 20 years under the most likely scenario. There is also considerable uncertainty around likely medium to long term forecast volumes of customer abolishments. Further, the future role for hydrogen and other renewable gases is also uncertain at this time.

Consistent with our draft decision, we have considered the balance between accepting some accelerated depreciation and also price stability. This is also consistent with our 2021 information paper, *Regulating gas pipelines under uncertainty*, which stated:

> '… regulated depreciation or risk compensation cannot be adjusted without constraint to guarantee cost recovery for the regulated businesses. [The AER] must have regard to consumers' interest in having affordable and stable or reasonably predictable gas access prices to encourage their use of the gas infrastructure. Having said that, it is fair to note that regulated businesses also

22 Victorian State Government, *Gas Substitution Roadmap*, July 2022.

> have an interest to maintain price affordability to avoid further decline in gas customer numbers.'

In submissions received, stakeholders were mostly supportive of the draft decision price path constraint approach and they acknowledged the impact of uncertainty of future demand in assessing accelerated depreciation. Several stakeholders raised concerns about increasing the draft decision price path target of 0% per annum in the face of sustained rising cost of living stresses.

AGN's revised proposal acknowledged the importance of price stability, but considered our draft decision price path constraint of 0% per annum did not best balance the needs of current and future customers.

Having carefully assessed the material before us, we consider our final decision approach achieves an appropriate balance between what consumers pay now to mitigate future price increases, and the risk of greater increases in the future if mitigation is delayed. While we acknowledge stakeholders' concerns around affordability, we consider that on balance it is appropriate to increase the price path constraint above the 0% per annum set in the draft decision to reflect updated decision inputs since the draft decision including for opex (abolishments), forecast demand, WACC and inflation. Setting the base real price path constraint at 1.5% per annum allows for an appropriate amount of accelerated depreciation for each distributor.

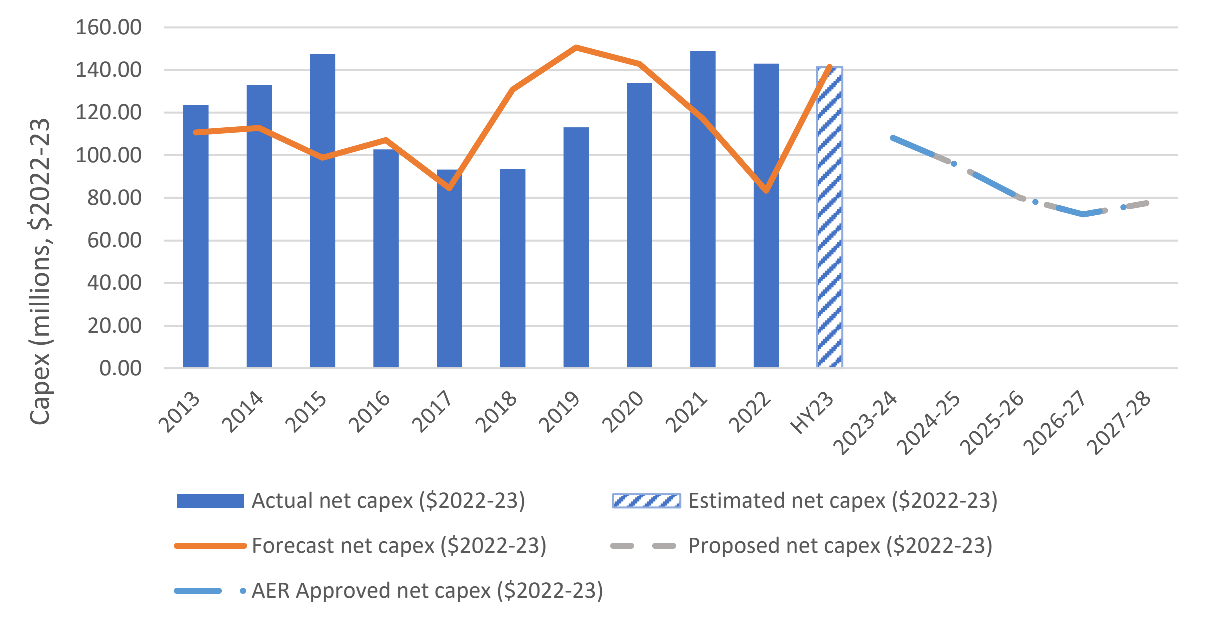
3.4 Capital expenditure

Capital expenditure (capex)—the capital costs and expenditure incurred in the provision of network services—mostly relates to assets with long lives, the costs of which are recovered over several access arrangement periods. Forecast capex directly affects the size of the capital base and the revenue generated from the return on capital and depreciation building blocks.

Our final decision includes total forecast capex of $433.5 million ($2022-23) for the 2023–28 access arrangement period. This is consistent with AGN's revised proposal.

It is $196.8 million (31%) lower than AGN's actual capex by the end of the 2018–22 access arrangement period, as shown in Figure 9. Stakeholders have raised concerns about the ongoing size of the capital programs in light of falling demand. In response to this, it is important to note that the AER must approve reasonable costs for operating a gas network, and many of these costs, such as safety cost, do not significantly fall in line with a reduction in demand. Our further reasons for accepting the proposal are set out below.

Figure 9 Historical and forecast capex ($ million, 2022–23)



Source: AER analysis.
Note: The six-month 2023 period (HY2023) has been annualised to make it comparable and consistent with other years.

This reduction reflects a change in the key drivers of capex as demand declines. Growth driven expenditure for new connections to the network, and augmentation (extension or expansion) of the network, is expected to be $223.9 million (9%) lower than in the current period as fewer customers seek to connect to the network and the amount of gas consumed at remaining connections falls. Forecast demand is discussed in section 4 below. Forecast capex of $166.1 million for new connections and $57.8 million for augmentation is consistent with our approved demand forecasts for the 2023–28 period.

Some stakeholders raised concerns about the ongoing size of the capital programs in light of falling demand and our decision to accept accelerated depreciation. We note that many capex drivers, including investment to maintain the safety, security and reliability of the network for remaining customers, will be less impacted by demand in the short term. While AusNet remains obligated to provide gas services to customers, it must continue to do so to regulated safety and reliability standards. This means that ongoing investment in capex categories such as IT, augmentation, meter replacement and the completion of AGN's mains replacement program are still required over the 2023–28 access arrangement period. Forecasts of lower customer numbers and reduced throughput on the network will have minimal impact on the scope and costs of these programs in the immediate term.

We provide a detailed explanation of the treatment of capex and our response to submissions in Attachment 5.[23]

23 AER, *AGN 2023-28, Final decision, Attachment 5 – Capital expenditure,* June 2023.

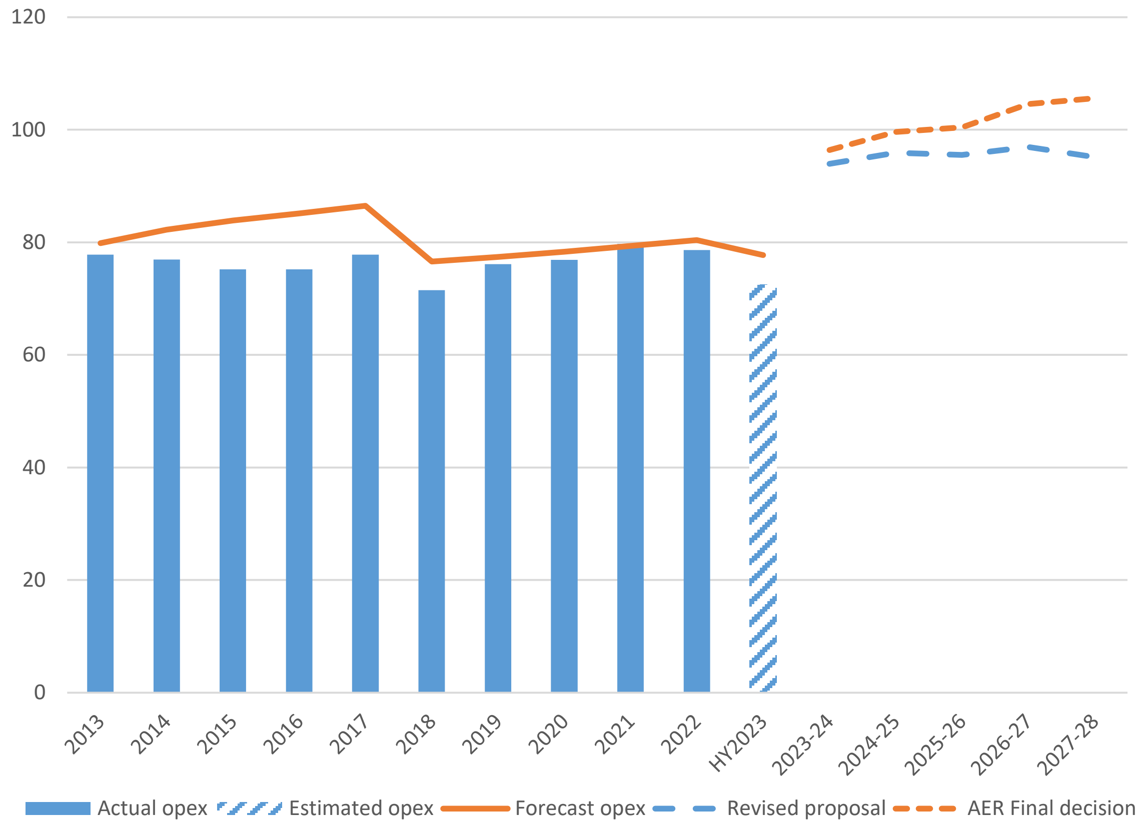
3.5 Operating expenditure

Operating expenditure (opex) is the operating, maintenance and other non-capital expenses incurred in the provision of pipeline services.

Our final decision is to include a total opex forecast of $506.5 million ($2022–23) for the 2023–28 access arrangement period, excluding ancillary reference services and including debt raising costs. Our final decision approves higher total forecast opex than in AGN's revised proposal, because we have added $29.1 million ($2022–23) for forecast costs of small customer connection abolishments. We consider these costs meet the opex criteria[24] and forecasts and estimates criteria.[25] As in our draft decision, we remain satisfied that other elements of AGN's opex forecast also satisfy the opex criteria and the criteria for forecasts and estimates. These contribute the remaining $477.5 million ($2022–23) of the total opex forecast approved in this final decision.

In Figure 10, we compare our final decision opex forecast for the 2023–28 period (the orange dashed line) to AGN's revised proposal (the blue dashed line, which also reflects our draft decision). We also show the forecasts we approved for the last two access arrangement periods from 2013–2022 (the solid orange line) and AGN's actual opex across those periods (the blue bars).

Figure 10 Historical and forecast opex ($million, 2022–23)



24 NGR, r. 91.

25 NGR, r. 74.

Source: AGN, *Regulatory accounts*, 2013 to 2021; AGN, *Revised proposal 2023–28, PTRM*; AGN, *Access arrangement, PTRM* (multiple periods: 2013–17, 2018–22, 2023–28); AER analysis.

Note: Includes debt raising costs and movements in provisions. The six-month 2023 period (HY2023) has been annualised to make it comparable and consistent with other years.

The total opex forecast in AGN's revised proposal, and our draft decision, was $94.6 million ($2022–23) higher than actual opex for 2018–22 period, most significantly as a result of the inclusion of previously capitalised overheads as opex, and the reclassification of certain capex activities (such as sampling or repair and maintenance type activities) as opex.

Some stakeholders raised concerns around the total opex forecast approved in our draft decision, particularly in relation to increases in the total opex forecast at a time when demand is expected to fall, allowing opex in excess of our alternative estimate, and funding of the Priority Service Program (PSP). In our draft decision, we tested AGN's total opex forecast by developing an alternative estimate using our top-down 'base–step–trend' forecasting approach. While we arrived at our alternative estimate in a different way to AGN, we did not find a material difference to AGN's proposed opex forecast, which we accepted. This included taking into account forecast changes in demand. We encouraged AGN to continue to work with relevant stakeholders in preparing its revised proposal for the PSP. We are disappointed that further detail was not provided about a refined scope for the program in the revised proposal. However, consistent with the outcomes our *Towards Energy Equity Strategy* is seeking to achieve, we expect AGN to be able to demonstrate tangible outcomes for customers in vulnerable situations under this program at the start of its next access arrangement period.

Our final decision is $29.1 million ($2022–23) higher[26] than AGN's revised proposal (and our draft decision) as we have included additional opex for small customer abolishment costs. This reflects our final decision to socialise the bulk of small customer connection abolishment costs across haulage reference service tariffs, and establish a discounted standalone ancillary reference service tariff, to ensure the safe operation of the network. This means that a significant proportion of small customer connection abolishment costs will be recovered via haulage reference opex and associated charges. This results in higher forecast opex than included in AGN's revised proposal.

AGN's revised proposal re-stated its position that a standalone small customer connection abolishment cost reflective tariff was appropriate and it did not include any small customer connection abolishment costs in its total opex forecast for haulage reference services. In light of our decision to socialise the bulk of small customer connection abolishment costs and recover them via haulage reference service charges, we developed an estimate of the associated forecast opex using:

- The abolishment costs to be socialised of $730, which was determined via AGN's cost reflective tariff for abolishments of $950[27] *less* the $220 ancillary reference charge.

[26] This is equivalent to the $33.7 million increase to opex noted in section 1 of this overview, but in real $2022–23 terms and excluding ancillary reference services.

[27] AGN, *Revised final plan, Access Arrangement 2023–28, Tracked version – Current AA with credit support*, January 2023, p. 52.

- Our forecast of abolishments over the 2023–28 period, which is lower than AGN's forecast as we have:
  - lagged AGN's abolishments forecast by two years, assuming a consistent gradual increase from AGN's current abolishment volumes to its forecast abolishment volumes during this lag period, to better reflect likely customer behaviour and responses to current and any future government initiatives incentivising electrification.
  - reduced AGN's abolishments forecast by 26% to account for customers who electrify their homes but wish to retain their gas connection for the 'option value' it provides.

AGN, however, did not agree with our approach to forecasting small customer connection abolishments. We have set out our forecast of abolishments, and our reasons, in greater detail in Attachment 6.

Because of the significant uncertainty around these small customer abolishment costs, we have also decided to include a true-up mechanism to ensure costs are only recovered for the actual number of connections abolished, and that any cost savings achieved are returned to customers. This is discussed further in section 5.2.1.

3.6 Revenue adjustments

Our calculation of total revenue for AGN includes adjustments under the opex Efficiency Carryover Mechanism (ECM) and Capital Expenditure Sharing Scheme (CESS) in its access arrangement. These mechanisms provide a continuous incentive for AGN to pursue efficiency improvements in opex and capex, and provide for a fair sharing of these between AGN and users.

Our final decision includes a negative adjustment of $12.0 million ($2022–23) from the application of the ECM in the 2018–22 period, excluding ancillary reference services. While AGN's revised proposal proposed a negative adjustment of $5.7 million, this included ancillary reference services.[28] In a response to an information request about this, AGN agreed with our approach to exclude ancillary reference services and accepted our draft decision.[29] We have updated our final decision for inflation, but this did not have a material impact.

We have also included a negative adjustment of $12.7 million under the CESS for the five-year period. This negative adjustment is $0.2 million higher in magnitude than AGN's revised proposal. This difference reflects updates to the consumer price index (CPI) and WACC inputs.

We have also approved AGN's proposal that the ECM and CESS continue to apply during the 2023–28 period. For the ECM, the minor revisions required to AGN's 2023–28 Access Arrangement are set out in Attachment 6 of our final decision. For the CESS going forward,

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28 AGN, *Revised final plan, Access Arrangement 2023-28, Attachment 12.3 – Updated ECM model*, January 2023.

29 AGN, *Response to IR#28 – ECM – Draft decision, February 2023.*

differences between forecast and actual connections capex will be excluded from the calculation of rewards or penalties.

3.7 Corporate income tax

Our determination of the total revenue requirement includes the estimated cost of corporate income tax for 2023–28 period. Under the post-tax framework, this amount is calculated as part of the building blocks assessment using our PTRM.

Our final decision determines an estimated cost of corporate income tax amount of $28.0 million ($ nominal) for AGN over the 2023–28 period. This is an increase of $6.8 million (31.7%) from AGN's revised proposal of $21.3 million. This increase is primarily due to a higher regulatory depreciation in our final decision, which in turn increased AGN's revenue for tax purposes and therefore cost of corporate income tax.

4 Forecast demand

Forecast demand plays an important role in these access arrangements:

- It is a key input into the derivation of reference tariffs under the current price cap form of control. In simple terms, tariffs are determined by dividing cost (a forecast total revenue requirement) by total demand. This means that for the same revenue amount a decrease in forecast demand leads to an increase in tariffs, and vice versa.
- Forecast demand also drives elements of operating and capital expenditure (opex and capex for new connections and augmentation of the network), which inform our decision on forecast revenue.

The NGR require demand forecasts and estimates that are arrived at on a reasonable basis and represent the best forecast or estimate possible in the circumstances.

In the draft decision, we provisionally accepted AGN's demand forecasts, while noting that we expect the revised proposal would include forecasts based on the latest information, including the outcome of AEMO's 2023 Gas Statement of Opportunities (GSOO).

AEMO released its 2023 GSOO on 16 March 2023. On 30 March 2023, AGN provided a submission noting that it would not be adjusting its demand forecast to account for the GSOO. We compared AGN's forecast trend to AEMO's GSOO trend. We considered the difference in the trend between the two was moderate, with AGN's total demand falling below the GSOO trend. If the GSOO trend were adopted, AGN's reference tariffs would be lower, provided other inputs were held equal. Consequently, we decided to adjust AGN's demand forecast using a Victorian GSOO index, which results in a marginally higher demand forecast than AGN proposed, and lower reference tariffs.

As noted in the opex discussion at section 3.5, we consider AGN's abolishment forecast should be lower. If fewer customers are leaving the network, it follows that the forecast of customer numbers should be higher. We consider one less abolishment is equal to one more customer on the network where we have lagged AGN's abolishment forecast. Consequently, we have revised AGN's forecast of customer numbers upwards, in direct proportion to the reduction in the abolishments forecast.

5 Reference services and tariffs

AGN's access arrangement specifies the reference services it will provide, the tariffs for those services, and the other terms and conditions on which they will be provided.[30]

5.1 Services covered by the access arrangement

AGN is to provide access to its reference services on the terms set out in the access arrangement but may negotiate alternative terms and conditions at alternative prices with users. AGN may also offer other non-reference services (negotiated services) which are not subject to regulation under the access arrangement. We may be called upon to determine the tariff and other conditions of access to services if an access dispute arises.[31]

Our draft decision was to accept AGN's reference service proposal for the 2023−28 period, other than for abolishment – residential (small customer connection abolishment). While we accepted small customer connection abolishment as a reference service, we did not accept it as a standalone price capped ancillary reference service, as proposed by AGN. Our draft decision was to keep open the possibility of bundling small customer connection abolishment with haulage tariffs, known as socialising, and seek stakeholder comment. We did so because we were concerned that cost reflective pricing may, in this case, be inconsistent with public safety.

Connection abolishment involves removal of pipes connecting a consumer's premises to the mains pipeline, sealing the mains and making the site safe. The alternative cease of service options are to either cap supply at the meter (a temporary disconnection that can be reversed by removing the cap at a later date), or to have the meter itself removed while connecting pipes are retained. In both cases, safety issues arise because gasified connection pipes remain underground. While these alternatives are considerably cheaper than abolishment, they raise issues such as the safety aspect of gas pipelines remaining underground and the costs to maintain this unused service.

The decision on which type of cease of service is safest is not for us to make. It sits with Energy Safe Victoria (ESV) as the jurisdictional safety regulator. ESV's current position is that permanent abolishment is required for gas distributors to meet their obligations to minimise the safety risks of permanent disconnection as far as practicable.[32]

In reaching our draft decision to keep open the possibility of socialising small customer connection abolishment, we considered a submission from ACT gas distributor, Evoenergy, which noted that some of its small customers are avoiding abolishment tariffs with the result that unused, but live, connections were remaining in situ. We also noted reports from energy retailers that some customers are indeed avoiding abolishment tariffs. Most stakeholder submissions on our draft decision supported socialising small customer connection abolishment costs, even if some submissions canvassed cost recovery across both gas and

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30 NGR, r. 48(1).

31 NGL, Chapter 6.

32 Energy Safe Victoria, letter to the AER, *Abolishment of gas connection due to electrification*, April 2023, p.2.

electricity customers – an option the AER is unable to deliver in the context of gas access arrangement reviews.

AGN's revised proposal re-stated its position that a standalone small customer connection abolishment cost reflective tariff is appropriate. In doing so, AGN referenced stakeholder views elicited through its consultation processes. AGN also noted the financial impact of socialising abolishment costs on customers remaining connected to its network.

We have taken AGN's revised proposal into account in reaching our final decision. We have also given weight to stakeholder submissions received in response to our draft decision. We further engaged with AGN since releasing our draft decision. We observed a Retailer Reference Group workshop hosted by AGN, MGN and AusNet where small customer connection abolishment was the primary focus, in which engineering staff of the distributors emphasised the importance of abolishing unused gas connections for public safety, consistent with ESV's position.

Our final decision is to socialise the bulk of small customer abolishment costs across haulage tariffs and establish a discounted standalone ancillary reference service tariff.

While we are concerned about the financial impact on remaining gas customers, on balance, we consider mitigating risks to public safety is the more urgent objective. Our approach for the 2023−28 period, to socialise the bulk of abolishment costs across remaining gas customers, can be only an interim solution to the public safety issue we have identified. The impact on prices, as we have discussed above, will only increase should demand continue to fall and should more customers consider leaving the network. Further work between market bodies, distributors and other market participants, and governments is needed to develop a more sustainable solution for future access arrangement periods.

With respect to AGN's reference service revised proposal, our final decision is to accept it. It clearly delineates between small and large customer abolishment services as required by our draft decision. We discuss in the next section below our final decision on the tariff for small customer abolishment.

5.2 Reference tariff setting and variation mechanism

Our draft decision was that the same tariff setting and tariff variation mechanisms that have applied in the current period should continue to apply to AGN in the 2023−28 period, except for small customer abolishment. Our final decision is consistent with our draft decision.

5.2.1 Small customer abolishment

On small customer abolishments, our final decision is to set a consistent discounted tariff across the 3 Victorian distributors of $220 for 2023−24, escalated annually by CPI across the remaining years of the 2023−28 period. The balance of small customer connection abolishment tariffs will be recovered via haulage tariffs for all customers remaining connected to AGN's network.

We consider setting the small customer abolishment at $220 balances a range of considerations:

- It is around one quarter of the cost reflective tariffs proposed by the Victorian distributors, mitigating the incentive for customers to avoid requesting abolishments, so also mitigating the accompanying public safety risk.
- It is marginally higher than the combined cost of standalone tariffs for temporary disconnection and meter removal across all 3 distributors, so avoids creating a perverse incentive for customers renovating their homes to request abolishment when temporary disconnection and meter removal are clearly the most appropriate services.
- Customers remaining connected to Victorian distribution networks are not required to finance the full cost of abolishment services requested by customers who choose to cease their gas service.
- Setting a single, consistent, tariff across the 3 Victorian distributors will assist messaging to customers by distributors and retailers.

While we consider $220 represents a reasonable balance of the above considerations, we recognise that other tariff levels, whether higher or lower, may also be justified. We further recognise that differentiating the abolishment tariff across the 3 Victorian distributors could better align it with the distributors' varying tariffs for temporary disconnection and meter removal. However, in this instance, given the public safety aspect of our final decision, we consider setting a single state-wide tariff provides benefits in the form of simple, predictable abolishment costs that make this an appropriate resolution.

The balance of abolishment costs that are to be socialised across haulage tariffs will be financed through an ex ante opex allowance based on each distributors' per unit cost reflective abolishment tariff and forecasts of the number of annual abolishments undertaken. Our final decision is to build into the Victorian distributors' access arrangements a true-up mechanism that will reduce haulage tariffs should either abolishment volumes, or the per unit cost, be lower than currently expected. This will protect customers from paying higher haulage tariffs than necessary over the next five years. We consider this is an important element of our overarching approach to dealing with abolishment tariffs, given the significant uncertainty about the number of abolishments to be undertaken during the 2023–28 period. There is also uncertainty about the future per unit cost of small customer abolishments. At time of writing, ESV is undertaking a review of appropriate abolishment methods in the context of potentially large numbers of customers permanently disconnecting from Victoria's gas networks. Our abolishment true-up mechanism will adjust haulage tariffs for any lower cost abolishment methods should they be approved by ESV.

5.2.2 Safeguard mechanism

With their revised proposals, the Victorian distributors raised a new issue: the Commonwealth Government's Safeguard Mechanism which will impose carbon emissions permit costs on liable entities, such as gas distributors. Specifically, the distributors proposed to recover their costs of complying with the Safeguard Mechanism by amending the tariff variation mechanism for haulage services.

Our final decision is to approve the distributors' proposal. We note the proposed approach is the same as used by them to recover equivalent costs associated with the previous carbon price. We further note that costs are initially expected to be relatively low, but will increase each financial year to 2030. If we do not establish a mechanism for cost recovery now, the distributors will be unable to recover these costs.

To inform our final decision, we requested further information from the distributors to augment what was provided with their revised proposals. We also considered the Safeguard Mechanism policy development undertaken to date by the Commonwealth Government and the existing level of uncertainty over some remaining policy issues.

While we consider it unfortunate that the Safeguard Mechanism was raised by distributors only in the revised proposals, thereby limiting the ability of stakeholders to engage with it, we recognise that related policy is still in development. Passing through to customers only those costs actually incurred will protect customers from paying higher haulage tariffs than necessary.

5.2.3 Cost pass through events

Our final decision confirms that the cost pass through events available to AGN in the current period will continue to apply in the 2023–28 period. These reflect the minor revisions we made in the draft decision, which AGN accepted.

In relation to the retailer insolvency cost pass through event, AGN sought to modify this event so it was no longer subject to a materiality threshold. It proposed this alongside other proposed changes to its credit support arrangements which it sought to align with credit support arrangements from other jurisdictions in which the National Energy Customer Framework applies (and part 21 of the NGR). Our final decision is to include a Retailer Insolvency Event which is subject to a separate assessment process than that applicable to other pass through events included in the 2023–28 access arrangement period. This is because we consider the modified Retailer Insolvency Event should be subject to equivalent application and assessment processes and requirements as Retailer Insolvency Events which occur in other jurisdictions where part 21 of the NGR applies. We consider this is consistent with the intent of AGN's proposed change to the Retailer Insolvency Event which was to enable better alignment of its credit support arrangements with other jurisdictions. Consistent with AGN's proposed approach, the revised cost pass through does not include a materiality threshold.

Our final decision is to not accept the new 'Unrecovered Abolishment Event' that AGN included in its revised proposal. AGN proposed this event to recover abolishment service charges where there was no customer to pay for the abolishment, or it was a requirement under law or an approved safety mandate. It proposed the cost pass through would apply to costs that exceeded the materiality threshold. Our final decision is to socialise the bulk of small customer abolishment costs across haulage tariffs and establish a discounted standalone ancillary reference service tariff, and to include a true-up mechanism (as set out in sections 3.5 and 5.2.1). This means it is no longer likely that AGN will experience a material impact from unrecovered abolishment service charges. This consideration informs our decision not to include the Unrecovered Abolishment Service Charges Event in the 2023–28 access arrangement.

Our final decision also includes a fixed principle that AGN proposed which enables the recovery of approved cost pass revenues in the 2023–28 period. This is consistent with our standard practice.

5.3 Non-tariff terms and conditions

As in our draft decision, our final decision approves the majority of the non-tariff components of AGN's proposed access arrangements for the 2023–28 period including:

- proposed queuing, extension and expansion, and capacity trading requirements
- the proposed approach to changing users' receipt or delivery points
- the new proposed review submission date (the date by which AGN must submit its next access arrangement proposal) of 1 June 2027. In response to the suggestion in our draft decision, this is now one month earlier than the minimum required under the NGR.
- the proposed revision commencement date (the date on which AGN's next access arrangement period will commence) of 1 July 2028.[33]

In response to stakeholder submissions, our draft decision set out a small number of elements of the terms and conditions set out in the proposed access arrangement that required revision. AGN's revised proposal has now largely addressed the required amendments. The exception is proposed revisions to retailer credit support requirements.

Concerns were raised prior to, and in submissions on, AGN's initial proposal that AGN's current credit support arrangements (which were proposed to apply to both AGN and MGN networks going forward) were unduly onerous, and out of step with those of other gas distributors and of electricity distributors in Victoria. Our draft decisions, therefore, required AGN to consider and put forward an alternative to the proposed current credit support framework, to re-balance the risk of a retailer failing to pay AGN's charges between AGN, retailers and customers. We suggested AGN rely less on pre-emptive, up-front risk management and balance this with ex post recovery only where the risk is realised.

In its revised proposal, AGN maintained its preference that any changes to the credit support requirements in their access arrangements be made through a rule change, and should not be treated the same way as other terms and conditions which are proposed, assessed and subject to revision as part of this access arrangement review. However, in response to our draft decisions their revised proposals did include proposed amendments to their access arrangements should our final decision require this. The proposed amendments were based on the credit support model in Part 21 of the NGR, which applies to retailers and gas distributors in other jurisdictions, including AGN's South Australian gas distribution network. Our final decision accepts this direction as an appropriate solution to the revisions required by our draft decision. However, we have made a number of additional drafting revisions to

33 Section 62(2) of the National Gas (Victoria) Act provides that, despite anything to the contrary in the National Gas (Victoria) Law or the Rules, or any access arrangement proposal, the AER must, in a full access arrangement decision that approves the access arrangement proposal, fix 1 July following the date of the decision as the date on which the full access arrangement, or a revised full access arrangement, to which the decision relates takes effect.

achieve the intended alignment more consistently in different parts of the access arrangement (as set out in Attachment 11).

We have also accepted AGN's assessment and conclusion that the proposed access arrangement does not require amendment or revision to give effect to the *National Gas Amendment (DWGM Distribution connected facilities) Rule 2022* when it takes effect from 1 May 2024.

A List of submissions

Submission	Received
AGL	24 February 2023
Brotherhood of St. Laurence	28 February 2023
Consumer Challenge Panel, sub-panel 28	26 February 2023
Darebin Climate Action Now	23 February 2023
Energy Users Association of Australia	23 February 2023
John Godfrey	23 February 2023
Origin Energy	23 February 2023
Alan Pears	23 February 2023
Red Energy / Lumo Energy	27 February 2023
David Strang	23 February 2023
Victorian Community Organisations	28 February 2023

Glossary

Term	Definition
AGN	Australian Gas Networks: AGN means AGN Vic in the case of the network to the extent that the network is located within the State of Victoria, and AGN Albury in the case of the network to the extent that the network is located within the State of NSW, where AGN Vic means Australian Gas Networks (Vic) Pty Ltd (ABN 73 085 899 001) and AGN Albury means Australian Gas Networks (Albury) Limited (ABN 84 000 001 249)
ARS	Ancillary reference service
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AusNet	AusNet Gas Services
CESS	Capital expenditure sharing scheme
DWGM	Declared Wholesale Gas Market
ECM	Efficiency carryover mechanism
GSOO	Gas Statement of Opportunities
MGN	Multinet Gas Networks
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
Capex	Capital expenditure
CCP/CCP28	Consumer Challenge Panel, sub-panel 28
CPI	Consumer price index
NPV	Net present value
Opex	Operating expenditure
PTRM	Post-tax revenue model
RBA	Reserve Bank of Australia
Roadmap	Victorian Gas Substitution Roadmap
RORI	Rate of Return Instrument
RFM	Roll forward model
RRG	Retailer Reference Group

Term	Definition
SoMP	Statement on Monetary Policy
VGNSR	Victorian Gas Networks Stakeholder Roundtable
WACC	Weighted average cost of capital