AUSTRALIAN ENERGY REGULATOR

Our Ref: 30,779,480
Your Ref: GRC0082
Contact Officer: Dale Johansen

30 October 2025

Alisa Toomey
AEMC Project sponsor

Dear Ms Toomey

Re: Gas networks in transition

The Australian Energy Regulator (AER) welcomes the opportunity to provide a submission to the Australian Energy Market Commission (AEMC) on National Gas Rules (NGR) change proposals submitted by Energy Consumers Australia (ECA) and the Justice and Equity Centre (JEC) in addition to matters raised by the AEMC.

The AER's role

We are the economic regulator for major scheme (full regulation) gas distribution networks in New South Wales (NSW), Victoria, South Australia and the Australian Capital Territory (ACT).

We determine the regulated revenues of scheme gas distributors every 5 years via an incentive-based regulatory framework incorporating a 'building block' assessment of access arrangement proposals, with allowances for operating costs (opex), return on capital (the rate of return), return of capital (depreciation) and tax. Underlying the return on and of capital is our assessment of proposed capital expenditure (capex). Linked to our opex and capex determinations are our decisions on the application of incentive schemes. We also determine the structure of gas network tariffs and the form of regulation applied to scheme gas distributors, the tariff variation mechanism – sometimes known as the form of control.

In determining regulated revenues and related matters for scheme gas distributors, we are guided by the National Gas Law, including the National Gas Objective, and NGR. We too, like the AEMC, are focused on promoting the long term interests of consumers through efficient investment, operation and use of energy services. The NGO guides our decision making on the regulatory issues discussed in Attachment A. While we have discretion to exercise our judgement, we are also bound by the national regulatory framework and by the parameters of our role as an economic regulator.

On a number of issues, the AEMC consultation paper *Gas networks in transition* contemplates the AER being given new responsibilities. We note that our resources are aligned with our current functions and the existing level of complexity we must engage with. Any changes to the regulatory framework we administer will require careful consideration of the resourcing impact, including how we may continue to deliver our current functions while taking on new or more complex roles.

We also note that NGR provisions relate to both scheme gas distribution networks and scheme transmission pipelines, notwithstanding that the focus for the current AEMC process and this submission is the distribution sector. How, or whether, new or updated NGR provisions may relate to transmission pipelines remains to be seen, given the different expectations for the two sectors, with transmission assets to serve expected growth in gas powered generation.[1]

Changed context for the NGR, gas distributors and economic regulators

The NGR was established at a time when growing the number of customers connected to gas distribution networks was beneficial because the relatively fixed cost of providing network services could be shared amongst more customers, providing lower per-unit network tariffs and therefore lower gas bills. The NGR reflect this growth paradigm. Consistent with this paradigm, we have applied price cap regulation to gas networks to incentivise them to grow the volume of gas carried by their networks.[2] Now though, price cap regulation of gas networks appears inconsistent with the emissions reduction element of the updated National Gas Objective, and with national and jurisdictional emissions reduction targets. As a result, we are moving away from price cap regulation towards hybrid approaches that blend elements of both price cap and revenue cap regulation.

For scheme gas distribution networks, the context in which the NGR and economic regulators operate has fundamentally changed. As our 10 July 2025 submission to the AEMC on *Updating the regulatory framework for gas connections* noted, the Australian Energy Market Operator (AEMO) expects Australia's east cost gas consumption (excluding gas power generation) to decline by 70% from 2025 to 2044. The number of gas customers is already falling in some parts of Australia, while the rate of growth in customer numbers has slowed elsewhere. In both cases, the per customer use of gas continues its long-term decline.

Our response to date

We have been responding to the new and emerging policy and gas market context for several years. In 2021 we released an information paper *Regulating gas pipelines under uncertainty*.[3] In 2023 we reviewed, through a public process, tariff variation mechanisms and tariff structures applicable to scheme gas distributors.[4] Our access arrangement determinations have also been evolving.

Under the NGR propose-response regulatory model, our determinations on gas distributor access arrangement proposals for Victoria 2023−28 and NSW 2025−30 incorporated new approaches to capital base cost recovery, billing customers for permanent disconnections, tariff structures and tariff variation mechanisms.[5] Over 2024 and early 2025 we determined not to vary an approved Victorian access arrangement in response to a reopener proposal that would, if approved, have imposed additional costs on customers.[6]

In each case, our decision papers have noted the opportunities and risks associated with transitioning gas networks, while emphasising that the long term interest of consumers is central to our considerations. We are now seeing the same issues in access arrangement proposals for South Australia and the ACT, notwithstanding the very different policy contexts for those two access arrangement determinations.

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1 AEMO, *Gas Statement of Opportunities for Australia's East Coast Gas Market*, March 2025, pp.6-7.

2 Contrasting with our application of revenue caps to electricity networks.

3 AER, *Regulating gas pipelines under uncertainty*, November 2021.

4 AER, *Review of gas distribution network reference tariff variation mechanism and declining block tariffs*, November 2023.

5 AER, *Final decision – AGN 2023−28 Overview*, June 2023; AER, *Final decision – AusNet 2023−28 Overview*, June 2023; AER, *Final decision – MGN 2023−28 Overview*, June 2023.

6 AER, *AusNet 2023−28 Access arrangement variation proposal* – Final decision, May 2025.

Achieving a least cost transition requires holistic policy frameworks

While we are taking steps to respond to the challenges raised by the transition, our interactions with technical/safety regulators are also growing, pointing to the need for a holistic and responsive framework encompassing the roles of regulators, governments, gas distributors and their investors. We note too, the importance of customer and environmental advocates, some of whom have initiated the rule change proposals central to this AEMC process. Achieving a least cost transition will take a collective effort with shared understandings of the benefits and costs of different pathways that will emerge at different times in different parts of Australia.

Attachment A to this letter provides our initial views on issues raised by the *Gas networks in transition* consultation paper. We look forward to engaging with the AEMC and others as this rule change proceeds. We will also continue to engage with the other rule changes currently under way: *Updating the regulatory framework gas connections* and *Establishing a regulatory framework for gas disconnection and permanent abolishments*.

Yours sincerely

[redacted]

Dr Kris Funston
Executive General Manager – Network Regulation

Attachment A

This attachment sets out our views under headings that align with the AEMC's *Gas networks in transition* workstreams.

Expenditure assessments

Capex criteria

ECA proposed to amend NGR r.79 'New capital expenditure criteria' (capex criteria) due to its view that the regulatory framework may be facilitating over investment in the context of declining demand for gas. We understand ECA's concern that gas distributors are proposing new capex investments while also proposing to bring forward recovery of their past capital investments (accelerated depreciation) due to heightened risk of economic stranding. However, the existing capex criteria are not driving this dynamic.[7] The capex criteria are neutral in terms of investment levels to meet expected demand for gas being higher or lower than in the past.

New capex arises from the need to maintain safe, reliable services, and from new connections. There will remain a need to reinvest in network assets and back-office technologies for as long as network services continue to be provided. Subject to the partial prohibitions on new gas connections now in effect in Victoria and the ACT, to the extent distributors remain obligated to offer to connect new customers, the ongoing new connections require us to approve connections capex notwithstanding our concerns about growth in a distributor's capital base and commensurate growth in risk of asset stranding. Distributors are required to propose connections capex when new connections are expected.

We have previously submitted our support for the ECA rule change *Updating the regulatory framework for gas connections*.[8] Newly connecting customers incurring upfront cost-reflective connection charges will alleviate one source of new capex. To illustrate this benefit, for its 2026−31 access arrangement period AGN (SA) proposed to add $155 million in connections capex to its capital base – around one third of its total capex proposal.[9] Avoiding this value being added to AGN (SA)'s capital base will benefit its existing customers in the form of lower bills in the future than otherwise and mitigate long-term risk of asset stranding, also benefiting AGN (SA). Notably, connections regulatory reform does not directly relate to the NGR capex criteria, but to other NGR provisions.

This is not to say though that reforming the capex criteria should be ruled out. Stepping back from the capex criteria and taking a wider view of the regulatory framework, amendments to the NGR that better reflect expectations of declining use of gas network assets may be beneficial in terms of framing access arrangement proposals. There may be long-term benefits from such re-framing, including of the capex criteria, in terms of achieving a least-cost transition for scheme gas distributors.

We are open-minded about the potential for such reforms, where there is weight placed on regulatory flexibility. The rate of change in the gas distribution sector requires economic regulators to adapt decision-making for emerging market trends and evolving policy settings. The different policy settings evident now across jurisdictions is a good example of why

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7 The NGR provides built-in checks and balances, such as r.79(2) – a network must justify its investments and we assess that justification.

8 AER, *Submission - Updating the regulatory framework for gas connections*, July 2025.

9 *AGN (SA), AGN SA Final plan 2026/27 – 2020/31*, July 2025, p.103.

binding regulators with prescriptive regulations is not the right approach. More principles-based approaches are needed.

Some level of capex will remain required into the future, though it should be lower than historical levels both because of connection costs being recovered directly from connecting customers (and in some cases new connections being prohibited) and because augmentation of existing assets is unlikely given expectations of declining gas use.[10]

The concept of non-network solutions has been raised in respect of gas network services, seemingly as an extension of its application to electricity networks. However non-network in an electricity context often relates to energy storage by batteries or use of other consumer energy resources such as smart appliances. Gas networks typically don't have equivalent technologies or ancillary service business models to rely on as substitutes for more traditional network services.

The ECA rule change proposal's reference to network reliability and the customer value of that reliability in respect of capex investment should be considered in light of the differences between the network electricity and gas sectors. While network reliability and safety are intrinsically linked within both sectors, this relationship is more pronounced for gas networks such that poor gas network reliability could align directly with greater safety risk. Gas network reliability in Australia is currently very high. Unplanned supply disruptions are exceedingly rare, which is beneficial for both customer reliability and safe operations.

On capex to facilitate renewable fuel projects, we look forward to seeing the views of other stakeholders as to whether related network costs should be excluded from recovery via reference tariffs. In the longer term, AEMO's gas consumption forecasts suggest that most small customers will electrify their gas appliances, while some large commercial and industrial customers are likely to need a renewable gas supply, particularly for high heat production processes and as feedstock inputs. This potentially justifies cost recovery of distributor renewable gas investments from large customers as the tariff class most likely to use a renewable gas service. This is not the same as proposed by ECA, which instead raised the potential to excise renewable gas expenditure by distributors from the regulated space and instead make it unregulated. This requires further consideration, particularly in light of some gas distributors having already undertaken investment to facilitate renewable gas blending in their gas supply.

Under NGR r.80 'Advance capex determinations' gas distributors may apply to us for a determination that capex will be taken as approved in the context of an upcoming access arrangement determination. We may make a determination or decide not to. ECA proposed to either abolish the mechanism or add a requirement for the AER (and by extension the ERA in Western Australia) to consult stakeholders on advance capex proposals submitted to us ahead of an access arrangement reset.

It's not clear that there's a good rationale for removing the mechanism altogether. In terms of mandating stakeholder consultation, in practice we have consulted publicly on the small number of r.80 applications submitted to us to date. Our standard approach is to consult on any material expenditure proposal. With this in mind, we raise no objections to the proposal to mandate consultation. However, we should have the ability to not consult stakeholders on a r.80 proposal where a distributor's proposal is for non-material expenditure or lacks supporting evidence.

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[10] Subject to the AEMC's final rule on *Updating the regulatory framework for gas connections* being consistent with the draft rule.

Opex criteria

ECA proposed to remove from the NGR opex definition ‘expenditure incurred in increasing long-term demand for pipeline services and otherwise developing the market for pipeline services’. In principle, we agree with ECA that it is inappropriate for gas distributors to be recovering from customers the cost of promoting gas consumption in a declining market. However, how this reform proposal interacts with potentially growing use of hydrogen and bio-methane in gas supply, and the legitimate need for that renewable gas service by a subset of customers in the longer term, would need consideration.

Incentive mechanisms

The AEMC notes the NGR does not specify incentive schemes to apply to gas distributors, contrasting with the regulatory framework for electricity networks, and that incentives we choose to apply to gas distributors relate only to expenditure, not service levels. The consultation paper referenced our 2023 review of network incentive schemes, which did not recommend additional schemes be applied to gas networks.[11]

The absence of gas network incentives around service levels reflects the very reliable nature of gas network services in Australia. We understand though that if distributors become uncertain about their ability to recover the cost of their investments, because of asset stranding or capital redundancy determinations, they may become reluctant to invest with commensurate impacts on reliability. The link between gas network reliability and safety adds weight to this issue.

As raised by the AEMC, should decommissioning become a real prospect for gas distributors, incentives of some kind may be required to motivate distributors to continue to provide reliable and safe network services. Whether such incentives can be driven by the regulatory framework without the involvement of governments needs to be considered. In this light we are open to further considering whether service level incentive schemes could be one lever used to maintain network services while customers need them.

Capital base recovery

Depreciation

Both ECA and JEC proposed to reform the NGR in respect of depreciation for previous capex investments, or even to simply prohibit approaches other than ‘straight-line’ depreciation – the methodology generally used in Australia which forms a baseline depreciation from which accelerated depreciation proposals are applied. The context for these rule change proposals is that scheme gas distributors are now consistently proposing to recover the cost of their capex investments faster than would otherwise be the case. These distributor proposals are understandable as they face risk of material under-recovery of their capital base if jurisdictional net zero target dates in 2050, or 2045 in the case of the ACT and Victoria, are enforced.

We consider a measured start to accelerated depreciation is necessary to retain the incentive for distributors to continue to provide network services while managing bill impacts. In our recent decisions on access arrangement proposals from gas distributors in Victoria and NSW, we have carefully assessed accelerated depreciation proposals and have granted

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[11] AER, *Review of incentive schemes for networks – Final decision*, April 2023, p.23.

only around half.[12] Customers are no doubt reluctant to carry that cost, seemingly on behalf of distributors and their investors, but a balance must be struck.

We consider our approach to approving some accelerated depreciation strikes the right balance. Our approach is consistent with approaches taken by economic regulators in other parts of the world in respect of their gas networks where there is, or is expected to be, declining network use. As a regulatory tool, accelerated depreciation provides flexibility for the future if demand doesn't decline as expected. We have been considering these issues for some time, as set out in our information paper *Regulating gas pipelines under uncertainty*.[13] As we and others have noted, economic regulators have limited levers with which to manage asset stranding risk, due to bill impacts for customers and impacts on the incentives for distributors to continue to provide services.

In undertaking our regulatory responsibility to assess depreciation proposals we have explicitly considered the bill impact on customers of accelerated depreciation being passed through to gas retail offers. In determining the amount of accelerated depreciation, we have applied a limit on the real network tariff increase as a guardrail to ensure price stability and affordability during the energy transition.[14] Our approach also manages risk of triggering a rush of customers leaving gas networks that could in turn leave remaining gas customers (including vulnerable customers) with the burden of high per unit network costs, and place increasing pressure on the existing electricity network and supply.

Rule change proposals that would establish one or more pre-requisites for accelerated depreciation to be granted would risk setting up achievable thresholds which would then facilitate what ECA and JEC are generally opposed to – accelerated depreciation being granted. Unless regulators can exercise discretion, the level of accelerated depreciation that may be approved under a tick-a-box framework could be larger than otherwise is prudent or justified. While we are open to amended NGR providing guidance to regulators, discretion is a critical element to ensure outcomes match the circumstances in which regulatory decisions are to be made.

A premise for ECA and JEC proposals on depreciation is that AER decisions are inappropriately transferring investment risk from distributors and their investors to customers. In response, we note it is not within our scope to determine other sources of investment cost recovery. Nor do the NGR currently provide a robust capital redundancy mechanism for regulators to make use of, as we discuss below.

Redundant asset provisions

JEC's proposal to reform NGR r.85 Capital redundancy' is timely. The existing redundant asset mechanism arose from a time when ongoing growth in gas networks was the norm. Rule 85, like its equivalent provision in the now obsolete Gas Code, appears intended to manage the issue of a discrete section of pipeline that may fall into disuse because, for example, a customer has procured an alternative energy source or changed location. As a stand-alone provision within a regulatory framework that otherwise does not contemplate the potential redundancy of large proportions of existing gas networks, it is not fit-for-purpose. A broader capital redundancy mechanism, properly integrated within a re-focused regulatory framework, is now required.

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[12] Sinc 2023, gas networks have proposed around $831 million in accelerated depreciation (not including the 2026−31 Evoenergy and AGN (SA) access arrangement reviews currently under way). Our decisions have accepted around $448 million, 54% of what was proposed.

[13] AER, *Regulating gas pipelines under uncertainty*, November 2021.

[14] AER, *Final decision – Jemena Gas Networks (NSW) access arrangement 2025 to 2030 – Overview*, May 2025, p.vii.

JEC proposed a principles-based decision making framework for regulators to be guided on capital redundancy decisions. This matches our preference generally for principles-based regulatory approaches to guide but not constrain our decision making, so we may match outcomes to changing circumstances. On JEC's proposal for the AER to develop 'redundancy guidelines', further consideration is required. In broad terms though, this again matches our preference for the details of regulatory approaches to be set out in guidelines or guidance notes.

We agree with JEC that the existing description of 'redundant assets' is not optimal. Subject to expectations of declining gas use being confirmed over time, it may become economically efficient for scheme gas distributors to strategically decommission specific areas of their networks as demand for gas falls, but before those assets 'cease to contribute in any way to the delivery of pipeline services'.[15]

While we support reforming r.85, we note the same balanced approach we have taken to accelerated depreciation needs to also be taken to capital redundancy decisions. The incentive for distributors to continue to provide services must be weighed against the prospective benefit to customers from alleviating their capital base recovery burden. There is also potential for regulatory decisions and government policy to be linked, reflecting our view that decisions about the nature and timing of any gas network decommissioning sit better with governments than economic regulators.

Prices

Reference tariff provisions

On reference tariffs, the AEMC asked for stakeholder views on possible changes to tariff rules to provide more efficient price signals or manage potential impacts of declining demand on tariff levels. The context for this discussion is our focus on reforming declining block tariffs of scheme gas distributors, which incentivise more gas consumption. Our approach is informed by our 2023 review of gas distribution tariff variation mechanisms and tariff structures, through which we heard from a wide range of stakeholders, including gas retailers, academics, customer advocates, environmental advocates, and gas networks themselves.[16]

While we will continue to address distribution tariff structures in the absence of NGR changes, the AEMC and others may prefer to see an additional, more prescriptive statutory driver for this reform, beyond the National Gas Objective and existing NGR and NGL provisions on tariff setting. Or the AEMC or other stakeholders may prefer a different approach to tariff structures. We are open to working with the AEMC and others on appropriate NGR provisions.

Form of regulation

The AEMC raised the potential to mandate inclusion of tariff variation mechanism proposals in distributor reference service proposals, submitted to us 12 months ahead of an upcoming access arrangement review. This would align with the current practice, undertaken by gas distributors voluntarily rather than mandatorily, again arising from our 2023 review of tariff structures and tariff variation mechanisms.[17]

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15 NGR r.85(1).

16 AER, *Final decision – Review of gas distribution network tariff variation mechanism and declining block tariffs*, October 2023

17 AER, *Final decision – Review of gas distribution network tariff variation mechanism and declining block tariffs*, October 2023.

Formalising this regulatory function would provide benefits in terms of certainty and add weight to our reference service proposal decisions on tariff variation mechanisms, which at this stage are not binding on distributors. There should also remain some flexibility to change approaches during an access arrangement review in response to new learnings and/or changing market or policy circumstances.

Access arrangement mechanics and planning

The AEMC identified in its consultation paper that the Rules currently provide us with limited discretion to vary the length of access arrangement periods and no discretion to reopen approved access arrangements in response to changed circumstances.

Reopener and trigger event provisions

Only a scheme gas distributor may propose to reopen its access arrangement during an access arrangement period. Neither the regulator nor customers or other stakeholders have this option. We welcome the AEMC's discussion of this issue and the prospect of the regulator having the flexibility, if warranted, to reopen access arrangements.

Noting the associated administrative burden of reopening an access arrangement on a distributor and ourselves, in addition to the uncertainty reopeners provide for customers and other stakeholders, reopeners should be used as a last resort. We note too that many energy sector stakeholders are, and have been for some time, experiencing consultation-fatigue. Other flexibility mechanisms, such as cost pass throughs, speculative capex and advance capex determinations, are likely to be preferable.

NGR-based guidance on when such discretion should be used may be appropriate. We would like to engage with the AEMC on the circumstances where it would be appropriate to reopen an access arrangement.

Access arrangement length

We also welcome the AEMC considering giving regulators more scope to amend the length of access arrangement periods. While at this stage we consider 5-year periods are appropriate, the rate of sectoral change is accelerating. Having flexibility to adjust access arrangement periods seems prudent, though again exercising such a statutory power would need to be carefully considered. The administrative cost and uncertainty that would be created would need to be weighed against the potential benefits.

As per our discussion above of the potential for regulator-driven access arrangement reopeners, significant additional regulatory burden would be imposed on gas distributors by shortening access arrangement periods. Our own resources are calibrated for our existing functions and responsibilities, including the current 5-yearly access arrangement regulatory cycle. Shortening that cycle would increase our workload significantly, requiring redistribution of our resources away from other activities, impacting delivery of our other functions.

Network plans

ECA proposed to establish a new public information reporting obligation on gas distributors, a 'Gas annual planning report', or GAPR. Again, this reflects a concept taken from electricity network regulation, though in this case focused on a long term planning horizon of 20 years. The AEMC noted that a GAPR requirement would need to be premised on a transparent planning methodology set out in the NGR, interactions with access arrangements would need to be considered, and the relationship to potential decommissioning needs to also be thought through.

In principle we can see value in the sort of long-term planning and stakeholder consultation envisaged by ECA's proposal, though annual (or even bi-annual) release of a 20 year planning document is unlikely to be the most appropriate cadence. Confirming the potential value of this proposal requires further consideration of the administrative costs that would ultimately be borne by a distributor's customers, and the prospective benefits. An alternative option would be to bring a long-term (potentially 20 year) planning horizon into the 5-yearly access arrangement framework, as canvassed by the AEMC's consultation paper.