

To: The Australian Energy Market Commission (AEMC)

From: Gippsland Climate Change Network (GCCN)

Date: 29 October 2025

Subject: Submission on National Gas Rule Amendments 2026 (Gas Networks in Transition)

Re: Feedback on the AEMC National Gas Rule Amendments 2026 (Gas Networks in Transition)

1. Introduction

The Gippsland Climate Change Network (GCCN) is a community-based, not-for-profit organisation that drives climate action across Gippsland, Victoria. We work with local communities, business, education providers, Traditional Owners, and government to deliver practical initiatives that support carbon neutrality in Gippsland beyond 2030. Our focus is on building local capacity, increasing energy literacy, and ensuring that the energy transition delivers tangible benefits to regional communities.

GCCN welcomes the opportunity to provide feedback on the Australian Energy Market Commission's (AEMC) consultation paper on the National Gas Rule Amendments 2026 (Gas Networks in Transition). This is an important consultation that acknowledges the structural decline in gas demand and the urgent need to plan for a fairer and more manageable transition. GCCN recognises that the energy transition is a complex shift away from traditional energy uses and that not all consumers can respond to changing conditions equitably. The proposed amendments will shape how gas distribution and transmission networks respond to declining utilisation, the risk of asset stranding, and the interaction between gas and electricity systems during electrification.

Gippsland is one of Victoria's most energy diverse regions and has a rich history embedded on its past reliance on natural gas and coal to provide reliable energy resources to households and businesses. It hosts major generation assets, emerging renewable energy hubs, offshore wind zones, sustainable practices, and extensive distribution networks that will be directly affected by the shift away from fossilised gas and coal. Communities in towns such as Traralgon, Morwell, Sale, and Wonthaggi are already seeing household electrification and fuel switching. GCCN's regional experience gives us a clear view of how regulatory settings influence consumer costs, local jobs, and social acceptance during this transition.

This submission responds to eight key areas applicable to the issues discussed and responds to elements of the 16 questions outlined in the NGR consultation paper. These central topics are strongly relevant to Victorian consumers, regional distribution networks, and community transition planning, and also applicable to gas transition strategies in all jurisdictions across Australia.

2. Key Points for Consideration

1. Recognising structural decline in gas demand

Why this matters:

The consultation paper clearly acknowledges that residential and small business gas demand is structurally declining due to electrification, efficiency improvements, and state policies around net zero and the phasing out of new gas connections. This is a fundamental shift in the purpose of gas networks and must be explicitly recognised within the National Gas Rules. The Commission notes that demand decline is not temporary but systemic, driven by government emission targets, technology costs, and consumer choice to be more environmentally sustainable. However, the current regulatory settings still assume stable or growing demand, which creates a disconnect between how networks are planned and the energy landscape communities now face. Both Energy Consumers Australia (ECA) and the Justice and Equity Centre (JEC) identified this structural decline as the central problem driving their proposed rule changes, noting that current frameworks assume growth in demand rather than its ongoing reduction.

In Gippsland, this reality is already visible. Many households are switching to reverse-cycle electric heating and heat pumps, while local governments such as Wellington and Latrobe Shire are embedding electrification within their regional decarbonisation strategies. Victoria's Gas Substitution Roadmap signals that widespread disconnections will occur in line with emissions targets by the early 2030s, and distributors will need a clear framework for managed withdrawal and asset retirement. Recognising structural decline ensures that regulators, distributors, and consumers can plan this process transparently rather than reacting to demand loss with uncoordinated tariff increases.

GCCN recommends:

- **Amend the NGR** to include explicit recognition of declining gas demand as a material planning and regulatory consideration. This could be embedded within the revenue and expenditure assessment principles. For example, this could require gas distributors to reference official state or national emissions reduction targets and show how their forecasts align with expected gas phaseout pathways under Victoria's Gas Substitution Roadmap (GSR).
- **Require regulators to assess all new proposals** against each jurisdiction's decarbonisation and electrification policies. For example, in Victoria this would include the GSR and Net Zero by 2045 Act. For instance, when the Australian Energy Regulator (AER) reviews a distributor's access arrangement, it could check that proposed capital works are consistent with the Victorian Government's target to halve gas use by 2035 and the broader net zero by 2045 pathway.
- **Establish a formal obligation for distribution businesses** to include demand-decline scenarios in access arrangement submissions, showing how capital recovery and maintenance strategies adjust as connections decrease. The NGR could specify that declining demand and decarbonisation policy targets must be treated as "material factors" in network planning, similar to how electricity forecasts already consider distributed energy resources and electrification trends.

As an additional actionable example, distributors should be required to publish a “decline-adjusted” asset life forecast in every access arrangement, detailing when sections of the network are expected to become uneconomic and how costs will be managed beyond that point.

2. Tighten future capital expenditure

Why this matters:

The current NGRs allow service providers to propose capital expenditure based on maintaining existing service capacity, with limited consideration of future utilisation. ECA has proposed amending Rule 89(1)(a) to delete the phrase “promotes efficient growth in the market for reference services,” ensuring the NGR no longer assumes ongoing demand growth when assessing new capital projects. This is because it has encouraged over-investment and reinforced a cycle where consumers back assets that may not be fully used (Sections 2.1.1–2.1.3, Q2–Q3). ECA’s capex rightly points out that the regulatory test does not require distributors to justify why continued replacement or augmentation is necessary in the context of long-term demand decline. The consultation paper acknowledges this risk but does not embed specific limits or criteria to prevent overcapitalisation. ECA’s submission proposes targeted amendments to Rule 79 to ensure that distributors explicitly consider declining demand forecasts, assess non-network alternatives, and include abolishment and decommissioning costs when justifying new capex proposals.

For regional communities like Gippsland, which already face declining output, this is a critical issue. Continuing to replace pipelines or meters as though demand will remain constant unfairly shifts stranded asset risk to the remaining consumers, often those least able to afford it. A more transparent framework would require networks to prove that new expenditure represents least-cost value for consumers when compared with non-network alternatives, such as local electrification or targeted demand management.

This approach aligns with GCCN’s broader purpose of ensuring the energy transition is socially fair and financially responsible. It reflects local experience through projects such as the Gippsland 2035 Transition Plan, where investment decisions increasingly weigh community benefit, timing, and total cost across multiple energy sectors rather than within a single fuel network such as offshore gas.

GCCN recommends:

- **Tighten the NGR capital expenditure test** by inserting an explicit requirement that distributors demonstrate investment efficiency under declining demand and decommissioning scenarios. For example, a distributor proposing to replace 5 km of low-pressure main would need to model three cases: 1. stable demand, 2. 10% demand decline, and 3. partial network retirement – and show that the project remains efficient in all cases before it is approved.
- **Mandate evaluation of non-network alternatives**, including managed electrification and community resilience solutions. For example, a local trial could assess whether replacing a small rural pipeline is less efficient than funding reverse-cycle heat pumps or all-electric hot water systems for affected customers. Instead of replacing an ageing rural pipeline that serves 40 households, a distributor could be required to test whether providing electric heat pump upgrades and solar battery rebates delivers the same service reliability at lower lifetime cost.

- **Include asset retirement and site remediation costs** within business-case modelling so that total lifecycle costs are visible before approval. For instance, when submitting a replacement project, the business would also estimate decommissioning costs. This could include elements such as pipe removal, soil and vegetation restoration efforts/standards, and safety compliance, all of which can give regulators a clearer view of future financial liabilities.
- **Require that any renewable gas or hydrogen trials** are transparently cost estimated outside standard reference tariffs, with funding sourced through innovation programs or government grants. If a distributor proposes a hydrogen readiness project in a regional town, the cost of that trial would appear in a separate reporting line, funded by the Victorian Government’s Hydrogen Hubs program or ARENA, not recovered through ordinary customer tariffs.

Additionally, when approving a new capital project, the AER should be required to review a “transition efficiency statement” showing whether non-pipeline alternatives have been publicly consulted and evaluated satisfactorily.

3. Long-term and transparent Gas Annual Planning Reports (GAPR)

Why this matters:

ECA’s proposed Gas Annual Planning Report (GAPR) would require distributors to provide a 20-year scenario based planning document outlining network utilisation, forecast disconnections, useful life of assets, and interaction with electricity networks (Sections 2.5.2–2.5.3, Q7). ECA envisages establishing this requirement through two complementary rules: one setting the process for the GAPR and another defining publication parameters – to ensure consistency and comparability across networks. This is one of the most transformative reforms in the consultation paper. It directly addresses the absence of long-term planning obligations for gas distributors, unlike the detailed reporting already required of electricity networks. ECA proposed that the GAPR be established through two complementary rules: one governing the process for the GAPR, and another governing publication parameters to ensure consistent reporting across all distribution networks.

For communities and councils in regions such as Gippsland, where energy and planning decisions are tightly linked, the GAPR would fill a crucial information gap. Local governments are often left guessing about when gas infrastructure will become redundant, limiting their ability to plan electrification of housing, local grid upgrades, or transition support. Transparency of planning data will enable strategic, community driven transition rather than disorderly implementation or withdrawal. For example, a distributor serving South Gippsland could be required to model electrification uptake in specific centres like Inverloch and Wonthaggi and consult with AusNet and Bass Coast Shire Council on timing and capacity for network decommissioning.

The requirement also aligns with Victoria’s planning framework and the work of regional alliances that are mapping decarbonisation pathways. Integrating gas and electricity planning cycles ensures a coordinated approach that prevents both stranded assets and local network congestion when heating loads shift to electricity.

GCCN recommends:

- **Support mandatory publication of GAPR** for all distributors, with a minimum 20 year horizon and alignment with electricity distribution annual planning reports. This could look like a distributor such as Multinet or AusNet publishing an annual 20-year forecast of expected gas disconnections, remaining pipeline life, and asset replacement timing, aligned with the Victorian Distribution Annual Planning Report (DAPR). This would enable both gas and electricity networks to better plan upgrades together to increase service and network efficiency, reducing issues faced by distributors and consumers.
- **Require a standard methodology** for scenario analysis, including base, rapid transition, and policy-aligned scenarios consistent with each state’s net zero targets. Increasing uniformity between jurisdictions would reduce regulation complexity and improve gas transition efforts nationwide. Each GAPR would model at least three scenarios: 1. business-as-usual demand decline, 2. accelerated electrification consistent with Victoria’s GSR, and 3. a robust decarbonisation pathway meeting 2045 net zero goals so that future policy changes are already factored into network planning.
- **Mandate consultation with local councils, electricity networks, and community organisations** on each draft report to ensure regional knowledge is captured. Before finalising a GAPR, distributors would meet with councils such as Wellington Shire, energy agencies, and local networks like GCCN to discuss disconnection trends, new housing developments, and resilience and transition social planning.
- **Reporting alternates between “light” and “full” updates** (e.g. statistical in one year, full forecast the next) to manage costs and administration. In even years, distributors could publish a concise update showing changes in disconnection rates and demand; in odd years, they would release the full forecast, stakeholder feedback summary, and scenario analysis.

4. Protecting vulnerable and hard-to-electrify consumers

Why this matters:

The consultation paper acknowledges that as customers leave the gas network, the cost burden on those remaining will increase, with the highest risk falling on renters, low income households, and those in multi-unit dwellings or public housing (Section 1.1.2; Section 4.3.1). These risks create an inequitable transition where households least able to disconnect incur rising fixed costs while wealthier consumers are better positioned to electrify and reduce their utility costs.

This issue is particularly significant in Gippsland, where many older homes still rely on bottled or reticulated gas and where some communities face high upfront costs for appliance replacement and switchboard upgrades. A well-designed transition must therefore ensure that pricing and regulatory changes do not deepen social disadvantage. The NGR should not only focus on efficiency signals but also on fairness and practical support for lower income consumers. GCCN’s community programs and profile in managing different energy projects show that equitable transition planning increases public acceptance and participation. The AEMC explicitly includes “equity considerations” within its proposed assessment criteria, aligning with GCCN’s following recommendations.

GCCN recommends:

- **Embed consumer protection and equity principles** directly within the National Electricity Rule's (NER) assessment schemes outlined in Section 3.4.1, ensuring that better social outcomes for those still connected to gas are considered in determining access arrangements. When assessing an access-arrangement proposal, the AER could be required to evaluate how the proposal affects low income and rental households. For instance, if accelerated depreciation or tariff rebalancing disproportionately raises bills for concession customers, the AER must apply an equity test before approval. In addition, the NER should Require that the AER responds by developing a “hard-to-electrify index” for each distribution zone to target policy interventions and tariff design that will reduce cost burden on concession holders and other disadvantaged small businesses and households.
- **Require distributors to publish social impact assessments** showing tariff impacts on different customer cohorts (e.g. renters, concession card holders, apartment residents). Before each access-arrangement review, distributors could publish a short appendix showing how their proposed reference tariffs affect at least three income and dwelling-type categories, similar to the distributional impact modelling already used in electricity pricing reviews.
- **Create targeted funding and rebate schemes** for vulnerable consumers to transition off gas, supported jointly by federal and state programs. For instance, Victoria's Solar Homes rebate model could be expanded to include efficient electric heating for retiring gas customers. Similarly, Victoria's Energy Upgrades (VEU) could expand to include high efficiency electric heating, hot-water replacements, or switchboard upgrades for households retiring gas. The NGR could reference this principle to encourage coordinated funding rather than leaving vulnerable consumers stranded.
- **Support mechanisms for “last resort” service areas** where maintaining minimal gas infrastructure for safety reasons may still be required, with costs shared transparently between network and government rather than small numbers of consumers. In remote or low density townships where full decommissioning is delayed for safety or emergency response reasons, the state government could co-fund the remaining network costs rather than allowing per-unit prices to spike for just a few customers still connected.

5. Scrutinising accelerated depreciation and cost recovery

Why this matters:

The AEMC's consultation paper acknowledges that a growing number of gas distributors are requesting accelerated depreciation to recover sunk costs more quickly as customer numbers decline (Sections 2.2–2.3.3, Q4–Q5). This trend reflect concern about asset stranding but also raises equity issues. Accelerated depreciation brings forward cost recovery while the customer base is still larger, effectively loading the transition cost onto current consumers rather than spreading it across the full asset life. Both ECA and the JEC warn that without tighter controls, this could create “windfall gains” for networks and transfer all transition risk to households. The JEC raises the argument that accelerated depreciation should not be used in isolation but only alongside a transparent redundancy process that fairly allocates stranded-asset costs between networks and consumers.

For Gippsland consumers, this dynamic is not abstract. Many residents are already paying higher network tariffs as part of the state's broader transition away from gas. Accelerated depreciation, if applied without clear conditions, could amplify these costs just as households begin electrifying. Equities must therefore guide how and when early cost recovery occurs. Depreciation schedules should reflect realistic demand trajectories and incentivise distributors to plan for decommissioning rather than to simply recover sunk costs sooner. GCCN recognises the JEC's related proposal, which emphasises that accelerated depreciation should only occur alongside a transparent redundancy assessment and cost sharing mechanism. The JEC also warns that without such linkage, early cost recovery could transfer unquantified risks to households, particularly in communities where decommissioning plans are not yet confirmed.

GCCN supports ECA's concept of "contingent accelerated depreciation," which conditions early recovery on demonstrable consumer benefit and alignment with net zero transition planning. This approach ensures that any cost brought forward is tied to clear public interest outcomes such as early retirement of inefficient infrastructure, improved safety, or lower long-term costs. It also recognises that regulatory flexibility is needed for a just and climate targeted transition rather than purely financial adjustment.

GCCN recommends:

- **Adopt a conditional model for accelerated depreciation** similar to ECA's "contingent" approach. Allow early recovery only where the distributor demonstrates that acceleration supports fair transition outcomes, including early network retirement or reduced long-term expenditure. Before approving early recovery, the AER could require the distributor to show that a specific section of network will be retired earlier than originally planned, and that this will avoid future replacement costs. If the distributor cannot link faster cost recovery to an actual consumer benefit such as avoided capex or safety improvement, the acceleration would not be approved.
- **Link depreciation proposals to transparent planning assumptions**, including demand forecasts, connection limits, and regional electrification policies. For example, If a distributor wants to shorten asset lives from 40 years to 20 years, they should have to show forecast exit of customers in the affected suburbs, local government electrification timelines, and any state policy on gas phaseout, so that the shorter life is grounded in evidence rather than used as a default for revenue.
- **Require independent review of all accelerated depreciation applications** by the AER against social impact and consumer equity criteria. An accelerated depreciation application would include a short distribution impact statement showing which customer classes (for example, concession households or public housing tenants) would take the largest immediate bill increase. The AER would have to explicitly consider whether that impact is reasonable before approving.
- **Publish a public statement of reasons** outlining how each approved accelerated depreciation proposal contributes to efficient network exit or safety, rather than simply preserving investor certainty. Releasing a statement of reasons would reinforce confidence in the public. For instance, If the reason is essentially "protect investor returns," it should be deemed inequitable and not be passed. If the reason is "this acceleration will fund safe retirement of a high-risk main and avoids \$20 million of future spend," that would pass.

- **Prohibit blanket acceleration** consistent with ECA’s contingent conditions outlined above without corresponding redundancy assessments or cost sharing provisions, as proposed by the JEC. If a distributor tries to use accelerated depreciation across its entire asset base to protect itself from future demand decline, it should be rejected unless it has also undertaken a redundancy assessment showing which assets are actually on track to become redundant and how those specific costs will be shared fairly.

6. Strengthening treatment of redundant assets and managed decommissioning

Why this matters:

The JEC’s proposal (Sections 2.4.1–2.4.3; Sections 2.5.1–2.5.3, Q6–Q7) calls for proactive identification and transparent treatment of redundant or “anticipated redundant” assets. Under current rules, assets are only removed from the regulated base after they have ceased providing services. This delays acknowledgement of inefficiency and hides the true cost of operating oversized networks. As gas use declines, this approach risks spreading redundant asset costs across remaining customers rather than addressing them through planned retirement or repurposing. The JEC proposes that the definition of “redundant assets” be broadened to include assets that are “no longer economically efficient to use.” Its submission recommends requiring distributors to include formal redundancy assessments in every access-arrangement proposal, supported by AER-issued redundancy guidelines that outline how costs are shared. The JEC specifically proposes broadening the definition of “redundant assets” to include assets “no longer economically efficient to use,” introducing “redundancy assessments” as part of each access arrangement proposal, and empowering the AER to develop redundancy guidelines that set out principles for cost sharing. They also suggest capping the share of redundancy costs recoverable from consumers at 50% to protect vulnerable households and encourage proactive decommissioning.

A stronger redundancy framework would create a structured pathway for identifying, consulting on, and decommissioning unviable network sections. This would improve regulatory certainty, avoid reactive decision-making, and align with community expectations for transparent use of public and consumer funds. For Gippsland, where some smaller townships and coastal areas may be among the first to see significant disconnection rates, an orderly process for network downsizing is essential to maintaining safety, affordability, and public confidence.

This also links directly to Victoria’s and Australia’s net zero commitments. Decommissioning old fossil gas infrastructure is an essential step in achieving emissions targets and should be treated as a legitimate transition activity, not a failure of investment. Managed retirement can create new employment opportunities through remediation and electrification works while reducing long-term costs for consumers.

GCCN recommends:

- **Amend Rule 85 of the NGR** to require gas distributors to identify “anticipated redundant assets” in their access arrangement submissions, with supporting analysis of cost-sharing and timing. A distributor would have to include a schedule of pipe sections and stations that are forecast to serve only a handful of customers within 5 years. That schedule would include residual asset value, proposed timing of withdrawal, and a clear cost sharing proposal.

- **Require public consultation and local coordination** before any major redundancy decision, involving electricity networks, local councils, and community organisations to manage impacts. Before declaring part of the local network in a coastal town redundant, the distributor would be required to meet with the council, the local electricity distributor, and affected customers, and publish a plain language summary of the proposed retirement plan.
- **Link approval of accelerated depreciation** to redundancy assessments so networks must demonstrate alignment between early cost recovery and planned decommissioning. If the distributor asks to accelerate depreciation on a specific pipeline, it must also show that this pipeline is scheduled for retirement, not just that demand is falling generally. This prevents early cost recovery from being used on assets that the distributor still intends to continue operating indefinitely.
- **Develop national guidelines for decommissioning processes**, including safety standards, site remediation expectations, and repurposing options for biomethane or district heating infrastructure. A standard guideline would set out minimum safety steps for physical disconnection, soil remediation requirements, and whether any portion of that pipeline could be repurposed for low pressure biomethane or used as a conduit in a future district heating loop rather than dug up several times.

7. Coordinating gas and electricity network planning

Why this matters:

The AEMC's consultation paper and supporting analysis (Section 1.2; Section 3.3.1, Q8) emphasise the importance of coordination between gas and electricity network planning. As gas networks wind down, electricity systems will face increased demand from electrified heating, cooking, and industrial processes. Without cohesive planning and information sharing, there is a risk of bottlenecks, voltage instability, or unnecessary duplication of infrastructure investment.

In Gippsland this coordination is critical, with large-scale renewable generation, offshore wind projects, and distribution upgrades already underway. The interaction between declining gas demand and rising electricity load must be managed to ensure that consumers experience a stable and affordable transition. For example, electrification of heating in Morwell and Sale may require local distribution upgrades that should be planned in tandem with the retirement of nearby gas assets.

The AEMC also highlights that greater flexibility in setting the duration of access arrangement periods could assist in aligning gas and electricity regulatory reviews, improving coordination between sectors. A coordinated framework supports climate action by aligning infrastructure investment with the broader net zero plan. It ensures that the costs and benefits of electrification are distributed efficiently, and that regional resilience improves rather than declines as gas networks downgrade.

GCCN recommends:

- **Align regulatory review cycles** for gas and electricity distribution networks to facilitate joint decision-making on investment and tariff design. Instead of gas and electricity reviews occurring in different years, the AER could set aligned review windows in

Victoria so that gas withdrawal in a given suburb is assessed at the same time as local electricity augmentation needs.

- **Require data sharing between gas distributors and electricity networks**, especially regarding forecast disconnections, load transfer, and timing of infrastructure retirement. For example, a gas distributor planning to decommission a feeder in three years would be required to give the local electricity distributor spatial data on expected additional winter peak load so that transformer or feeder upgrades can be staged effectively.
- **Promote joint transition plans** in areas of known overlap, such as growth corridors or industrial estates expected to electrify rapidly. For example, where a food processing precinct in the Latrobe Valley expects to electrify process heat and exit gas within five years, both networks should be encouraged or required to submit a combined transition plan that covers timing, infrastructure, workforce implications and tariffs. This also demonstrates that enhanced synchrony between sectors can lead to a more coordinated transition that benefits the whole community and improves social license.
- **Encourage pilot projects** where gas decommissioning and electricity reinforcement are planned together, using joint community engagement models. A pilot could include coordinated community forums where both distributors explain timing, outages, appliance changeover needs, and bill impacts, rather than forcing households to navigate two separate processes. For example, a coordinated “Gippsland Energy Transition Zone” pilot could align AusNet’s electricity planning with gas network withdrawal timelines, using shared forecasts and co-funded upgrades to minimise cost duplication or accrument.

8. Preventing misuse of renewable gas justification for capital expenditure

Why this matters:

ECA and several stakeholders raised concern that some distributors are using renewable gas or hydrogen pilot projects to justify continued capital investment or expansion of existing networks (Section 2.1.2, Q3). This presents a risk that speculative technologies will be used to delay necessary network needs or to shift experimental costs onto general consumers. While renewable gases are indicating a strong role in the future in specific industrial applications, their near-term use in household distribution networks remains uncertain and limited.

The AEMC’s role is to ensure that innovation does not become a substitute for promised planning. Allowing unproven hydrogen or biomethane projects to be rolled into regulated tariffs would undermine trust and burden customers who may face delays or never benefit from those investments. In Section 2.1.4, ECA also recommends removing the operating expenditure definition that allows costs intended to “increase long-term demand for pipeline services,” ensuring that funding of speculative renewable gas projects cannot be justified as promoting demand growth during a period of structural decline. GCCN supports renewable energy innovation, but it must occur in a way that complements electrification and climate action objectives, not in competition with them.

In Gippsland, where renewable energy development is already strong through offshore wind, community solar, and bioenergy projects, there are opportunities for local hydrogen demonstration hubs. However, these should be transparently funded through innovation programs or industry partnerships rather than embedded in household gas bills. Ensuring that

renewable gas initiatives are properly overseen supports climate action while maintaining equity and accountability.

GCCN recommends:

- **Require clear separation of renewable gas project costs** from regulated tariffs, with funding sourced through research, innovation, or government pilot programs. A distributor trialling hydrogen integration in a regional network could not automatically charge all residential customers for that trial through reference tariffs. Instead, the costs would be funded through a state innovation grant or private partner.
- **Amend the NGR to define renewable gas investment tests**, ensuring projects demonstrate consumer benefit, emissions reduction potential, and credible commercial pathways before cost recovery. Before any renewable gas project can be added to the capital base, the distributor must provide evidence that the project will reduce emissions at a reasonable cost per tonne, and that there is a clear pathway to evaluate. If it is simply exploratory, it should not sit in the regulated asset base.
- **Mandate public disclosure of renewable gas trial outcomes** and prohibit their costs being socialised across all customers unless independent review confirms system-wide benefit. For instance, networks should have to publish trial results on cost, safety, operability and customer impacts. Only if the AER determines there is broad, demonstrated benefit across the customer base would any portion of costs be recoverable through tariffs.
- **Encourage alternative innovation funding models**, such as joint projects with hydrogen producers or Clean Energy Finance Corporation (CEFC) support, rather than regulated revenue recovery. A distributor could set up a special purpose vehicle with an industrial hydrogen innovator to fund a pilot. That separates commercial risk from households and small businesses who are unlikely to ever use hydrogen for space heating. For example, a Victorian hydrogen blending trial should be funded through state innovation grants or industry partnerships, with explicit exclusion from distribution network tariffs until long-term viability is proven. This assures households that their bills are not being inflated to pay for speculative technology.

3. Additional Considerations (lessons from Section A on international case studies)

The case studies in Section A of the draft provide valuable lessons on how regulators globally are managing declining demand and stranded-asset risk. GCCN highlights the following insights relevant to Australian networks.

a. International precedents for planned decommissioning

Countries such as Denmark and the Netherlands have introduced clear legislative frameworks for gas network phaseout. Denmark's approach, anchored in government ownership of gas distribution assets and a national timeline for full household electrification by 2030, ensures socialised but predictable cost recovery. Similarly, the Netherlands uses coordinated planning between gas and electricity regulators to manage and rationalise networks while protecting customers. Australia currently lacks a national framework for decommissioning, resulting in inconsistent state approaches. Establishing a coordinated national policy, aligned with Question 7 in the consultation paper on future planning requirements, would reduce the risk of

fragmented responses and ensures that communities such as those in regional Victoria transition more equitably.

b. Transparent treatment of stranded asset

Regulators in the Netherlands and Austria have introduced mechanisms to manage stranded assets without indefinite cost socialisation. For example, the Netherlands allows one-off compensation or controlled removal from the Regulated Asset Base (RAB), while Austria's alignment of regulatory depreciation with accounting values ensures asset lives better reflect actual economic use. These approaches demonstrate how transparency and fairness can be maintained while protecting consumers from paying for assets no longer in use.

c. Managing accelerated depreciation and price impacts

In Germany and the United Kingdom, accelerated or front-loaded depreciation has been allowed to mitigate stranding risk, but only under strict affordability safeguards. Germany's model caps tariff rises through regulated depreciation schedules aligned with national decarbonisation goals (2045), while the UK's regulators require social impact assessment before approving early cost recovery. The AEMC should adopt a similar principle where accelerated depreciation should only proceed where affordability modelling confirms that cost volatility for regional and low-income consumers can be avoided.

d. Incentivising efficient use of existing assets

Spain's incentive mechanism model, which rewards operators for maintaining the safe operation of fully depreciated gas transmission assets, illustrates how regulators can encourage efficiency rather than replacement. By linking modest operation expense rewards to continued service provision, Spain has avoided unnecessary reinvestment while keeping tariffs stable. A comparable approach could be considered in Australia for pipelines that remain technically sound but underutilised, particularly in regional areas where continued service supports resilience and affordability during the transition. Models for rewarding operators for continued use of fully depreciated assets shows how incentives can reduce unnecessary reinvestment. Similar mechanisms could be explored for Australian gas networks that remain safe but underused.

e. Australian precedents

Existing Australian regulators already employ similar tools in other sectors. The Independent Pricing and Regulatory Tribunal (IPART), the Queensland Competition Authority (QCA) and the Australian Competition and Consumer Commission (ACCC) have used accelerated depreciation, asset-life adjustments and proportional cost sharing to address declining utilisation in rail, port and telecommunications networks. These decisions confirm that the NGR already contain adaptable mechanisms, such as depreciation scheduling, capital redundancy and tariff-variation frameworks that can be applied to gas networks without creating windfall gains for asset owners.

GCCN recommends:

- Establish a national guideline for gas network decommissioning, drawing from European approaches that combine equity, transparency and long-term electrification planning.

- Require the AER to incorporate explicit social impact and affordability criteria into any assessment of accelerated depreciation or decommissioning proposals.
- Investigate financial smoothing mechanisms, such as Belgium’s regulatory fund, to distribute transition costs fairly across current and future users.
- Strengthen coordination between gas and electricity transition planning, using Energy Ministers’ governance forums to align investment decisions and avoid duplication of network costs.

4. Conclusion

GCCN supports the AEMC’s recognition that gas networks are entering a period of managed decline and transition. The reforms proposed in the National Gas Rule Amendments 2026 are a vital opportunity to modernise the regulatory framework, protect consumers, and ensure that the transition is sufficiently planned rather than reactive.

In summary, this submission highlights eight key priorities:

1. Recognising and responding to structural decline in gas demand.
2. Tightening capital expenditure to prevent stranded assets.
3. Introducing transparent long-term planning through the Gas Annual Planning Report.
4. Protecting vulnerable and hard-to-electrify consumers.
5. Ensuring fair and conditional accelerated depreciation through scrutinising current frameworks.
6. Strengthening redundancy and decommissioning policies.
7. Coordinating gas and electricity network planning more efficiently.
8. Preventing unjustified renewable gas spending through consumer tariffs.

We also draw attention to global case studies that show practical ways to manage declining networks while maintaining fairness, safety, and investor confidence.

Gippsland Climate Change Network appreciates the opportunity to contribute to this consultation and would welcome continued engagement with the Australian Energy Market Commission and proponents as the final rule is developed. Our network is ready to assist in liaising gas transition frameworks that benefit regional communities, particularly in Gippsland and Victoria, which will help Australia achieve a fairer energy transition that meets net zero targets.

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