evoenergy

Appendix 3.3: HoustonKemp assessment of the AER’s draft decision on depreciation

Revised 2026–31 access arrangement information

ACT and Queanbeyan-Palerang gas network access arrangement 2026–31

Submission to the Australian Energy Regulator

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Assessment of the AER's draft decision on depreciation

Expert report of Dale Yeats

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1. Introduction

I have been asked to prepare this report by Evoenergy. Its subject is the Australian Energy Regulator's (AER's) draft decision on the access arrangement for Evoenergy's gas distribution network for the period from 1 July 2026 to 30 June 2031 (2026-31).

In particular, Evoenergy has asked me to provide my opinion on whether the AER's draft decision on depreciation complies with the requirements of the National Gas Law and National Gas Rules, and to comment on the resulting implications for efficient investment in Evoenergy's gas network. Evoenergy also asked me to comment briefly on other elements of the AER's draft decision that have implications for the promotion of efficient investment in gas network services.

1.1 Relevant experience

I am a Partner at HoustonKemp Economists, a firm of expert economists. I have over 15 years' experience applying economics to a diverse range of problems across a range of industries.

I have extensive experience of the economics of infrastructure and, specifically, on estimation of the efficient cost of providing infrastructure services and the price of access to monopoly infrastructure. I have accrued this experience in the context of regulatory reviews, litigation proceedings and major commercial arbitrations and negotiations. I have also assisted in the preparation of material that formed the basis of expert evidence in a merits review of a regulatory decision on depreciation under the national gas rules.

My sectoral experience spans the electricity, gas, port, water, resources, airport, heavy vehicle, construction, taxi, education, air navigation, retirement village, steel, stevedoring, cemetery and telecommunications sectors. I have undertaken economic analysis that informed decision making in the context of regulatory reviews across a range of industries, native title proceedings, major commercial arbitrations and negotiations, class-actions, anti-dumping proceedings, pricing intercompany transactions and policy development.

I hold a Master of Economics with first class honours and a Bachelor of Commerce (first class honours) in Economics from the University of Auckland. I attach a copy of my curriculum vitae at Annexure A.

I have been assisted in the preparation of this report by my colleague, Elaine Luc, who holds a post-graduate degree in economics. Notwithstanding this assistance, the opinions in this report are my own and I take full responsibility for them.

1.2 Key findings

I explain in section 3 that the AER's decision not to accept Evoenergy's proposed depreciation is based on its view that the associated increase in network price will drive a material reduction in demand, which:

- is inconsistent with the assumption on the responsiveness of demand to changes in price on which its own forecast of demand is based, ie, that the price elasticity of demand is equal to -0.05;
- is inconsistent with evidence in the economics literature and the Australian Capital Territory (ACT) specific research commissioned by Evoenergy and undertaken by the Centre for International Economics (CIE), which found that demand for gas is relatively unresponsive to changes in price; and
- overlooks the ability and strong incentive for Evoenergy to respond to any unexpected increase in disconnections by decreasing price below the level approved by the AER.

I explain also that, in my opinion, the AER's draft decision on depreciation does not provide Evoenergy a reasonable opportunity to recover at least its efficient costs, which contravenes a foundational principle of economic regulation and creates perverse incentives:

- not to undertake efficient investment in the network, owing to the likelihood that Evoenergy will not recover those efficient costs;
- to favour investment in assets with a relatively shorter economic lives, since the recovery of those costs is subject to relatively less risk; and
- to favour operating expenditure over capital expenditure, since operating expenditure is recovered in the year it is incurred.

The AER's 'base real price increase limit' approach to depreciation also creates a perverse incentive for Evoenergy to trade-off efficient operating expenditure against the recovery of its capital costs when preparing a proposed access arrangement.

The resulting distortions to the incentives for ongoing efficient investment by Evoenergy risk a future deterioration in the quality, safety, reliability and security of supply of gas on its network, which is not in the long term interests of consumers.

In my opinion, the AER's draft decision on depreciation is inconsistent with the requirements of the depreciation criteria in the National Gas Rules (NGR) and the revenue and pricing principles and the National Gas Objective (NGO) in the National Gas Law.[1]

Further, in section 4 I highlight other elements of the AER's draft decision that reinforce these conclusions and combine to create pressure across-the-board on the opportunity for Evoenergy to recover at least its efficient costs. In particular, I explain that the AER's draft decision:

- on the tariff variation mechanism leaves Evoenergy's opportunity to recover its efficient costs dependent on its ability to accurately forecast demand for gas, which the AER acknowledges is uncertain and can be affected significantly by factors beyond Evoenergy's control, eg, ACT government policy;
- on forecast demand and Evoenergy's tariff structure may exacerbate the risk that the tariff variation mechanism acts to prevent Evoenergy from recovering its efficient costs;
- on the capital expenditure sharing scheme (CESS) does not provide a reasonable opportunity for Evoenergy to recover at least its efficient costs, does not provide incentives to improve the efficiency of capital expenditure and may create a perverse incentive to over-spend capital expenditure in some circumstances; and
- on the treatment of the Utilities Network Facilities Tax (UNFT) and Energy Industry Levy (EIL) is grounded in a flawed rationale and is not supported, as the AER suggests, by the revenue and pricing principle to provide effective incentives to improve economic efficiency.

The resulting distortions to the incentives for ongoing efficient investment by Evoenergy risk a future deterioration in the quality, safety, reliability and security of supply of gas on its network, which is not in the long term interests of consumers.[2]

1.3 Structure

The remainder of this report is structured as follows, ie:

- in section two, I describe the regulatory framework for the determination of depreciation and the ACT government's emissions reduction target, along with Evoenergy's proposal and the AER's draft decision on depreciation;

[1] See: NGR, rule 76; and NGL, s 23 and s 24.

[2] National Gas Law, s 23.

- in section three, I present my assessment of the AER's draft decision on depreciation and its implications on the opportunity for Evoenergy to recover its efficient capital costs; and
- in section four, I describe other elements of the AER's draft decision that have implications on the opportunity for Evoenergy to recover at least its efficient costs.

In Appendix A1 I include a summary of the economics literature on the responsiveness of demand for natural gas to changes in the price of natural gas. I attach a copy of my curriculum vitae at Annexure A.

2. Context

In this section I describe the regulatory framework for the determination of depreciation, the ACT government's policy on emissions reductions and its implications for Evoenergy's gas network. I also describe key elements of Evoenergy's proposal and the AER's draft decision on depreciation, both of which are coloured by the ACT's emissions reduction objectives.

2.1 Regulatory framework

The regulatory framework for the gas network services provided by Evoenergy is established by the NGL and the NGR.

2.1.1 Depreciation criteria

The NGR requires the determination of total revenue for each regulatory year of the access arrangement period using the building block approach.[3] It also specifies the building blocks that comprise total revenue, being a return on capital, depreciation, the estimated cost of tax, forecast operating expenditure and adjustments from the operation of incentive mechanisms.[4]

Rule 89 of the NGR specifies criteria for determining the depreciation component of total revenue (the depreciation criteria). It provides that:[5]

> (1) The depreciation schedule should be designed:
>
> a) so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services; and
>
> b) so that each asset or group of assets is depreciated over the economic life of that asset or group of assets; and
>
> c) so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or a particular group of assets; and
>
> d) so that (subject to the rules about capital redundancy), an asset is depreciated only once (ie that the amount by which the asset is depreciated over its economic life does not exceed the value of the asset at the time of its inclusion in the capital base (adjusted, if the accounting method approved by the AER permits, for inflation)); and
>
> e) so as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.
>
> (2) Compliance with subrule (1)(a) may involve deferral of a substantial proportion of the depreciation, particularly where:
>
> a) the present market for pipeline services is relatively immature; and
>
> b) the reference tariffs have been calculated on the assumption of significant market growth; and
>
> c) the pipeline has been designed and constructed so as to accommodate future growth in demand.

[3] NGR, rule 76.

[4] NGR, rule 76.

[5] NGR, rule 89.

The depreciation criteria do not specify a particular approach (eg, straight line depreciation) that must be applied to calculate a depreciation schedule, either as a starting point or end-point.

The first element of rule 89(1) provides that the depreciation schedule should be designed so that reference tariffs vary over time in a way that promotes efficient growth in the market for the reference service. In economics, efficient growth (including negative growth) is consistent with the promotion of allocative efficiency, which typically is achieved by setting prices that reflect the marginal cost of providing a service. In the context of declining demand and excess capacity on a network, allocative efficiency and efficient negative growth is likely to be promoted by maximising the use of available capacity over the economic life of the network.

The second element of rule 89(1) provides that the depreciation schedule should be designed so that each asset or group of assets is depreciated over its economic life. The implied recovery of capital costs over the economic life of assets provides the regulated business with a reasonable opportunity to recover its efficient capital costs, while also promoting the recovery of capital costs from those customers that benefit from their use.

The third element of rule 89(1) further provides that the depreciation schedule should be designed so as to allow, as far as reasonably practicable, for adjustments to reflect changes in the economic life of assets. In my opinion, this requirement reflects the challenges that can arise from a reduction to the economic life of an asset, owing to the potential price implications of recovering efficient capital costs over a shorter period.[6]

In the context of declining demand, a depreciation schedule that allows for potential future changes in the economic life of an asset should therefore avoid unnecessary deferral of the recovery of capital costs, since it would exacerbate the challenges that arise from any future reduction in the economic life of assets.

Rule 89(2) refers to three scenarios in which a substantial deferment in depreciation may be contemplated by reference to rule 89(1). Consistent with the challenges that can arise from deferral of depreciation in the face of declining demand, as reflected in rule 89(1)(c), each of these scenarios reflect circumstances in which demand is expected to be higher in the future.

2.1.2 Revenue and pricing principles

The NGL mandates that in performing or exercising its economic regulatory functions or powers, the AER must, when exercising any discretion, take into account the revenue and pricing principles.[7] The NGR require that any incentive mechanism that is included in an access arrangement must be consistent with the revenue and pricing principles.[8]

The revenue and pricing principles include that:[9]

- a service provider should be provided with a reasonable opportunity to recover at least the efficient costs incurred in providing reference services and complying with a regulatory obligation or requirement or making a regulatory payment;
- a service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides, and that the economic efficiency that should be promoted includes—
  - efficient investment in, or in connection with, a pipeline with which the service provider provides reference services;
  - the efficient provision of pipeline services; and

[6] The economic challenges that arise from an extension to the economic life of an asset are typically more limited.

[7] NGL, s 28(2).

[8] NGR, rule 98(3).

[9] NGL, s 24.

  - the efficient use of the pipeline;

- regard should be had to the capital base adopted for a pipeline in previous access arrangement decisions or in the NGR;
- a reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which that tariff relates; and
- regard should be had to the economic costs and risks of the potential for under and over investment and for under and over utilisation of a pipeline with which a service provider provides pipeline services.

That a service provider should be provided with a reasonable opportunity to recover the efficient costs it incurs in providing reference services is a foundational principle of economic regulation.[10] Absent a reasonable opportunity to recover its efficient costs, a regulated business will be disinclined to undertake the investment necessary to maintain the regulated service. This will ultimately lead to a deterioration in the quality, safety and reliability of the regulated service, to the detriment of consumers.

Compliance with this revenue and pricing principle therefore promotes efficient investment in and the efficient operation of the reference service. It also reinforces the depreciation criteria that assets should be depreciated over their economic life and to allow, as far as reasonably practicable, for adjustments to reflect changes in economic life.

The revenue and pricing principles also provide that a service provider should be provided with effective incentives to promote economic efficiency, and that the economic efficiency to be promoted includes efficient investment in a pipeline, the efficient operation of a pipeline and the efficient use of a pipeline.[11]

Incentives that comply with this revenue and pricing principle should therefore encourage a service provider:

- to incur only efficient costs, while being provided with a reasonable opportunity to recover those efficient costs, consistent with the promotion of efficient investment in and operation of reference services; and
- to set tariffs that promote the efficient use of a reference service.

Consistent with the focus on efficient investment that I describe above, the revenue and pricing principles also require that regard be had to the economic costs and risks of the potential for under and over investment.[12]

The further requirements that regard should be had to the economic costs and risks of the potential for under or over utilisation of a pipeline reflects the promotion of efficient use of the reference service, which is one of three widely recognised dimensions to economic efficiency.[13]

2.1.3 National Gas Objective (NGO)

The NGL mandates that in performing or exercising its economic regulatory functions or powers, the AER must do so in a manner that will, or is likely to, contribute to the achievement of the NGO.[14]

[10] NGL, s 24(2).

[11] NGL, s 24(3).

[12] NGL, s 24(6).

[13] NGL, s 24(7).

[14] NGL, s 28(1)(a).

The NGL specifies the NGO as follows, ie:[15]

> The objective of this Law is to promote efficient investment in, and efficient operation and use of, covered gas services for the long term interests of consumers of covered gas with respect to—
>
> (a) price, quality, safety, reliability and security of supply of covered gas; and
>
> (b) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

The promotion of efficient investment in and the efficient operation of covered gas services is consistent with one of three widely recognised dimensions to economic efficiency, being productive efficiency. Efficient investment in and operation of services is reflected in:

- the revenue and pricing principles that a service provider should be provided with:
  - a reasonable opportunity to recover at least the efficient costs of providing services; and
  - with effective incentives in order to promote economic efficiency, including for efficient investment in and provision of pipeline services; and
  - that regard should be had to the economic costs and risks of the potential for under and over investment.
- the depreciation criteria that the depreciation should be designed:
  - so that assets are depreciated over their economic life; and
  - so as to allow, as far as reasonably practical, for adjustment reflecting changes in the expected economic life of assets.

The other two dimensions of economic efficiency – allocative and dynamic efficiency – are reflected in the promotion of the efficient use of reference services and the clarification that efficiency is to be promoted for the long term, rather than short term, interests of consumers.

2.2 ACT government policy on natural gas

The ACT government has legislated the achievement of net zero greenhouse gas emissions by 2045, based on 1990 levels.[16]

The path to achievement of this target includes reducing emissions by:[17]

- 50 to 60 per cent by 2025;
- 65 to 75 per cent by 2030; and
- 90 to 95 per cent by 2040.

The ACT sourced 100 per cent of its electricity from renewable energy sources by 2020, which underpinned its achievement of a 47 per cent reduction in total emissions (below 1990 levels) in 2023.[18]

[15] NGL, s 23.

[16] See: ACT government website, *ACT Climate change strategy*, available at: https://www.climatechoices.act.gov.au/policy-programs/act-climate-change-strategy, accessed 5 January 2025; and the *Climate Change and Greenhouse Gas Reduction Act 2010*.

[17] ACT government website, *ACT Climate change strategy*, available at: https://www.climatechoices.act.gov.au/policy-programs/act-climate-change-strategy, accessed 5 January 2025.

[18] See: ACT government website, *What the ACT government is doing*, available at: https://www.climatechoices.act.gov.au/energy/what-the-act-government-is-doing, accessed on 5 January 2025; and ACT government, *Integrated Energy Plan*, 2024, p 11.

The Integrated Energy Plan (IEP) published in 2024 sets the long term pathway for the transformation of the ACT's energy system to achieve net zero by 2045. It highlights that:[19]

> The ACT will now focus on reducing emissions from our two most significant sources: fossil fuel gas use and transport. More than 84 per cent of the ACT's current emissions come from a combination of transport (64.6%) and fossil fuel gas combustion (19.9%).

To this end, the ACT government has signalled the eventual shut-down of the natural gas network and, in December 2023, introduced regulations preventing new gas connections in the ACT.[20]

One of the key actions in the IEP is to:[21]

> Develop policy and regulatory frameworks to support safe, efficient and equitable decommissioning of the gas network.

The IEP also identified that sections of the gas network will be safely decommissioned over the 2035 to 2040 period.[22]

2.3 Evoenergy's proposed depreciation

Evoenergy proposed total regulatory depreciation equal to $168 million, in FY26 dollar terms, over 2026-31.[23]

Evoenergy's proposed level of depreciation is shaped by its proposal:

- to set the economic life of its assets as ending in 2045, consistent with the ACT government's legislated emission reduction targets and policy intention to transition away from natural gas; and
- to derive the time profile of depreciation using the sum-of-years-digits approach that was adopted by Ofgem, the regulatory authority for energy networks in the United Kingdom, to calculate depreciation for gas networks.

Setting the economic life of assets to end in 2045 ensures that Evoenergy has an opportunity to recover its efficient capital costs over their economic life, consistent with the requirements of the NGR and NGL.[24]

The sum-of-years-digits approach to depreciation brings forward in time the recovery of Evoenergy's capital costs, in comparison to the straight-line approach that was used in the previous access arrangement.

Given the ongoing decline in the number of customers connected to the gas network, this enables relatively more costs to be recovered when there are more customers connected to the network, which will result in more stable and predictable network prices over the period to 2045.[25] It also promotes the opportunity for Evoenergy to recover its efficient capital costs over the period to 2045 because doing so does not rest on recovering much higher levels of cost from the much smaller cohort of customers that are last to disconnect from the gas network.

[19] ACT government, *Integrated Energy Plan*, 2024, p 12.

[20] ACT government, *Integrated Energy Plan*, 2024, p 55.

[21] ACT government, *Integrated Energy Plan*, 2024, p 9.

[22] ACT government, *Integrated Energy Plan*, 2024, p 19.

[23] Evoenergy, *Attachment 6: Depreciation Access arrangement information ACT and Queanbeyan-Palerang gas network access arrangement 2026–31, June 2025, p 27.*

[24] See: NER, clause 89(1)(b); and NGL, sections 23 and 24.

[25] Evoenergy, *Attachment 6: Depreciation Access arrangement information ACT and Queanbeyan-Palerang gas network access arrangement 2026–31, June 2025, pp 24-26.*

Evoenergy explains that its approach therefore sets the foundations for an equitable transition path, delivers long term benefits to customers and is consistent with the regulatory framework by:[26]

- **equitably sharing past investment costs** across different customers over time, taking into consideration that those most likely to remain on the network for longer are also likely those least able to transition
- **enabling price stability and predictability** through to 2045 by using a methodical accelerated depreciation approach which allocates proportionally less depreciation to each remaining year through to 2045, aligned with reducing gas demand over time
- **providing Evoenergy with a reasonable opportunity** to recover efficient past investment costs, noting that our proposed depreciation approach alone may not be sufficient to enable Evoenergy to recover all of those costs given we still face a material risk of asset stranding as gas prices increase in the second half of the transition, and if gas demand falls faster than forecast
- **providing effective incentives for Evoenergy to undertake efficient investment in, and for the efficient use of, its gas distribution network**, noting that, in circumstances where the return on capital does not compensate Evoenergy for the imminent risk of asset stranding, Evoenergy will otherwise be deterred from undertaking the efficient investment, or incurring the efficient operating and maintenance expenditure, required for a safe, reliable and secure gas supply during the transition period
- **complying with the depreciation criteria in the Rules** to reflect economic asset lives, promote efficient (negative) growth in the market and seek to recover Evoenergy's reasonable cash flow needs.

2.4 AER's draft decision on depreciation

The AER's draft decision is not to accept the level of regulatory depreciation proposed by Evoenergy and, instead, to adopt a depreciation profile that gives effect to regulatory depreciation equal to $95 million (FY26 dollars) over the five year access arrangement.[27]

It follows that the AER's draft decision is to reduce Evoenergy's proposed regulatory depreciation by $73 million (FY26 dollars), or 43 per cent.[28]

The AER highlights that the increase in the average residential bill over 2026-31 is:[29]

- $37 per annum under its draft decision, based on a 4.5 per cent per annum price increase in constant dollar terms (which includes a 0.5 per cent upwards price adjustment for incentive scheme amounts); rather than
- $118 per annum under Evoenergy's proposal, based on a 15.3 per cent per annum price increase in constant dollar terms.

The AER's draft decision on depreciation is shaped by its decision to adopt what it refers to as a 'base real price increase limit' approach. I understand that it involves selection of a real change in network price based

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[26] Evoenergy, *Attachment 6: Depreciation Access arrangement information ACT and Queanbeyan-Palerang gas network access arrangement 2026–31, June 2025, p 18.*

[27] Calculating by converting the regulatory depreciation amounts presented by the AER in dollar of the day terms to real FY26 dollars based on the AER's forecast of inflation equal to 2.65 per cent during the access arrangement. See: AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 11.

[28] I calculated the $72.7 million reduction in regulatory depreciation equal to $167.9 million - 95.2 million. I calculated a 43 per cent reduction equal to (-$72.7 million / $167.9 million).

[29] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 27.

on the AER's regulatory judgment and then imputing the level of depreciation that gives effect to that real price change, given Evoenergy's other costs.

The AER explains that its draft decision is:[30]

> …to apply a 4.0% 'base' real price increase limit when determining the amount of accelerated depreciation. Setting this limit on price increases, in our judgment, best ensures the depreciation schedule will be adjusted consistent with the requirements of rule 89 of the NGR, in particular rule 89(1)(a)

The economic role of depreciation in the AER's draft decision is therefore as a 'balancing item' that ensures its draft decision in totality produces the price outcome that it deems to be appropriate, based on its judgment.

The AER does not explain in any precise terms how it selected a 4.0 per cent price limit. It does however explain that the relatively higher prices that arise from Evoenergy's proposed depreciation:[31]

> …risks the use of the network (including the number of customers) to decline [sic] faster than anticipated, which further increases the risk of asset stranding and of costs being borne by an even smaller number of customers in the future. As such, in determining the amount of accelerated depreciation for this draft decision, we have applied a 'base' real price increase limit of 4.0% as a guardrail.

The AER's draft decision is also not to accept Evoenergy's proposal that the economic life of its assets ends in 2045 – ie, asset lives no longer than 19 years – so as to align with the ACT government policy to achieve net zero by 2045, and to decommission the gas network to that end.

Specifically, the AER's draft decision is to adopt standard asset lives for high pressure (HP) and medium pressure (MP) asset classes equal to 30 years and 25 years, respectively.[32]

In practice, this leaves unchanged the remaining life of existing HP services and MP mains assets, which are already slightly below the standard asset life, ie, 28 years and 20 years, respectively. It does however reduce the remaining asset life for HP mains and MP services from 55 years to 30 years and from 31 years to 25 years, respectively.[33]

The AER's draft decision also means that new HP and MP assets that enter service during 2026-31 will have asset lives equal to 30 years and 25 years, respectively, which implies economic lives for those assets that extend materially beyond 2045, and as late as 2061.[34]

The longer asset lives adopted by the AER act to spread the recovery of capital costs, in the form of depreciation, over a longer period and therefore to reduce the level of depreciation in 2026-31, in comparison to Evoenergy's proposal.

Table 2.1: presents a comparison of assets lives proposed by Evoenergy for existing HP and MP asset classes, in comparison to those in the AER's draft decision.

[30] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 27.

[31] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 14.

[32] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 16.

[33] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 16.

[34] For instance, application of a 30 year standard life to a HP asset that enters service in 2031 will have an economic life that ends in 2061.

Table 2.1: Evoenergy and AER remaining asset lives for existing HP and MP assets

	Remaining asset life		End of economic life	
	Evoenergy proposal	**AER draft decision**	**Evoenergy proposal**	**AER draft decision**
HP mains	19 years	30 years	2045	2056
HP services	19 years	28 years	2045	2054
MP mains	19 years	20 years	2045	2046
MP services	19 years	25 years	2045	2051

Table 2.2 presents the same analysis, but as relevant to new HP and MP assets that enter service in 2030.

Table 2.2: Evoenergy and AER asset lives for new HP and MP assets in 2030

	Standard asset life		End of economic life	
	Evoenergy proposal	**AER draft decision**	**Evoenergy proposal**	**AER draft decision**
HP mains	15 years	30 years	2045	2060
HP services	15 years	30 years	2045	2060
MP mains	15 years	25 years	2045	2055
MP services	15 years	25 years	2045	2055

The basis for adoption of economic lives that extend materially beyond 2045 is the AER's view that:[35]

> While we consider the likelihood that Evoenergy's network will be decommissioned by 2045 to be high, we do not consider there is sufficient evidence to suggest a 100% likelihood of this outcome as suggested by Evoenergy's proposal

It is informative to observe that the economic role of asset lives in determining depreciation over 2026-31 is neutralised by the AER's overarching adoption of a 'base real price increase limit' approach. If the AER accepted the asset lives adopted by Evoenergy and therefore adopted higher depreciation for HP mains and MP services for 2026-31, under the 'base real price increase limit' approach the AER would make a commensurate, offsetting reduction to depreciation to ensure its draft decision produces a 4.0 per cent real price change per annum.

[35] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 17.

3. Assessment of draft decision on depreciation

In this section I present my assessment of the AER’s draft decision on depreciation. In particular, I:

- describe the economics literature on the price elasticity of demand for gas and its implications for the expected effect of a higher gas price on demand for gas;
- evaluate the AER’s adoption of a ‘base real price limit’ approach for the determination of depreciation;
- comment on the AER’s decision to extend the economic life of some assets beyond the year in which the ACT government has committed to achieving net zero;
- comment on the promotion of efficient growth in the market for these reference services;
- describe the implications of the AER’s draft decision for the emissions reduction element of the NGO; and
- draw a conclusion on the implications of the AER’s draft decision for efficient investment and the long term interest of customers.

3.1 Responsiveness of demand to changes in price

In this section I describe the economics literature on the responsiveness of demand for gas to changes in the price of gas. In economics, this is referred to as the price elasticity of demand, where demand is said to be:

- relatively inelastic if a percentage increase/decrease in the price of a good or service results in a relatively smaller percentage decrease/increase in demand for that good or service; and
- relatively elastic if a percentage increase/decrease in the price of a good or service results in a relatively larger percentage decrease/increase in demand for that good or service.

By way of example, price elasticity of demand equal to -0.05 indicates that a one per cent increase (or decrease) in price is associated with a 0.05 per cent decrease (or increase) in demand.

I note that the negative value of price elasticity of demand reflects the inverse relationship between price and demand, eg, the quantity of a good or service demanded typically decreases (or increases) as its price increases (or decreases). Further, a price elasticity of demand equal to zero indicates that demand is perfectly inelastic, ie, it is unresponsive to changes in price.

In the remainder of this section I:

- describe the economics literature of the price elasticity of demand for gas;
- evaluate the extent to which the assumptions adopted by Evoenergy and the AER on the price elasticity of demand for gas in their respective demand forecasts is consistent with the economics literature; and
- provide context to the implications on demand for gas of different changes in network price in the 2026-31 access arrangement period.

For completeness, in section 3.2 I describe the implied role of the price elasticity of demand for gas in the AER’s decision on depreciation. I also assess the extent to which the basis for the AER’s draft decision is consistent with the economics literature, as well as the research commissioned by Evoenergy and the assumptions underpinning the AER’s demand forecast.

3.1.1 Economics literature

I have undertaken a desktop review of the economics literature on the price elasticity of both demand for gas and gas connections, focusing on peer-reviewed papers.[36]

My review identified a range of literature on the price elasticity of demand for gas consumption, but I was unable to identify reliable literature on the price elasticity of demand for connections to the gas network. The literature that I identified focused on countries other than Australia, ie, principally in the United States and other countries that are members of the Organisation for Economic Co-operation and Development (OECD).

Existing studies commonly report that demand for gas is price inelastic in both the short and long run.[37] Another commonality across these studies is that demand for gas is slightly less inelastic in the long run, as compared with the short run.[38] This is likely to reflect the challenges associated with changing appliances and home infrastructure in the short run in response to changes in price, and the greater flexibility to do so in the long run.

Estimates of the price elasticity of demand for natural gas vary depending on a range of factors, including:

- customer characteristics,[39] eg, size and structure of homes, income level, usage level, residential building composition and the extent of dual heating systems could influence customers' responsiveness to price changes;
- the sector of the economy,[40] eg, industrial customers with higher energy intensity and more alternatives for energy may have more elastic demand; and/or
- by country,[41] eg, climatic conditions, gas price level or national gas grid coverage could influence customers' responsiveness to price changes.

Notwithstanding, the results of the studies that I identified suggest that, even for customers with similar customers and with similar economic and geographic settings, estimates of price elasticity can still differ depending on model specification, time period of assessment and data sources. Further, most of these studies present a range of estimates that reflect different permutations of these characteristics.[42]

Another characteristic of the literature is a general lack of recent studies on the price elasticity of demand for natural gas, which is also recognised in the literature itself.[43] For instance, Bernstein and Madlener (2011)

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[36] I note that my review was undertaken in the relatively tight timeframe between the AER's draft decision at the end of November and Evoenergy's revised proposal in early January.

[37] See, for example: Burke and Yang, *The price and income elasticities of natural gas demand: international evidence*, Energy Economics 59 (2016): 466-474; Bernstein and Griffin, *Regional differences in the price-elasticity of demand for energy*, National Renewable Energy Lab (United States), No. NREL/SR-620-39512 (2006).

[38] See, for example: Burke and Yang, *The price and income elasticities of natural gas demand: international evidence*, Energy Economics 59 (2016): 466-474; Bernstein and Madlener, *Residential Natural Gas Demand Elasticities in OECD Countries: An ARDL Bounds Testing Approach*, Future Energy Consumer Needs and Behavior Working Papers 15/2011, E.ON Energy Research Center; and Bernstein and Griffin, Regional differences in the price-elasticity of demand for energy, National Renewable Energy Lab (United States), No. NREL/SR-620-39512 (2006).

[39] See, for example: Rubin and Auffhammer, *Quantifying heterogeneity in the price elasticity of residential natural gas*, Journal of the Association of Environmental and Resource Economists 11.2 (2024): 319-357; Asche, Nilsen, and Tveteras. *Natural gas demand in the European household sector*, The Energy Journal 29.3 (2008): 27-46.

[40] See, for example: Andersen, Nilsen, and Tveteras. *How is demand for natural gas determined across European industrial sectors*, Energy Policy 39.9 (2011): 5499-5508.

[41] See, for example: Andersen, Nilsen, and Tveteras. *How is demand for natural gas determined across European industrial sectors*, Energy Policy 39.9 (2011): 5499-5508.

[42] The range of elasticity estimates is also observed by a number of authors of the academic papers I reviewed. See, for example: Joutz, Trost, Shin and McDowell, *Estimating regional short-run and long-run price elasticities of residential natural gas demand in the US*, United States Association for Energy Economics working paper, August 2009.

[43] See, for example: Bernstein and Madlener, *Residential Natural Gas Demand Elasticities in OECD Countries: An ARDL Bounds Testing Approach*, Future Energy Consumer Needs and Behavior Working Papers 15/2011, E.ON Energy Research Center; and Asche, Nilsen, and Tveteras. *Natural gas demand in the European household sector*, The Energy Journal 29.3 (2008): 27-46.

observe that nearly all of the econometric analysis of natural gas demand are from the 1960s and 1980s.[44] Hahn and Metcalfe (2022) similarly observe the 'dearth of causal studies on estimating the price elasticity of demand for natural gas'.[45]

Nevertheless, a persistent theme across these studies is that the price elasticity of demand for gas consumption is relatively inelastic for residential customers. When assessed by reference to retail price, the price elasticity of demand for gas consumption is relatively inelastic for residential customers and typically falls between -0.44 and -0.03, with the mid-point of this range being -0.235.[46]

I summarise the results from my review of the economics literature in Table 3.1 and include at Appendix A1 a short summary of each of these studies.

Table 3.1: Summary of estimated price elasticity in the economics literature

Author(s)	Year	Country/region	Sector	Time period	Short-run price elasticity	Long-run price elasticity	Type of price
Rubin and Auffhammer	2022	California	Residential	2010 to 2014	-0.15 to -0.19 (medium-run elasticity)		Retail
Hahn and Metcalfe	2021	California	Residential	2012 to 2015	-0.29 to -0.35		Retail
Burke and Yang	2016	44 countries	Industrial and residential	1978 to 2011	-0.13 to -0.37*	-0.82 to -1.09*	Industrial and residential end-user price
Arora	2014	United States	Industrial, residential and inventories	1993 to 2013	-0.10 to -0.16	-0.24 to -0.29	Industrial and residential end-user price
Andersen et al.	2011	13 OECD countries	Industrial	1978 to 2003	-0.06 to -0.18*	-0.16 to -0.62*	Industrial end-user price
Bernstein and Madlener	2011	12 OECD countries[47]	Residential	1980 to 2008	-0.23	-0.51	Retail
Asche et al.	2008	12 European countries[48]	Residential	1978 to 2002	-0.03 to -0.15	-0.44 to -0.1	Retail
Joutz et al.	2009	United States	Residential	1992 to 2006	-0.09 to -0.11	-0.18 to -0.2	Retail
Bernstein and Griffin	2006	United States	Residential	1977 to 2004	-0.12	-0.36	Retail
Berkhout et al.	2004	Netherlands	Residential	1992 to 1999	-0.19	Not estimated in the paper	Retail
Maddala et al.	1997	United States	Residential	1970 to 1990	-0.09 to -0.12	-0.24 to -0.27	Retail
Bohi and Zimmerman	1984	United States	Residential	1960s to 1970s	-0.2	-0.3	Depending on underlying study

** I include these estimates for transparency as to the sample of papers that I reviewed. I do not consider these estimates in establishing the plausible range of elasticity estimates applicable to Evoenergy's customers for the following reasons. The Andersen et al (2011) paper provides estimates for non-residential users only. The Burke and Yang (2016) paper do not apply an estimation methodology that account for heterogeneous demand responses, which is likely a material problem given the large sample of countries compared to other*

[44] Bernstein and Madlener, *Residential Natural Gas Demand Elasticities in OECD Countries: An ARDL Bounds Testing Approach*, Future Energy Consumer Needs and Behavior Working Papers 15/2011, E.ON Energy Research Center.

[45] Hahn and Metcalfe, *Efficiency and equity impacts of energy subsidies*, American Economic Review 111.5 (2021): 1658-1688.

[46] The bounds for this range are -0.03 and -0.44. The range is not informed by the estimates from Andersen et al (2011) and Burke and Yang (2016) for reasons I set out in the note that accompanies Table 3.1.

[47] The countries examined in this study include Austria, Finland, France, Germany, Ireland, Japan, Luxembourg, the Netherlands, Spain, Switzerland, the United Kingdom and the United States.

[48] The countries examined in this study include Austria, Belgium, Denmark, France, Germany, Ireland, Italy, the Netherlands, Spain, Sweden, Switzerland and the UK.

studies. Details of the discussion of these papers are provided in the appendix.

3.1.2 Consistency with assumptions used by Evoenergy and the AER

As set out above, my review of the economics literature suggests that the price elasticity of demand for residential gas consumption generally lies between -0.44 and -0.03.

In my opinion, the assumptions that underpin both Evoenergy's proposal and the AER's draft decision on forecast demand are consistent with the economics literature.

Evoenergy commissioned customer research that was specific to the Australian Capital Territory, was undertaken in 2025 and focused on the price elasticity of demand for connections to the gas network. This study concluded that the price elasticity of demand for connections to the gas network for residential customers was relatively inelastic, with price elasticities that fall within a range of -0.022 to -0.061.[49] The slightly more elastic estimates correspond to longer timeframes, which is also consistent with the economics literature.[50]

Similarly, the forecast of demand for gas in the AER's draft decision is based on an assumption that the price elasticity of demand for gas heating is equal to -0.05.[51] This estimate was based, in turn, on the assumption adopted by the Australian Energy Market Operator (AEMO) in its gas demand forecasting methodology that the price elasticity of demand for gas heating was equal to -0.05.[52] AEMO explained in that same report that it set the price elasticity of demand for baseload gas equal to zero, which implies that it is perfectly inelastic and unresponsive to changes in price, ie, it explained that:[53]

> Price rises were estimated to have minimal impact on base load, as it was assumed that baseload usage is largely from the daily operation of appliances such as a cooktop or a hot water heating system that are price inelastic. If consumers change their cooktop or hot water heating system, this impact is captured in the modelling of energy efficiency and fuel-switching. Therefore, the price elasticity for base load was set to 0.

3.1.3 Effect of the draft decision on demand for gas

In this section I estimate the effect of changes in price on demand for gas consumption, based on different permutations of changes in network price and assumptions as to the price elasticity of demand for gas.

At the outset, it is informative to note that the effect on demand of changes in network price is muted by network prices comprising only around 29 per cent[54] of retail prices, which implies that a one per cent change in network price translates to an approximate 0.29 per cent change in retail price.

Since the available estimates of price elasticity relate to retail prices, the first step in my analysis is to convert a change in network price to a change in retail price. I have assumed that network prices comprise 29 per cent of retail prices at the start of the access arrangement and that non-network prices remain unchanged in constant dollar terms.[55]

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[49] Centre for International Economics, Price elasticity of demand for natural gas – Stated preference research, 23 June 2025, p 52.

[50] Centre for International Economics, Price elasticity of demand for natural gas – Stated preference research, 23 June 2025, p 52.

[51] Frontier Economics, *Gas demand forecasts for Evoenergy – prepared for the Australian Energy Regulator*, 5 November 2025, pp 19 and 50.

[52] AEMO, *Gas demand forecasting methodology information paper*, March 2025, p 22. See Step Change and Green Energy Exports scenarios.

[53] See: AEMO, *Gas demand forecasting methodology information paper*, March 2025, p 22.

[54] I understand that, for the purpose of the bill impact assessment in its revised proposal, Evoenergy adopted an assumption that the network component of the retail price is 29.2 per cent.

[55] I understand that, for the purpose of the bill impact assessment in its revised proposal, Evoenergy adopted an assumption that the network component of the retail price is 29.2 per cent. I adopt this same assumption as at the start of the access arrangement for the purpose of my analysis. When combined with an assumption that non-network prices remain unchanged, this means that assumed future increases in network prices have the effect of increasing slightly the network share of retail prices over time.

The retail prices that I present as corresponding to each network price change reflect this dynamic. I express the change in retail price as an average annual change in retail price over the five year access arrangement.

My analysis reflects three scenarios for the change in network price per annum over the access arrangement, ie:

- 4.5 per cent per annum, reflecting the AER's draft decision, inclusive of an additional 0.5 per cent per annum change to reflect the operation of incentive mechanisms;[56]
- 8.6 per cent per annum, reflecting Evoenergy's revised proposal;[57] and
- 15.3 per cent per annum, reflecting Evoenergy's original proposal.[58]

For each price change scenario, I estimate the change in gas consumption based on three different price elasticity values, ie:

- -0.05, consistent with the value underpinning the AER's draft decision on demand, and as adopted by AEMO;[59]
- -0.061, consistent with the most price elastic of the headline price elasticity estimates from the customer research commissioned by Evoenergy and undertaken by CIE;[60] and
- -0.235, as a conservative reference point based on the mid-point of the range of price elasticity derived from my review of the economics literature.

I estimate the effect on demand for gas by multiplying the average annual change in retail price by the applicable price elasticity. By way of example, based on a 4.5 per cent per annum increase in network price and a price elasticity of demand equal to -0.05, I estimate:[61]

- an average annual increase in retail price equal to 1.4 per cent per annum;[62]
- a decrease in demand per annum equal to 0.07 per cent;[63] and
- a total decrease in demand over the access arrangement equal to 0.35 per cent.[64]

I present the results of my analysis in Table 3.2.

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[56] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 27.

[57] Evoenergy, *Attachment 3: Depreciation Revised access arrangement information – ACT and Queanbeyan-Palerang gas network access arrangement 2026-31*, Draft as at 8 January 2025, section 3.4.4.

[58] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 27.

[59] Frontier Economics, *Gas demand forecasts for Evoenergy – prepared for the Australian Energy Regulator*, 5 November 2025, pp 19 and 50.

[60] Centre for International Economics, Price elasticity of demand for natural gas – Stated preference research, 23 June 2025, p 52. This estimate is based on the price elasticity of connections over the period to 2041. The estimates presented on page 53 of the CIE report indicate that the corresponding estimates of price elasticity of consumption (rather than connections) are more inelastic.

[61] All steps of calculation are undertaken with unrounded values. Rounding only occurs in the reporting of the results in this example, and Table 3.2.

[62] Based on assumptions that network price comprises 29 per cent of retail price, with network price increasing by 4.5 per cent per annum from the first year and non-network price remaining constant over the five year assessment period, retail price would increase by 1.31, 1.36, 1.40, 1.44 and 1.48 per cent over the five year period. This is equivalent to a 1.40 per cent increase per annum (with the result rounded to the second decimal place).

[63] Calculated equal to 1.40% x -0.05, with the result rounded to the second decimal place.

[64] Calculated equal to 1 – (1-0.07%)^5, with the result rounded to the second decimal place.

Table 3.2: Estimated effect on demand for gas

Change in network price*	Change in retail price**	Change in demand*** (on average per annum, values in brackets represent total change over five-year assessment period)		
		Price elasticity = -0.05	*Price elasticity = -0.061*	*Price elasticity = -0.235*
4.5% per annum	1.4% on average per annum	0.07% per annum (0.35% total 5 years)	0.09% per annum (0.43% total 5 years)	0.33% per annum (1.63% total 5 years)
8.6% per annum	2.8% on average per annum	0.14% per annum (0.70% total 5 years)	0.17% per annum (0.86% total 5 years)	0.66% per annum (3.27% total 5 years)
15.3% per annum	5.4% on average per annum	0.27% per annum (1.35% total 5 years)	0.33% per annum (1.65% total 5 years)	1.28% per annum (6.23% total 5 years)

*Note: *Change in network price represents annual change of the defined amount over the five-year assessment period.*
***Change in retail price differs from year to year due to the increasing network share of retail prices (as a result of assuming non-network prices remain unchanged over the assessment period). The 'change in retail price' represents the annual change, on average over the five-year assessment period.*
**** Following the same reasoning as that set out above, change in demand represents the annual change, on average over the five-year assessment period.*

I present estimates using an elasticity of -0.235, being the mid-point estimate from the economics literature, as a conservative reference point only. These estimates are based on data prior to 2015, and typically much earlier, and so are unlikely to reflect the current technical landscape for gas appliances and electrification. Further, none of them are specific to the ACT or Australia with the consequence that they are unlikely to reflect the current circumstances faced by gas customers in the ACT or Australia, eg, the ready availability of and appetite for electrification and distributed energy generation.

My results indicate that, based on the price elasticity of demand implicit in the AER's forecast – as used by AEMO – and based on the ACT-specific research commissioned by Evoenergy, the total decrease in the demand for gas over the five year access arrangement would be:

- 0.35 per cent to 0.43 per cent, based on the AER's draft decision;
- 0.70 per cent to 0.86 per cent, based on Evoenergy's revised proposal; and
- 1.35 per cent to 1.65 per cent, based on Evoenergy's initial proposal.

In my opinion, this analysis indicates that no material effect on demand would be expected to arise from the price implications of either the AER's draft decision or Evoenergy's proposal. It follows that neither the AER's draft decision nor Evoenergy's proposal would be expected to have material implications for the efficient growth or use of reference services during 2026-31.

This is important context to the significantly higher depreciation facilitated by Evoenergy's proposal and the adverse implications of the AER's decision for ongoing efficient investment in the safe, secure and reliable operation of Evoenergy's network over the period until it is decommissioned, consistent with the long term interest of consumers. I describe these adverse implications in the remainder of section 3.

3.2 Base real price increase limit

The AER says that, when compared with Evoenergy's proposal, its 'base real price increase limit' approach to setting depreciation:[65]

> …better meets the NGR criteria for depreciation schedules and promoting the NGO…

[65] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 20.

The apparent driving force behind the AER's adoption of its 'base real price increase limit' approach – being short term price impacts – is absent from the depreciation criteria, the revenue and pricing principles and the NGO.

The AER attempts to reconcile its focus on short term price impacts with the NGR and NGL by explaining that:[66]

> …There is a real risk that adopting a policy of accelerating depreciation, without clearly defined limits, would be likely to result in large and repeated increases in future gas prices. This would not align with the long-term interests of customers, as it risks the use of the network (including the number of customers) declining faster than anticipated, which further increases the risk of asset stranding and of costs being borne by an even smaller number of customers in the future.

The AER's rationale is predicated on demand for gas being responsive to changes in price, such that higher network prices lead to higher disconnections and lower demand. In contrast, the analysis that I present in section 3.1 indicates that neither the AER's draft decision or Evoenergy's proposal would be expected to have a material effect on demand for gas.

The AER's implied assertion that Evoenergy is proposing to increase the risk of asset stranding to its own detriment, itself, warrants pause for reflection.[67] Rather, the opportunity for Evoenergy to recover at least its efficient costs, consistent with both the revenue and pricing principles and its own commercial interests, rests on it *minimising* disconnections and the risk of asset stranding. In my opinion, Evoenergy therefore faces strong incentives to minimise disconnections over the remaining economic life of its gas network.

The AER is also incorrect to assume implicitly that:[68]

- its decision on depreciation for 2026-31 necessarily requires the adoption of that, or any other approach, in future regulatory periods; such that
- an alternative to the 'base real price increase limit' approach will precipitate a self-perpetuating process of ever-higher prices and disconnections.

In contrast, Evoenergy's proposed approach provides significant flexibility to respond to the uncertain profile of gas demand and connections over the period to 20245, as described in the section that follows.

3.2.1 Asserted flexibility

Inherent in the AER's approval of maximum network prices for 2026-31 is the ability for Evoenergy to reduce prices below the level approved by the AER, along with the inability to raise prices above that level.

As foreshadowed in the preceding section, minimising disconnections is central to the opportunity for Evoenergy to recover at least its efficient costs. Evoenergy therefore has a strong incentive to reduce prices below the maximum level approved for 2026-31 if its proposal was to result in an unexpected decrease in demand for gas.

In my opinion, Evoenergy therefore has both the ability and a strong incentive to respond to any unexpected decline in demand for gas during 2026-31.

Further, in the context of declining demand, the recovery of relatively more costs in 2026-31 provides flexibility to align future reductions in demand with commensurate reductions in the level of total cost recovered each year, thereby keeping prices stable and promoting an orderly transition to electrification.

[66] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 20.

[67] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 20.

[68] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 20.

In my opinion, this promotes concurrently the long term interests of customers and the opportunity for Evoenergy to recover at least its efficient costs.

In its proposal, Evoenergy demonstrated the relatively more stable network prices that arise from its proposed approach to depreciation over the period to 2045, in comparison to straight-line depreciation.[69]

In response to Evoenergy's long term analysis, the AER assessed the price path that would be likely to arise from Evoenergy's proposed approach, under various future demand scenarios.[70]

However, the AER presented no such quantitative analysis of its draft decision. Neither did the AER estimate nor compare with Evoenergy's approach the long term outcomes that would be likely to arise from its approach, under those same future demand scenarios.

Consistent with the intuitive logic that relatively higher future prices arise from leaving materially higher costs for recovery when less customers are connected to the network, I understand that Evoenergy's revised proposal includes an analysis that demonstrates the relatively higher future prices that would arise from the AER's draft decision, in comparison to its revised proposal.[71]

Further, the AER's qualitative comparison is undertaken by way of reference to a generic alternative approach that does not have a price limit, rather than Evoenergy's actual proposal.

Instead, the AER asserts that its approach:[72]

> …offers more flexibility, allowing the depreciation schedule (and in turn prices) to be adjusted in a way that better promotes efficient growth (including negative growth) in the market for reference services, consistent with NGR rule 89(1)(a). Under this approach, the immediate price impact of accelerated depreciation is limited when prices are already raising significantly due to declining demand or when other costs (such as interest rates) are high. This ensures better price stability and affordability, thereby promoting efficient use of reference services. Conversely, when prices are relatively stable and affordable or other costs are low (such as during a period of low interest rates), more accelerated depreciation can be applied. This helps offset some of the price impacts from accelerated depreciation and increases the likelihood of cost recovery, supporting incentives for efficient investment.

The AER does not present a sound economic basis for its conclusion that:

- its approach promotes efficient negative growth, given the empirical evidence that demand is relatively unresponsive to changes in price;
- deferral of the recovery of efficient costs increases the likelihood of cost recovery in circumstances where demand is declining; and
- interest rates are relevant to its decision on depreciation, along with an absence of any explanation of how it assessed interest rates now (or over 2026-31) and how it did (or would in the future) determine whether they are 'high' or 'low'.

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[69] Evoenergy, *Attachment 6: Depreciation Access arrangement information ACT and Queanbeyan-Palerang gas network access arrangement 2026–31, June 2025, p 24.*

[70] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, pp 23-24.

[71] Evoenergy, *Attachment 3: Depreciation Revised access arrangement information – ACT and Queanbeyan-Palerang gas network access arrangement 2026-31*, Draft as at 8 January 2025, section 3.4.11 and 3.6.3.

[72] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 21.

Nevertheless, implicit in the AER's draft decision appears to be a conclusion that, by reference to some unspecified reference point, the relevant interest rates are 'high' and so depreciation should be lower than proposed by Evoenergy in 2026-31.[73]

The flawed nature of this framework for decision-making on depreciation, and its absence of any clear nexus with the NGR and NGL, is illustrated by the likely deterioration in economic conditions that would precipitate a material decline in interest rates from current levels.

The AER suggests that it is in these circumstances that 'more accelerated depreciation could be applied'.[74] In my opinion, the AER is highly unlikely to approve higher levels of depreciation in the context of a deterioration in economic conditions. Rather, a deterioration in economic conditions would be expected to heighten affordability concerns and exacerbate the effects of price increases on vulnerable customers, which are both considerations cited by the AER as a basis for not accepting a higher level of depreciation in 2026-31.[75]

In my opinion, the AER's decision-making framework is therefore likely to be interpreted as a signal that Evoenergy's network prices will not increase by more than four per cent per annual (in constant dollar terms) over the remaining economic life of its network.

This is because a material decrease in interest rates would, for the reasons I describe above, be more likely to correspond to higher affordability concerns and effects on vulnerable customers, rather than to mitigate those considerations and facilitate higher levels of depreciation, as suggested by the AER.

3.2.2 Implications of back-solving depreciation

The NGR require that a building block approach is used to determine the revenue to be recovered in each regulatory year of an access arrangement, while also setting out the requirements for the determination of those building blocks, eg, the depreciation criteria.[76]

In my opinion, the economic effect of the AER's 'base real price increase limit' approach is to circumvent these requirements and, instead, to determine the revenue recovered in each year of an access arrangement so as to achieve a price outcome that was determined based on its own judgment.

This is because the economic role of depreciation in the AER's decision is that of a 'balancing item' that ensures that its draft decision, in totality, produces the price outcome that it selected based on its own judgment.

It follows that, in contrast to the requirements of the depreciation criteria in the NGR, depreciation is determined equal to the difference between:

- the level of revenue implied by the price outcome selected by the AER; and
- the sum of the cost building blocks specified at rule 76 of the NGR that do not relate to depreciation, ie, as specified at rule 76(1)(a) and (c) to (e).

The 'base real price increase limit' approach therefore also introduces a degree of arbitrariness to the determination of the other building blocks specified in the NGR, since the key determinant of total revenue is the real price increase selected by the AER based on its judgment.

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[73] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 21.

[74] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 21.

[75] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, pp 15, 20 and 26.

[76] NGR, rule 76 and, for example, rules 87 to 98.

The practical outworking of this framework is that increases/decreases in Evoenergy's other efficient costs for an upcoming access arrangement can be expected to result in a commensurate, offsetting decrease/increase in depreciation, holding the AER's price target constant.

This may also create a perverse incentive for Evoenergy not to propose operating expenditure that would otherwise be efficient, since its inclusion in total revenue would correspond to an offsetting reduction in depreciation. This dynamic would implicitly require Evoenergy to trade-off efficient operating expenditure against the recovery of its capital costs when preparing a proposed access arrangement.

The treatment of the UNFT in the AER's draft decision can be used to illustrate this concept.

Utilities Network Facilities Tax (UNFT)

UNFT is a tax levied by the ACT government on owners of any network facility on land in the Australian Capital Territory.[77] It is a material cost for Evoenergy and, during the 2021-26 access arrangement, comprised 24 per cent of its total operating expenditure.

The AER did not accept Evoenergy's proposal to recover $44.4 million of costs related to UNFT through a tariff variation mechanism, such that it would be excluded from the determination of total revenue and differences between actual and forecast UNFT would be accounted for in a separate true-up.[78] The AER's draft decision was instead to include forecast UNFT costs in the forecast operating expenditure building block component of total revenue.[79]

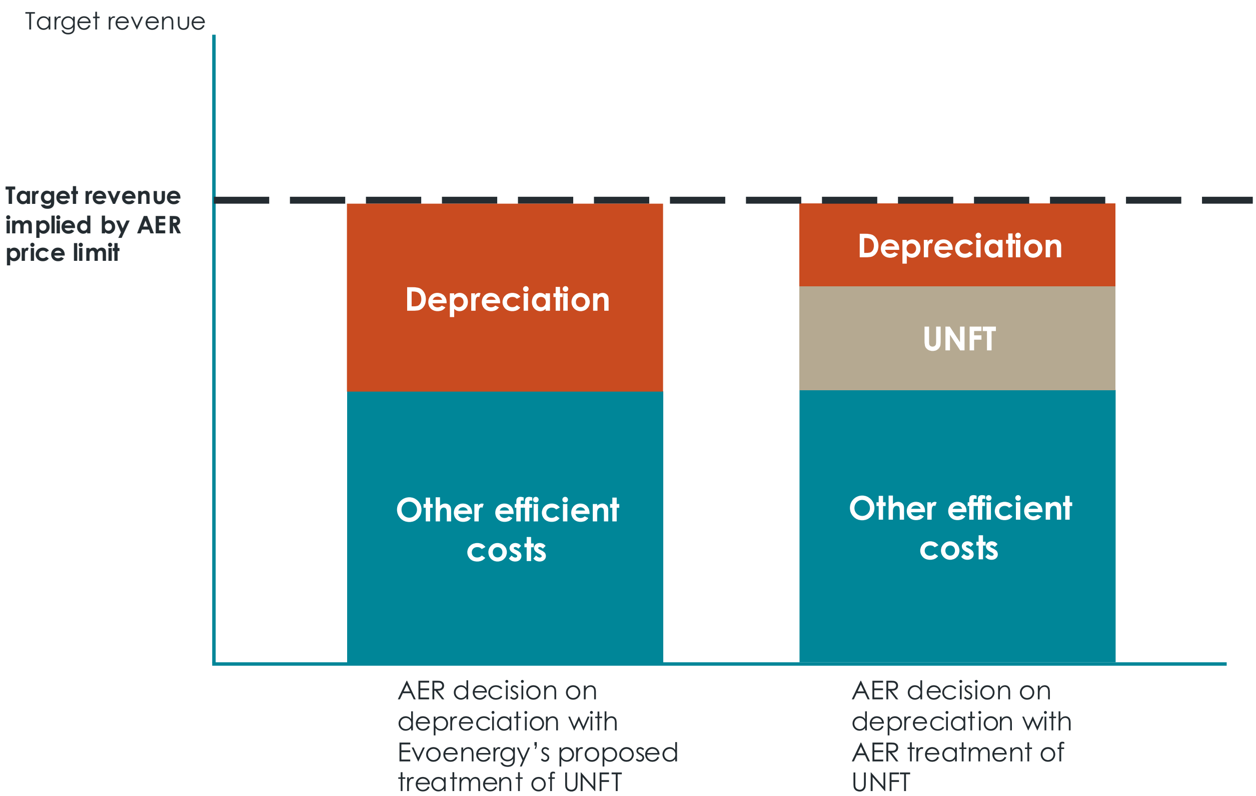
The outworking of including UNFT in operating expenditure is to reduce the depreciation allowance that would otherwise arise from the AER's draft decision. This dynamic is shown in the stylised illustration in Figure 3.1.

[77] Evoenergy, *Attachment 9: Tariff variation mechanism ACT and Queanbeyan-Palerang gas network 2026–31*, June 2025, p 42.

[78] Evoenergy, *Attachment 9: Tariff variation mechanism ACT and Queanbeyan-Palerang gas network 2026–31*, June 2025, pp 37 and 42-45.

[79] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 3 – Operating expenditure*, November 2025, p 2.

Figure 3.1: Illustration of AER's approach to depreciation with different treatment of UNFT[80]



As described above, this example illustrates how the AER's back-solving of depreciation means that increases/decreases in Evoenergy's other efficient costs for an upcoming access arrangement can be expected to result in a commensurate, offsetting decrease/increase in depreciation, given the AER's price target. This creates a perverse incentive for Evoenergy to trade-off efficient operating expenditure against the recovery of its capital costs when preparing a proposed access arrangement.

3.3 Economic life of assets

I explain in section 2.4 that the AER did not accept Evoenergy's proposal to align the economic life of HP and MP assets with the ACT government's legislated commitment to achieve net zero by 2045, and to decommission the gas network to that end.

The AER instead assumed that the economic life of HP and MP assets will end beyond 2050. The AER explained that: [81]

> While we consider the likelihood that Evoenergy's network will be decommissioned by 2045 to be high, we do not consider there is sufficient evidence to suggest a 100% likelihood of this outcome as suggested by Evoenergy's proposal.
>
> …We consider that demand for natural gas will likely continue to decline in line with the ACT's 2045 net zero emissions target. However, the actual rate of this decline is still uncertain.

[80] For the purpose of simplicity, this stylised illustration does not separately identify increments or decrements for the year resulting from the operation of an incentive mechanism to encourage gains in efficiency.

[81] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 17.

Uncertainty as to timing of the decommissioning of the gas network necessarily means there are a range of potential outcomes for the economic life of HP and MP assets.

In economics, the expected value of a variable reflects the sum of the potential outcomes, where each of those outcomes is weighted by the probability that it occurs. I illustrate this concept in Table 3.3, by reference to two future states of the world, where outcome A results in $0 and outcome B results in $10, and two scenarios as to the probability of outcome A and B coming to pass.

Table 3.3: Illustrative calculation of expected value

	Outcome A = $0	Outcome B = $10	Expected value	Calculation of expected value
Scenario A	50%	50%	$5	(50% x $0) + (50% x $10)
Scenario B	25%	75%	$7.5	(25% x $0) + (75% x $10)

The AER's view that the likelihood of the gas network being decommissioned by 2045 is high, combined with its adoption of an expected end of economic life for existing HP mains and MP services assets of 2051 and 2056, implies that there is a similarly high (if not higher) probability that the economic life of those assets extends beyond 2051 and 2056. Assignment of a similarly high (or higher) likelihood of an outcome beyond 2051 and 2056 is required to bring the expected value between those two outcomes, ie, in 2051 and 2056 respectively.

By way of a very simplified illustration, an end of life in 2045 with a 50 per cent probability of occurring and an end of life in 2067 with a 50 per cent probability of occurring would produce an expected value equal to 2056.[82]

The basis for the AER's implied assumption that there is a similarly high probability of an end of life significantly beyond 2051 and 2056, for MP services and HP mains, respectively, is limited to its observation that the decommissioning of the gas network has uncertain timing.[83]

In my opinion, the AER's observation that there is uncertainty as to the expected end of the economic life for these assets falls significantly short of establishing economic grounds for a conclusion that the gas network will not be decommissioned in line with the ACT government's legislated commitment to achieve net zero by 2045, and that there is a high probability of it occurring well beyond 2051 and 2056.

3.4 Promotion of efficient growth in the market

I explain in section 2.1.1 that rule 89(1)(a) of the NGR provides that depreciation should be designed so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services.

In the context of declining demand and the future decommissioning of Evoenergy's gas network, efficient negative growth is promoted by:

- maximising the use of the network over its remaining asset life, which the analysis I present in section 3.1 indicates is unlikely to be affected materially by changes in price; and
- the availability of safe, reliable and secure gas network services, which in turn requires ongoing efficient investment in the network by Evoenergy and, therefore, incentives for it to undertake those investments.

[82] Calculated equal to (2045 X 50%) + (2067 x 50%).

[83] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 16.

In my opinion, these same outcomes are in the long term interest of consumers and are consistent with Evoenergy's proposed approach to depreciation, since it provides Evoenergy with an opportunity to recover at least its efficient costs, while not being expected to drive material reductions in demand for gas.

3.5 Consistency with emissions reduction objective

The NGO provides that:[84]

> The objective of this Law is to promote efficient investment in, and efficient operation and use of, covered gas services for the long term interests of consumers of covered gas with respect to—
>
> (a) price, quality, safety, reliability and security of supply of covered gas; and
>
> (b) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

I explain in section 2.2 that the ACT government has committed to achieving net zero emissions by 2045, and to decommission the gas network to that end. I explain in section 3.2 that the AER's adoption of a 'base real price increase limit' approach to the determination of depreciation is focused on maintaining low gas network prices over 2026-31, and beyond.

The AER says that this is consistent with the NGO by virtue of its consistency with the long term interest of consumers of covered gas, presumably with respect to the price dimension of that service specified in NGO and its view that lower prices are necessarily better for customers.

However, the AER has no regard to the implications of its explicit intention to minimise disconnections to the gas network on the achievement of the ACT government's commitment to achieve net zero emissions by 2045.

On the AER's implicit assumption that demand for gas is responsive to changes in price, its draft decision to restrain the decline in gas demand by keeping prices low is necessarily inconsistent with the long term interests of consumers with respect to the ACT governments emissions reduction commitment.

In contrast to its absence as a consideration in the AER's draft decision on depreciation, the AER recognises elsewhere in its draft decision that lower demand for gas aligns with the emissions reduction element of the NGO, eg, it explains that:[85]

> The NGO now incorporates an emissions reduction element. A hybrid tariff variation mechanism reduces the incentive to grow gas demand (aligning with emissions reduction objectives)…

Similarly, in not accepting Evoenergy's proposed tariff structure, the AER highlighted that:[86]

> Evoenergy's gas transportation tariffs have a declining block structure, under which per unit charges decline as increasing volumes of gas are consumed. We consider this tariff structure promotes the use of gas, in conflict with the emissions reduction aspect of the NGO.

[84] NGL, s 23.

[85] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, November 2025, pp 22-23.

[86] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, November 2025, p 14.

3.6 Conclusion

The AER's decision not to accept Evoenergy's proposed depreciation is based on its view that a higher price will drive a material reduction in demand. In my opinion, this premise:

- is inconsistent with the assumption on the price elasticity of demand on which its own demand forecast is based, ie, that the price elasticity of demand is equal to -0.05;
- is inconsistent with evidence in the economics literature and the ACT-specific research commissioned by Evoenergy and undertaken by CIE, which found that demand for gas is relatively unresponsive to changes in price; and
- overlooks the ability and strong incentive for Evoenergy to respond to an unexpected increase in disconnections by decreasing price below the level approved by the AER.

In contrast, the analysis that I present in section 3.1.3 indicates that Evoenergy's proposed approach to depreciation will not result in any material decline in demand.

In comparison to Evoenergy's proposal, the AER's draft decision to adopt a 'base real price increase limit' approach with a four per cent per annum limit on the change in price (in constant dollar terms) acts:

- to defer recovery of a material proportion of Evoenergy's efficient capital costs beyond 2031, at which point the AER forecasts connections and total usage for Evoenergy's VI tariff, as an example, will be 14 per cent and 18 per cent lower, respectively;[87]
- to create a perverse incentive for Evoenergy to trade-off efficient operating expenditure against the recovery of its capital costs when preparing a proposed access arrangement;[88] and
- to signal to Evoenergy that the upper limit on future price changes is very likely to be 4.0 per cent per annum in constant dollar terms over the remaining economic life of its assets, which Evoenergy has estimated will result in it not recovering a significant amount of its efficient costs.[89]

In my opinion, the AER's draft decision on depreciation therefore does not afford Evoenergy a reasonable opportunity to recover at least its efficient costs.

Contravention of this foundational principle of economic regulation acts to distort the incentives for Evoenergy to undertake efficient investment by creating perverse incentives:

- not to undertake efficient investment in the network, owing to the likelihood that Evoenergy will not recover those efficient costs;
- to favour investment in assets with a relatively shorter economic lives, since the recovery of those costs is subject to relatively less risk; and
- to favour operating expenditure over capital expenditure, since operating expenditure is recovered in the year it is incurred.

In my opinion, the AER's draft decision on depreciation is inconsistent with the requirements of the depreciation criteria, the revenue and pricing principles and the NGO that promote efficient investment and the efficient operation of the network, as highlighted in section 2.1.

[87] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 4 – Demand*, p 1, table 4.1. Calculated equal to 121,708 / 142,033 -1 for fixed charges and equal to 4,481 / 5,459 – 1 for total usage.

[88] See section 3.2.2.

[89] Evoenergy, *Attachment 3: Depreciation Revised access arrangement information – ACT and Queanbeyan-Palerang gas network access arrangement 2026-31*, Draft as at 8 January 2025, section 3.4.7.

Further, the resulting distortions to the incentives for ongoing efficient investment by Evoenergy risk a future deterioration in the quality, safety, reliability and security of supply of gas on its network, which is not in the long term interests of consumers.

4. Opportunity to recover efficient costs

In this section I describe other elements of the AER's draft decision that have implications on the opportunity for Evoenergy to recover at least its efficient costs. In particular, I:

- explain the relevance of providing Evoenergy with a reasonable opportunity to recover its efficient costs, both conceptually and in the context of the NGR and NGL;
- describe relevant elements of the AER's draft decision that are not directly related to depreciation; and
- present my opinion on the resulting implications and incentives for Evoenergy to continue efficient investment in and efficient operation of its gas network.

4.1 Reasonable opportunity to recover efficient costs

It is a foundational principle of economic regulation that a service provider should be provided an opportunity to recover the efficient costs of the regulated service that it provides.[90]

Absent a reasonable opportunity to recover its efficient costs, a regulated business will be disinclined to undertake the investment necessary to maintain the regulated service. This will ultimately lead to a deterioration in the quality, safety and reliability of the regulated service, to the detriment of consumers.

It is for this reason that the provision of a reasonable opportunity to recover a service provider's efficient costs is reflected throughout the NGL and NGR, eg:

- in the NGO, by way of reference to the promotion of efficient investment in and efficient operation of the service for the long term interests of consumers;[91]
- in the revenue and pricing principles, which specify that the:[92]

> …service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in—
>
> (a) providing reference services; and
>
> (b) complying with a regulatory obligation or requirement or making a regulatory payment.

- in the requirement to calculate the total revenue recovered in each year of an access arrangement by reference to the sum of cost-based building blocks, along with one building block for adjustments related to incentive mechanisms that encourage efficiency;[93] and
- in the depreciation criteria, through the requirements that the depreciation schedule should be designed:[94]

> …so that each asset or group of assets is depreciated over the economic life of that asset or group of assets; and
>
> so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or a particular group of assets…

[90] Kahn, A E, *The economics of regulation: Principles and institutions*, Wiley, United Kingdom, 1988, p 40/I.

[91] NGL, s 23.

[92] NGL, s 24(2).

[93] NGR, rule 76. I note that total revenue also includes a building block relating to adjustments for the operation of incentive mechanisms.

[94] NGR, rule 89(1)(b)-(c).

4.2 Tariff variation mechanism

The AER's draft decision is not to accept Evoenergy's proposal to apply a tariff variation mechanism that included an annual true-up of any under- or over-recovery of revenue, relative to the level of revenue that underpinned the AER's decision.[95]

The annual true-up proposed by Evoenergy would mean that it can expect to recover the level of revenue approved by the AER for 2026-31, irrespective of any differences between forecast and actual demand for gas during the access arrangement. For instance, if actual demand was less than forecast such that Evoenergy derived less than the total revenue approved by the AER, its proposed true-up would apply a commensurate upwards adjustment to total revenue in a future year.

The AER's draft decision was instead to apply a hybrid approach, which it described by reference to a methodology adopted by another gas network and by explaining that:[96]

> Under one model of a hybrid mechanism, reference tariffs for gas transportation services are adjusted annually by the application of a weighted average price cap formula but include a 5% revenue constraint (revenue deviations beyond the 5% would be shared equally between Evoenergy and customers).

I understand the intention of the AER's draft decision to be a hybrid approach whereby:

- no adjustment to future revenue is made in respect of differences between actual and forecast revenue up to a specified threshold; and
- beyond that threshold, an adjustment to future revenue is applied based on a proportion of the difference between actual and forecast revenue.

The consequence of the AER's draft decision to account for differences between actual and forecast demand using a 'hybrid approach' is that Evoenergy's opportunity to recover the level of efficient costs approved by the AER rests on its ability accurately to forecast demand for gas.

However, The AER acknowledged throughout its decision the level of uncertainty that applies to future demand, and that the rate of decline rests on uncertain factors largely beyond Evoenergy's control, eg, the AER explains that:[97]

> The actual speed of gas demand reduction will depend on future developments in government policy, and evolving consumer sentiment and behaviour towards electrification.

4.3 Demand forecast

The AER did not accept Evoenergy's demand forecast in its draft decision and, instead, adopted a higher demand forecast.

By way of illustration, the AER's draft decision includes a forecast of connections and usage for Evoenergy's volume individual tariff that declines through time but, by the final year of the access arrangement in FY31, is 18 per cent and 15 per cent higher, respectively, than the level forecast by Evoenergy.[98]

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[95] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, November 2025, pp 19-23.

[96] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, November 2025, p 1.

[97] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 1 – Capital base, Regulatory depreciation and Corporate income tax*, November 2025, p 22.

[98] I calculated 18 per cent equal to 121,708 connections / 103,329 connections) -1, with the result rounded to one decimal place. I calculated 15 per cent equal to 4,481 terajoules per annum / 3,910 terajoules per annum) -1, with the result rounded to one decimal place. See: AER, *Draft decision Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 4 – Demand,* November 2025, p 1 (table 4.1) and p 2 (table 4.3).

To the extent that the demand forecast in the AER's draft decision incorporates an upwards bias – eg, say, because the findings of the research commissioned by Evoenergy and that underpin its forecast hold true – then Evoenergy can expect not to recover its efficient costs.

This is because, under the demand forecast risk sharing arrangement foreshadowed in the AER's draft decision, as discussed in section 4.2, Evoenergy will not be compensated for differences between actual and forecast revenue up to a specified threshold and, even beyond that threshold, will be permitted to recover only a proportion of the difference.

Further, the ACT government highlighted in the IEP that its focus is now shifting to reducing emissions from fossil fuel gas and transport.[99] The resulting likelihood of policy intervention by the ACT government aimed at further reducing demand for gas, in comparison to the historical downwards trend on which the AER's demand forecast is based, may create asymmetric forecast risk to the downside. Asymmetric forecast risk would arise where the likelihood of exogenous downwards shocks to demand, relative to the demand forecast, are much more likely than upwards shocks to demand.

Given the operation of the tariff variation mechanism described above, any asymmetry in demand forecast risk would further contribute to Evoenergy not having a reasonable opportunity to recover at least its efficient costs.

4.4 Capital expenditure sharing scheme

The NGR provide broad guidance for the specification of incentive mechanisms, ie:[100]

> (1) A full access arrangement may include (and the AER may require it to include) one or more incentive mechanisms to encourage efficiency in the provision of services by the service provider.
>
> (2) An incentive mechanism may provide for carrying over increments for efficiency gains and decrements for losses of efficiency from one access arrangement period to the next.
>
> (3) An incentive mechanism must be consistent with the revenue and pricing principles.

The CESS is a scheme designed by the AER to provide incentives for service providers to pursue efficiency improvements in capital expenditure during an access arrangement.

This is typically achieved by rewarding (or penalising) a service provider for spending less (or more) capital expenditure than was approved by the AER. For instance, Evoenergy receives an upwards adjustment to its revenue in 2026-31 because it spent less than the capital expenditure that was approved by the AER for the 2021-26 access arrangement.[101]

The AER explained in its August 2025 update of the CESS, as referenced in its draft decision, that the CESS:[102]

> …provides symmetric incentives in that the reward for an efficiency gain is equal to the penalty for an efficiency loss of the same quantum.

[99] ACT government, *Integrated Energy Plan*, 2024, p 12.

[100] NGR, Rule 98.

[101] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 6 – Capital expenditure sharing scheme*, November 2025, p 1.

[102] AER, *Capital Expenditure Incentive Guidelines for Electricity Network Service Providers*, August 2025, p 2. I note that this report is titled as specific to electricity service providers, but the AER's website identifies it as relevant to both the electricity and gas sectors and the AER explicitly referred to it in its draft decision for Evoenergy. See: AER website, 'https://www.aer.gov.au/industry/registers/resources/reviews/capital-expenditure-guideline-review-2025, accessed on 18 December 2025; and AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 6 – Capital expenditure sharing scheme*, November 2025, p 5 (footnote 15).

The AER's draft decision is to apply:[103]

> …an asymmetrical CESS which would require Evoenergy to forgo its rewards but maintains the incentive for it to incur capex efficiently by penalising any overspend.

I am not aware of any other application of the CESS, in either the gas or electricity sector, where the AER has applied a CESS of this nature.

The consequence of penalising Evoenergy for spending more than the level of capital expenditure approved by the AER, but not rewarding it for spending less, is that the expected value of each incremental dollar of capital expenditure is less than $1.[104]

It follows that the AER's draft decision on the CESS does not provide Evoenergy with a reasonable opportunity to recover at least its efficient costs, which is inconsistent with the revenue and pricing principles in the NGL and the requirement in the NGR that:[105]

> …an incentive mechanism must be consistent with the revenue and pricing principles.

Application of an asymmetric CESS also means that, if Evoenergy is outperforming (underspending) its approved capital expenditure during the early years of 2026-31, it faces no incentive to maintain that improvement in efficiency throughout the remainder of the access arrangement.

Rather, in these circumstances the AER's draft decision may create a perverse incentive to over-spend capital expenditure approved for the later years of 2026-31 so that, in aggregate, the capital expenditure allowance approved by the AER is spent over 2026-31. In practice, this incentive would likely relate to investment in short term assets in those later years, given the uncertain future demand for gas and the implications of the AER's draft decision on the opportunity for Evoenergy to recover at least its efficient costs.

The AER's draft decision to apply an asymmetric CESS is therefore also inconsistent with the revenue and pricing principle that:[106]

> A scheme pipeline service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted includes—
>
> (a) efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and
>
> (b) the efficient provision of pipeline services; and
>
> (c) the efficient use of the pipeline.

4.5 Utilities Facilities Network Tax and Energy Industry Levy

I highlighted in section 3.2.2 that the AER did not accept Evoenergy's proposal to recover costs related to UNFT through a tariff variation mechanism, such that it would be excluded from the determination of total

[103] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 – Attachment 6 – Capital expenditure sharing scheme*, November 2025, p 5.

[104] Based on an assumption that Evoenergy is equally likely to under- or over-spend its capital allowance over an extended future period.

[105] See: NGL, s 24(2) and NGR, Rule 98(3).

[106] NGL, s 24(3).

revenue and accounted for in a separate true-up.[107] The AER made the same draft decision in respect of the Energy Industry Levy (EIL).[108]

Evoenergy explained that:[109]

> Evoenergy proposes to change the forecasting approach for payment of the Utilities Network and Facilities Tax (UNFT) and the Energy Industry Levy, which are outside of our control (discussed in section 4.3.1). Allowing the forecasts to be updated in a rolling unders and overs mechanism using the latest available information helps support stable prices and avoids large annual true-ups that can occur if the five-year cost forecast is locked in at the start of a regulatory period.

Evoenergy further explained that, under its proposed approach:[110]

> …tariffs are adjusted each year to account for any under or over recovery in payment amounts associated with ACT Government taxes and levies through the unders and overs mechanism, consistent with the approach adopted for regulated electricity networks.

The AER's draft decision was instead to include those costs in the forecast operating expenditure building block component of total revenue.[111] More specifically, the AER included UNFT and EIL as a step change to operating expenditure with no true-up for any differences between actual and forecast UNFT and EIL over 2026-31.[112]

In relation to the potential for material differences between actual and forecast UNFT and EIL, the AER said that it considers:[113]

> …cost pass through arrangements to be sufficient to deal with material changes in costs associated with government fees and taxes such as UNFT and EIL.

The AER's draft decision is different to its treatment of UNFT and EIL in 2021-26, where these costs were treated as a category specific forecast within operating expenditure and were subject to a true-up through the reference tariff variation mechanism.[114]

The basis for the AER's draft decision not to allow a true-up for differences between actual and forecast UNFT and EIL is that it will provide an incentive for Evoenergy to lower its costs.[115]

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[107] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 3 – Operating expenditure*, November 2025, pp 19-21.

[108] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 3 – Operating expenditure*, November 2025, pp 19-21.

[109] Evoenergy, *Attachment 9: Tariff variation mechanism ACT and Queanbeyan-Palerang gas network 2026–31*, June 2025, p 37.

[110] Evoenergy, *Attachment 9: Tariff variation mechanism ACT and Queanbeyan-Palerang gas network 2026–31*, June 2025, p 44.

[111] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 3 – Operating expenditure*, November 2025, p 2.

[112] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 3 – Operating expenditure*, November 2025, pp 19-20.

[113] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 3 – Operating expenditure*, November 2025, p 20.

[114] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 3 – Operating expenditure*, November 2025, p 19.

[115] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 3 – Operating expenditure*, November 2025, pp 19-20.

However, Evoenergy has no apparent control over UNFT and EIL and so no ability to manage or reduce those costs.[116] Further, Evoenergy has highlighted that UNFT is a material proportion of its costs and is difficult to forecast.[117]

It follows that the basis for the AER's decision not to provide a true-up for UNFT and EIL lacks substance and is not supported, as the AER suggests, by the revenue and pricing principle to provide effective incentives to improve economic efficiency.[118]

The AEMC has also highlighted previously, in the context of a rule determination for electricity businesses, that accounting for material changes in jurisdictional costs through a cost-pass through mechanism did not promote productive efficiency, due to the additional administrative costs for the network and the AER.[119]

It also highlighted in that rule determination that requiring DNSPs to produce annual estimates of costs:[120]

> …would likely be more accurate than the five-year forecasts currently required. This improves the ability for DNSPs to recover any costs closer to the time they were actually incurred and increase the likelihood that costs are recovered from the customer base in relation to whom the costs were incurred.

4.6 Tariff structure

Evoenergy has in place four tariff structures, but where its 'volume individual' (VI) tariff applies to almost all its 150,000 customers.[121] Evoenergy's VI tariff comprises a fixed charge and a declining block structure for variable changes, whereby the marginal price of gas decreases progressively as consumption increases, as illustrated in Figure 4.1.

[116] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 3 – Operating expenditure*, November 2025, pp 19-20.

[117] AER, *Draft decision Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 4 – Demand,* November 2025,p 42.

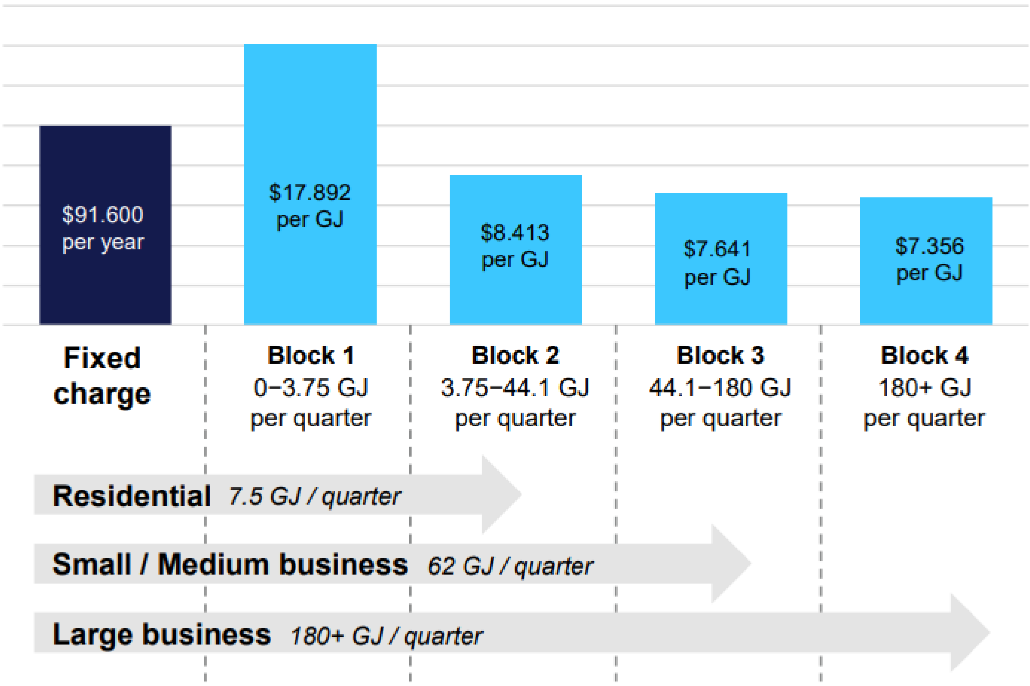
[118] NGL, s 24(3).

[119] AEMC, *Rule Determination – National Electricity Amendment (Payments under Feed-in Schemes and Climate Change Funds) Rule 2010*, July 2010, p 5.

[120] AEMC, *Rule Determination – National Electricity Amendment (Payments under Feed-in Schemes and Climate Change Funds) Rule 2010*, July 2010, p 5.

[121] AER, *Draft decision Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 4 – Demand,* November 2025, p 1 (table 4.1) and p 2.

Figure 4.1: Existing declining block structure for volume individual tariff



Source: Evoenergy, Attachment 7: Transportation (and metering) reference service and tariffs Access arrangement information ACT and Queanbeyan-Palerang gas network access arrangement 2026–31, June 2025, p 12.

The AER did not accept Evoenergy's proposal gradually to align the marginal price of the four blocks in the VI tariff, through progressively reducing the price of block one and increasing the price of blocks two to four.

The AER's draft decision is instead to require alignment of the blocks in the VI tariff *in the first year* of the access arrangement and to make similar changes to the volume boundary (VB) tariff, which Evoenergy had not proposed to amend.[122] The AER's draft decision is that Evoenergy should consider flattening its demand customer tariffs or, if a transition is supported by modelling, to present a plan to transition to a flatter structure.[123] Evoenergy did not propose to amend the tariff structure of its demand customer tariffs.[124]

The earlier flattening of the blocks in Evoenergy's VI and VB tariffs in the AER's draft decision can be expected to increase the effect on Evoenergy's actual revenue of any differences between forecast and actual demand for gas per customer.

4.7 Conclusion

In the preceding sections I highlight that the AER's draft decision:

- on the tariff variation mechanism leaves Evoenergy's opportunity to recover at least its efficient costs dependent on its ability to accurately forecast demand for gas, which the AER acknowledges is uncertain and can be affected significantly by factors beyond Evoenergy's control;

[122] See: AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, November 2025, p 14; and Evoenergy, Attachment 7: Transportation (and metering) reference service and tariffs Access arrangement information ACT and Queanbeyan-Palerang gas network access arrangement 2026–31, June 2025, p 20.

[123] AER, *Draft decision – Evoenergy (ACT) access arrangement 2026 to 2031 (1 July 2026 to 30 June 2031) Attachment 5 – Reference services, tariffs and non-tariff components*, November 2025, p 14.

[124] Evoenergy, Attachment 7: Transportation (and metering) reference service and tariffs Access arrangement information ACT and Queanbeyan-Palerang gas network access arrangement 2026–31, June 2025, p 7.

- on forecast demand and Evoenergy's tariff structure may exacerbate the risk that the tariff variation mechanism acts to prevent Evoenergy from recovering its efficient costs;
- on the CESS does not provide a reasonable opportunity for Evoenergy to recover its costs and, when cost efficiencies are achieved in the early years of an access arrangement, may create a perverse incentive to over-spend capital expenditure towards the end of 2026-31; and
- on the treatment of UNFT and EIL, is grounded in a flawed rationale and is not supported, as the AER suggests, by the revenue and pricing principle to provide effective incentives to improve economic efficiency.

These elements of the AER's decision, combined with its decision on depreciation that I describe in section 3, create pressure across-the-board on the opportunity for Evoenergy to recover at least its efficient costs and, in contrast to the requirements of the rules:

- do not afford Evoenergy with a reasonable opportunity to recover at least its efficient costs; and
- do not provide incentives for the efficient investment in and the efficient operation of Evoenergy's network.

In my opinion, the AER's draft decision is therefore inconsistent with the revenue and pricing principles that Evoenergy should be provided with:

- a reasonable opportunity to recover at least the efficient costs incurred in providing reference services and complying with a regulatory obligation or requirement or making a regulatory payment;[125] and
- effective incentives in order to promote economic efficiency with respect to reference services the service provider provides and that the economic efficiency that should be promoted includes—
  - efficient investment in, or in connection with, a pipeline with which the service provider provides reference services;
  - the efficient provision of pipeline services; and
  - the efficient use of the pipeline.[126]

The AER's draft decision is therefore also inconsistent with the requirements of the NGO to promote efficient investment in and the efficient operation of the network.[127]

Rather, the resulting distortions to the incentives for ongoing efficient investment by Evoenergy risk a future deterioration in the quality, safety, reliability and security of supply of gas on its network, which is not in the long term interests of consumers.[128]

[125] NGL s 24(2).

[126] NGL s 24(3).

[127] NGL, s 23.

[128] NGL, s 23.

A1. Appendix A – Literature review

In this section I present the results of my review of the economics literature on the responsiveness of demand for natural gas to changes in the price of natural gas, ie, the own price elasticity of demand for natural gas. I introduce this review in section 3.1 of my report.

A1.1.1 Bernstein and Madlener (2011)

Bernstein and Madlener, *Residential natural gas demand elasticities in OECD countries: an ARDL bounds testing approach*, Future Energy Consumer Needs and Behavior working papers 15/2011, E.ON Energy Research Center.

Bernstein and Medlener (2011) analyse the price elasticity of residential natural gas demand in twelve OECD countries using time series data regarding residential natural gas consumption, residential natural gas price, disposable income, CPI and heating from 1980 to 2008. The countries examined in this study include Austria, Finland, France, Germany, Ireland, Japan, Luxembourg, the Netherlands, Spain, Switzerland, the United Kingdom and the United States.

Using an autoregressive distributed lag (ARDL) and error-correction model, the study estimates that short-run and long-run elasticity of demand for residential natural gas, on average across the twelve examined countries, to be around -0.23 and -0.51 respectively. Across the examined countries, the study estimates that long-run price elasticity ranges from -1.62 to -0.14, whereas short-run price elasticity ranges from -0.54 to 0.12.

The largest negative (in absolute term) long-run elasticity belongs to Ireland and is the only estimate in this study that suggests demand is elastic. The second most negative estimate is -0.8 (for Switzerland), which suggests inelastic demand for natural gas. The authors provide no explicit explanation for this outlier estimate for Ireland.

All the examined countries are estimated to have negative short-run price elasticity, except for Netherlands with estimated short-run price elasticity of 0.12, but it is not statistically significant at one or five per cent level of significance. In contrast, a study by Berkhout et al (2004) uses more disaggregated data at household level between 1992 and 1999, and estimates that the short-run price elasticity for Netherlands is around -0.19.

In addition, the authors also observe considerable differences with other studies. The differences in the estimates can be attributed to the difference in the countries included in the respective studies, the difference in the time periods analysed, and the treatment of non-stationarity in the underlying time series.[129] For example, the study undertaken by Asche et al (2008) results in more inelastic natural gas demand, which can be attributed to the latter paper accounting for heterogeneous demand response and resolving the potential bias in the estimators that do not account for heterogeneity.

However, the authors observe consistency between their estimates and those obtained in a number of other studies. For example, Joutz et al (2008) find long-run run elasticity to be around -0.18 for the United States, which is consistent with the estimates of -0.16 in this study.

[129] The countries studied by Bernstein and Medlener (2011) does not include Belgium, Denmark and Italy, while the countries in Asche et al (2008) does not include Japan and the US. Furthermore, the study by Bernstein and Medlener analyses a longer time period, ie, from 1980 to 2008, as compared to the period from 1978 to 2002 examined in Asche et al (2008).

A1.1.2 Asche et al (2008)

Asche, Nilsen, and Tveteras, Natural gas demand in the European household sector, The Energy Journal 29.3 (2008): 27-46

Asche et al (2008) analyse twelve European countries [130] using a dynamic demand model (with lagged demand included) to estimate short-run and long-run elasticity of residential demand for natural gas. The data consists of annual observations of residential natural gas consumption per capita, and prices obtained from the International Energy Agency (IEA) from 1978 to 2002.

The study obtains country specific estimates to identify the structural differences between the different European countries. In addition, several structural factors are accounted for in the model (eg, natural gas grid coverage, government policies and regulations, climatic conditions, energy infrastructure and residential building composition). The study examines five estimators (pooled OLS, fixed effects, random effects, individual OLS and shrinkage estimator).

The authors focus on accounting for the structural differences between countries through the use of shrinkage estimator. The authors note that energy elasticities have been estimated by various methods and model approximations, and tend to differ substantially in the literature. They observe in this study that suppressing the heterogeneity in the parameters using homogeneous type estimators could lead to biased estimates.

The study estimates that the long-run price elasticity of natural gas demand for households ranges between -0.44 and -0.1, across the OLS and shrinkage estimators that account for heterogeneous demand responses. The short-run price elasticity is estimated to be between -0.03 and -0.15 across the same estimators.

A1.1.3 Andersen et al (2011)

Andersen, Nilsen, and Tveteras, How is demand for natural gas determined across European industrial sectors, Energy Policy 39.9 (2011): 5499-5508

Andersen et al (2011) estimate the elasticity of demand for natural gas in the manufacturing sector in 11 different industries[131] across 13 OECD countries. Instead of using aggregate manufacturing data, the authors examine interfuel substitution and energy demand in disaggregated manufacturing industries in each country from 1978 to 2003. The study applies a dynamic log-linear natural gas demand function which has been derived from a cost minimisation function, and a shrinkage estimator to account for heterogenous demand responses across countries and industries.

Since a dynamic model has been used, the coefficients represent the short-run elasticities, whereas the long-run elasticities are calculated using the short-run estimator divided by one minus the lag parameter. The results suggest that natural gas demand is highly inelastic for all industries/countries in the short run, ranging from -0.059 to -0.183. Long-run price elasticity ranges from -0.155 to -0.624. The difference in elasticities between industries could be due to differences in energy intensity, ie, a more energy intensive industry would be more responsive to changes in natural gas prices.

The findings in this study offer a complementary perspective to other studies of price elasticity in similar European countries, in that this paper focuses on the price elasticity across industries using industry-level data, whereas other papers analyse residential demand. The literature summarised in this appendix indicates that price elasticity for residential and industrial demand can differ.

[130] Countries examined in this study include Austria, Belgium, Denmark, France, Germany, Ireland, Italy, the Netherlands, Spain, Sweden, Switzerland and the UK.

[131] The industries in this study include chemical and petrochemical, construction, food and tobacco, iron and steel, mining and quarrying, non-ferrous metals, non-metallic minerals, paper, pulp and printing, textile and leather, transport equipment, wood and wood products.

This study does not inform the range that I use to derive a midpoint from the economics literature in section 3.1 because it relates to the manufacturing sector, rather than the residential sector.

A1.1.4 Arora (2014)

Arora, Estimates of the price elasticities of natural gas supply and demand in the United States, MPRA Paper 54232, University Library of Munich, Germany, 2014

Arora (2014) uses a multivariate approach[132] that is consistent with that adopted in similar studies for the US, with refinements made and additional variables (ie, inventories, market conditions and shale gas boom) accounted for.

The author examines price elasticity of both supply and demand. In particular, his multivariate approach differentiates between changes in supply and demand, thus he can calculate the price elasticities of demand based on shifts in natural gas supply, and calculate the price elasticities of supply based on shifts in natural gas demand. In addition, three types of demand are separately considered, ie, demand for use in industrial production, residential demand and inventories.

The analysis is based on series of weekly, monthly and quarterly data regarding natural gas consumption and natural gas prices. Weekly data is over the period from 2008 to 2013, and the monthly and quarterly data span over the period from 1993 to 2007, and 1993 to 2013 respectively.[133]

The study estimates that the short-run price elasticity of gas demand to range between -0.10 and -0.16, across different frequencies of data. The long-run price elasticity is estimated to range between -0.24 and -0.29. These results cover the data of the period when there was a shale gas boom.

Notably, the author observes that customers are less responsive to prices in a relatively low-price environment, since percentage changes in price in a low-price environment reflects smaller level changes, compared to a higher-price environment. The inclusion of the shale gas boom period coincides with a low-price period. This explains why price elasticities, both long-run and short-run, are less responsive when the shale gas boom period is examined, compared to what elasticities would be when the shale gas boom is excluded.

The author observes that demand for gas consumption is more elastic compared to those estimated by a number of similar studies during the same time, but in line with earlier ones. Comparison with other studies of price elasticity for United States customers are provided in appendix A1.1.7.

A1.1.5 Burke and Yang (2016)

Burke and Yang, The price and income elasticities of natural gas demand: international evidence, Energy Economics 59 (2016): 466-474

Burke and Yang (2016) estimate the price elasticity of demand for natural gas from 44 countries.[134] The study analyses national data over a period from 1978 to 2011, using final consumer prices[135] of natural gas that are sector-specific (ie, industry prices and household end-user prices) and published by the IEA.

[132] In particular, the author uses a vector-autoregression model.

[133] 'Long run' is defined as one year, five years and 15 years in the weekly, monthly and quarterly model variants respectively. 'Short run' is defined as one week, one month, and one quarter in the weekly, monthly, and quarterly model variants respectively.

[134] These countries represent 50 per cent of the world's population and 72 per cent of global natural gas consumption as of 2011.

[135] The prices include fixed charges.

The authors address the problem of endogeneity, being that price and quantity demanded are often determined simultaneously, by instrumenting natural gas prices with proved natural gas reserves.[136] In econometrics, this is referred to as an instrumental variable.

The authors apply a number of different panel estimators, including between estimators (for long-run elasticity), fixed effect estimators (for short-run elasticity) and pooled OLS (for comparison purpose).

The authors present separate estimates of price elasticity for natural gas demand by industrial and residential sectors. The estimates suggest that long-run price elasticity is relatively similar between the industrial and residential sectors, whereas short-run elasticity in the residential sector is much smaller than that in the industrial sector. In particular, long-run price elasticity[137] is estimated to range between -0.82 and -1.09 for industrial demand, and -0.9 and -1.13 for residential demand. Short-run elasticity is estimated to be around -0.37 and -0.13 for industrial and residential demand, respectively.

The range of estimates presented above cover those obtained with and without the instrumental variable. The results reflect that the instrumental variable results are relatively similar to those without instrumental variable (ie, single-equation results), which suggests that the price/quantity endogeneity issue might not be substantial when estimating demand at the aggregate level. This contrasts to the findings obtained in studies that use household-level data, where endogeneity is observed to cause biased and inconsistent estimates.[138]

The relatively large (in absolute terms) estimate for long-run price elasticity can be attributed to the absence of treatment for heterogeneous demand responses across countries in this study. This problem is observed and addressed in studies such as Asche et al (2008) with shrinkage estimators. Asche et al argue that suppressing the heterogeneity in the parameters using homogeneous type estimators could lead to biased estimates. On the other hand, the study by Asche et al does not account for the problem of endogeneity, which is the focus of this study by Burke and Yang.

A number of other papers I reviewed also mention the potential problem of biased estimators when heterogeneous demand response is not accounted for in the estimation methodology. These papers include Andersen et al (2011)[139] and Maddala et al (1997).[140]

Given the large number of countries examined in this study, particularly in comparison to other papers I reviewed, it is reasonable to expect a diverse range of customers' characteristics, economic and geo-spatial conditions that in turn warrant an allowance of heterogeneous demand response in the estimation methodology for price elasticity. While this study addresses the problem of endogeneity, it is likely a material problem to leave heterogeneity unaccounted for, particularly given the large sample of countries evaluated in Burke and Yang (2016), compared to the other studies I reviewed.

Based on these reasons, I do not consider these estimates in establishing the plausible range of elasticity estimates applicable to Evoenergy's customers.

[136] This includes both domestic reserves and distance-weighted reserves from other countries, giving more weight to deposits in neighbouring nations because proximity reduces transport costs and often leads to lower domestic prices.

[137] These estimates are obtained from the between estimators.

[138] See, for example: Hahn and Metcalfe, *Efficiency and equity impacts of energy subsidies*, American Economic Review 111.5 (2021): 1658-1688; and Rubin and Auffhammer, *Quantifying heterogeneity in the price elasticity of residential natural gas*, Journal of the Association of Environmental and Resource Economists 11.2 (2024): 319-357.

[139] The authors observe that 'the potential structural differences between cross-sections (industry sectors and countries) in energy demand indicate that using homogeneous type estimators can be inappropriate'. See: Andersen, Nilsen, and Tveteras. *How is demand for natural gas determined across European industrial sectors*, Energy Policy 39.9 (2011): 5499-5508.

[140] The authors reference studies by other authors that 'discussed the biases that are likely to occur in the estimation of long-run elasticities if parameter heterogeneity is ignored and the data are pooled'. See: Maddala et al, *Estimation of short-run and long-run elasticities of energy demand from panel data using shrinkage estimators*, Journal of Business & Economic Statistics 15.1 (1997): 90-100.

A1.1.6 Joutz et al (2009)

Joutz, Trost, Shin and McDowell, Estimating regional short-run and long-run price elasticities of residential natural gas demand in the US, United States Association for Energy Economics working paper, August 2009

Joutz et al (2009) estimate the price elasticity of natural gas demand in a sample of households that represents around 28 per cent of United States customers. The authors use monthly consumption and price data from 1992 to 2006, at Local Distribution Companies (LDC) level.

The paper applies a dynamic log-linear demand model that separates the estimates for the short and long run through lagged prices and capital stock adjustments. In addition, the methodology allows separation of price effects from natural changes in demand due to increasing use of other efficient technologies. It is estimated that around one per cent decline of use per customer each year is due to purchases of other more efficient capital equipment.

The authors estimate short-run elasticity to range between -0.09 and -0.11, while the long-run elasticity estimates to range between -0.18 and -0.20.

The estimates in this study suggest that demand for gas is more inelastic than the findings in other studies of the US data. For example, Arora (2014) estimates long-run elasticity to be between -0.24 and -0.29. The more inelastic estimate in this paper can be attributed to the fact that this paper uses more disaggregated data (ie, at LDC level) than the study by Arora in 2014, and that the author accounts for the effect of natural decline in demand due to increasing use of efficient technologies when estimating the price effect.

A comparison with other studies of price elasticity for United States customers is included in section A1.1.7.

A1.1.7 Maddala et al (1997)

Maddala et al, Estimation of short-run and long-run elasticities of energy demand from panel data using shrinkage estimators, Journal of Business & Economic Statistics 15.1 (1997): 90-100

Maddala et al (1997) estimate the residential natural gas and electricity demand in the United States across 49 states using end-user price data between 1970 and 1990 (as provided by the Energy Information Administration). The paper applies a dynamic demand model with partial adjustment and error-correction with five estimators.[141]

The authors apply the shrinkage estimators as the main estimators to account for heterogeneous demand responses across states. They observe that when heterogeneity is not accounted for (as in the case of pooled estimator), biases are likely to occur in the estimation of price elasticities.

The short-run price elasticity of demand for residential natural gas across all estimators, except for the pooled estimators,[142] range from -0.092 to -0.116. The long-run price elasticity of demand ranges from -0.239 to -0.273.

Despite the differences in estimation methodology, data sources and time periods, these estimates are broadly consistent with a number of other studies for the United States, eg:

- Bernstein and Griffin (2006) estimate short-run elasticity to be -0.12 and long-run elasticity to be -0.36;
- Joutz et al (2009) estimate short-run elasticity to range between -0.09 and -0.11, while the long-run elasticity estimates to range between -0.18 and -0.20;

[141] The estimators used in the paper include pooled with fixed effects, pooled without fixed effects, mean of individual state OLS estimates, Bayesian shrinkage estimator, and Stein-rule shrinkage estimator.

[142] The pooled estimators are excluded because they are only provided for the purpose of comparison with the other estimators that allow for heterogeneity. The authors note that when heterogeneity is not accounted for (as in the case of pooled estimators), long-run elasticities may be 'exaggerated'.

- Arora (2014) estimates that the short-run price elasticity to range between -0.10 and -0.16, and long-run price elasticity to range between -0.24 and -0.29;
- Rubin and Auffhammer (2022) estimates medium-run price elasticity of demand in California to range from -0.15 to -0.19

The broad consistency provides relatively strong evidence of the robustness of the estimates provided by these studies. However, it should not be surprising if other estimates are identified to be less consistent with this sample of studies, since a key theme across the literature is that estimates of price elasticity may vary depending on the settings of particular studies.

A1.1.8 Bernstein and Griffin (2006)

Bernstein and Griffin, Regional differences in the price-elasticity of demand for energy, National Renewable Energy Lab (United States), No. NREL/SR-620-39512 (2006)

This study by Bernstein and Griffin, prepared for the National Renewable Energy Laboratory, analyses the differences in the relationship between prices and demand of natural gas at national, regional, state or utility levels.[143] The data for residential natural gas spans from 1977 to 2004. A dynamic demand model is used, which estimates long-run and short-run demand by using lagged demand, current and lagged prices, income, population, and climate variation.[144]

At national level, the authors estimate short-run elasticity to be -0.12 and long-run elasticity to be -0.36. These results are consistent with the consensus values of -0.2 and -0.3 respectively, as concluded by Bohi and Zimmerman in their literature review in 1984 (see section A1.1.9). In addition, these estimates are broadly in line with a number of other studies on United States customers. Comparison with other studies of price elasticity for United States customers are provided in appendix A1.1.7.

In addition, the authors find that there are differences between regions in the price elasticity of natural gas demand. States within a region tend to have less material differences. This finding is somewhat consistent with that obtained by Bohi and Zimmerman in 1984, who also concluded that there are no significant differences between states for the demand of natural gas.

A1.1.9 Bohi and Zimmerman (1984)

Bohi and Zimmerman, An update on econometric studies of energy demand behaviour, Annu. Rev. Energy (United States) 9 (1983)

Bohi and Zimmerman (1984) provide a comprehensive review of energy demand modelling, specifically evaluating how statistical results are sensitive to different modelling techniques and sample data. In general, the scope of the review is restricted to partial equilibrium models of demand for individual energy products (ie, electricity, natural gas, petroleum products, and coal) that are consumed by distinct sectors of the economy (ie, residential, commercial, industrial, and transportation).

The authors focus on data samples from the early 1970s, being after the energy crisis. Before the energy crisis in 1974, energy prices were relatively stable and thus it was hard to find data on how demand shifts due to changes in price. However, the price instability after 1974 provides bigger variation in prices and allowed the authors to track demand responses.

[143] This paper examines three components: electricity use in the residential sector, natural gas use in the residential sector and electricity use in the commercial sector.

[144] The short-run elasticity is calculated through analysing the current period, while the long-run elasticities are calculated through changes reflected in the lagged dependent variable.

In addition, the authors observe that the availability of household-level surveys allowed researchers to avoid biases inherent in aggregate data and account for specific housing and demographic characteristics in their studies.

From all the studies reviewed, Bohi and Zimmerman conclude that the consensus values for short-run and long-run residential demand for natural gas elasticity are -0.2 and -0.3 respectively.

A1.1.10 Berkhout et al (2004)

Berkhout, Ferrer-i-Carbonell, and Muskens, The ex post impact of an energy tax on household energy demand, Energy economics 26.3 (2004): 297-317

Berkhout et al. (2004) calculate residential natural gas demand elasticities in the Netherlands, using two large Dutch panel data sets that observes households over the period between 1992 and 1999. The authors analyse household reaction to the introduction of an energy tax through the analysis of demand for natural gas and for electricity.[145]

The use of household level data in this study provides a useful complement to the studies using more aggregated data (eg, national-level data). In addition, the authors account for a larger set of variables such as outside temperature, type of house and house insulation, household cooking behaviour, and number of durable goods and electrical appliances.

The authors estimate short-run price elasticity of demand for natural gas to be -0.19 on average across households. Due to the use of more disaggregated data in this paper, it is reasonable to consider that this estimate is relatively more robust than the 0.12 (statistically insignificant) estimated for Netherlands by Bernstein and Medlener (2011) who uses national-level data. In addition, the authors of this paper find that owning durable goods is not affected by changes in energy prices in the short run.

The authors focus on short-term responses of consumers and do not take into account long term structural considerations.

A1.1.11 Rubin and Auffhammer (2022)

Rubin and Auffhammer, Quantifying heterogeneity in the price elasticity of residential natural gas, Journal of the Association of Environmental and Resource Economists 11.2 (2024): 319-357

Rubin and Auffhammer (2022) use household billing data from 2010 to 2014[146] to estimate the price elasticity of residential natural gas demand in California. To this end, the authors analyse millions of natural gas bills from Pacific Gas and Electric, and Southern California Gas company, which include monthly consumption and price schedules.

The authors observe that retail price does not have one-directional causal effect on demand for residential natural gas in California. In fact, higher demand could lead to higher retail price due to the two-tiered block-rate structure of retail prices. In econometrics, this is referred to as an endogeneity problem, and appropriate estimation methodology is required to obtain unbiased and consistent estimates.

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[145] Demand is modelled using a two-stage budgeting model: an almost ideal demand system and a linear expenditure system.

[146] Specifically, the authors analyse billing data of Pacific Gas and Electric Company's customers between 2003 and 2014, and of Southern California Gas Company's customers between 2010 and 2015. Therefore, the data overlap from 2010 to 2014.

In this context, the authors use the Henry Hub[147] spot price to address the endogeneity problem. In addition, the authors use five different variants of prices[148] in its estimation of price elasticity. The main results reflect the use of the two-month lag of the various prices.

In addition, the authors estimate price elasticity in different customer groups (by season and income status) to provide insights into the different degree of responsiveness across customers' characteristics. Income level is accounted for through CARE status while season is accounted for through weather data.

The estimates for price elasticity of demand for natural gas of all customers in the studied data range from -0.15 (average marginal price) to -0.19 (average price). When using marginal price, the estimated elasticity is -0.17. It is observed that the estimated elasticities across the different types of price show little difference.

However, the authors note that this elasticity varies substantially across seasons, income groups, and their interaction. The results suggest that subsidised (low income) customers have the largest price elasticity (in absolute term) during winter months (when demand for heating is high). The price elasticity of this group of customers is estimated to be as high as -0.46 during winter months, although this estimate is not statistically significant from that for the higher income customers.

In addition, as the authors assess the sensitivity of the estimated elasticities with the various lag periods of price, they find that the results are consistent with the expectation that customers are responsive to changes in price two to four periods prior to the period of consumption (as opposed to contemporaneous or one-month-lagged prices).

Notably, the authors contrast these estimated elasticities with those obtained using an OLS estimator, and observe that the OLS estimates reflect the bias resulting from prices being a function of quantity (ie, the endogeneity problem described above), which yields estimates that suggest positive elasticities (ie, upward-sloping demand curves).

A comparison with other studies of price elasticity for United States customers is provided in appendix A1.1.7.

A1.1.12 Hahn and Metcalfe (2021)

Hahn and Metcalfe, Efficiency and equity impacts of energy subsidies, American Economic Review 111.5 (2021): 1658-1688

Hahn and Metcalfe (2021) use monthly natural gas consumption data in California from 2012 to 2015 to assess the economic and environmental impacts of the California Alternate Rates for Energy (CARE) subsidy. To this end, the authors estimate the price elasticity of demand for natural gas using a large natural field experiment in California.

The study examines data from over 70,000 low-income households through Southern California Gas (SoCalGas) and focused on households that are eligible/enrolled in the CARE program. Eligible customers were randomly selected to receive encouragement letters to sign up for the CARE subsidy, which provides a 20 per cent reduction in the marginal price of the natural gas they consume.

To estimate the price elasticity of energy demand, the authors apply a two-stage least squares econometric model to obtain the Local Average Treatment Effect (LATE), which represent the price elasticity. They find that over 12 to 18 months, the price elasticity estimates were between -0.29 and -0.35, and around -0.35 for a representative CARE customer.

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[147] Henry Hub connects to 13 intrastate and interstate pipelines. The Henry Hub is the designated delivery point for the New York Mercantile Exchange's natural gas futures contracts, and the Henry Hub price is generally regarded as one nationally relevant price.

[148] The different types of price include marginal price, average price, average marginal price, baseline price (ie, the first-tier price) and simulated marginal price. The relevant price structure in this study is two-tiered block-rate pricing.

The authors also find that low-income customers have more elastic demand than the higher-income customers. In addition, they find that high-usage households are more price sensitive than low-usage households.

The authors observe that their elasticity estimates are different from those obtained in an earlier working paper by Rubin and Auffhammer (which led to the paper in 2022) in that the latter measure price elasticity after people enrol onto CARE and spend several years on the pricing subsidy. In comparison, the authors in this paper are primarily interested in the quantity response that results from a 20 per cent price decrease when people sign up for CARE.

A2. Annexure A – Curriculum vitae

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Overview

Dale specialises in the application of economics to complex problems arising in regulatory, commercial and policy settings. He has deep experience in the economics of infrastructure services and, more broadly, in applying economic principles and empirical analysis to inform high stakes decisions.

Dale draws upon experience spanning the electricity, gas, port, water, resources, airport, heavy vehicle, construction, taxi, retirement village, steel, stevedoring, cemetery and telecommunications sectors. On matters of economic regulation, he has assisted both regulated businesses and regulatory authorities in addressing a broad range of challenges, with particular experience in the pricing of infrastructure services, the return on and of capital and price/revenue modelling.

Dale has significant experience applying economics to assist decision-making in a broad range of contexts, including major commercial arbitrations and negotiations, class-actions, anti-dumping proceedings, native title proceedings, regulatory reviews, the pricing of intercompany transactions and policy development.

He has assisted in the preparation of material for expert reports relied upon by businesses, regulatory authorities and state and federal government agencies, and that formed the basis of testimony before the Federal Court and the Competition Tribunal.

Prior to Joining HoustonKemp, Dale was an Economic Analyst at NERA Economic Consulting and, before that, a Senior Consultant at Deloitte. Dale holds a Masters in Economics with first class honours from the University of Auckland as well as a Bachelor of Commerce (first class honours) in Economics and International Business from the University of Auckland.

Qualifications

2008	**University of Auckland, New Zealand** Master of Commerce in Economics (First Class Honours)
2007	**University of Auckland, New Zealand** Bachelor of Commerce (Hons) in Economics (First Class Honours)
2004-2006	**University of Auckland, New Zealand** Bachelor of Commerce, majoring in Economics and International Business

Prizes and Scholarships

2008	New Zealand Treasury Post-Graduate Scholarship
2006	University of Auckland Senior Prize in Economics

Career Details

2014-	**HoustonKemp Economists** Partner Senior Economist Economist
2013-2014	**NERA Economic Consulting** Economic Analyst
2009-2012	**Deloitte** Senior Consultant

Project Experience

Dale's project experience is summarised below by reference to two broad categories, ie:

- economic regulation: and
- legal proceedings, commercial arbitrations and negotiations.

<u>Economic regulation</u>

2025	**Arnold Bloch Leibler / QCoal** Dale assisted in the preparation of two expert reports that were submitted to the Queensland Competition Authority in support of an application to declare the coal handling service provided at the North Queensland Export Terminal under *the Queensland Competition Authority Act 1997*.
2025	**Airservices Australia** Since early 2025, Dale has been leading a team that is supporting Airservices' development of a price notification for submission to the Australian Competition and Consumer Commission. This includes advice on regulatory strategy, preparation of expert reports, development of an air traffic demand forecast, preparing economic support for a generational step change in investment (circa $7 billion), drafting the price notification, engaging with Airservices' executives and representing Airservices at in-person workshops with the ACCC and airlines.
2025	**Energy Networks Australia** Dale led the team that advised Energy Networks Australia on development of a rule change request to improve flexibility for network tariffs during a regulatory control period. This included drafting a rule change request that was submitted to the Australian Competition and Consumer Commission in late 2025.
2025	**Energy Queensland** Dale advised Energy Queensland on development of a new network pricing methodology and network pricing model aimed at streamlining its modelling and brining its price-setting process into line with best-practice.

2024	**Dalrymple Bay Terminal** **Capacity utilisation** Dale assisted in the design of a mechanism to promote the efficient utilisation of existing capacity that is contracted to users of Dalrymple Bay Terminal under take-or-pay contracts, but that is also currently underutilised.
2024	**Energy Queensland** **Network tariff design** Dale provided wide-ranging advice to Energy Queensland on reforms to its network tariffs and price-setting methodologies for large customers and new technologies such as grid-connected batteries.
2024	**Energy Networks Australia** **Tariff flexibility** Dale led the preparation of a report that evaluated the degree of flexibility for network tariffs under the existing regulatory framework and identified options and recommendations to improve flexibility. This project involved close and ongoing engagement with all distribution networks service providers in the national electricity market.
2024	**Queensland Cane Growers** **Irrigation pricing review** Dale assisted Queensland Cane Agriculture and Renewables Ltd and other industry bodies in the Queensland Competition Authority's Rural Irrigation Price Review for 2025-29.
2024	**Vector New Zealand** **Electricity Authority connection pricing review** Dale assisted in the preparation of a report that critically evaluated the Electricity Authority's proposed approach to connection pricing and recommended a range of potential improvements that would better meet its economic objectives.
2024	**Evoenergy** **Pricing model** Dale led the development of a new pricing model for electricity network services, which included the development of a new practical methodology for the allocation of costs to network tariffs.
2024	**Ausgrid** **Distribution loss factors** Dale undertook an audit of Ausgrid's calculation of the distribution loss factors that apply to each of its network tariffs, for submission to the Australian Energy Regulatory and the Australian Energy Market Operator.
2023	**Dalrymple Bay Infrastructure** **Pricing options for terminal expansion** Dale developed options for the pricing of a significant terminal expansion at DBT and provided advice on the implications of those options.
2023	**Ausgrid** **Cost benefit assessment** Dale advised Ausgrid on how best to estimate and incorporate certain benefits in its cost/benefit assessment for a new enterprise resourcing system.

2023	**Evoenergy** **Tariff strategy and regulatory proposal** Dale provided wide-ranging strategic advice to Evoenergy on a tariff strategy for the FY24-29 period to address the rapid uptake of EVs in the ACT, new pricing options for data centres and grid-scale batteries and the potential introduction of export prices. Dale also provided hands-on assistance preparing Evoenergy's tariff structure statement and modelling network prices for those five years.
2023	**Endeavour Energy** **Tariff strategy and regulatory proposal** Dale provided strategic advice on Endeavour Energy's tariff strategy for the FY24-29 period and provided hands-on assistance with the preparation of its tariff structure statement, which was described by the Australian Energy Regulator as 'among the best that we have seen'.
2023	**Energy Queensland** **Pricing framework for very large customers** Dale led a review of the methodology by which Energy Queensland develops tariffs for very large electricity customers, including advice on potential improvements and the presentation of that methodology in its regulatory proposal.
2022	**Western Power** **Tariff structure statement and pricing model** Dale led the development of Western Power's five-year tariff strategy, which included drafting the initial and revised regulatory submissions, developing a distribution and transmission pricing models, presentations to executives, representing Western Power at stakeholder engagement sessions.
2022	**Dalrymple Bay Infrastructure** **Rate of return and ESG considerations** Dale assisted in the preparation of multiple expert reports that were submitted to the Queensland Competition Authority in relation to its approach to estimating the rate of return, including how best to account for the increasing effects of environmental, social and governance considerations on the cost of capital for businesses in the coal supply chain.
2022	**Ausgrid, Endeavour Energy, Essential Energy, Evoenergy** **Forecast meter reading volume and cost** Dale led the development of a geospatial methodology for forecasting the volume of electricity meter reads for four network businesses, and for estimating the operating cost of reading those meters.
2022	**Ausgrid, Endeavour Energy, Essential Energy, Evoenergy, TasNetworks** **Value of customer energy resources** Dale assisted in the development of a framework for estimating the value of customer energy resources, which included the estimation methodology for the customer export curtailment value.
2022	**Evoenergy** **Tariff structure Statement** Dale provided wide-ranging assistance during the preparation of Evoenergy's tariff structure statement, including drafting support, strategic advice on tariff reforms and estimating the marginal cost of providing export services.

2022	**Ausgrid** **Long run marginal cost** Dale developed location-specific estimates of the long run marginal cost of import network services, which formed the basis of Ausgrid's network prices for the 2024-29 regulatory period.
2022	**Endeavour Energy** **Tariff Structure Statement** Dale provided wide-ranging assistance on Endeavour Energy's tariff structure statement, including drafting support, strategic advice on tariff reforms and estimating the marginal cost of providing import and export services.
2021	**Evoenergy** **Side Constraint** Dale assisted in the preparation of a report that highlighted shortcomings and presented solutions for the Australian Energy Regulator's (AER's) specification of the side constraint mechanism, which was submitted to the AER.
2021	**Evoenergy** **Tariff trials** Dale advised Evoenergy on a methodology for setting prices for a suite of innovative tariff trials targeted at residential customers with behind the meter batteries and home energy management systems, and for large-scale grid-connected batteries.
2021	**Clean Energy Finance Corporation** **Energy market updates** Dale managed the preparation of comprehensive quarterly updates on regulatory developments in the electricity supply chain that were presented to the Clean Energy Finance Corporation.
2021	**Ausgrid** **Scenario model** Dale assisted in the preparation of an integrated revenue and pricing model that enabled Ausgrid to assess the effect on network prices of various revenue and volume scenarios.
2021	**Transgrid** **Operating expenditure efficiency** Dale prepared a report on the efficiency of Transgrid's proposed base year operating expenditure that it used as the basis to forecast operating expenditure for the five year regulatory period.
2021	**Sydney Airport** **Rate of return** Dale assisted in the preparation of an expert report for Sydney Airport on the rate of return for a benchmark Australian airport providing aeronautical services.
2021	**Jemena** **Data centres** Dale assisted in assessing the commercial and pricing implications of large data centres connecting to the electricity distribution or transmission network.

2021	**Ausgrid** **Tariff trials** Dale assisted in the development of a suite of innovative tariff trials implemented in Ausgrid and in its related engagement with the Australian Energy Regulator and customer representatives.
2021	**Ausgrid** **Annual Pricing Proposal** Dale assisted in modelling prices for Ausgrid's annual pricing proposal that was submitted to and accepted by the Australian Energy Regulator.
2020	**Ausgrid** **Network pricing strategy** Dale assisted in the ongoing development of Ausgrid's network pricing strategy for innovative network services, including in relation to community batteries, electric vehicle charging points and dynamic connection agreements. This included the development of a network pricing framework for Ausgrid's community battery trial.
2020	**Dalrymple Bay Terminal** **Regulatory strategy** Dale provided wide-ranging strategic advice concerning the potential economic implications of a light handed access framework for the DBCT service under the Queensland Competition Act.
2019	**Brookfield Infrastructure Group** **Vendor regulatory due diligence report** Dale managed the preparation of a vendor due diligence report to support the proposed sale of the Dalrymple Bay Terminal (DBT), which described in full the regulatory framework and evaluated the implications of potential new access frameworks.
2019	**King & Wood Mallesons/confidential client** **Taxi non-cash payment surcharge** Dale assisted in the provision of advice to a provider of non-cash in-taxi payment services and the drafting of its submission in relation to the Essential Services Commission's review of the taxi non-cash payment surcharge.
2019	**Greater Melbourne Cemetery Trust** **The pricing of cemetery services** Dale led a review of the economics of providing cemetery services and its implications for the efficient pricing of rights to interment, which included a review of the Greater Melbourne Cemetery Trust's pricing methodology that was presented to Trust members.
2019	**Chorus** **Risk free rate, cost of debt and tax adjusted market risk premium** Dale assisted in the preparation of a report on the appropriate risk free rate, cost of debt and tax adjusted market risk premium to be applied by the Commerce Commission to fibre fixed line access services during the implementation period and upon the subsequent commencement of economic regulation.
2019	**Powerco** **Review of distribution pricing principles** Dale prepared an assessment of the Electricity Authority's proposed amendments to the electricity distribution pricing principles that was submitted to the Electricity Authority.

2019	**TransGrid** **Projection of the allowed rate of return** Dale assisted in forecasting the allowed rate of return to apply to TransGrid in the forthcoming and subsequent regulatory control period, which was presented to TransGrid's Board.
2018	**Ausgrid and Endeavour Energy** **Forecasting operating expenditure productivity growth** Dale prepared a report on the determination of the operating expenditure (opex) productivity growth component of the 'rate of change' formula applied by the Australian Energy Regulator.
2018	**Ausgrid** **Acting pricing manager** Dale was acting pricing manager during the preparation of Ausgrid's tariff structure statement. His role included presenting contentious elements of Ausgrid's pricing strategy to the AER and stakeholders at public forums, engaging with Ausgrid Executives, preparing material for Board and Steering Committee meetings, preparing Ausgrid's pricing proposal for the 2019 financial year and drafting Ausgrid's proposed tariff structure statement.
2018	**Victorian and South Australian distribution network businesses** **Forecasting operating expenditure productivity growth** Dale assisted in the preparation of a report on the determination of the operating expenditure (opex) productivity growth component of the 'rate of change' formula applied by the Australian Energy Regulator. This also involved a review of contemporary evidence on historical changes in opex productivity.
2018	**Endeavour TSS** **long run marginal cost and tariff structure statement** Dale assisted in the development of an approach to estimating the long run marginal cost of providing electricity network services that reflected avoidable replacement expenditure. This involved working closely with Endeavour Energy's engineers and presenting the approach to the Australian Energy Regulator.
2018	**Evoenergy** **Long run marginal cost** Dale assisted in the development of a methodology for estimating long run marginal cost that reflected avoidable replacement expenditure and a methodology for allocating residual costs.
2017	**Ausgrid** **The price elasticity of demand for electricity** Dale assisted in an econometric study of the own and cross-price elasticity of demand for electricity services. This study was the first of its kind in the National Electricity Market. The results were presented to the Australian Energy Regulator and guided Ausgrid's tariff strategy.
2017	**Department of Environment and Energy** **Minimum energy efficiency standards for residential dwellings** Dale assisted in an economic evaluation of the costs and benefits of more stringent provisions in the National Construction Code for newly constructed residential dwellings at a state and national level.

2017	**Perth Airport** **The development of a building block model for aeronautical services** Dale advised Perth Airport on the development of a building block model to determine the price of aeronautical services.
2017	**APA Group** **The definition of reference services** Dale assisted in the development of an economic framework for considering the implications of defining more than one reference service on the Roma to Brisbane Pipeline.
2017	**Auckland International Airport** **The introduction of a Runway Landing Charge** Dale assisted in the provision of advice to Auckland International Airport on its proposed runway landing charge in preparation for the construction of a new runway.
2017	**Confidential Client** **Customer impacts of more efficient tariffs** Dale assisted in the preparation of a report that evaluated the impact on particular customers groups of more efficient network tariffs and advised on how distribution network businesses would be expected to amend their tariff strategies in response to particular jurisdictional requirements.
2017	**National Transport Commission** **The allocation of road expenditure to heavy vehicles** Dale assisted in the preparation of a report that evaluated the methodology used to allocate road expenditure to heavy vehicles and that considered how particular aspects of the cost allocation methodology might be amended so as to be consistent with a forward-looking cost base approach to heavy vehicle charging.
2017	**Ausgrid** **Quality assurance of annual pricing proposal** Dale undertook a quality assurance review of Ausgrid's annual pricing proposal proposal for the year ending June 2018, which included a detailed review of its pricing model and an evaluation of whether its price levels and the resulting customer impacts were compliant with the rules and Ausgrid's approved TSS.
2016	**Perth Airport** **Regulatory approaches to the weighted average cost of capital** Dale assisted in the preparation of a report describing alternative regulatory approaches to estimating the weighted average cost of capital (WACC), along with their respective merits and shortcomings, which formed the basis of Perth Airport's WACC strategy for its negotiations with airlines.
2016	**Ausgrid** **Revised Tariff Structure Statement** Dale led the development of Ausgrid's revised tariff structure statement (TSS), which included broad collaboration within Ausgrid, undertaking economic analysis, engaging with Executives and the AER, leading Ausgrid's stakeholder engagement forum and drafting Ausgrid's revised TSS.
2016	**Western Power** **Distribution pricing reforms** Dale assisted Western Power with the development of its tariff strategy for distribution network services, which included working closely with Western Power's forecasting team to assess demand and Western Power's potential forward looking costs. Dale provided advice on the appropriateness of particular tariff structures, the

	estimation of LRMC, alternative approaches to recovering residual costs and the assessment of customer impacts.
2016	**APA Goldfields Gas Pipeline** **Assessment of the ERA's decision on depreciation** Dale assisted in the preparation of an expert report reviewing the Economic Regulation Authority of Western Australia's draft decision on depreciation in the Access Arrangement for the Goldfields Gas Pipeline (GGP).
2015	**Government of New South Wales** **Economic regulation of electricity distribution services** Dale managed the preparation of a vendor due diligence report to support the partial lease of Ausgrid, which described the entire regulatory framework applying to electricity distribution services in the NEM, and assessed likely future changes to that framework.
2015	**ATCO** **Report on the return of capital** Dale assisted with the preparation of an expert report on the economic interpretation of provisions in the national gas law and rules in relation to the return of capital. This report was submitted to the Economic Regulation Authority of WA (ERA) and relied upon by ATCO in its application for leave to appeal to the Tribunal.
2015	**Energex** **Regulatory price review** Dale assisted in the preparation of an expert report on the economic interpretation of provisions in the national electricity law and rules and the application of the national electricity objective in the Australian Energy Regulator's final determination.
2015	**Chorus** **Response to Spark's advice regarding the social cost of high service prices** Dale assisted in the preparation of an expert report on the effect on welfare of reducing unbundled bitstream access (UBA) prices and unbundled copper local loop (UCLL) prices, which was submitted to the New Zealand Commerce Commission.
2015	**Essential Services Commission of South Australia** **Estimating the Rate of return** Dale assisted in the preparation of a report and the provision of ad hoc advice on the return on debt for SA Water for the provision of retail water and sewerage services.
2015	**ActewAGL Distribution** **Economic review of the AER's draft decision** Dale assisted in an economic review of the AER's draft decision for the 2015-19 regulatory control period, which assessed whether an alternative approach would likely result in a materially preferable decision in terms of the achievement of the National Electricity Objective.
2015	**TransGrid** **The cost of debt** Dale assisted in the preparation of an expert report that assesses the AER's draft decision to a 'trailing average' allowance for the cost of debt and to use two third party data sources to calculate annualised debt yields.

2015	**Sydney Water** **The Equity Beta** Dale assisted in the preparation of a report for submission to the Independent Pricing and Regulatory Tribunal on empirical evidence of the equity beta for a benchmark Australian water network service provider.
2014	**Queensland Competition Authority** **Review of Regulatory models** Dale undertook a quality assurance review of the models used to calculate regulated revenues for Queensland water utilities, which considered the formulation of the WACC, the intra year timing of cash flows as well as the structural, computational and economic integrity of the models.
2014	**NSW Department of Premier and Cabinet** **Ownership and electricity network performance** Dale assisted in the preparation of a report that examined the effect of private ownership of electricity network businesses on network performance. This included interviews with executives from private network businesses in South Australia and Victoria.
2014	**ATCO** **Access Price Review** Dale assisted with the preparation of two expert reports on the economic interpretation of provisions in the national gas law and rules on the return of capital and the application of the national gas objective to the entire draft decision, submitted to the Economic Regulation Authority of WA.
2014	**DLA Piper / Confidential capital city airport** **Expert reports on the economic and regulatory principles** Dale assisted in the preparation of three expert reports on the economic and regulatory principles used to allocate shared costs, support peak pricing and develop an economic framework for pricing airport services.
2014	**TransGrid** **Framework for a cost benefit analysis** Dale assisted in the development of a framework to evaluate the business case for installing optical fibre ground wire in sections of TransGrid's transmission network.
2014	**APA Goldfields gas pipeline** **Report on the return of capital** Dale led the preparation of a report on the methodology used to calculate the return of capital for the Goldfields Gas Pipeline in the 2015 to 2019 access arrangement, which was submitted to the Economic Regulation Authority of WA.
2014	**Ashurst / TransGrid** **Report on the appropriate return on capital of a regulated electricity network** Dale assisted in the preparation of an expert report that developed an approach to determining TransGrid's return on capital in accordance with the recently amended National Electricity Rules.
2014	**TrustPower Limited** **Report on Regulatory Change Management** Dale assisted in the preparation of a report on how best to manage regulatory change in the context of the New Zealand Electricity Authority's proposal to amend avoided cost of transmission payments to distributed generation.

2014	**SingTel Optus Pty Ltd** **Accounting for NBN revenue in the Fixed Line Services Model** Dale assisted in the preparation of a submission to the ACCC that considered the appropriate treatment of payments from NBN Co to Telstra for the purchase or lease of assets within Telstra's fixed-line network, where those assets also form part of the regulatory asset base used to determine regulated access prices for declared fixed-line services.
2013	**Essential Services Commission (ESC)** **Financeability discussion paper** Dale contributed to a discussion paper on the financeability testing of Victorian water utilities. The paper described the role and objective of financeability testing in the regulatory regime, assessed the various qualitative and quantitative indicators of financeability and recommended an approach to financeability testing for the ESC.

Legal proceedings, commercial arbitrations and negotiations

2025	**Northern Land Council** **Future Act Determination** Dale authored an expert report that was submitted to the Native Title Tribunal in relation to a future act determination under the Native Title Act.
2024	**Crown Solicitor of New South Wales** **Adjustment to compensation in industrial awards** Dale assisted in the preparation of multiple expert reports that addressed questions related to the appropriate adjustment to compensation in various industrial awards in New South Wales. These reports were filed in proceedings before the New South Wales (NSW) Industrial Relations Commission.
2023	**Clayton Utz / Western Sydney Airport** **Economic advice on contract negotiations** Dale provided economic advice to Western Sydney Airport on its long term pricing strategy for aeronautical and other services, as well as on the negotiation of a long term access agreement with a foundational airline customer.
2023	**Allen Overy / Confidential Client** **Native title compensation claim** Dale assisted in the development of an economic framework for establishing compensation for the ongoing impairment of native title rights for the purpose of mining activities, subject to a legal framework that has not previously been put before the courts.
2023	**DLA Piper and Arnold Bloch Liebler** **Confidential clients** Dale provided advice in relation to a contractual price review for access to export terminal infrastructure services.
2023	**Northern Land Council** **MacArthur River Mine compensation claim** Dale assisted in the development of an economic framework for establishing compensation for the ongoing impairment of native title rights for the purpose of mining activities, and in the preparation of an expert report that formed the basis of testimony before the Federal Court of Australia.

2023	**Arnold Bloch Leibler / Aveo retirement villages** **Class action** Dale assisted in the development of an expert report on the price of retirement village residences that would likely have been struck if observed transactions were the subject of contractual frameworks with different allocations of cost, risks and returns. The expert report was filed in the Federal Court.
2022	**Dalrymple Bay Infrastructure** **Commercial negotiation of access prices** Dale provided wide-ranging assistance to DBI on its commercial negotiations with access holders, which included the development of an economic framework for price negotiations under a negotiate/arbitrate framework and assisting in the preparation of expert reports on the rate of return and the level of efficient operating costs.
2022	**DLA Piper and Arnold Bloch Liebler** **Confidential clients** Dale provided advice in relation to a contractual price review for access to export terminal infrastructure services.
2021	**Shine Lawyers** **Shareholder class action** Dale assisted in the preparation of various expert reports on the extent of liability and potential damages arising from a shareholder class action alleging breach of ASX disclosure obligations by Iluka Resources Limited. The reports formed the basis of expert testimony before the Federal Court.
2020	**Slater & Gordon** **Shareholder class action** Dale assisted in the development of expert reports on the extent of liability and potential damages arising from a shareholder class action alleging breach of ASX disclosure obligations by Spotless Group Holdings Limited. The class action was ultimately the subject of a $95 million settlement. The reports formed the basis of expert testimony before the Federal Court.
2019	**Seyfarth Shaw / DP World** **Economic effects of industrial action** Dale assisted in the preparation of an expert report that evaluated the economic effect on the Australian economy of industrial action at DP World's container stevedoring terminals at the Port of Brisbane, Port Botany, the Port of Melbourne and/or the Port of Fremantle.
2019	**DLA Piper / confidential capital city airport** **Aeronautical charges** Dale assisted in the provision of advice to an Australian airport in relation to various matters underpinning its commercial negotiations with a major airline on the price of landing and terminal services.
2018-19	**DLA Piper & Arnold Bloch Liebler / confidential clients** Dale is assisting in an ongoing proceeding in the Supreme Court of Queensland in relation to the handling charges permitted to be charged to users by the operator of the Abbott Point Coal Terminal.

2017-19	**DLA Piper & Arnold Bloch Liebler / confidential clients** Dale is assisting in an ongoing commercial arbitration concerning the price to be charged for use of the coal loading facilities at Abbott Point Coal Terminal. Issues the subject of this arbitration include asset valuation, cost of capital, forecast operation and maintenance costs, financial modelling and the economic interpretation of building block regulation.
2018	**Liberty OneSteel** **Anti-dumping proceedings for steel rod in coil** Dale assisted in the preparation of an expert report on an economic review of the analysis underpinning the Australian Government Anti-Dumping Commission's decision as to the effect on Vietnam domestic prices of steel rod in coil of various interventions by the Government of Vietnam. This expert report was submitted to the Australian Government Anti-Dumping Review Panel.
2017	**Confidential Client** **Shareholder class action** Dale assisted in the development of an expert report on the extent of liability and potential damages arising from a shareholder class action alleging breach of ASX disclosure obligations by Myer Holdings Limited. The expert report formed the basis of expert testimony before the federal court.
2016	**Australian Government Solicitor / Commonwealth of Australia** **Native title compensation** Dale assisted in the preparation of expert reports relied upon in the landmark native title compensation claim against the Northern Territory for certain acts extinguishing native title in the town of Timber Creek, which was heard in the Federal Court. These reports considered the economic framework to be applied in determining the level of compensation to be paid for the extinguishment of native title as much as 35 years ago.
2016	**Department of Finance / Western Australian Government** **Assessment of returns and price outcomes at Utah Point** Dale assisted in the preparation of an expert report assessing the historical returns and price outcomes at the Utah Point bulk-handling facility at Port Hedland, which was identified in the WA government's asset sale program as a potential asset for disposal. This expert report was submitted to the Legislative Council's Legislation Committee.
2014-15	**Optus** **The price of access to electricity poles** Dale assisted in the provision of economic advice and other assistance in relation to negotiations between Optus and electricity distribution networks throughout Australia on the price of access to electricity poles to support hybrid fibre coaxial cables. This included Dale working on site at Optus' offices for an extended period.
2014	**Gilbert + Tobin / Confidential Client** **Coal Terminal Arbitration** Dale assisted in the preparation of several expert reports in the context of an arbitration concerning the price to be charged for use of the coal loading facilities at Abbott Point Coal Terminal. Issues addressed included asset valuation, cost of capital, forecast operation and maintenance costs and the economic interpretation of building block regulation.

2013	**Freehills / North West Shelf Gas** **Gas Supply Agreement Arbitration** Dale reviewed and analysed the contractual terms in a range of major gas supply contracts and assisted in the preparation of several expert reports for an arbitration concerning a foundation gas supply agreement in Western Australia.
2013	**Freehills / Santos** **Gas Supply Agreement Arbitration** Dale assisted in reviewing and analysing a number of gas supply contracts in the context of a gas price arbitration for a foundation gas supply agreement in Eastern Australia.

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