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Mr Warwick Anderson
General Manager
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

By email: RateOfReturn@aer.gov.au

3 September 2021

Dear Warwick,

Submission on rate of return omnibus papers

Jemena welcomes the opportunity to comment on the AER's July 2021 draft omnibus working papers (Equity Omnibus, Debt Omnibus and Overall Rate of Return). We appreciate the Australian Energy Regulator's (**AER**) consultative approach in its development of the 2022 Rate of Return Instrument (**2022 RoRI**). The 2022 RoRI will apply to Jemena Electricity Networks (Vic) Ltd (**JEN**) from 2026-31 and Jemena Gas Networks (NSW) Ltd (**JGN**) from 2025-30.

As recognised by the AER in its strategic plan, the energy system is undergoing a fundamental transformation. The Energy Security Board put it well when it said:

It is difficult to overstate the scale and pace of change across Australia's electricity sector as, both large and small scale, renewable generation enters the system rapidly and in volume.[1]

The consumer choice, market dynamics and policy and technological changes behind the increase in renewable generation are also driving dramatic changes in gas usage and consumption.

Gas networks have the potential to help decarbonise our energy system by facilitating access to green gases, provide a lower cost pathway to net-zero by avoiding costly upgrades to our electricity networks and generation fleet, firm the electricity grid, offer storage products and help decarbonise other sectors, such as transport. However, in some future scenarios gas networks may play a much smaller role. As an example, in three of the five scenarios currently being considered by the Australian Energy Market Operator (**AEMO**) residential gas heating loads will be entirely (or almost) entirely electrified by 2050.[2]

The 2022 RoRI will apply to network business at perhaps the most critical moment in the energy transition: the period to 2031. It is essential that the 2022 RoRI enables us to continue to invest so that we can continue to provide a safe and reliable (and soon to be decarbonised) source of energy for our consumers.

While the future is uncertain, what is clear is that we cannot assume that gas networks will continue to provide the same services they do today into perpetuity. We need to revisit and review the

[1] 2021 Energy Security Board, Post-2025 Market Design Final advice to Energy Ministers Part 1, *p7.*

[2] 2021 AEMO, 2021 Inputs, Assumptions and Scenarios Report, July, p.41

assumptions which underpin the regulatory framework to ensure it is fit-for-purpose for an energy system in transition.

Accordingly, the 2022 RoRI needs to adopt a future focussed approach. This will require:

- Identifying how the 2022 RoRI as part of the broader regulatory framework, will achieve the revenue and pricing principles,[3] in particular with the real and heightened risk of asset stranding. To support this consideration we have attached a report by NERA (**Attachment 2**) to support consideration of this issue.
- Considering forward looking datasets and evidence from other countries to ensure risks are appropriately compensated for.

We also consider that there are other opportunities to improve on the 2018 RoRI by:

- Avoiding volatile and lottery type outcomes for customers and investors which are caused by the return on equity estimates moving one to one with the risk free rate.
- Providing a safeguard for investors when economic conditions or forecast inflation approach results in negative real risk free rates.

We elaborate further on these key issues in **Attachment 1**.

We remain committed to working constructively with the AER and welcome any further queries in relation to this letter. If you wish to discuss this submission please contact Sandeep Kumar on [redacted] or [redacted].

Yours sincerely

[signed]

Ana Dijanosic

General Manager – Regulation

[3] Specifically, how will network businesses be provided with a reasonable opportunity to recover at least the efficient costs with regard to the economic costs and risk of potential for under-utilisation of distribution systems.

Attachment 1

1. Financial Capital Maintenance Issue for Gas Networks

The financial capital maintenance (FCM) principle that is used in regulation of natural monopolies ensures that shareholders in an efficient regulated firm have an expectation of preserving the purchasing power of their equity over the life of their investment. This by definition requires that there is an ex-ante expectation for investors to fully recover their investment over time, along with a return that is commensurate with the risk of investing. The revenue and pricing principles in the National Gas Law requires that the network service providers are allowed a reasonable opportunity to recover at least their efficient costs in provision of those services and <u>regard must be had of the economic costs and risks of potential for under and over utilisation of a pipeline with which the service provider provides pipeline services</u>. This is consistent with the principle of FCM. The FCM principle also forms the basis of the building block approach adopted by the AER.

The New Zealand Commerce Commission (**NZCC**) notes in its process and issue paper published on 4 August 2021[4] that one of its key economic principles is FCM and that it is important to provide the network businesses with an opportunity to maintain the value of their investment:

Real financial capital maintenance (FCM): we provide regulated suppliers the ex-ante expectation of earning their risk-adjusted cost of capital (a 'normal return'). This provides suppliers with the opportunity to maintain their financial capital in real terms over timeframes longer than a single regulatory period. However, price-quality regulation does not guarantee a normal return over the lifetime of a regulated supplier's assets. <u>The decarbonisation of the energy sector (which we discuss in Chapter 3) will provide additional challenges and uncertainty to the business of conveying natural gas by pipeline, and the returns on and of capital from doing so.</u>

The NZCC further notes:

In the context of transitioning to net carbon zero by 2050, changes in government policy may make it difficult or impossible to set a price path with an expectation of full capital recovery or FCM. For example, if gas use (or alternative gas use) were banned (or heavily restricted) at some point in the future, we may be unable to set price paths that provide an expectation of full capital recovery (or suppliers may not be able to charge those prices even if we allowed them).

And

Our current view is that most economic network stranding risks for GPBs are likely to be non-systematic in nature, and not relevant to WACC. This includes the risk of government policy interventions that restrict gas use (or gas pipeline use – which could also lead to physical asset stranding) and the risk of competitive stranding associated with technological developments specific to the energy or gas industries. However, given the relatively low penetration of gas infrastructure in New Zealand, economic network stranding risk may be partly systematic. <u>In the context of decarbonisation and likely declines in gas demand, it is plausible that adverse economic shocks could further curtail growth and potentially accelerate disconnections increasing economic network stranding risk.</u>

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[4] NZCC, Resetting default price-quality paths for gas pipeline businesses from 1 October 2022

It is important to consider the risks for gas networks through the lens of FCM. The AER's equity omnibus paper considers that stranding risk does not merit consideration under the 2022 RoRI review because of its non-systematic nature.

Tackling risks in such a compartmentalised way is likely to ignore the long term interests of consumers because it would assume that addressing these risks is tied to the assumptions of a particular asset pricing model, rather than ensuring that the objective of FCM is met. In absence of an industry wide framework to assess stranding risk, it is not clear how the AER intends to ensure that the FCM principle is maintained.

To ensure consistency with the FCM principle, the AER should consider whether the regulatory framework is allowing ex-ante expectation of full capital recovery and, if not, whether the risk of under-recovery is compensated elsewhere. For example, one approach to reduce capital recovery risk could be to apply no indexation to regulatory asset base going forward for gas networks. This links directly to the rate of return framework because it will change from real to nominal compensation. Such an approach could be beneficial when responding to stranding risks and take into account the needs of current and future customers in a potentially declining demand environment.

In its report for APGA, CEG notes:[5]

There are many ways in which accelerated cost recovery can be implemented within the confines of an NPV=0 building block regulatory building block. These include: shortening asset lives while retaining a straight line depreciation assumption; leaving asset lives the same while moving from straight line to diminishing value depreciation; <u>stopping indexing the RAB for inflation</u>; or some combination of the above…..

Removing inflation indexation has a similar effect on the pattern of cost recovery as does switching from straight line depreciation to diminishing value depreciation… Removing inflation indexation from the base-case reduces, but does not eliminate, stranding risk (and the necessary stranding uplift).

Similarly, NERA in its report for JGN (see attached report), notes:[6]

a. There a number of tools for addressing stranding risk:

  a. Shortening asset lives attempts to avoid stranding by providing recovery before stranding occurs;

  b. Accelerating depreciation and non-indexation of the regulatory asset base (RAB) attempts to minimise stranding risk by reducing the amount to be recovered in the future;

  c. Ex ante compensation provides compensation for stranding now but leaves regulated firms subject to the actual stranding risk being different from expectations (thus incentivizing suppliers to take mitigating actions); and

  d. Ex post compensation allows regulated firms to continue to recover the costs of stranded assets from remaining customers, but is typically only practical for discrete assets rather than network wide stranding.

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[5] CEG, Stranding risk depreciation vs uplift, Sep 2021

[6] NERA, Stranding risk for gas networks, Sep 2021

b. *These tools are generally complimentary. For example, front loading recovery (accelerated depreciation, reduced asset lives, non-indexation of the RAB) is unlikely to completely eliminate stranding risk and thus it can be combined with ex ante compensation. This is the approach the New Zealand Commerce Commission (NZCC) has recently proposed for fibre networks; and*

c. *Regulators are starting to recognize the stranding risk faced by gas networks and allowing front loaded recovery or ex ante premiums. This is, however, a developing area many regulators are just starting to grapple with as climate risk accelerates, so there is not yet substantial precedent.*

NERA also points out to a number of international regulators who have engaged on this issue as part of their rate of return determination, as shown in Table 1.

Table 1: Decisions by international regulators (% nominal)

Regulator	Industry	Year	Type and size of recovery	Reason for including recovery
France	GT + GD	2020	Higher asset beta for gas transport (0.5) and gas distribution (0.48) compared to electricity transmission (0.37) and electricity distribution (0.36), implying a beta uplift of 0.13 and 0.12.	To reflect the consideration of the increased financial risk, in particular stranded costs, that the energy transition places on shareholders of gas infrastructure companies
New Zealand	GD + GT	2016	Asset beta of 0.4 which is an uplift of 0.05 over electricity.	Reflecting systematic stranding risk and higher income elasticity of demand of gas vs electricity.
Sweden	GT	2019	Higher beta compared to electricity transmission (0.43 versus 0.32), implying a beta uplift of 0.11 Additional cost of equity premium of 1.5% for gas transmission	Higher customer substitution risk; political and regulatory risk, high demand risk (small number of clients) and high supply risk (depend on one Danish pipeline).
Finland	GT + GD	2017	Higher beta compared to electricity transmission (0.45 versus 0.4), implying a beta uplift of 0.05. Additional cost of equity premium of 1.7% for gas transmission and 1.3% for gas distribution	Higher supply risk due to dependence on Russia as sole supplier of gas. Higher sales risk given customers can substitute fuels if there is insufficient gas price competition.
Austria	GT	2021	Cost of equity premium of 3.5% for gas transmission.	For taking on the marketing risk of network capacities for which there is no demand. Specifically, existing contracts expire before the remaining life of the assets.
Austria	GD	2017	Reduced regulatory depreciation periods for gas distribution from 40 to 30 years.	Economic uncertainty surrounding the future of gas networks.
Belgium	GT	2020	Pipeline assets invested in after 2000 can be fully depreciate by 2050, reducing the regulatory depreciation period from 50 year.	A prudent decision in response to uncertainty around energy transition. CREG is keeping open the option to revisit this decision in the future when uncertainty is resolved.
Netherlands	GT	2021	Accelerated regulatory depreciation for gas transport assets, switch to a nominal WACC allowance (i.e. non-indexation of the RAB) and removal of divestments from the RAB.	To bring forward the costs of GTS to address the risk of asset stranding, and in particular the potential increase in network tariffs from the reduction in gas consumption Netherlands.
UK	GD + GT	2021	Front loaded depreciation profile using sum-of-years'-digits.	Likely lower utilisation of gas distribution networks in the future.

Source: NERA report for JGN, Stranding risk for gas networks, Sep 2021

Jemena is not seeking an arbitrary adjustment on top of an equity beta estimate to compensate for stranding risk. We encourage the AER to engage with this material as part of the 2022 RoRI as well as in its development of a framework for adapting to potential changes in utilisation of gas networks. We look forward to further engagement on this issue.

Jemena engaged NERA to set out the conceptual basis for stranding risk, and regulatory tools that can be used to address stranding risk. APGA has also submitted a report from CEG that discusses tools for addressing stranding risk issue for gas businesses.

CEG, in its report for APGA, notes that:

The two primary grounds for addressing stranding risk relate to providing surety for future investment. The first ground is economic efficiency. If the opportunity to recover costs is denied by a regulator, this risks raising the cost of capital above the competitive level leading to a lower than optimal allocation of investment in the provisions of services.[7] *……………….. The second grounds for addressing stranding risk is to ensure regulation is consistent with an implied compact between individual consumers and investors. In this framework, the regulator acts as an arbitrator of a fair deal between the parties to the compact. For investments to be made investors will require an expectation of cost recovery.*

CEG concludes that:

Holding other things equal, the slower the rate that capital is returned to investors the higher the expected cost of future asset stranding and the higher the compensation required for that asset stranding.

2. Systematic risk compensation for Gas Networks

The current equity omnibus paper does not seek to measure the true systematic risk for gas networks. Currently there is only one live/currently listed gas firm (APA) in the AER's asset beta sample. Given the lack of observations and sample size, the AER's current preference is to consider historical data on listed energy firms that no longer exist and were primarily dominated with electricity portfolios. This is justified on the basis that use of historical data of firms improves precision of its estimate.

Such an approach assumes that there is no change in risks over time for businesses – which is contrary to AER's lowering beta estimate from 0.8 in 2009 to 0.7 in 2013 and 0.6 in 2018 reflecting changes in risk over time. In saying so we do not believe the 2018 estimate of 0.6 reflects the systematic risk faced by gas networks as these businesses have lesser penetration compared to electricity networks, face greater volume uncertainty and have higher income elasticity.

Due to absence of domestic data on gas businesses there is no way to demonstrate the difference in risk to electricity networks. This should not mean that an assumption that the risks across electricity and gas networks are the same. An effort should be made to understand the different characteristics of the gas networks such as penetration rates, income elasticities, exposure to volume risk and climate policy risk.

We do not consider that using data on firms de-listed in the early 2000s deterministically for estimating risks over the 2025-31 period consistent with sound regulatory judgement. Also, by using just two live sample firms means that recent estimates could be impacted by other market announcements of the two businesses, not related to the changing risks of these businesses.

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7 Brennan, T. J., & Boyd, J. (1997). Journal of Regulatory Economics, 11(1), 41–54

We are unclear why international data cannot be used to understand the change in risk profile for gas businesses. AER's expert Brattle Group identified use of international sample as a remedy with the ever shrinking domestic beta sample:[8]

The AER prefers locally-based companies, which leaves a very small sample, while some European regulators (ACM, Ofgem, ARERA) often rely on companies from other European jurisdictions (or in some cases North American companies).The NZCC uses a very broad set of companies from different jurisdictions. While even in the US there are very few listed pure-play gas pipelines, for gas and electricity distribution there is generally a large sample of companies to choose from in North America. <u>If utilities that operate in different jurisdictions have comparable business risks and regulatory frameworks (including all of the jurisdictions in this report that regulate energy utilities), the use of betas from a non-Australian market can provide information about the systematic risk of the industry in Australia</u>.

Currently, the AER's dataset has no pure gas network business. We don't consider that a sample with no pure gas business can be used to determine the risk for the gas networks. We understand the AER has been reluctant to use international sample because, from an academic perspective, it would be more consistent to use it with an international MRP. However, we encourage the AER to consider the merits of using the international dataset available for pure gas network businesses as it provides useful information about the changing risks of those businesses against the need for academic consistency.

We agree with Brattle Group that we could get useful insights by considering an international sample set. Brattle notes:

Measuring beta can be unreliable if the local market index is not diverse. However, we note that the Australian, the UK and US stock market indices are quite diverse with no one industry accounting for more than about 18% of the index. <u>Thus, in these cases, the beta estimates against the local index are likely to reflect readily available diversification options. Therefore, a beta estimate would reflect reasonably well the systematic risk of the utility peers against a broad market index.</u>

The APGA engaged CEG to look at whether systematic risk for gas networks has changed over time. Using the NZCC comparator sample CEG concluded:

- An increase of 0.08 in the 10 year asset beta is observable from the 10 year period ending in 2016 to 2021
- Applying the same 0.08 increase on the asset beta adopted by the AER, would imply an increase in the asset beta for gas networks from 0.24 to 0.32.

We recommend the AER use this information to estimate the asset beta for gas networks and engage with the issue of significant uncertainty around the future of gas networks.

3. Contingency for expected risk free rate measurement

In its regulatory decisions for JGN's 2020-25 Access Arrangement review, the AER adopted 0.94% and 1.03% as the nominal risk free rate in its draft and final decisions respectively. It also adopted inflation forecasts of 2.45% and 2.27% for the two decisions. The combination of the low nominal interest rate and high inflation forecasts resulted in real risk free rates of -1.47% and -1.21% respectively, in JGN's draft and final decisions.

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[8] The Brattle Group, A Review of International Approaches to Regulated Rates of Return, June 2020

The Table 2 provides a summary of AER's draft and final decisions for JGN.

Table 2: AER's decision on JGN's rate of return (% nominal)

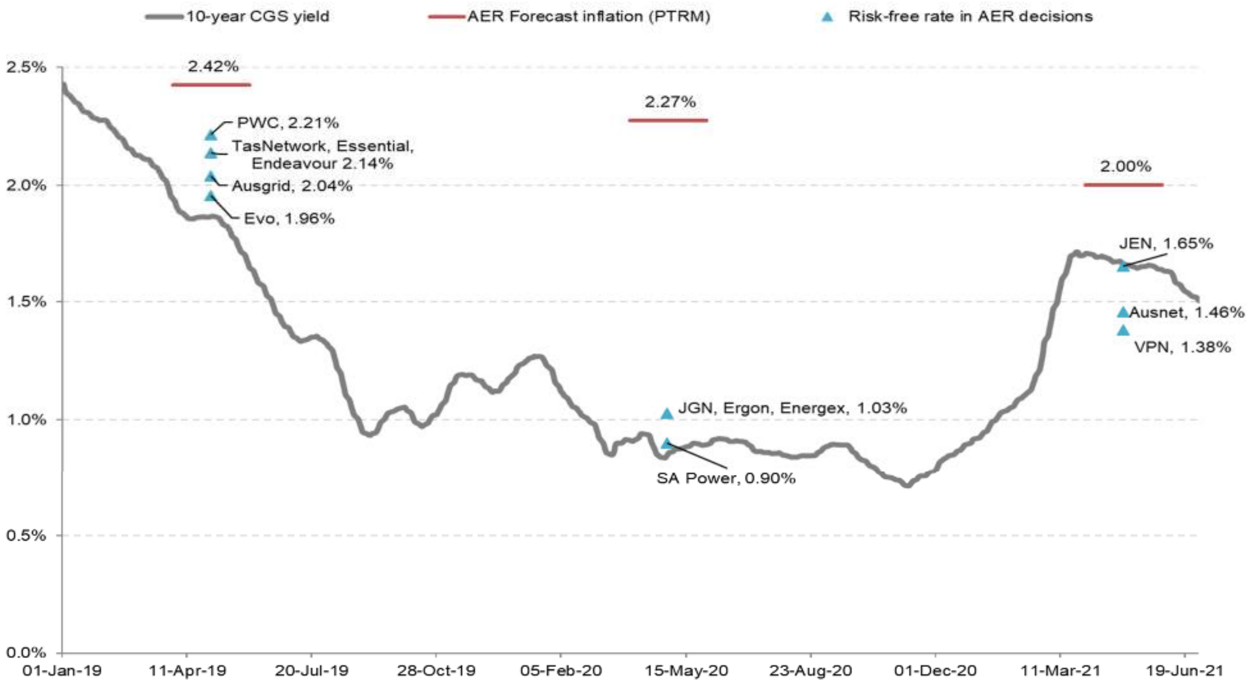
Parameter	AER draft decision	AER final decision
Nominal risk free rate	0.94%	1.03%
Equity beta	0.60	0.60
MRP	6.10%	6.10%
Return on equity	4.60%	4.69%
Expected inflation	2.45%	2.27%
Real risk free rate*	-1.47%	-1.21%

Source: AER's final decision for JGN, * Derived using Fisher equation

The 2018 RoRI has no means of dealing with situations that result in negative risk free rates as the expected time value of money to investors. The time value of money cannot be expected to be negative for investors that provide large amount of funds for long term investment in network assets.

Since its final decision for JGN's 2020-25 AA, the AER has improved its inflation forecast approach. The AER's April 2021 final decisions for the Victorian electricity networks adopted a five year inflation tenor, which lowered the mismatch between the inflation forecast used in Post-tax Revenue Model (**PTRM**) and the actual inflation used in the Roll Forward Model (**RFM**). However, this approach does not mitigate the issue that, in a low interest rate environment, the RoRI can result in the use of a negative real risk free rate. As shown in the chart below, the AER's inflation forecast continues to be higher than the ten year nominal Commonwealth Government Securities (**CGS**) yield.

Figure 1: Nominal risk-free rate and the AER's forecast inflation (2019-21)



The 2018 RoRI provides the AER with no means to adopt a risk free rate other than the 10 year CGS, or to apply an uplift to the CGS in the event it turns negative. We recommend that the 2022 RoRI includes a contingency that establishes a floor to the real risk free rate. A conservative floor of a zero real risk free rate should be considered when the real risk free rate turns negative due to a low interest rate environment and/or a high forecast of expected inflation that is higher than the nominal 10 year CGS. This would provide stability to the framework and not penalise investors for short term market movements, or unusually high inflation forecasts due to a mechanistic approach being adopted in the low interest rate environment. It would also ensure that the value of money would not reduce over the five year regulatory period.

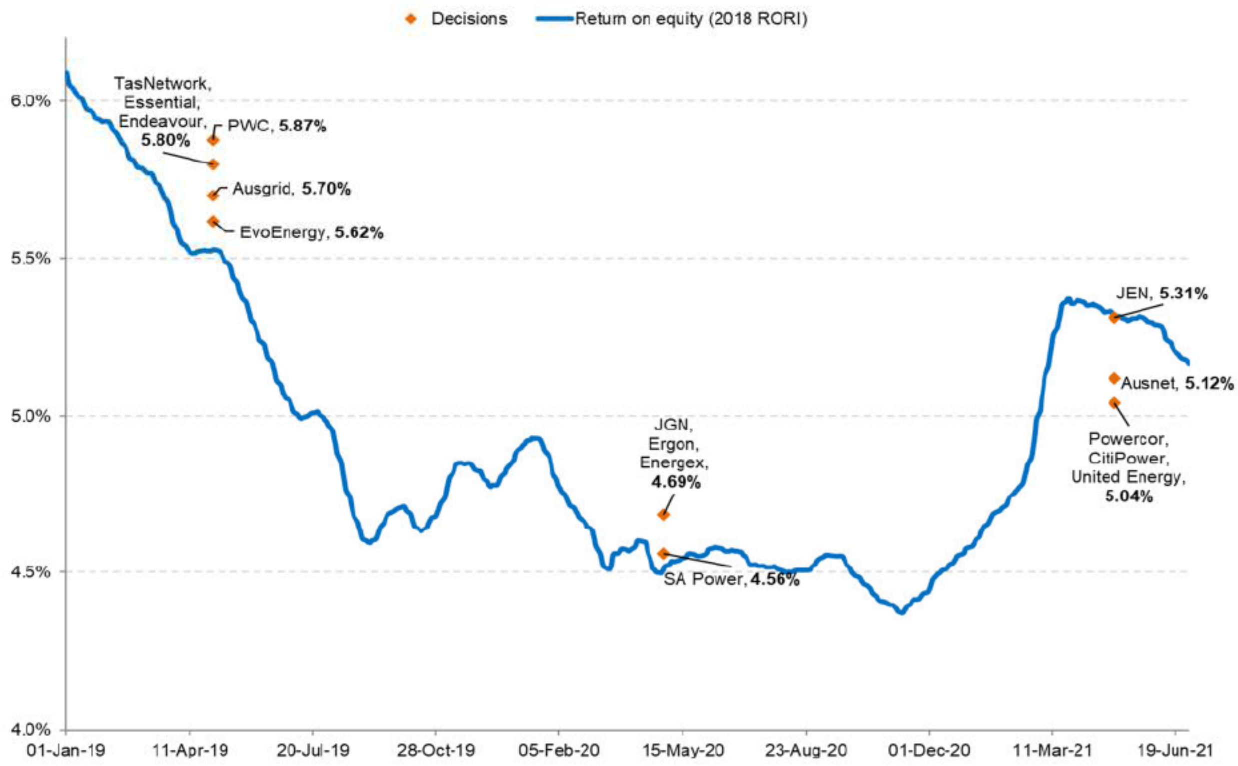
This contingency would only be triggered when the economy is experiencing either (or a combination of) low interest rate conditions or high inflation expectations resulting in a negative real risk rate. We recommend the AER include this contingency in the 2022 RoRI.

4. Use of forward looking MRP

The AER currently uses a fixed value of historical MRP determined at the time of determining the RoRI. There is potential gap of up to four years when the RoRI could be applied in a price reset decision, which means that the return on equity outcomes over the four year horizon will move one to one with the risk free rate which is the only variable component in the AER's return on equity equation.

We understand that the AER has employed this approach over a long time and is to a large extent wedded to it. However, if the RORI does not make part of MRP estimation variable, to respond to movement in the risk free rate, it will continue to result in highly volatile outcomes. This can be seen in Figure 2 which shows the returns on equity over the last three years under the 2018 RoRI.

Figure 2: AER's return on equity decisions over 2019-21



The chart above reflects the speculative outcomes 2018 RORI delivered over the last three years for investment in similar assets over the same period. A RORI that delivers such speculative outcomes for essential services cannot be consistent with revenue and pricing principles in the National Electricity/Gas Law or safeguard the long term interests of customers.

The ENA has provided some useful suggestions to the AER for estimating MRP, including use of DGM. We endorse these suggestions. However, if the AER is reluctant to use DGM we propose that, at a minimum, it should consider combining its current approach with an approach that estimates total market returns, and adjusts to movements in the risk free rate. An illustration of such an approach is presented below in Table 3.

Table 3: Estimating MRP and Return on equity (% nominal)

Parameter	Estimate 1	Estimate 2	Estimate 3
a. Nominal risk free rate	3.0%	1.5%	4.5%
b. Equity beta (2018 estimate)	0.6	0.6	0.6
c. Total market return (illustrative)	9.0%	9.0%	9.0%
d. MRP – based on total market return (c - a)	6.0%	7.5%	4.5%
e. MRP – based on AER's current approach (not impacted by risk free rate)	6.1%	6.1%	6.1%
f. Average MRP (50:50 weight on d and e)	6.1%	6.8%	5.3%
g. ROE – AER's current approach (a + b*e)	6.7%	5.2%	8.2%
h. ROE – Average MRP approach (a + b*f)	6.6%	5.6%	7.7%

The above example shows the return on equity estimate using AER's current single MRP estimate of 6.1% compared to an alternative approach which uses an average of the current AER's approach and an estimate based on total market return.

Under AER's current approach the return on equity estimate moves from 5.2% to 8.2% simply due to movement in the risk free rate, a deviation of 300bp. If the total market return approach is given 50% weight, this variation is reduced by 90bp to 210bp (due to lower movement between 5.6% and 7.7% ROE estimates). The more weight that is placed on the total market return approach for measuring MRP the lower will be the variation.

The AER could engage with stakeholders on how much weight should be given to each MRP estimate. Such an approach would provide protection to customers in high interest rate environments, and to investors in low interest rate environments.

We recommend that the AER considers adopting an approach that responds, to some extent, to the movement in the risk free rate to lower the volatility and the resulting lottery type outcomes for customers and investors. Such an approach would be more pragmatic, result in reasonable and efficient commercial outcomes and would be consistent with long term interest of consumers.