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Stranding risk for gas networks

Jemena Gas Networks

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Project Team

Will Taylor, PhD
Kevin Counsell
Kate Eyre
Barbara Kaleff

NERA Economic Consulting
One International Towers
100 Barangaroo Avenue
Sydney NSW, Australia 2000
+61 2 8864 6535
www.nera.com

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1. Introduction and summary

1. As part of its Rate of Return Instrument (RORI) process, the Australian Energy Regulator (AER) has recently released, and is seeking submissions on, its draft Equity Omnibus paper (the "EO Paper").[1] This paper proposes to set a single benchmark for the cost of equity across electricity and gas networks. Part of the AER's justification for doing so is its view that while gas pipelines are subject to stranding risk, it does not consider this risk to be systematic and relevant for the cost of capital:[2]

   > *In relation to gas pipelines, there may be risks of extreme changes in demand which present the potential for asset stranding. However, we do not consider these risks likely to be systematic in nature. Therefore, we do not consider they should be accounted for in the equity beta or the regulated rate of return. Nevertheless, if these risks are sufficiently material to require a regulatory response, adjustments can be made to the way regulated cash flows are set (for example, providing prudent discounts or accelerated depreciation provisions).*

2. Against this context, Jemena Gas Networks (JGN) asked us to prepare an expert report that assesses stranding risk for its gas distribution network in New South Wales (NSW). In particular, we have been asked to:

   a. Set out the conceptual basis for stranding risk;

   b. Comment on whether this stranding risk is likely to have a systematic component;

   c. Describe the factors which influence stranding risk for JGN specifically; and

   d. Discuss the regulatory tools that can be used to address stranding risk (including local and international regulatory precedent).

3. A summary of our conclusions is as follows:

   a. Stranding risk, if not addressed, can result in the *ex ante* net present value (NPV)=0 / financial capital maintenance (FCM) principle being violated. This can have negative implications for ongoing investment incentives;

   b. Gas distribution networks are subject to material stranding risk due to trends towards electrification and climate change policy;

   c. A transition to hydrogen does not completely mitigate this risk and indeed could introduce new stranding risks;

   d. There may be a systematic component to the stranding risk faced by gas networks that have low penetration, and more generally if the drivers of gas stranding risk are correlated with the overall market;

   e. There is a 'point of no return' after which regulators can no longer accelerate depreciation to avoid stranding. This occurs when attempts to front load recovery would trigger substitution to electrification. Regulators must therefore act before this point is reached if they are committed to ensuring gas networks have the opportunity to recover their efficient costs;

   f. It is important to undertake a reasoned analysis of the nature of stranding risks for the specific gas network in question. In this regard, the characteristics of demand and the customer base in NSW suggest JGN is particularly exposed to stranding risk. In particular, the majority of the customer base (in revenue terms) is residential, and these customers pose a particular risk of substituting to electricity given hot water heating is the key use for gas in NSW and solar photovoltaic (PV) penetration is increasing;

[1] AER (2021), *Rate of Return Equity Omnibus*, Draft working paper, July 2021.

[2] EO Paper, pg.50.

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

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

   ii. **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;

   iii. ***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

   iv. ***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.

h. 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

i. 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.

4. In the remainder of this report we:

   a. Provide an overview of the conceptual framework for stranding risk (section 2);

   b. Set out the specific stranding risk that gas distribution networks face, discuss why some of this risk may be systematic and assess the specific situation facing JGN (section 3);

   c. Describe the regulatory toolkit for addressing stranding risk and how the different tools can be complimentary (section 4);

   d. Survey international regulatory precedent for addressing stranding risk for energy networks (section 5); and

   e. Provide an overview of the methodology developed by the NZCC to calculate an *ex ante* stranding premium, describe the NZCC's application of this methodology to fibre networks and provide high level thoughts on the model's potential application to gas (section 6).

2. Conceptual overview of stranding risk

5. 'Asset stranding' is used to describe the situation when a change or changes occur which lead to insufficient demand, such that a firm is unable to earn a competitive return on its historic capital expenditure. Guthrie (2020, pg.273), for example, refers to asset stranding for firms as:[3]

> *[S]ustained reductions in demand that result in excess capacity and an inability to fully recover the costs of their past investments*

6. Under the National Gas Law (NGL), principle 1 of the revenue and pricing principles (RPP) (24(2) of the NGL) requires that:[4]

> *A service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in:*
>
> - *providing regulated services; and*
> - *complying with a regulatory obligation or requirement or making a regulatory payment*

7. The AER has interpreted this aspect of the RPP as requiring it complies with the 'NPV=0 condition', which is a situation whereby there is an *ex ante* expectation of recovering the costs of the asset over its life:[5]

> *We consider that a reasonable opportunity to recover efficient costs of providing regulated services is achieved when the rate of return satisfies the 'NPV=0' condition. The NPV=0 condition means that the ex-ante expectation is that over the life of an investment the expected cash flow from the investment meets all the operating expenditure and corporate taxes, repays the capital invested and there is just enough cash flow left over to cover investors' required return on the capital invested*

8. The New Zealand Commerce Commission (NZCC) refers to this same principle as the regulatory principle of 'financial capital maintenance' (FCM). The NZCC describes this principle and its justification as follows:[6]

> *Real financial capital maintenance (FCM): we set our regulatory rules in a way that provides a regulated provider with an ex-ante opportunity to earn a normal return on capital. A normal return is the return on capital that an efficient firm has an ex-ante opportunity to earn in a workably competitive market (see also paragraph 2.26 above).* ***Allowing regulated providers the ex-ante opportunity, but not the guarantee, of earning normal returns provides them with a chance to maintain the financial capital they have invested, therefore maintaining incentives to invest****. [emphasis added]*

9. The NZCC thus views the *ex ante* NPV=0 / FCM principle as critical to maintaining investment incentives, which is important in fulfilling its statutory obligation to promote the long term interests of consumers, an obligation the AER also has under the National Gas Objective (NGO).[7] In the present context, stranding is thus a concern if it means that investors no longer have an expectation of the opportunity of earning a normal level of return.

10. It can be helpful to categorise a reduction in demand as having the potential to strand assets in two ways:

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[3] Graeme Guthrie (2020), "Regulation, Welfare, and the Risk of Asset Stranding", *Quarterly Review of Economics and Finance*, 78, 273-287.

[4] *National Gas Law 2008*, ch 1 pt 3 div 2 para 24(2) (Austl.).

[5] AER (2021), *Assessing the long term interest of consumers*, Position paper, May, p.15.

[6] NZCC (2020), *Fibre input methodologies: Main final decisions – reasons paper*, 13 October, para.2.280.1.

[7] Note that unlike the situation in Australia where *ex ante* NPV=0 / FCM is essentially enshrined as a statutory objective, in New Zealand it is a principle which the NZCC uses as an aide to promoting the statutory objective. Note the objective (Commerce Act 1986, pt 4 s 54A) is very similar in structure to the NGO, in that both reference promoting the long term interest/benefits of consumers.

a. **Physical stranding:** which occurs when there is such a demand reduction that the assets are no longer physically used. For example, households disconnect from the gas network, but the distribution network remains in the ground with no alternative use, despite not being utilized; and

b. **Economic stranding:** which occurs when assets remain in use, but the historic capital costs are spread over a demand base that is not willing to pay a sufficiently high enough price to recover those costs.

11. It is worth elaborating on the latter categorization. It may be that as consumer preferences change, technology changes, competitive alternatives become available, and/or government policy changes, households start to disconnect from the gas network to switch to alternatives. While this may physically strand some assets (e.g., gas lines beyond the property boundary, that are no longer used by the household), other assets (e.g., the core gas network) continue to be used by remaining customers.

12. However, for a regulated gas business, if the costs of those assets are unchanged but are spread over a smaller demand base, then this will lead to an increase in the regulated price for those remaining customers. In turn, the higher price may lead to further demand reductions, as more customers switch to alternatives, leading to even further regulated price increases. The cycle of falling demand and increasing price, known as the 'death spiral', may reach an unsustainable point where the willingness to pay of those customers that remain on the network is insufficient to recover the historical costs of the assets that they are using. As Simshauser (2017, pg.285) states:[8]

> *[T]he feedback loop of rising prices and contracting volumes in the presence of a discontinuity can produce a very destructive price cycle (colloquially known as a Death Spiral).*

13. Note that if stranding occurs because the willingness to pay of future consumers is insufficient to recover the asset's historic costs, this does not mean that an asset is inefficient or has not provided net benefits to consumers. It could simply mean that the bulk of the benefits occurred prior to the asset's costs being fully recovered. This is important in the context of the RPP's phrasing of 'efficient costs'. An asset can provide net benefits in the sense of comparing the total costs and benefits in present value terms, but still become stranded if cost recovery is backloaded to a period after the benefits have already been realised.

14. In this regard, another aspect of the RPP is potentially relevant. Principle 6 of the RPP (24 (6) of the NGL) requires that:[9]

> *Regard should be had to the economic costs and risks of the potential for under and over utilisation of a pipeline with which a service provider provides pipeline services.*

15. The AER interpret this principle as requiring them to be cognisant of setting the rate of return too high, as this will result in over investment and therefore underutilisation. Similarly, setting the rate of return too low will result in under investment and therefore overutilization. An alternative, or perhaps complimentary, reading of this principle is that economic stranding due to underutilisation is a cost and risk the AER needs to account for when discharging its duties.

16. An illustration of economic stranding is provided by the "Windows Of Opportunity PaSt" (WOOPS) framework, recently proposed by Dampier Bunbury Pipeline (DBP),[10] which is based

[8] Paul Simshauser (2017), "Monopoly regulation, discontinuity and stranded assets", *Energy Economics*, 66, 384-398.

[9] *National Gas Law 2008*, ch 1 pt 3 div 2 para 24(6) (Austl.).

[10] The proposal was part of DBP's submissions to the Economic Regulation Authority of Western Australia regarding revisions to the access arrangement for the Dampier to Bunbury Natural Gas Pipeline for the 2021-2025 period. See DBP (2020), "Attachment 9.2: Assessment of the Economic Life of the DBNGP", January 2020.

on the work of Crew and Kleindorfer (1992).[11] The WOOPS framework recognizes that when there is technological change with respect to the substitutes for an asset (or the commodity that uses that asset in the case of gas), at some point that alternative becomes the binding constraint on pricing, as opposed to the regulated price.

17. The insight from the WOOPS framework is that once the alternative technology is the binding constraint on price, that price will no longer be sufficient for the pipeline owner to recover its efficient costs (i.e., it is below the regulated price determined using a building blocks model). That is to say, economic stranding will occur. The WOOPS framework provides an approach for determining accelerated depreciation, such that the pipeline owner can compete with competitive alternatives for longer and improve the chances of recovering its efficiently incurred investments.[12] It also allows for determination of the point at which sufficient depreciation can no longer be brought forward to cover the cost of the asset.

18. As described by DBP's consultant that operationalized the model:[13]

> *The purpose of the ACIL Allen model is to establish the point for each scenario modelled where regulation of the DBP would no longer fully recover deployed capital because competitive based pricing from that point would be less than regulated pricing required to fully recover capital deployed.*

19. This is illustrated in Figure 1, which is adapted and expanded from the figure that appears in DBP's asset lives proposal. In Panel A:
    a. the yellow line shows regulated revenue under a business-as-usual (BAU) path (essentially, building blocks determined revenue with no adjustments to asset lives or depreciation);
    b. the green line shows the regulated firm's revenue if it were to match its prices to a substitute product (i.e., priced up to the point that substitution to electrification occurred) that is subject to technological change (so that the price falls as time passes); and
    c. the red line then shows the regulated firm's *actual* revenue, which at some point in time falls below the regulated revenue. This is because the firm must price to match the substitute product, or risk a material loss in demand.

20. Panel A illustrates the point at which the substitute technology becomes the binding constraint on price, which is where the yellow and green lines intersect. After this point in Panel A, the regulated firm is not able to earn a normal return on capital (as given by the BAU path), as its revenue ultimately drops below this level.

21. Panel B overlays two shaded areas to show:
    a. The **additional revenue that could be brought forward** (the blue shaded area), being the difference between BAU regulatory revenue and revenue if price was increased up to the constraint of the alternative technology; and
    b. The **revenue shortfall if no regulatory action is taken** (the yellow shaded area), being the difference between the firm's actual revenue once the alternative technology is the binding constraint and the BAU revenue path.

22. Panel C shows a situation where the regulator allows the firm to recover more revenue upfront, shown by the steeper red line for the firm's actual revenue path. This allows the firm to compete

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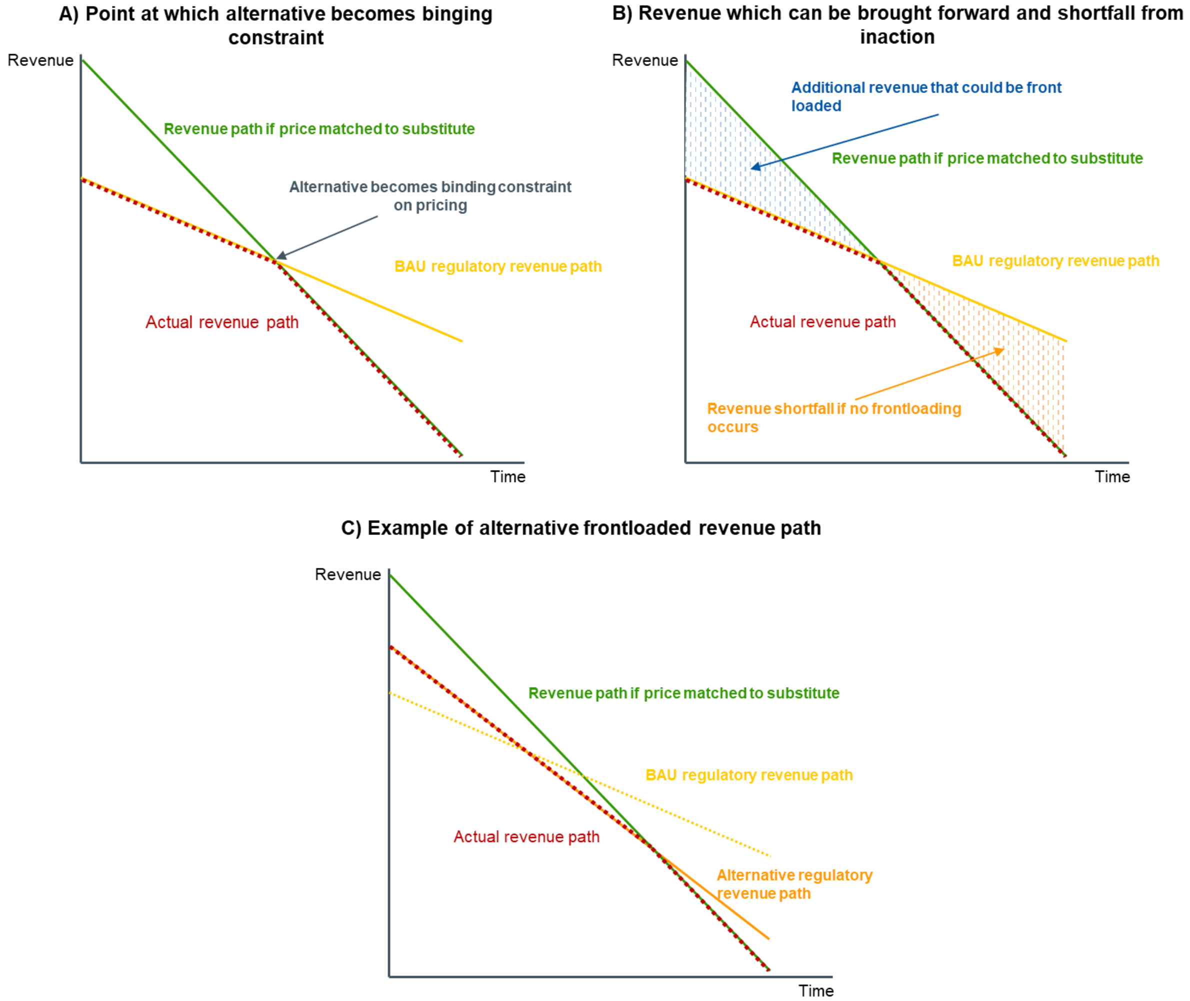
[11] Michael A. Crew and Paul R. Kleindorfer (1992), "Economic Depreciation and the Regulated Firm under Competition and Technological Change", *Journal of Regulatory Economics*, 4(1), 51-61, 1992.

[12] See DBP (2020), *Attachment 9.2: Assessment of the Economic Life of the DBNGP*, January 2020, pg.20.

[13] ACIL Allen Consulting (2019), *Dampier to Bunbury Natural Gas Pipeline: Economic Depreciation Study*, 20 December 2019, pg.3.

with the substitute product for longer, as the intersection of the green and yellow lines has shifted out in time.

Figure 1: Stylised illustration of WOOPS framework



Source: Adapted from Figure 12 of DBP (2020)

23. A key insight from the WOOPS framework is that if there is a risk of stranding in the future, it is important for regulators to act sooner rather than later, as there is eventually a point where front loading depreciation has no impact, since competitive forces control prices and not the regulator. That is, there is a 'window of opportunity' for regulators to act. As Simshauser (2017, pg.390) states, this window is contingent upon having:[14]

> *(1) a suitable suite of policy mechanisms available, and (2) the conviction (by policymakers or regulators) to act before a crisis actually develops.*

24. As we discuss later, there is a suitable suite of policy mechanisms, and therefore what remains is the importance of regulators willing to act now rather than deferring action till it becomes too late. This insight is particularly relevant in the context of the RPP in section 24 of the NGL, which requires that service providers are provided with a reasonable opportunity to recover their efficient costs. Deferring action addressing stranding risk could thus be contrary to the NGL. That is, it undermines the ability for the regulated firm to recover its efficient costs over the lifetime of its assets. In this regard we note the approach of the regulator in Belgium, which has

[14] Paul Simshauser (2017), "Monopoly regulation, discontinuity and stranded assets", *Energy Economics*, 66, 384-398.

considered it is prudent to accelerate depreciation now given current uncertainty, but that this decision could be revisited once there is more certainty about the future role of gas:[15]

> *The CREG confirms that the impact of accelerated depreciation is not significant. This measure should be seen from the perspective of a prudent manager in light of the discussions currently taking place in Europe and Belgium on the subject of the energy transition. However, the CREG says that the measure will be evaluated once we have a better view of the energy mix in the medium and long term*.

25. Other important conceptual background to stranding is the reason for, and nature of, stranding risk. Stranding may occur for reasons such as technological change, and competitive entry or expansion. For example, technological developments such as solar PV panels and battery storage can strand gas network assets, as these technologies allow gas customers to shift on to distributed electricity generation. Competition from electrical appliances, such as in respect of space and water heating, may also reduce demand for gas. Other stranding risks might be due to government policy interventions, for example, restrictions on household gas use or new gas exploration as governments seek to decarbonize their economy via electrification in response to climate change.

26. The risks associated with asset stranding can be considered as either systematic or non-systematic. Non-systematic risks are firm-specific, so an investor with a diversified portfolio can manage these risks. For example, an investor faced with reduced demand due to alternative technologies could invest in technologies so as to manage the associated stranding risk. In contrast, systematic risks affect the entire market and are not able to be diversified away by investing in other industries. For example, shocks to the economy, or wars, recessions or pandemics can affect all sectors of the economy, and may reduce demand and increase the risk of asset stranding. Specifically, stranding risk would be systematic if a market downturn increased the likelihood of stranding occurring.

27. Under the AER's current regulatory approach set out in the EO Paper, investors are only compensated for systematic risks.[16] The AER states in the EO Paper that:[17]

> *…the risk of asset stranding due to technological changes, breakdown in the supply chain, labour strikes, and liquidity issues can be mitigated as investors would be able to diversify away such risks by investing in other industries.*

28. The AER further states that:[18]

> *In relation to gas pipelines, there may be risks of extreme changes in demand which present the potential for asset stranding. However, we do not consider these risks likely to be systematic in nature. Therefore, we do not consider they should be accounted for in the equity beta or the regulated rate of return.*

29. We return to the issue of systematic stranding risk later in this report (in section 3.2).

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[15] CREG (2018), *Rapport de la consultation relatif au projet d'arrêté (Z)1110/9 fixant la méthodologie tarifaire pour le réseau de transport de gaz naturel, l'installation de stockage de gaz naturel et l'installation de GNL pour la période régulatoire 2020 -2023*, 7 June 2018, para.33. Available at: https://www.creg.be/fr/consultations-publiques/methodologie-tarifaire-2020-2023-fluxys-belgium-et-fluxys-lng. Automatic translation from French by Google Translate.

[16] EO Paper, pg.17.

[17] EO Paper, pg.37.

[18] EO Paper, pg.50.

3. Stranding risk for gas networks

30. In this section we discuss:

    a. The drivers of stranding risk for gas networks (section 3.1);

    b. How there is likely to be a systematic component to the stranding risk for gas networks, given the nature of demand for gas networks (section 3.2); and

    c. Specific factors driving stranding risk for JGN (section 3.3).

3.1. Drivers for stranding risk for gas networks

31. In this section we discuss three key (somewhat interrelated) factors that drive stranding risk for gas networks:

    a. electrification;

    b. government policy change around climate change; and

    c. conversion to hydrogen.

32. **Electrification** may lead to reduced demand for gas in one of two ways. First is the availability of substitute electric appliances; for example, heat pumps as a substitute for gas heating; electric or induction cooktops as an alternative to gas cooking; and electric water heating as a substitute for gas. While the use of electric appliances is not a new phenomenon, the main drivers of gas stranding risk are the increasing efficiency of these products relative to gas-fired appliances and the perception that these appliances can be supplied by renewable forms of energy (compared to 'fossil fuel gas').

33. The second aspect of stranding risk due to electrification is a shift to lower cost distributed electric generation, for example, through solar PV and batteries. The falling costs and increasing availability of rooftop solar panels, combined with increasing battery storage capacity, provides households and businesses with an alternative means of power supply. This provides the impetus to switch to electric powered appliances as an alternative to gas, exacerbating the above effects.

34. Battery storage is an important component of substitution to solar PV, as it allows electricity usage to be spread across time to periods of low sunshine. This is particularly the case when using solar for heating, although we note that for hot water heating, the hot water cylinder itself is a form of storage. As we show later in this report, the majority of gas usage on JGN's network is in respect in water heating, and therefore it may be the case that battery storage is less critical relative to gas networks where the main use is for space heating.

35. **Government policy** change around climate change is an interrelated stranding risk. It is related to electrification, because government policy regarding moving towards net zero carbon can encourage customers to switch to, for example, solar PV and electric appliances. For example, subsidies for solar installs or taxes/emissions trading schemes that raise the costs of gas usage may accelerate trends in electrification.

36. However, there is also a broader risk related to government policy, which is that stronger measures will be implemented which will more directly reduce gas demand. Specific examples are government subsidies directly targeted at replacing gas appliances with electric alternatives, mandates that seek to phase out gas usage, or government bans on new gas exploration. Such measures are likely to accelerate electrification and directly reduce gas connections, as gas users find that there is either insufficient supply of gas (likely coupled with higher prices) or that they are constrained in their demand for gas.

37. Stranding risk may also arise around **conversion to hydrogen**. In many ways, repurposing the existing gas pipeline network to shift to hydrogen mitigates the stranding risk associated with

electrification and decarbonisation policy, as it seeks to maintain customer demand while decarbonising gas usage. However, this may still result in some (physical and economic) stranding of existing gas assets, given many assets with current technology are not be suitable for hydrogen.[19] Moreover, conversion to hydrogen may require customers to replace their appliances, and in doing so there is a risk that they will electrify.

38. Indeed, given the inherent electrical inefficiency of producing green hydrogen,[20] compounded by the relative efficiency of heat pumps (as discussed earlier), there is a risk that demand for hydrogen does not materialise for the applications in question because direct electrification is cheaper. The National Hydrogen Strategy estimated that, by 2030, the breakeven price point for hydrogen to deliver the equivalent amount of heat as 1GJ of heat using natural gas is $1.20 per kg of hydrogen.[21] In comparison, the National Hydrogen Strategy estimates the cost of clean hydrogen to be in the range of $2-$3.25 per kg of hydrogen.[22] On these estimates, hydrogen is not cost-competitive with gas. Countering this, hydrogen is however much easier/cheaper to store than electricity.[23] The relative economics of electrification and green hydrogen are an area of significant uncertainty for gas networks. We return to this discussion in section 3.3 when we discuss the specific uses of gas by customers on the JGN network.

39. There is also the expectation that hydrogen will reduce the effective capacity of the network, thus reducing the volumes (i.e., energy rather than physical volume of gas) over which the network costs can be recovered. A recent JGN submission to AER notes:[24]

> *Hydrogen will require greater capacity and flows of gas. Blending hydrogen into the gas pipeline networks will reduce network storage and flowing capacity due to lower heating values and gas blend densities, possible gas quality variations into the network, and non-uniformity of higher heating value within the network. Although a gas network is used to transport a physical gas, commercial contracts and billing are calculated in energy content, rather than by volume or mass. GPA Engineering estimates that the magnitude of the capacity loss with a 10% hydrogen blend is on average estimated as approximately 2.4%. [GPA (2019), "Hydrogen in Gas Distribution Networks", p.35] Other things being equal, this can be expected to make JGN's gas transportation services more expensive in the future.*

40. Overall, this ultimately presents a risk that demand continues to fall despite a conversion to hydrogen, stranding not only the existing gas pipeline network, but also the sunk capital associated with the hydrogen conversion.

41. Consistent with this, we note recent modelling by CSIRO and ClimateWorks Australia on decarbonisation scenarios in Australia. While this work incorporated a scenario of hydrogen

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[19] JGN has previously noted that its high pressure mains are steel and may be affected by embrittlement if exposed to hydrogen. See JGM (2020), *Revised 2020-25 Access Arrangement Proposal: Attachment 8.2 Response to the AER's draft decision – proposed changes to asset lives for new investments*, January 2020.

[20] A report prepared by the International Energy Agency (IEA) states that the efficiency of existing electrolyser systems used to extract hydrogen from water ranges between 60% and 81%, depending on the technology type and load factor. It further notes that producing all of the current hydrogen output from electricity demand would result in electricity demand that exceeds the total annual electricity generation of the European Union. IEA (2019), *The Future of Hydrogen: Seizing today's opportunities*, Report prepared by the IEA for the G20, Japan, 2019, pg.43.

[21] COAG Energy Council (2019), *Australia's National Hydrogen Strategy*, pg.xiv.

[22] COAG Energy Council (2019), *Australia's National Hydrogen Strategy*, pg.6.

[23]See IEA (2019), *The Future of Hydrogen: Seizing today's opportunitie*s, Report prepared by the IEA for the G20, Japan, 2019, pg.158-159, explaining that hydrogen storage can provide much more storage than comparable battery storage, and that "compressed hydrogen storage becomes the most economic storage option [compared to e.g., battery and pumped-hydro storage] at discharge durations longer than 20-45 hours".

[24] See JGN (2020), *Revised 2020-25 Access Arrangement Proposal: Attachment 8.2 Response to the AER's draft decision – proposed changes to asset lives for new investments*, January 2020, pg.15.

blended in to gas pipelines, it also includes two scenarios in which “the residential consumption of gas (natural gas or hydrogen) is entirely displaced [by electricity] by 2050”.[25]

42. In summary, trends towards electrification and decarbonization could result in a significant reduction in demand for the gas network, with the resultant risk of widespread stranding of gas network assets. While a conversion to hydrogen somewhat mitigates this risk, converting the network to hydrogen may itself:

    a. strand assets not suitable for transporting hydrogen, such as high pressure mains;

    b. result in a reduction in effective demand due to the lower energy content of hydrogen vs natural gas; and

    c. not mitigate substitution to electrification if hydrogen ends up being more expensive, which would result in the stranding of both existing assets and any investments made to convert to the network.

43. Thus it would be inappropriate to make blanket assumptions that gas networks are not subject to stranding risk. Rather, what is required is a reasoned analysis of the nature of the above risks.

3.2. Stranding risk in gas *may* have a systematic component

44. As noted earlier, the AER considers that stranding risks for gas pipelines are not systematic in nature, and therefore should not be accounted for in the equity beta or regulated rate of return.[26]

45. We note that the New Zealand Commerce Commission (NZCC) came to a differing view in respect of its 2016 review of the cost of capital for gas pipeline businesses (GPBs)[27] and has restated this view in the recently released Issues Paper for the upcoming reset of default price-quality paths for GPBs. As the following quotes from the NZCC illustrate, it found that most stranding risks for gas pipeline businesses were non-systematic, but there did remain some partly systematic stranding risk:[28]

    > *Our current view is that most economic network stranding risks for GPBs are likely to be non-systematic in nature, and not relevant to the 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 industry.*
    >
    > *However, given the relatively low penetration of gas infrastructure in New Zealand, economic network stranding risk may be partly systematic. 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.*

46. The NZCC’s point on low penetration relates to the ‘death spiral’ argument discussed earlier. Given that penetration was considered to be relatively low in New Zealand (relative to electricity penetration), the NZCC’s view was that this placed gas suppliers closer to the ‘tipping point’ at which a small loss of customers leads to the remaining customers being unwilling to pay for the remaining average network costs.[29]

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[25] CSIRO and ClimateWorks Australia (2021), *Multi-sector energy modelling*, July 2021, pg.52.

[26] The ERA reached a similar conclusion in its last rate of return instrument review. See para.290 & 292 of ERA (2018), *Final Gas Rate of Return Guidelines Explanatory Statement*, 18 December 2018.

[27] NZCC (2016), *Input methodologies review decisions: Topic paper 4: Cost of capital issue*s, 20 December 2016, para.433.

[28] NZCC (2021), *Resetting default price-quality paths for gas pipeline businesses from 1 October 2022, Process and Issues Paper*, 4 August 2021, para.D23-24.

[29] NZCC (2021), *Resetting default price-quality paths for gas pipeline businesses from 1 October 2022, Process and Issues Paper*, 4 August 2021, para.D9.3.

47. In respect of the NZCC's earlier process for specifying Input Methodologies for gas pipelines, Dr. Martin Lally noted that stranding risk for gas pipeline businesses is "partly systematic" (albeit that there was insufficient empirical evidence to warrant the WACC uplift being proposed to reflect this). Dr Lally states:[30]

> *Thirdly, Oxera (2016, section 3.3.2) argues that stranding risk is greater for regulated gas businesses than regulated electricity businesses in New Zealand, because the viability of the businesses rests on increasing the customer base, adverse GDP shocks may curtail such growth and even induce some gas customers to disconnect and switch to electricity, thereby raising prices in accordance with the regulatory process, leading to further loss of customers, and eventually to stranding. Since such stranding risk is partly systematic, the betas of regulated gas businesses must be higher than regulated electricity businesses. I agree with this reasoning but nothing in it implies that the beta increment for gas businesses is sufficiently large to warrant an uplift of 0.10. The ultimate arbiter here is empirical evidence on betas, there are too few New Zealand businesses to supply such evidence, and foreign beta estimates do not support such an increment (possibly because they are drawn from markets in which some relevant features of the markets differ from those in New Zealand).*

48. Moreover, there may also be an argument that risks related to government policy on climate change are systematic. In this regard, the International Energy Agency (2007, pg.97) states:[31]

> *On the one hand, climate change policy uncertainty might be considered diversifiable, since there will be winners as well as losers arising from unexpected changes in climate policy. On the other hand, given the basic nature of energy consumption to the economy, climate change policy may be fundamental enough to affect the market as a whole, and may therefore be considered a systematic risk.*

49. Indeed, for stranding risk to be diversifiable, it must be that there is an associated upside for an investor to diversify into, to counteract the downside of reduced gas demand. If this reduction in demand was purely a matter of substitution from gas to electricity, then there would be a valid diversification strategy, for example, in respect of solar or battery technologies. However, it may also be that some existing gas customers 'exit the market', by reducing their gas consumption, without any one-for-one increase in electricity consumption. As well as undermining the ability for investors to hold a diversified portfolio, a reduction in overall energy consumption may have knock on effects in respect of economic activity. As a result, there may be a greater systematic component to gas stranding risk than has been acknowledged by the AER.

50. A related point was made by the NZCC in respect of its recent decision on Input Methodologies for fibre telecommunications services. In its decision, the NZCC could not rule out there being a small systematic component to stranding risk, "when the drivers for stranding risk have some correlation with the overall market".[32] The NZCC gives the example of fibre demand being correlated to the overall market and wider economy, but noted that it had not seen evidence of this dynamic. However, it may be that this correlation is considerably stronger in respect of the factors driving stranding risk for gas pipelines.

51. While other regulators for whom it is common to benchmark frameworks against have not agreed that stranding risk is systematic,[33] this may in part be a factual issue related to penetration of the gas network. In the UK, a recent 'provisional determination' by the Competition and Markets Authority (CMA) found that the Gas and Electricity Markets Authority (GEMA) had not made an error in failing to allow for an uplift for stranding risk for electricity and gas businesses.[34] The CMA decision relates to an appeal by various electricity and gas businesses of GEMA's price

[30] Martin Lally (2016), *Review of Further WACC Submissions*, report to the NZCC, 23 November 2016.

[31] International Energy Agency (2007), *Climate Policy Uncertainty and Investment Risk*, 2017.

[32] NZCC (2020), *Fibre input methodologies: Main final decisions – reasons paper*, 13 October 2020, para.6.1038.

[33] See Section 5 of this report.

[34] CMA (2021), *RIIO-2 Energy Licence Modification Appeals: Summary of provisional determination*, 11 August 2021.

control determination. The appellants argued that GEMA had set the cost of equity too low and failed to "aim up" (essentially, apply an uplift), but the CMA found that the appellants offered no compelling evidence that such aiming up was required.

52. The UK can be distinguished on the basis that over 80% of households are connected to the gas network.[35] Therefore, given the systematic component for stranding risk relates to gas networks having low penetration, the situation in the UK is factually distinguishable from the NZCC's findings. We understand this high penetration is driven by the fact that natural gas is the primary form of space heating in the UK.[36] As a result, domestic gas usage dwarfs electricity usage in the UK. For example, in 2019 average household consumption of electricity was 3,731 kWh compared to 11,526 kWh (approximately 41GJ) for gas.[37] That is, household gas consumption is 309% of electricity consumption.

3.3. Stranding risk for JGN in NSW

53. We discuss in this section the stranding risk for JGN's gas network in NSW, particularly given the nature of its demand base and the risk around reductions in that demand base.

54. On a consumption basis, aggregate residential gas consumption in 2018-19 was approximately 28PJ, relative to electricity consumption of 78PJ, or 35%.[38] This is a stark contrast to the figure of 309% for the UK described in the previous section.

55. Figure 2 and Figure 3 show demand for gas on the JGN network and customer connections respectively, across residential, commercial and industrial users. Overall demand has been relatively static, although by user type residential demand has been increasing, commercial static, and industrial falling. Customer connections have been increasing for both residential and commercial, while connections have fallen slightly for industrial (the small number of industrial connections makes this difficult to see in Figure 3).

56. Figure 2 and Figure 3 show that the majority of connections on the JGN network are residential and the majority of gas usage/demand is industrial. While residential and commercial make up a relatively smaller proportion of JGN's demand (e.g., in 2019-20, 31% of demand is residential, 14% is commercial and 55% is industrial), these user types make up a large share of JGN's customer connections and revenue. From Figure 3, residential customers make up approximately 97% of total connections in 2019-20. In Figure 4 we show JGN's annual revenue for residential and commercial combined and industrial. In 2019-20, for example, industrial makes up only around 9% of JGN's revenue.

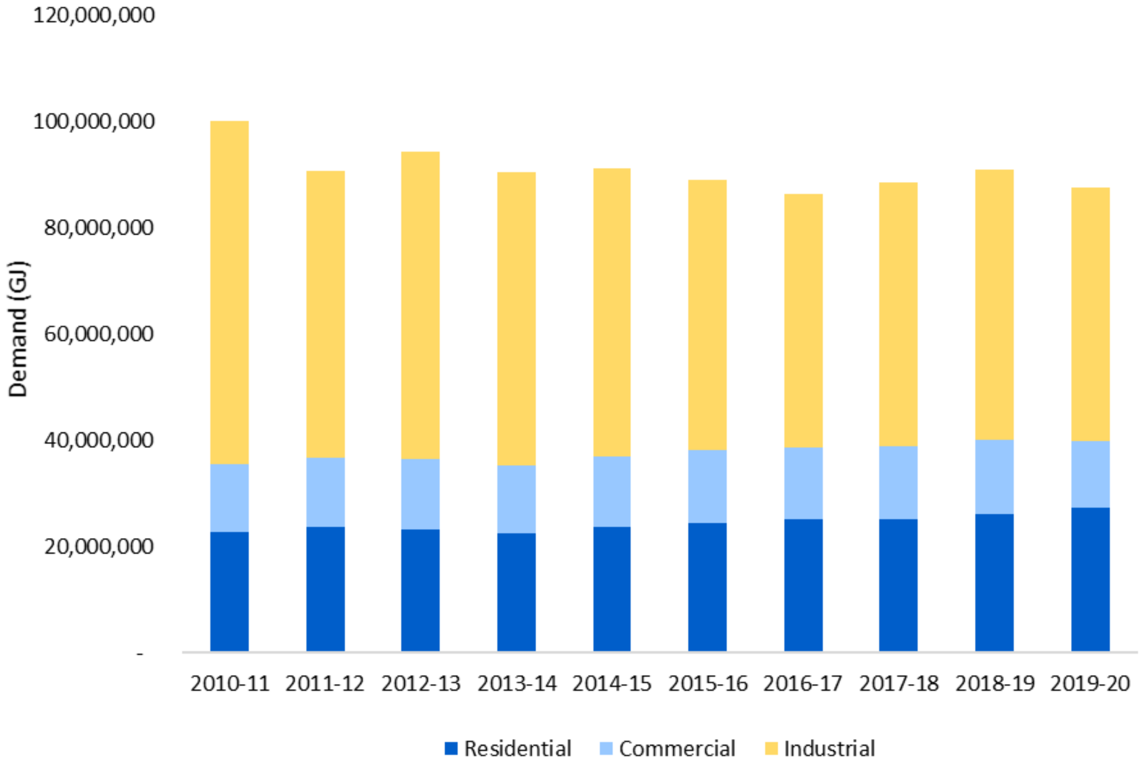
[35] Approximately 81% of households in the UK are connected to the gas network. This is estimated as the number of domestic gas meters divided by the number of households, based on data available at https://www.gov.uk/government/statistics/lsoa-estimates-of-households-not-connected-to-the-gas-network. We note the caveat that in using these data, aggregation at the country-level may not be appropriate because "in some output areas the application of disclosure control means that the number of households not connected to the gas grid is under reported". This number should therefore be taken as an approximation only. We note that the NZCC has reported data showing 86% of UK households have gas connections, which is a similar order of magnitude (NZCC (2016), *Input methodologies review decisions: Topic paper 4: Cost of capital issues*, 20 December 2016, para.418.2).

[36] See, e.g., UK Department of Energy and Climate Change (2014), *Special feature – Estimates of heat use in the UK*, December 2014. Table 2 shows that 79% of domestic consumption for heat was natural gas.

[37] Department for Business, Energy, and Industrial Strategy, *Energy Consumption in the UK*, data available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/928354/2020_consumption_tables_-_web_copy.xlsx

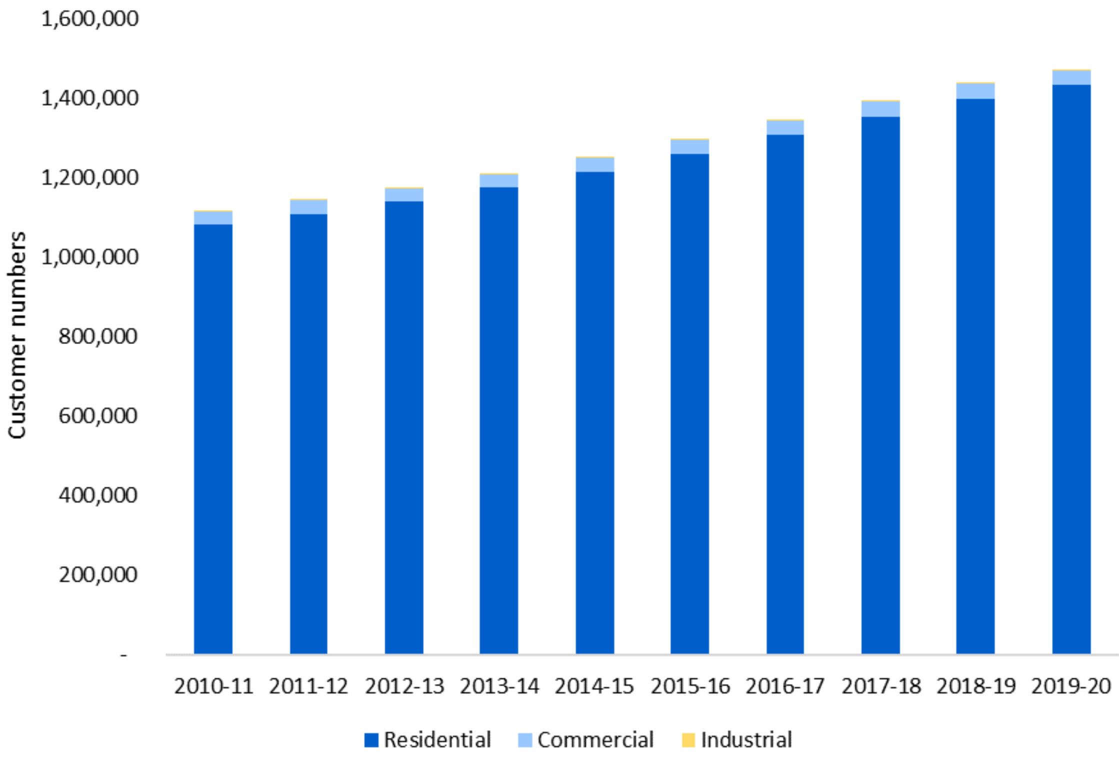
[38] Australian Energy Statistics, Table F2, Energy consumption in NSW, by industry and fuel type.

Figure 2: JGN demand by customer type, 2011-2020



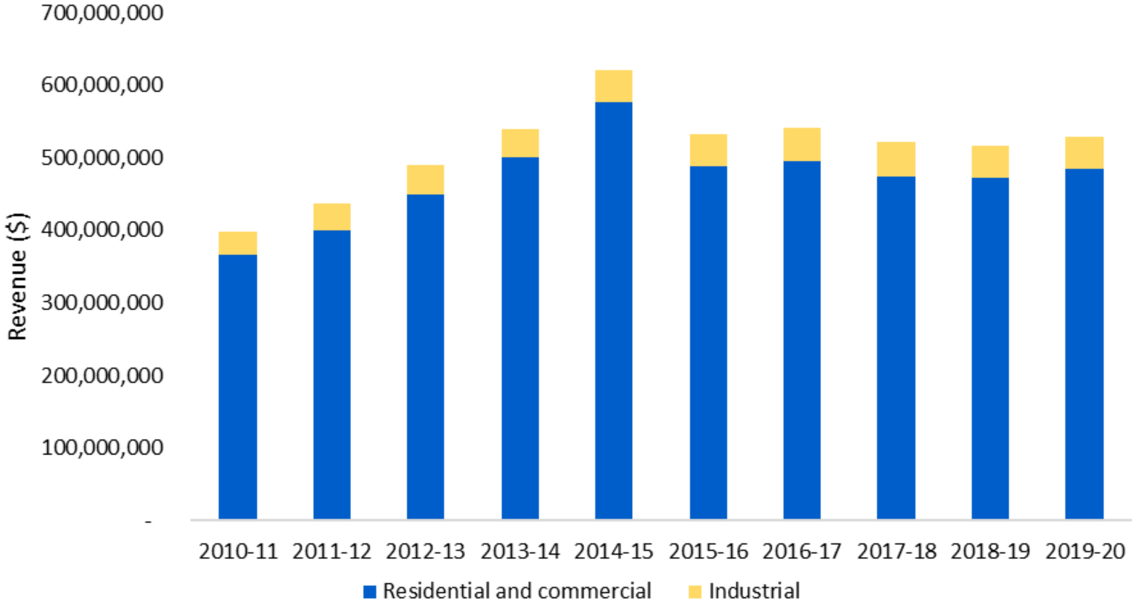
Source: NERA analysis of data provided by JGN

Figure 3: JGN customer numbers by customer type, 2011-2020



Source: NERA analysis of data provided by JGN

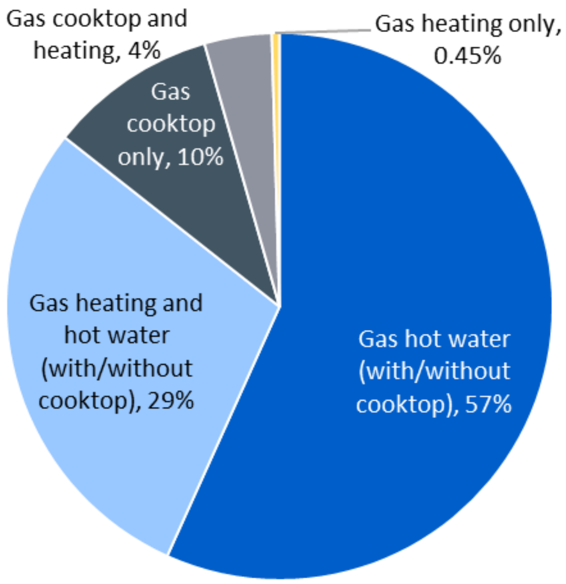
Figure 4: JGN revenue by customer type, 2011-2020



Source: NERA analysis of data provided by JGN

57. The above analysis shows that JGN is particularly exposed to residential customers switching to alternatives to gas. This may heighten the risk that JGN's network is stranded as electrification of residential use is likely to be more straightforward than industrial usage.[39] In this regard, JGN has also provided us with estimates of the use of gas by a sample of its residential customers. As shown in Figure 5, across this sample, the supply of gas is predominately for the use in gas hot water systems, with 57% of households estimated to be using gas for gas hot water only, and another 29% for gas heating combined with hot water.

Figure 5: Residential gas usage on JGN



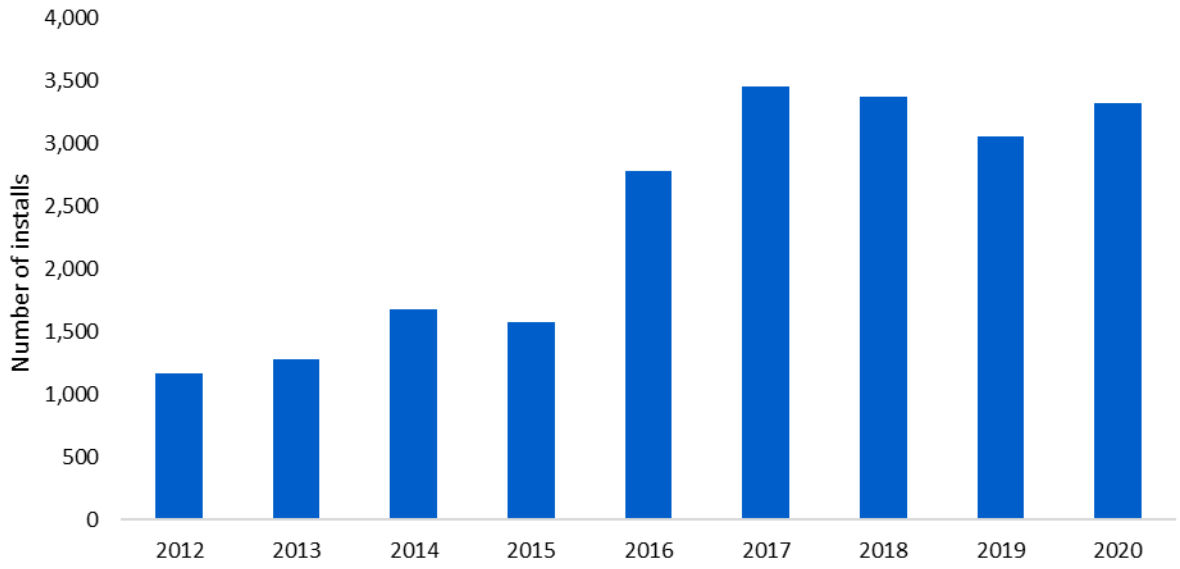
Source: NERA analysis of data provided by JGN from a sample of JGN's Sydney customers

[39] Kathryne Cleary (2019), *Electrification 101: An overview of how electrification can reduce emissions, from the feasibility of electrifying different technologies to the policy options for encouraging economy-wide electrification*, Resources for the Future, December 2019, pg.4. Available at: https://media.rff.org/documents/Electrification_Explainer_101_odobEoP.pdf

58. Gas hot water systems in residential dwellings are likely to be prone to stranding, due to a risk of substitution to heat pump electric hot water systems and solar hot water systems. Heat pump hot water systems will be particularly relevant for detached dwellings, which are more likely to have sufficient outdoor space to place the heat pump storage tank. We understand from JGN that approximately 75% of JGN's residential customers are in detached dwellings.

59. There has been strong growth in installations of heat pump hot water systems in NSW as shown in Figure 6, plotting data from CSIRO, based on the Clean Energy Regulator's Small-scale Renewable Energy Scheme, showing heat pump hot water installs for NSW from 2012 to 2020.

Figure 6: NSW heat pump hot water installs, 2012-2020



Source: NERA analysis of CSIRO data.

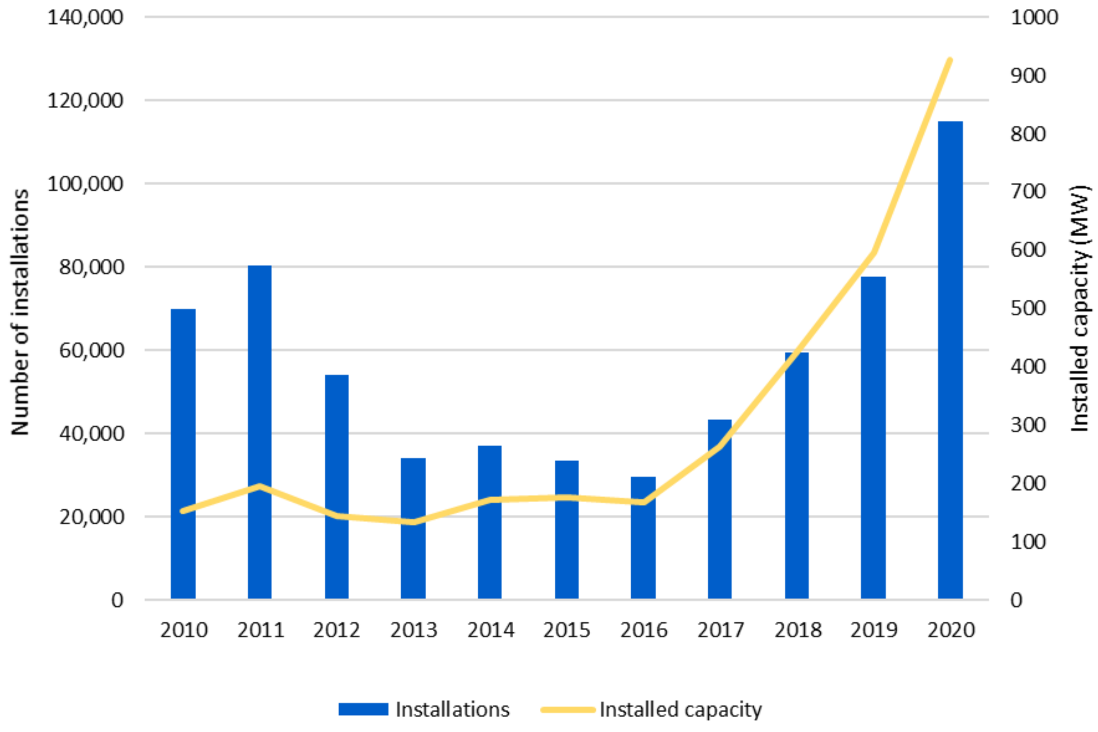
60. Hot water heating is likely to be particularly suitable for substitution to electric heating using excess roof top solar, given that excess solar generation generally occurs in the middle of the day. A timed hot water heater could use excess generation during the day and store it as hot water for use later. In this regard, we note there is evidence of an increasing trend of roof top solar PV installations in New South Wales. Figure 7 shows solar installations and installed capacity for NSW, based on Clean Energy Regulator data on installs of small-scale (rooftop) solar capacity.

61. We also illustrate, in Figure 8, the solar penetration rate – that is, the total number of solar installations, as a proportion of the estimated number of households in NSW. We estimate solar installations by determining the cumulative installations in each year using the data underlying Figure 7. We divide solar installations by the estimated number of households in NSW, based on ABS household projections, which are available from 2016 onwards.[40] Figure 8 shows that the solar penetration rate in NSW has been increasing over the 2016-2020 period, from 12% to 20%. This solar penetration is projected to continue to increase: CSIRO has forecast that, in 2050, the share of households with rooftop solar PV in NSW will range from a minimum of 35% to a maximum of 48%, depending on the modelled growth scenario.[41] In this regard. AEMO's scenario forecasts for the recently released ESSO also reflect substantial increases in rooftop PV, as shown in Figure 9.

[40] The data are sourced from ABS.Stat, "Projected households, Australia, 2016-2041", and we use the "Series I" projection assumption. The results are not materially different if we were to use the "Series II" or "Series III" projections also reported by ABS.

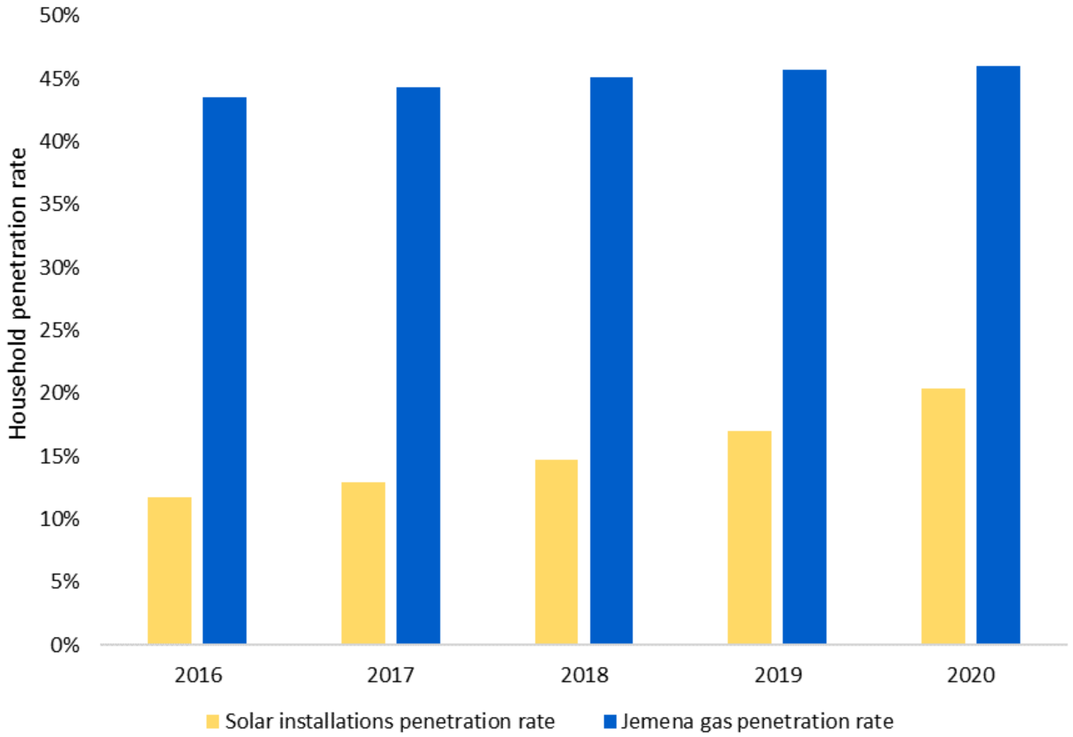
[41] Paul Graham (2021), *Small-scale solar and battery projections 2021*, May 2021, CSIRO, pg.48.

Figure 7: NSW solar installations and installed capacity, 2010-2020



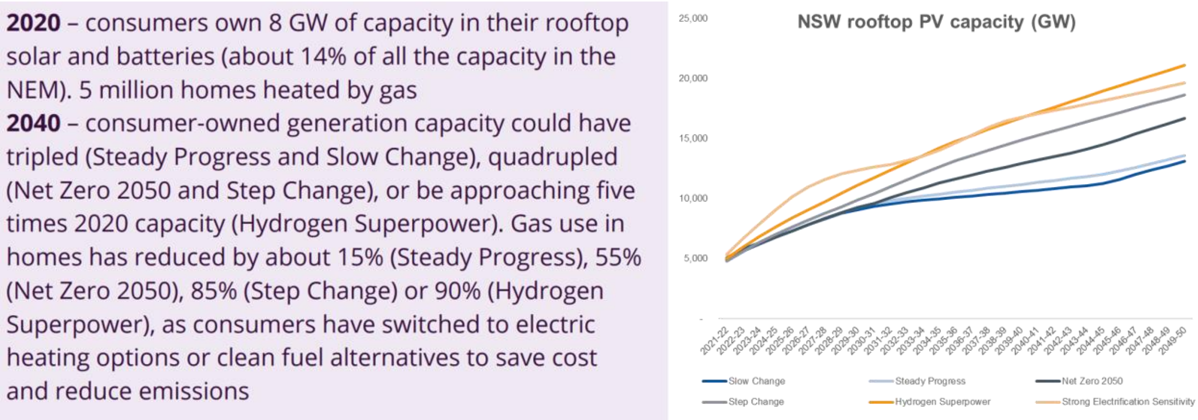
Source: NERA analysis of CER data.

Figure 8: Solar and gas penetration rate in NSW, 2016-2020



Source: NERA analysis based on CER, JGN and ABS data

Figure 9: AEMO rooftop PV forecasts in NSW



Source: AEMO 2021 Inputs, Assumptions and Scenarios workbook and 2021 Inputs, Assumptions and Scenarios Report Overview

62. As discussed earlier, the risk of government policy changes in relation to climate change has the potential to accelerate the electrification changes discussed earlier, and this can also affect stranding risk for JGN in particular. This risk applies generally in respect of climate targets: for example, under the Paris Agreement, the federal government has committed to reduce greenhouse gas emissions by 26-28% below 2005 levels by 2030;[42] and the NSW state government has its own emissions target of net zero emissions by 2050.[43] However, it also applies to policies that more directly reduce gas consumption. A pertinent example is given by the ACT government's proposal to remove mandatory gas connections in new housing developments.

63. In Table 1 we summarise the different climate policies at federal and state level that directly risk altering residential gas usage, along with policies around solar/battery subsidies which may encourage the uptake of these substitute technologies. While we note that it is only NSW state policies that are relevant to JGN, part of the purpose of this table is to illustrate climate policies elsewhere, as an indication on the nature of potential policy that risks affecting JGN's network.

[42] See: *Climate change – reducing Australia's emissions,* Emily Hanna, Parliamentary Briefing Book – Key issues for the 45th Parliament, Parliament of Australia, 2016. Available at: https://www.aph.gov.au/About_Parliament/Parliamentary_Departments/Parliamentary_Library/pubs/BriefingBook45p/EmissionsReduction

[43] NSW Government (2016), *NSW Climate Change Policy Framework*, November 2016, pg.1. Available at https://www.environment.nsw.gov.au/topics/climate-change/policy-framework#:~:text=The%20NSW%20Government%20is%20committed,resilient%20to%20a%20changing%20climate.

Table 1: Summary of federal, state and local climate and solar policies

	Climate policy that risks altering residential gas usage	Rebates/subsidies for rooftop solar installations and/or batteries
Federal	National Hydrogen Strategy investigating how to blend hydrogen into the existing gas supply, and upgrade the gas network and replace appliances such that 100% hydrogen could be used.[44]	Small-scale renewable energy scheme in which every kilowatt of panels installed creates certificates which the owner can sell to electricity retailers.[45]
NSW	Exploring injection of hydrogen into natural gas lines.[46]	Empowering Homes program, which will provide interest-free loans for solar-battery systems to eligible owner-occupier NSW households.[47]
ACT	Climate Change Strategy to 2025 has key priority to encourage a shift from gas to electricity by removing mandated requirement for gas connections in new suburbs, supporting gas to electric appliance upgrades and encouraging new-builds to be all electric.[48]	Sustainable Household Scheme provides zero-interest loans for eligible households to invest in energy efficient home upgrades, including rooftop solar panels and household battery storage systems.[49]
SA	Exploring injection of hydrogen into natural gas lines.[50]	Home Battery Scheme providing subsidies and low-interest loans for home battery system installations.[51]
WA	Exploring injection of hydrogen into natural gas lines.[52]	No specific policies.
QLD	No specific policies.	Recently ended solar scheme which offered interest free solar and storage loans.[53]
NT	No specific policies.	Home and Business Battery Scheme that provides grants for installing home battery systems.[54]
TAS	No specific policies.	No specific policies.

[44] COAG Energy Council (2019), *Australia's National Hydrogen Strategy*, 2019, pg.42.

[45] Clean Energy Regulator (2018), *Small-scale Renewable Energy Scheme*, 31 May 2018. Available at: http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/How-the-scheme-works/Small-scale-Renewable-Energy-Scheme.

[46] NSW Government (2020), *Net Zero Plan – Stage 1: 2020-2030*, Department of Planning, Industry and Environment, March 2020, pg.30. Available at: https://www.environment.nsw.gov.au/-/media/OEH/Corporate-Site/Documents/Climate-change/net-zero-plan-2020-2030-200057.pdf

[47] NSW Government, *Empowering Homes solar battery loan offer*. Available at: https://energy.nsw.gov.au/renewables/clean-energy-initiatives/empowering-homes.

[48] ACT Government, *ACT Climate Change Strategy 2019-25*, 2019, pg.37 & pg.66.

[49] *Sustainable Household Scheme*, ACT Government. Available at https://www.actsmart.act.gov.au/what-can-i-do/homes/sustainable-household-scheme.

[50] *Climate Smart South Australia – South Australia's greenhouse gas emissions*, Government of South Australia. Available at: https://www.environment.sa.gov.au/topics/climate-change/south-australias-greenhouse-gas-emissions

[51] *About the scheme*, Home Battery Scheme, Government of South Australia. Available at: https://www.homebatteryscheme.sa.gov.au/about-the-scheme.

[52] Government of Western Australia (2020), *Western Australia Climate Policy: A plan to position Western Australia for a prosperous and resilient low-carbon future*, November 2020, pg.15. Available at: https://www.wa.gov.au/sites/default/files/2020-12/Western_Australian_Climate_Policy.pdf

[53] Information no longer available on Queensland Government site. See, *Queensland Solar And Battery Grants/Loans Update*, SolarQuotes blog, 8 February 2019. Available at https://www.solarquotes.com.au/blog/qld-solar-battery-grants-mb0931/.

[54] *Home and Business Battery Scheme*, Northern Territory Government. Available at: https://nt.gov.au/industry/business-grants-funding/home-and-business-battery-scheme

64. Table 1 also does not capture policies at the local level, such as:

    a. **Sydney:** The City of Sydney, in its environmental strategy, aims to phase out natural gas from City operations by electrifying gas-using assets;[55]

    b. **City of Yarra:** Yarra City Council has pledged all Council buildings to be 100% electric with no use of gas by 2030,[56] and wants the state government to back a ban on gas connections in new homes. While the City of Yarra is in Melbourne, Victoria, so not directly relevant to JGN's network, this does illustrate the sort of climate policies that are implemented at the local level elsewhere;[57]

    c. **Canterbury Bankstown:** Bankstown Council have released a draft master plan for the future of Bankstown City Centre with aims to be powered by 100% renewable resources by 2050, including implementing mandatory sustainability measures for all new buildings. This includes all-electric buildings for new buildings, except where non-electric energy sources (such as gas) can be demonstrated to be required for a service;[58] and

    d. **Waverley Council:** The Waverly Council resolved in December 2020 to transition away from gas power, such that no new gas appliances or fittings on Council assets are to be installed, and where possible, phase out current gas fittings and appliances leading up to 2030.[59]

65. International examples also highlight the risk of policy changes that risk stranding gas assets. In New Zealand, in 2018 the government introduced a ban on new oil and gas exploration. The policy change was also relatively sudden, in a policy sense. For example, it was viewed, by the Parliamentary Commissioner for the Environment as one in which "limited analysis was offered and the stakeholder consultation process was truncated".[60] In advice to government, the Climate Change Commission has recommended a ban on new gas connections from 2030, to provide for a "complete transition away from fossil gas use in buildings by 2050".[61]

66. Similarly in California, over 40 cities and counties have either tightened rules on natural gas use in homes or, such as in San Francisco, banned it altogether.[62]

67. What these examples show is that there is a material risk of similar local, state or federal government policy changes that accelerate stranding of JGN's gas network.

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[55] City of Sydney, *Environmental Strategy 2021 – 2025*, July 2021, pg 27.

[56] Yarra City Council (2020), *Yarra Climate Emergency Plan*, 2 June 2020, pg.1.

[57] *Push to turn off gas to help reach state's climate goal*, Tom Cowie & Nick O'Malley, The Age, 5 May 2021. Available at: https://www.theage.com.au/national/victoria/push-to-turn-off-gas-to-help-reach-state-s-climate-goal-20210504-p57oof.html

[58] Canterbury Bankstown (2021), *Bankstown City Centre Master Plan*, March 2021, pg.99.

[59] Waverley Council, *Council Meeting*, 20 July 2021, pg.162-163.

[60] Parliamentary Commissioner for the Environment (2020), *Restricting the production of fossil fuels in Aotearoa New Zealand: A note on the ban on new petroleum permits outside onshore Taranaki*, March 2020.

[61] Climate Change Commission (2021), *Ināia tonu nei: a low emissions future for Aotearoa*, 31 May, pg.111.

[62] *California is closing the door to gas in new homes*, Anne C. Mulkern, Scientific America, 4 January 2021. Available at: https://www.scientificamerican.com/article/california-is-closing-the-door-to-gas-in-new-homes/

4. Toolkit for dealing with stranding risk

68. Having set out in the previous sections that stranding risk is an issue for gas networks and for JGN in particular, in this section we discuss the regulatory toolkit for addressing stranding risk.

4.1. High level overview of available tools

69. In workably competitive markets, firms that face stranding risk will seek to manage those risks so as to provide an expectation of a normal return on capital invested. For example, competitive firms may require a price premium that is sufficient to reflect the risk of asset stranding. For regulated firms, there are a number of tools that seek to mimic competitive market outcomes and address stranding risk in a way that provides the regulated firm with a normal return on its capital.

70. In broad terms, there are three ways in which asset stranding risk can be addressed for the regulated firm:

 a. **Front loading recovery,** which essentially amounts to attempting to remove or minimise stranding risk, by allowing the regulated firm to recover all of its capital investment prior to when stranding would otherwise occur;

 b. ***Ex ante* compensation**, which allows the risk of stranding to remain, but provides compensation for this risk to the regulated business on a forward looking/expectations basis. That is, the compensation would be set at a level such that firms *expect* to recover their capital, but firms are still exposed to the risk that the future is different from what was expected (for example, if technological change occurs faster than expected); and

 c. ***Ex post* compensation**, which is essentially a regulatory promise that if stranding occurs, the firm will still be able to recover the costs of the stranded cost after the fact.

4.2. Front loading recovery

4.2.1. Methods of front loading recovery

71. Front loading recovery can be achieved by using an **accelerated depreciation** profile or **shortening asset lives** used in the depreciation calculation. Both of these approaches have the effect of bringing forward the revenue that is recovered by the regulated firm to earlier in the lifetime of the assets, so that the firm earns more revenue earlier (and less later).

72. The two approaches are, however, subtly different in what they are attempting to achieve. Shortening asset lives is a method of trying to ***prevent stranding from occurring***. For example, if a regulator believed that in 10 years most gas appliances will be due for replacement and this is the point at which substitution to electricity would occur, it could set the remaining life of the gas network for regulatory depreciation purposes equal to 10 years. The value of the gas network would thus be recovered prior to the point stranding is likely to occur.

73. Using this same example, we can illustrate that front loading depreciation is in some sense a way of ***minimizing the value of the asset that is stranded.*** Using the same example whereby mass substitution away from gas is expected to occur in 10 years, if the asset has a technical remaining life of say, 15 years, it is exposed to the risk that it will not be able to recover one third of its capital. Accelerated depreciation could be used to concentrate the capital recovery in the first 10 years, but would still leave some recovery for the last 5 years. This still leaves, on an expectations basis, some capital at risk of stranding, as some capital recovery is still required to occur at the back end of the assets life.

74. To put this another way, front loading recovery (either though shortening asset lives or accelerating depreciation) is a form of risk *mitigation*, not a form of *compensation*.

75. There are a number of methods which can be used to calculate an accelerated depreciation schedule, examples of which include:

   a. **Sum-of-year digits depreciation** adds up all the years in the assets expected life (i.e., for a five year asset would be 1 + 2 + 3 + 4 + 5 = 15), and then calculates the depreciation rate for each year by dividing the remaining life at the start of the period by the sum of all years (i.e., year two for the five year asset would be 4/15 = 27%);

   b. **Double declining balance** depreciation uses a depreciation rate double that of straight-line depreciation, so that the asset depreciates twice as fast as with straight-line;

   c. **Tilted annuity** payment calculates the combined return on (i.e., rate of return) and of (i.e., depreciation) as a single cashflow with an NPV equal to the initial investment. This cashflow can either be constant or a have a growth rate (known as the tilt). This allows for NPV neutral reprofiling of capital recovery;[63]

   d. **Diminishing value** depreciation uses a depreciation rate that is a constant percentage of the asset's depreciated value, so that when the asset has a higher value (in the early years of its life), there is higher depreciation (in dollar terms) than when the asset is of lower value (in the latter years of its life);

   e. **Hybrid approaches,** which combine non-linear accelerated depreciation (e.g. diminishing value) early in the asset's life and straight-line depreciation later in the asset's life; and

   f. The **WOOPs framework** described above. In addition to illustrating that there is a point of no return, it also sets out a methodology for estimating the amount of depreciation that can be front loaded while still maintaining *ex ante* NPV=0.[64]

76. Accelerated depreciation and shortening asset lives are also complementary mechanisms that can be combined. For example, there is unlikely to be certainty about the precise point in the future in which stranding will occur, so it might be considered desirable to combine shortened assets lives with a form of accelerated depreciation.

77. Under the current regulatory framework, the RAB is indexed for inflation.[65] An alternative approach for front loading recovery is to not index the RAB. Indexing the RAB is the capital gain portion of the regulated return which offsets the depreciation charge i.e., the net depreciation per year is lower in early years because of this offsetting capital gain. Therefore, not indexing the RAB results in higher depreciation in earlier years, in much the same way as is provided for by an accelerated depreciation profile.

78. These approaches only alter the time path of revenue recovery (and therefore prices), but not the revenue recovery itself. That is, the revenue profile is spread out over the life of the asset in such a way as to retain the same net present value as an alternative revenue profile.

79. However, the downside of these front loading recovery approaches is that they rely on recovery occurring before a stranding event happens. As such, timing is crucial, and there is a risk that there will be insufficient recovery if stranding occurs earlier than expected. The WOOPS framework referred to earlier provides a way of determining this critical point in time. That is, the point at which sufficient depreciation can no longer be brought forward to cover the cost of the asset.

[63] The tilted annuity approach has been used in telecommunication with a negative tilt to recognize technology costs will fall over time and thus so should regulated prices. This has the effect of front loading recovery in that prices start higher but then fall over time.

[64] Essentially, the WOOPs framework provides a method for calculating the blue shaded area in Figure 1 (b) above, while also ensuring that the combination of regulated and deregulated prices still results in *ex ante* NPV=0.

[65] AER (2020), *Regulatory treatment of inflation: Final position*, December 2020, pg.11.

4.2.2. Efficiency/fairness concerns with front loading

80. One concern that can be raised in respect of front loading recovery is that it results in cross-subsidisation between customers, in the sense that current customers pay more while future customers pay less. For example, in rejecting JGN's proposal to shorten its asset lives, the AER argued:[66]

> *JGN's proposed reduction to the standard asset lives, based on the evidence provided, is likely to result in **network tariffs being set above the efficient cost** for providing reference tariffs in the access arrangement period [emphasis added]*

81. While 'cross-subsidy' is often used to describe 'different prices', economists define subsidy-free prices as falling between incremental cost and stand-alone cost.[67] In the present context where we are considering the efficiency of prices *over time*:

    a. **Incremental cost** is the marginal cost of using a pipeline in a given year, assuming pipeline transportation is already provided in other years; and

    b. **Stand-alone cost** is the marginal cost of using a pipeline assuming in a given year, assuming that transportation is not provided in any other year.

82. Therefore, provided prices are set to any generation of customers inside the range of incremental cost and stand-alone cost, then there is no cross-subsidy. Note that given the nature of the cost structure for pipelines, the range between standalone and incremental cost is very large, as 'standalone costs' involves recovering the entire pipeline cost in a single year.

83. A related point is made by Schmalensee (1989), who establishes an 'Invariance Proposition', showing that, provided regulators set the allowed return on capital equal to the regulated firm's actual cost of capital, then any depreciation approach is fair to consumers:[68]

> *…the Proposition indicates that depreciation policy can be altered to produce more efficient rates without being unfair in a present value sense to utilities or their customers.*

84. It is thus not clear how front loading recovery can result in prices being above the efficient costs when it is done in an NPV=0 manner. Instead, the concern is ultimately one of fairness.

85. A fairness issue with not front loading is essentially the opposite concern to that typically set out by regulators – by delaying recovery of the assets, this could disproportionately fall on a smaller subset of consumers who do not have alternatives to gas.

4.3. *Ex ante* compensation

86. Turning now to compensation for stranding risk, *ex ante* compensation allows the regulated firm to recover revenues upfront, regardless of whether or not stranding occurs. This allocates the risk of asset stranding to the regulated firm, on the basis of a belief that it is better able to manage that risk than consumers,[69] and reduces the risk of price shocks to consumers if stranding did occur. On the other hand, consumers pay higher prices overall if stranding does not occur, compared to front loading approaches where consumers pay a higher price upfront but a lower price later.

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[66] AER (2020), *JGN access arrangement 2020-25 – Attachment 4 – Regulatory depreciation*, June 2020, pg.9.

[67] See Gerald R. Faulhaber (1975), "Cross-Subsidization: Pricing in Public Enterprises", *American Economic Review*, 65(5), 966-977.

[68] Richard Schmalensee (1989), "An Expository Note on Depreciation and Profitability Under Rate-of-Return Regulation", *Journal of Regulatory Economics*, 1, 293-298.

[69] See, e.g., Lewis T. Evans and Graeme A. Guthrie (2003), "Asset Stranding is Inevitable: Implications for Optimal Regulatory Design", Working Paper, New Zealand Institute for the Study of Competition and Regulation, pg.3.

87. The most common approach to *ex ante* compensation is to add a premium to the WACC, to compensate firms for the expected cost of stranding. In a regulatory framework, the WACC is intended to compensate for systematic risk, and therefore a WACC premium would, at least in theory, not be appropriate if the intention is only to compensate for non-systematic stranding risk. However, in practice (as we illustrate in the next section), regulators often provide compensation for non-systematic stranding (and other) risks through a WACC premium out of convenience.

88. A similar approach is to provide *ex ante* compensation via an explicit adjustment to the regulated firm's cash flows, rather than via the WACC. The NZCC has recently proposed such an approach in respect of the regulatory framework for fibre telecommunications services. The NZCC describes the approach as one which:[70]

> *…examines the probability adjusted cash flows of the business and calculates the additional cash flow which provides the expectation of a normal return and provides for* ex-ante *NPV neutrality.*

89. In principle, this is conceptually similar to compensation via a WACC premium, however as the NZCC states:[71]

> *Including the adjustment in the WACC may lead interested persons to think that we are treating stranding risk as a systematic risk and create confusion. Instead, the compensation should be provided for explicitly in cash flows.*

90. Another way of conceptualizing *ex ante* compensation is that it functions like an insurance premium, in that it provides the regulated business with an allowance today to compensate it for the chance that it may not be able to recover the value of certain assets later. In this context, another *ex ante* compensation approach is to provide an opex allowance to the regulated business to purchase insurance against stranding risk. While obtaining such an insurance product may be difficult, an equivalent approach might be that the allowance provides for self-insurance by the regulated business.

4.4. *Ex post* compensation

91. The last approach we consider in the toolkit of available approaches for addressing stranding risk is *ex post* compensation. In this case, compensation only occurs if stranding actually occurs, in which case the firm is allowed to retain the stranded assets in the RAB so as to continue to recover the remaining costs from customers. This approach is relatively straightforward and easy to implement. However, it allocates the risk of stranding to consumers, who may not be best placed to manage that risk.

92. The AER has noted that this approach is already in place under the NGR:[72]

> *…we consider that there is effectively no stranding risk from underutilised assets in the current regulatory regime. Although an asset may become unused (or underutilised) on one part of the network, other consumers in other areas will continue to cover the residual costs of these assets. We are also required by the NGR to allow the business to recover the full costs of its assets, and apply a net present value (NPV) neutral approach so the business is compensated for its investment.*

93. In addition, it has the potential to lead to a situation where there are not enough customers remaining on the network to allow the investment costs to be recouped, so that the regulated firm will not be able to be sufficiently compensated. This is the 'death spiral' referred to above. It may also be subject to regulatory commitment problems, in that the regulator may ultimately be reluctant to allow prices to rise or consumers to pay for assets that they are not using. DBP (2020) notes also that this approach has been implemented by regulators when individual assets

[70] NZCC (2020), *Fibre input methodologies: Main final decisions – reasons paper*, 13 October 2020, para.6.1073.

[71] NZCC (2020), *Fibre input methodologies: Main final decisions – reasons paper*, 13 October 2020, para.6.1075.

[72] AER (2020), *JGN access arrangement 2020-25 – Attachment 4 – Regulatory depreciation*, June 2020, pg.12.

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are stranded, but it would have adverse consequences when assets are large relative to the system as a whole, by imposing significant costs on remaining customers.[73]

94. A variant of *ex post* compensation is discussed in Simshauser and Akimov (2018).[74] These authors propose an approach where the assets that are stranded are effectively ring-fenced, by being 'parked' and removed from the RAB, but established in their own 'parked RAB'. The parked RAB's debt is then financed by government-backed bonds. This allows partial (*ex post*) compensation for the debt component of this parked RAB, but not the equity component, albeit that Simshauser and Akimov (2018) state that equity return variants of the model are possible. The parked RAB can also be reassessed at the end of the regulatory period, to consider whether demand growth has occurred to the extent that these assets can be returned to service.

95. Simshauser and Akimov (2018) do note some limitations of their approach, such as how to determine the extent of excess capacity so as to define the parked RAB, and the potential for macroeconomic consequences if a substantial value of government bonds is required. The NZCC has also considered a variant of this model in respect of its fibre Input Methodologies, and states as follows:[75]

> *Simshauser has suggested ring-fencing stranded assets and placing them under a reduced compensation scheme where they can be reintroduced to full recovery at some point in the future if they provide value. This shares the asset stranding risk between firms and end-users. It would however be complicated to introduce and manage. In sum we consider that this would not be practical. We do not consider this option further. We prefer providing some ex-ante compensation.*

96. The preceding options all, to varying degrees, work within the existing regulatory framework. Another approach is to provide *ex post* compensation outside of the regulatory framework. This involves providing direct compensation to firms whose assets will be stranded. This can be funded through industry wide levies or general taxation. An example of this is the compensation provided to coal power plants in Germany as a result of the government policy to phase out the use of coal.[76]

4.5. Summary

97. A high-level summary of each of these mechanisms is set out in Table 2 below, including whether they are consistent with *ex ante* NPV=0 and *ex post* NPV=0.

98. This table illustrates that there are a number of tools for addressing stranding risk which are generally complimentary, in that sense that a combination may be required to achieve *ex ante* NPV=0. For example, accelerating depreciation is unlikely to completely eliminate stranding risk and thus it can be combined with an *ex ante* premium, as the NZCC has recently proposed for fibre networks.

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[73] DBP (2020), *Attachment 9.2: Assessment of the Economic Life of the DBNGP*, January 2020.

[74] Paul Simshauser and Alexandr Akimov (2018), "Regulated electricity networks, investment mistakes in retrospect and stranded assets uncer uncertainty", *University of Cambridge EPRG Working Paper*, 1828.

[75] NZCC (2020), *Fibre input methodologies: Main final decisions – reasons paper*, 13 October 2020, para.6.1078.

[76] See, e.g., *German govt adopts coal exit, fixes hard coal compensation*, Benjamin Wehrmann, Clean Energy Wire, 29 January 2020. Available at: https://www.cleanenergywire.org/news/german-govt-adopts-coal-exit-fixes-hard-coal-compensation

Table 2: High-level summary of conceptual methods for addressing stranding risk

Method	Description	Ex ante NPV=0?	Ex post NPV = 0?
Front loading recovery	Bringing forward recovery attempts to avoid stranding occurring (or minimise its impact) by allowing capital recovery before stranding event occurs.	So long as depreciation schedule is set so that capital recovery occurs before expected point assets are stranded, firms will expect to recover their capital.	If technological change occurs faster than expected, there will be a point at sufficient depreciation cannot be brought forward to ensure capital recovery. If technological change occurs slower than expected NPV is still 0 as altering deprecation doesn't change the NPV of revenues.
***Ex ante* compensation**	An allowance is provided to provide compensation prior to a stranding event occurring.	Allowances will be set to ensure an *expectation* of capital recovery based on an expectation of the magnitude and timing of stranding. Minimises rather than eliminates stranding risk so may not provide ex ante NPV=0	If reality turns out differently from expectations, then the firm may either over or under recover.
***Ex post* compensation**	No compensation is provided prior to stranding event, but compensation is provided after the fact.	So long as the promise of ex post compensation is credible, firms will expect to recover their capital.	This method is premised on ex post compensation, but this may not occur if, for example, this compensation relies on remaining customers paying more.

5. International regulatory precedent for addressing stranding risk for gas networks

99. In this section we survey recent international precedent for addressing stranding risk in gas networks. At the outset we note that this is an emerging issue that regulators internationally are only just starting to come to terms with. Indeed, a survey of member regulators by the Council of European Economic Regulators (CEER) regarding stranded assets in distribution networks found that most national regulatory authorities (NRAs) do not yet have any experience with stranded assets. The same survey found that most NRAs do not have any specific methods for addressing stranded asset issues.[77]

100. Stranding of gas networks is however recognized as an emerging issue in Europe and CEER has been conducting work on the future role of gas in a regulatory context.[78] This work has identified that regulators can address stranded assets using a number of approaches, which are consistent with the options we outline in Section 4.

101. Nonetheless, there is some regulatory precedent of regulators attempting to address stranding risk for gas networks. In Table 3 we summarise this precedent. This suggests that the approach to dealing with stranding type risks is a mixture of shortening asset lives and beta/WACC increments, and that the stranding risk is generally not considered to be systematic.

[77] CEER (2020), *CEER Note on Stranded Assets in Distribution Networks*, 3 July 2020, pg.2. Available at: https://www.ceer.eu/documents/104400/-/-/cbe00257-ab09-c1b2-91bf-b6081032f322.

[78] CEER (2020), *CEER Note on Stranded Assets in Distribution Networks*, 3 July 2020, pg.2.

Table 3: International regulatory precedent for frontloading recovery and WACC increments in gas networks

Regulator	Industry	Year*	Type and size of front loaded recovery	Reason for including front loaded recovery	Systematic / Non-systematic risk
WACC increments					
France	Gas transmission (GT) + Gas distribution (GD)	2020	Higher asset beta for gas transport (0.5)[79] and gas distribution (0.48)[80] compared to electricity transmission (0.37)[81] and electricity distribution (0.36)[82],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.	Mixed. Difference in observed beta mentioned, but then so is "long term gas outlook".
New Zealand	GD + GT	2016	Asset beta of 0.4 which is an uplift of 0.05 over electricity.[83]	Reflecting systematic stranding risk and higher income elasticity of demand of gas vs electricity.	Both.
Sweden	GT	2019	Higher beta compared to electricity transmission (0.43 versus 0.32), implying a beta uplift of 0.11. [84,85] 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).	Appears to be largely non-systematic.
Finland	GT + GD	2017	Higher beta compared to electricity transmission (0.45 versus 0.4), implying a beta uplift of 0.05.[86,87] 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.	Appears to be largely non-systematic.
Austria	GT	2021	Cost of equity premium of 3.5% for gas transmission.[88]	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.	Appears to be largely non-systematic.
Frontloading recovery					
Austria	GD	2017	Reduced regulatory depreciation periods for gas distribution from 40 to 30 years.[89]	Economic uncertainty surrounding the future of gas networks.	Appears to be largely non-systematic.
Belgium	GT	2020	Pipeline assets invested in after 2000 can be fully depreciate by 2050, reducing the regulatory depreciation period from 50 years.[90,91]	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.[92]	Appears to be largely non-systematic.
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.[93]	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.[94]	Appears to be largely non-systematic.
UK	GD + GT	2021	Front loaded depreciation profile using sum-of-years'-digits.[95]	Likely lower utilisation of gas distribution networks in the future.	Mixed – not specific about what might drive lower utilisation.

*Year of decision (in the case of methodology documents) or first year of the regulatory period.

[79] CRE (2020), *DELIBERATION NO 2020-012 - Deliberation by the French Energy Regulatory Commission of 23 January 2020 deciding on the tariffs for the use of GRTgaz's and Teréga's natural gas transmission networks*, January 2020, pg.42.

[80] CRE (2020), *DELIBERATION NO 2020-010 - Deliberation by the French Energy Regulation Commission of 23 January 2020 deciding on the equalised tariff for the use of GRDF's public natural gas distribution networks*, January 2020, pg.34.

[81] CRE (2021), *DELIBERATION NO 2021-12 - Deliberation of the French Energy Regulatory Commission of 21 January 2021 deciding on the tariffs for the use of public transmission electricity grids (TURPE 6 HTB)*, 21 January 2021.

[82] CRE (2021), *DELIBERATION N°2021-13- Deliberation of the French Energy Regulatory Commission of 21 January 2021 on the tariffs for the use of public distribution electricity grids (TURPE 6 HTA-BT*), 21 January 2021.

[83] NZCC (2016), *Input Methodologies review decisions – Topic paper 4: Cost of capital issues*, December 2016, para.452& para.455.

[84] Swedish Energy Markets Inspectorate, *Kalkylränta för tillsynsperioden 2019–2022.* Available at: https://www.ei.se/download/18.765ba991784b13246f1e49e/1619181961563/Bilaga_4_Kalkylranta-for_tillsynsperioden_2019-2022.pdf

[85] Swedish Energy Markets Inspectorate, *Ei yttrande 2019*, Available at: https://www.ei.se/download/18.22acd6711784a1f3a5b1788/1616425280513/Ei-yttrande-2019-102334.pdf

[86] Finland Energy Authority (2017), *Regulation methods during the third regulatory period from 1 January 2016 to 31 December 2019 and the fourth regulatory period from 1 January 2020 to 31 December 2023 - Natural gas transmission system*, April 2017, pg.37.

[87] Finland Energy Authority (2015), *Regulation methods in the fourth regulatory period of 1 January 2016 – 31 December 2019 and the fifth regulatory period of 1 January 2020 – 31 December 2023 Electricity transmission network operations, November 2015*, pg.50.

[88] E-Control (2021), *Methodology Pursuant To Section 82 Gaswirtschaftsgesetz (Gas Act, Gwg) 2011 For The Fourth Period For Transmission Systems Of Austrian Gas Transmission System Operators (Tsos)*, pg.7.

[89] E-Control (2017): *Regulierungssystematik für die dritte Regulierungsperiode der Gasverteilernetzbetreiber, 1. Jänner 2018 – 31. Dezember 2022*, 23 October 2017, pg.44. Available at: https://www.e-control.at/documents/1785851/1811582/Regulierungssystematik_f%C3%BCr_die_dritte_Regulierungsperiode_GAS.pdf/8165376e-2a5e-c4d3-3568-e3a65e47c7f2?t=1516373810332

[90] CREG (2018), *Arrêté fixant la méthodologie tarifaire pour le réseau de transport de gaz naturel, l'installation de stockage de gaz naturel et l'installation de GNL pour la période régulatoire 2020 -2023*, 28 June 2018, pg.11 & pg.29. Available at: https://www.creg.be/fr/publications/decision-z111011

[91] Pipelines are otherwise depreciated on a straight-line basis at 2% a year which implies a 50-year asset life.

[92] CREG (2018), *Rapport de la consultation relatif au projet d'arrêté (Z)1110/9 fixant la méthodologie tarifaire pour le réseau de transport de gaz naturel, l'installation de stockage de gaz naturel et l'installation de GNL pour la période régulatoire 2020 -2023*, 7 June 2018, para.32-33. Available at: https://www.creg.be/fr/consultations-publiques/methodologie-tarifaire-2020-2023-fluxys-belgium-et-fluxys-lng.

[93] ACM (2020), *Bijlage 4 bij het Methodebesluit GTS 2022-2026*, 1 February 2020, para.44. Available at: https://www.acm.nl/sites/default/files/documents/wijziging-schattingsmethode-efficiente-kapitaalkosten.pdf.

[94] ACM (2020), *Methodebesluit GTS 2022-2026*, 1 February 2020, para.67-68. Available at: https://www.acm.nl/nl/publicaties/methodebesluit-gts-2022-2026.

[95] See: Ofgem (2021), *RIIO-2 Final Determinations – Finance Annex (REVISED)*, February 2021, pg.112-113 and Ofgem (2011), *Decision on strategy for the next transmission and gas distribution price controls – RIIO-T1 and GD1 Financial Issues*, March 2011, pg.12.

6. The NZCC's ex ante compensation model

102. In this section we:

a. Provide an overview of the methodology used by the NZCC to calculate an *ex ante* stranding premium;

b. Set out the NZCC's application of this model to fibre telecommunications networks; and

c. Discuss some conceptual aspects of relevance to how this model might be applied to JGN.

6.1. The NZCC approach for calculating an ex ante stranding premium

103. In its fibre Input Methodologies decision,[96] the NZCC considered that the main risk of asset stranding of the fibre telecommunications network was in respect of technological advances, and it considered this risk to be material. The NZCC uses a mix of approaches to address the risk of asset stranding. In particular, the NZCC:

a. Allows unused assets to be retained in the RAB;

b. Allows for the possibility of shortening asset lives (or alternative depreciation profiles); and

c. Allows a 10 basis point *ex ante* allowance as compensation (implemented via cash flows). In this regard, the NZCC considered that the combination of the first two mechanisms risked being insufficient to account for stranding risk, hence the need for an additional allowance to compensation for the residual risk.

104. The NZCC has indicated that it may also apply this methodology in the upcoming gas pipelines reset.[97]

105. To quantify the *ex ante* allowance, the NZCC uses an approach based on a model set out in Dixit and Pindyck (1994),[98] supplemented by some of the NZCC's own calculations. This model uses inputs on the probability of stranding over a certain time period and the proportion of the RAB that is stranded to calculate an implied discount rate increment to account for stranding.

106. More formally, the discount rate increment ($d\delta$) to account for stranding risk is:

$$d\delta = -R\frac{\ln{(1-Q)}}{T}$$

where Q is the cumulative probability of stranding, T is the timeframe over which that cumulative probability is measured and R is the proportion of the RAB that is stranded.

107. For example, if the probability of stranding is $Q = 5\%$, over a timeframe of 10 years ($T = 10$) and 20% of the RAB is expected to be stranded ($R = 10\%$), then substituting these values into the above equation yields a discount rate increment of approximately 0.1% (or 10 basis points).

108. The NZCC's approach was to assess the risk over a 10-year period, and it considered that the probability of stranding was in the range of 5-10% and that the percentage of the RAB that would be stranded was in the range of 10%-40%. This assessment gave a basis point range for the

[96] This section is drawn from para.6.981-6.1251 of NZCC (2020), *Fibre input methodologies: Main final decisions – reasons paper*, 13 October 2020.

[97] NZCC (2021), *Resetting default price-quality paths for gas pipeline businesses from 1 October 2022, Process and Issues Paper*, 4 August 2021, para.D39.

[98] Avinash Dixit and Robert Pindyck (1994), "Investment Under Uncertainty", Princeton University Press, 1994.

discount rate increment of 5 to 40 basis points. Ultimately the NZCC chose a relatively low point in this range, to give an increment of 10 basis points.

6.2. NZCC calculation of ex ante stranding premium for fibre telecommunications

109. Regarding the NZCC's application of this model to fibre, as already noted, the model only needs three parameters: the timeframe, the probability of stranding and the proportion of the RAB that is stranded.

110. Starting with the timeframe, the NZCC used a 10-year timeframe, with the NZCC noting that doing so was intended to "ease decision making".[99] Indeed, in some ways the choice of timeframe is less important. While a longer timeframe would, if all else remains unchanged, lower the discount rate increment, we may in fact expect a higher probability of stranding over a longer timeframe, which has the effect of increasing the discount rate increment. We note that the increment to the discount rate itself is applied by the NZCC over a one-year period,[100] and the choice of the timeframe, T, in the NZCC's model is not relevant to this. Following the approach used by the NZCC, we also use a 10-year timeframe.

111. To illustrate the results of the NZCC's approach using this timeframe, in Table 4 we set out the increment to the discount rate (measured in basis points) for varying combinations of the probability of stranding and the percentage of the RAB stranded, using the equation set out in the previous section with a value of $T = 10$. The shaded cells are the area captured in the NZCC's assessment for fibre telecommunications, giving the discount rate increment of approximately 5 to 40 basis points.

Table 4: Increment to discount rate (basis points) in NZCC approach, for varying probability of stranding and proportion of RAB stranded

	Probability of stranding over 10-years									
% RAB stranded	**5%**	**10%**	**15%**	**20%**	**25%**	**30%**	**35%**	**40%**	**45%**	**50%**
100%	51	105	163	223	288	357	431	511	598	693
90%	46	95	146	201	259	321	388	460	538	624
80%	41	84	130	179	230	285	345	409	478	555
70%	36	74	114	156	201	250	302	358	418	485
60%	31	63	98	134	173	214	258	306	359	416
50%	26	53	81	112	144	178	215	255	299	347
40%	21	42	65	89	115	143	172	204	239	277
30%	15	32	49	67	86	107	129	153	179	208
20%	10	21	33	45	58	71	86	102	120	139
10%	5	11	16	22	29	36	43	51	60	69

Note: Shaded cells are the area captured by the NZCC's range for fibre telecommunications.

112. Regarding the probability of stranding, the NZCC considered this to be in the range of 5-10% for fibre telecommunications. The main risk of stranding of fibre comes from customers switching to 'fixed wireless access' (FWA) broadband products, which allow customers to connect to broadband services at home through mobile telecommunications networks. The NZCC noted that FWA connections in New Zealand had been growing (to around 200,000 connections in mid-2019

[99] NZCC (2020), *Fibre input methodologies: Main final decisions – reasons paper*, 13 October 2020, para.6.1172.

[100] NZCC (2020), *Fibre input methodologies: Main final decisions – reasons paper*, 13 October 2020, clause 3.3.5(2).

– we note that this equates to a penetration rate of approximately 11%),[101] and that as mobile networks densify this will allow for more FWA over time.[102]

113. On the other hand, the NZCC considered that the 10% upper bound was reasonable, given that:[103]

a. Unused assets would not be removed from the RAB;

b. Fibre providers could continue to compete with FWA providers, particularly since FWA will mostly likely occur in low-cost areas;

c. Some assets will not be sunk and can be sold; and

d. Connections require higher speeds are less likely to switch to FWA.

114. In a report filed with the NZCC in respect of the fibre Input Methodologies, we considered that the NZCC had underestimated the probability of stranding for various reasons, and a more plausible estimate was likely to be in the range of 10-20%.[104]

6.3. Conceptual issues in applying the NZCC model to JGN

115. In this section we take the NZCC's approach of quantifying an *ex ante* allowance for stranding risk and discuss some of the conceptual issues that would need to be considered were it to be applied to JGN. As noted above, this approach uses three inputs: the cumulative probability of stranding; the timeframe over which that cumulative probability is measured; and the proportion of the RAB that is stranded.

116. In respect of JGN, the probability of stranding is likely to be greater than that estimated by the NZCC for fibre networks, for the following reasons:

a. Stranding risk for gas networks arises partly from competition from solar PV installations, and as estimated above solar installations in NSW had reached approximately 20% penetration by 2020. This compares with the FWA penetration that was considered by the NZCC, of around 11%;

b. Moreover, competitive stranding risk for gas arises not only from substitution to solar but from electrification more generally, which as discussed earlier in this report can arise because of the increased efficiency of substitute electric products and greater penetration of these products. To put this another way, a new technology (solar) is not necessary to achieve substitution away from gas; substitution can be achieved to electrical appliances even without solar. In contrast, telecommunications customers are not able to substitute away from fibre without FWA as the new technology; and

c. Government policy risk is unlikely to be material in respect of fibre, in the sense that there are unlikely to be any immediate government policy changes that seek to shift consumer demand away from fibre and on to FWA. In contrast, as discussed earlier in this report, government policy around climate change presents a material risk to stranding of gas networks.

117. We do note, however, that there may be some mitigating factors in respect of gas stranding risk e.g. conversion to hydrogen. However, as noted earlier, there are a number of risks that remain, and there may be impediments depending on the current pipeline specification. For example, the

[101] Based on approximately 1.8 million households in New Zealand (Statistics New Zealand household projections data, sourced from NZ.Stat).

[102] NZCC (2020), *Fibre input methodologies: Main final decisions – reasons paper*, 13 October 2020, para.6.1207.1-6.1207.4.

[103] NZCC (2020), *Fibre input methodologies: Main final decisions – reasons paper*, 13 October 2020, para.6.1206.1-6.1206.4.

[104] NERA Economic Consulting (2020), *Assessment of Type II asymmetric risk for Chorus' fibre network*, report for Chorus, 22 January 2020.

high pressure steel pipelines (primary, trunk and pipeline) currently in place are primarily designed to operate at moderate to high stress, and may not be capable of allowing significant blend of hydrogen unless these mains are replaced by plastic mains.[105]

118. Regarding the proportion of the RAB that is stranded, the NZCC estimated that at most 40% of the fibre RAB would be stranded. The NZCC's view was that the extent of the RAB being stranded would be mitigated by factors such as:

a. The ability of fibre providers to continue to compete with FWA;[106]

b. The use of some of the fibre assets to provide fibre services to cell towers; and

c. The ability for some of the assets to be redeployed or sold (particularly the 'layer 2' electronics that complement the physical infrastructure).

119. However, a comparison with JGN suggests many of these factors are unlikely to apply. This would be particularly the case if the gas network is stranded due to government policy that seeks to transition residential energy use away from gas. If this were the case, then JGN could not continue to compete with electricity as an alternative use. Nor could it use its existing assets in the event of full electrification, because electricity networks and gas pipelines do not have any complementarities. In the NZCC framework this would essentially involve 100% of the RAB being stranded.

120. The only mitigating factor would be if gas networks could be converted to hydrogen, which would avoid stranding for some gas assets. But this conversion itself may strand existing assets as already noted above with respect to the high pressure steel mains. So in a hydrogen scenario, the NZCC framework would consider the proportion of the RAB made up by assets that would be stranded by hydrogen conversion, and assume they are stranded with a relatively high probability.

[105] GPA (2019), *Hydrogen Future Study*, report for JGN, 24 December 2019, pg.i.

[106] NZCC (2020), *Fibre input methodologies: Main final decisions – reasons paper*, 13 October 2020, para.6.1176.1-6.1176.5.

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NERA Economic Consulting
One International Towers
100 Barangaroo Avenue
Sydney NSW, Australia 2000
www.nera.com

NERA Australia Pty Ltd, ABN 34 092 959 665