Regulatory tools applied to gas networks to accommodate energy transition

Note prepared for Firstgas, Vector and Powerco

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1 Introduction

1.1 The New Zealand Commerce Commission (NZCC) is currently undertaking a review of the Default Price-Quality Paths (DPP) that apply to gas distribution and gas transmission businesses in New Zealand.[1] In this context, Firstgas, Vector and Powerco (the 'gas infrastructure businesses') have asked Oxera to review precedent on regulatory tools that can be used to facilitate the delivery of the energy transition in New Zealand.

1.2 Accordingly, in this note, we review regulatory tools that European regulators have used to manage asset stranding risk to gas networks, to address uncertainty about energy transition pathways, while incentivising innovation. European approaches are particularly relevant to New Zealand because these countries apply a similar style of economic regulation to gas pipelines and also have made strong, often legislative, commitments to net zero.

1.3 We first review regulatory precedent in managing asset stranding risk in recent price controls (see section 2). These regulatory measures include net present value (NPV)-neutral approaches such as shortening asset lives, changing

[1] New Zealand Commerce Commission (2021), 'Resetting default price-quality paths for gas pipeline businesses from 1 October 2022', Process and Issues paper, 4 August.

depreciation profiles, and changing regulatory asset base (RAB) inflation indexation; as well as some NPV-positive solutions, such as an uplift to the allowed rate of return.

1.4 We then review some of the instruments that have been used by regulators for addressing the uncertainty associated with net zero, such as price control re-openers, and the need to incentivise innovation, such as innovation allowances and rate of return uplifts (see section 3).

2 Asset stranding risk

2.1 There is no clear and uniform definition of stranded assets in the regulation of energy networks. Similarly, at the European level, there is no regulatory regime focused on the risk of stranded assets or a standard regulatory measure to mitigate this risk.[2]

2.2 In the case of natural gas networks, such as the assets held by gas infrastructure businesses in New Zealand, the risk of asset stranding is related to the possibility of not being able to fully recover investments because of a decline in demand, driven by policy decisions to curb and potentially stop the consumption of natural gas.

2.3 The New Zealand Commerce Commission has explained the asset stranding risk faced by gas networks as follows:[3]

> There is a risk that GPBs[gas pipeline businesses]will be unable to, at some point in the future, fully recover their historic capital investment as customers disconnect from GPB networks.

2.4 Regulators cannot eliminate asset stranding risk. However, they can manage the risk by allocating it to a party that is better positioned to bear it, e.g. transfer it from networks and (a smaller base of potential) future users to (a larger base of) current users. In this section, we provide an overview of the regulatory tools that European regulators use to manage the risk of stranded assets within the building blocks framework.[4] The tools are related to the depreciation and return on the RAB allowances, and include the following:

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[2] CEER (2018), 'Study on the Future Role of Gas from a Regulatory Perspective', 6 March, section 5.1.2.1, https://www.ceer.eu/documents/104400/-/-/6a6c72de-225a-b350-e30a-dd12bdf22378 (last accessed 20 August 2021).

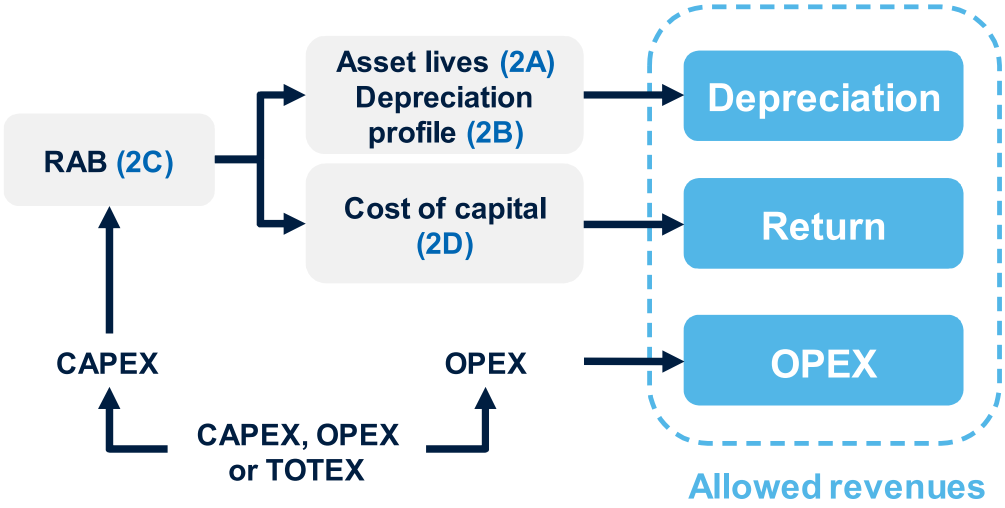
[3] Commerce Commission (2021), 'Resetting default price-quality paths for gas pipeline businesses from 1 October 2022', 4 August 2021, p. 6, para. X12.3.

[4] Also referred to as RAB–WACC regulation. According to the building blocks framework, the total allowed revenue is estimated based on the operational expenditure (OPEX), return and depreciation allowances, where depreciation and return allowances depend on the value of the RAB. See Figure 2.1 for illustration.

- the choice of appropriate asset lives(section 2A);
- the choice of depreciation policy (section 2B);
- an adjustment of the RAB indexation method (section 2C);
- an uplift to the cost of capital (section 2D).

2.5 Figure 2.1 illustrates the role of these regulatory tools and inputs within a typical building blocks framework.

Figure 2.1 Adjustments to cash flows tackling asset stranding risk



Note: Labels such as '2A' refer to respective section headings (e.g. section 2A) in this note.

Source: Oxera.

2A Shortening of asset lives

2.6 One of the ways regulators can manage the asset stranding risk is by shortening regulatory asset lives. Figure 2.2 shows that shortening asset lives increases annual depreciation charges (i.e. allowances) in the short term, allowing investors to recover their investments faster. The impact is NPV-neutral.[5]

2.7 This option of addressing the asset stranding risk is associated with the following concerns.

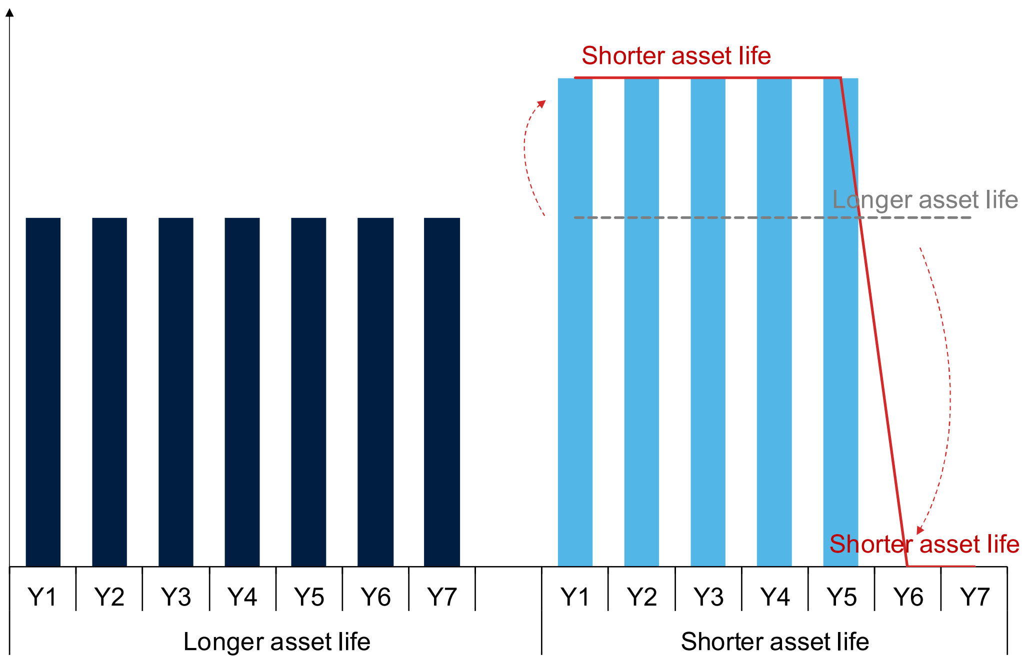
- As Figure 2.2 shows, such a change leads to an immediate increase in capital charges, and thus customers' tariffs. Regulators may want to avoid the

[5] In this context, NPV-neutrality refers to a situation in which two outcomes result in the same value to the network, estimated as the sum of depreciation and return allowan ces over the lifetime of the asset, discounted at a fixed discount rate equal to the allowed rate of return.

upward tariff shocks—not least because in the face of declining demand, a higher tariff may encourage users that are still connected to the network to disconnect.

- A further implication concerns the possible misalignment between the regulatory and economic life of the assets. If a shortening of regulatory asset lives is undertaken to accelerate cash fows, and the asset then remains in use beyond the shortened regulatory life, no revenue allowances will correspond to that assetat that point in time. As a result, future users may use the asset for free or for less than current users, leading to intergenerational inequality. The network may also experience challenges in investing in and maintaining assets.

Figure 2.2 The impact of shortening asset lives on the annual depreciation allowances ($)



Source: Oxera.

2.8 In the rest of this section, we describe how French and Belgian energy networks' regulators managed the asset stranding risk in recent price controls, by shortening asset lives.

2A.1 The case of France

2.9 The French Commission de Régulation de l'Energie (CRE) reduced some asset lives of the gas distribution network GRDF, to address the expected gradual reduction in gas consumption and the corresponding risk of stranded assets.[6] It 'adopts a reduction from 45 to 30 years for the depreciation period regarding building connections and pipes […], which is a way to reduce the risk of stranded costs'.[7]

2.10 This follows GRDF's proposal to CRE, according to which the 30-year period corresponded to the period of a typical consumer being connected to the grid.

2A.2 The case of Belgium

2.11 In its decree on the tariff methodology for the 2020–23 regulatory period, the Commission de Régulation de l'Energie et du Gaz (CREG) determined that the pipelines invested in Fluxys, a gas transmission network, after 2000 can be fully depreciated by 2050. De facto, the depreciation period for these assets will be reduced (from 50 years used in the previous regulatory period[8]):[9]

> For the most part, the CREG maintains the depreciation periods as provided for in the previous Tariff Methodology. These periods are based on an international comparison. In order to continue to pursue a consistent policy of asset valuation, the CREG has decided not to make any changes, except for [gas] pipelines invested after 2000, which can be fully depreciated in 2050 [automatic translation from French by DeepL]

2.12 The decision to allow full depreciation of pipes invested after 2000 by 2050 corresponds to aligning the depreciation period with the economic life of the assets—i.e. the period over which they can be operated at a profit. This economic life itself depends on exogenous factors, such as political decisions, or the possibility of converting the network to other fuels.

2.13 CREG explained that such a measure was introduced in response to the debates on energy transition, but that it could reconsider this choice at a later stage:[10]

> This measure must be seen from the perspective of a prudent manager in the light of current discussions in Europe and Belgium about energy transition. However, the CREG states that the measure will be evaluated when a better view

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[6] Commission de Régulation de l'Energie (2010), 'Délibération de la Commission de régulation de l'énergie du 23 janvier 2020 portant décision sur le tarif péréqué d'utilisation des réseaux publics de distribution de gaz naturel de GRDF', p. 36, https://www.cre.fr/en/Documents/Deliberations/Decision/equalised-tariff-for-the-use-of-grdf-s-public-natural-gas-distribution-networks (last accessed 20 August 2021).

[7] Ibid, p. 3.

[8] CREG (2014), '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', 18 December, article 15, para. 4.

[9] CREG (2018a), '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, article 15, para. 2, https://www.creg.be/sites/default/files/assets/Publications/Decisions/Z1110-11FR.pdf (last accessed on 23/08/2021).

[10] CREG (2018b), '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, para. 33, https://www.creg.be/sites/default/files/assets/Consult/2018/1110-9/RA1110-9FR.pdf (last accessed on 23/08/2021).

of the energy mix in the medium and long term is available[automatic translation from French by DeepL]

2B Regulatory depreciation profiles

2.14 As discussed above, reducing the asset life while maintaining a straight-line depreciation profile results in the assets being fully depreciated (and hence not being in the RAB) sooner. An alternative, which similarly allows cash flow allowances to be brought forward, is accelerating the depreciation profile. The resulting front-loaded depreciation profile would spread the depreciation charges (and allowance) over the entire life of the asset while anticipating the majority of them in the earlier years. This profile could be matched to the expected changes in the customer base (i.e. higher tariff recovery from a larger base of users in the earlier years and lower recovery from a small base of users in the later years) for more equal allocation of total charges among current and future customers.

2.15 Similar to shortening the asset lives, this method leads to an immediate increase in capital charges and could cause free or subsidised services to future users. This could arise if the customer base decreases to a lesser extent than expected, with significantly depreciated assets remaining in use.

2.16 In this section, we describe how Dutch and GB regulators have accelerated depreciation profiles.

2B.1 The case of the Netherlands

2.17 One of the measures that the Dutch regulator, ACM, uses to manage the expected decline in the utilisation of gas networks is accelerating depreciation charges.[11]

2.18 The expected decline in the utilisation of gas networks would cause the assets to be used less intensively—however, their average economic lifetime is estimated to remain the same. To distribute the costs of those assets among all (current and future) customers that would benefit from them evenly,ACM has decided not to reduce the asset life, but rather to modify the depreciation profile

[11] ACM, 'Methodebesluit GTS 2022-2026. Besluit van de Autoriteit Consument en Markt als bedoeld in artikel 82, tweede lid, van de Gaswet', Ons kenmerk : ACM/UIT/542662, Zaaknummer : ACM/19/035346, https://www.acm.nl/sites/default/files/documents/methodebesluit-gts-2022-2026.pdf (last accessed 25 August 2021).

starting from 2022, switching from a straight-line one to a ‘variable declining balance’ method with an acceleration factor of 1.3.[12]

2.19 This logic extends to ACM’s rationale for an immediate increase in tariffs—it states that this upward effect in the short term prevents larger tariff increases in the long term.[13]

2.20 Measures to accelerate cash flows are used with caution because of redistributional and intergenerational effects.[14] By positioning the acceleration of cash flows as a necessity to redress the intergenerational implications of doing nothing (i.e. maintaining the same depreciation and capitalisation policies, notwithstanding a declining user base), ACM is thereby advancing the regulatory debate.

2.21 In addition to accommodating the declining user base, in ACM’s view, the alternative depreciation profile also needed to be flexible, allowing ACM to adjust the pace of depreciation in the future on the basis of new insights into the development of gas network use. That is achieved by the ‘variable declining balance’ method, whereby ACM can revisit the degree of declining balance depreciation. This time, ACM has selected an acceleration factor of 1.3 on the basis of its expectations on the level of investments and utilisation over the regulatory period.

2.22 Overall, this change will have an upward effect on depreciation charges in 2022, compared to the continuation of the straight-line depreciation method, which will decline thereafter until a ‘straight-line floor’ is reached.[15] Figure 2.3 provides an illustration.

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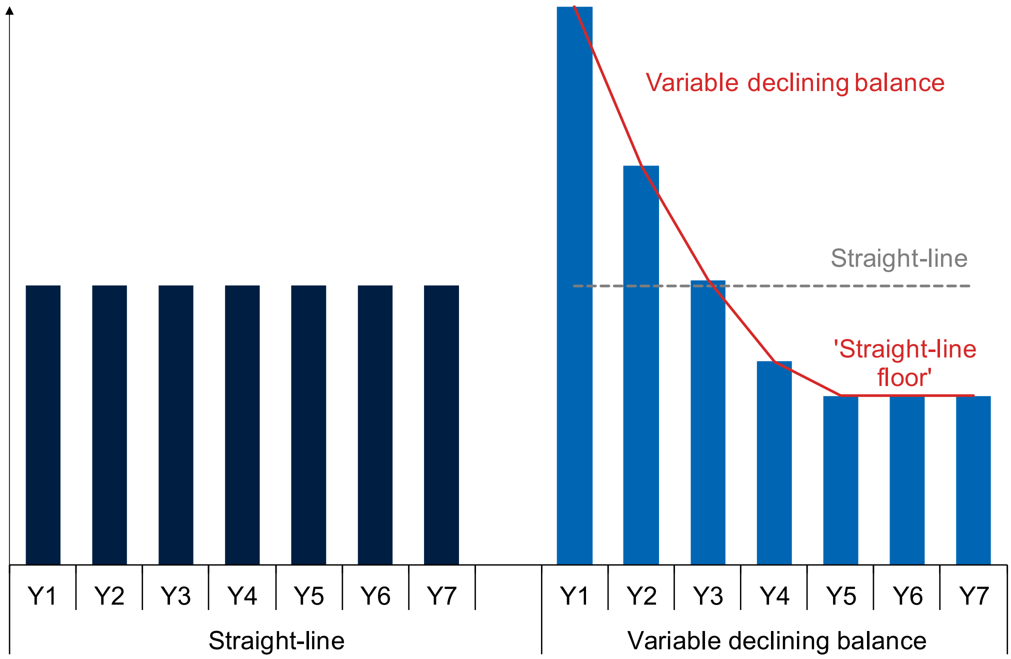
[12] As an example, with an acceleration factor of 1.3, 130% of the annual straight-line depreciation charge is depreciated in the first year. For example, for an investment of €1m with a depreciation period of ten years, the first year straight-line depreciation charge would be €0.1m, while the declining balance depreciation change would be €0.13m. In the following years, each time the same percentage of the remaining asset value is depreciated. In this example, the percentage is 13% (a factor of 1.3 divided by ten years). The depreciation charge has a floor, which is based on an alternative straight-line depreciation profile. Specifically, the annual depreciation charge flatlines at the point in time when the straight-line depreciation of the residual asset value in the next year exceeds the ‘variable declining balance’ estimate. The entire asset value depreciates in this manner.

[13] ACM, ‘Methodebesluit GTS 2022-2026. Besluit van de Autoriteit Consument en Markt als bedoeld in artikel 82, tweede lid, van de Gaswet’, Ons kenmerk : ACM/UIT/542662, Zaaknummer : ACM/19/035346, para. 68, https://www.acm.nl/sites/default/files/documents/methodebesluit-gts-2022-2026.pdf (last accessed 25 August 2021).

[14] See, for example, a joint discussion paper by Ofwat and Ofgem as far back as the mid-2000s—Ofwat, Ofgem (2006), ‘Financing Networks: A discussion paper’, February, paras 40 and 179.

[15] The term ‘straight-line floor’ refers to the flatline level as explained in footnote 12.

Figure 2.3 The impact of the 'variable declining balance' depreciation policy on the annual depreciation allowances ($)



Note: The mechanics of the 'variable declining balance' depreciation method are described in footnote 12. In this example, the 'straight-line floor' is reached in year 5.

Source: Oxera.

2.23 ACM further adjusts the resulting depreciation allowances in recognition that some assets could be redeployed for hydrogen and therefore do not need to be depreciated faster. ACM addresses that by reducing the extra depreciation allowances by 10%—based on an estimate of the expected proportion of assets to be redeployed for hydrogen.[16]

2.24 Another of ACM's modifications to the depreciation policy concerns the timing of removing divestments from the RAB.[17] The regulator explains that following this modification, depreciation charges increase in the year of divestment but decrease in the following years.[18] As with the change to the 'variable declining balance' depreciation method, this pattern in depreciation charges allows ACM to spread the costs over a (currently) larger number of grid users.

[16] ACM, 'Methodebesluit GTS 2022-2026. Besluit van de Autoriteit Consument en Markt als bedoeld in artikel 82, tweede lid, van de Gaswet', Ons kenmerk : ACM/UIT/542662, Zaaknummer : ACM/19/035346, para. 166, https://www.acm.nl/sites/default/files/documents/methodebesluit-gts-2022-2026.pdf (last accessed 25 August 2021).
[17] Ibid., paras 167–169.
[18] ACM states that the remaining asset value is now to be fully depreciated at the point of divestment.

2B.2 The case of the UK

2.25 For the ongoing RIIO-GD2 and RIIO-GT2 price controls, the GB energy networks regulator, Ofgem, has aligned the GT depreciation policy with that applied to the GD sector in the previous price control (RIIO-GD1). Now, in both sectors, the depreciation profile for RAB additions from 2002 is front-loaded. The asset lives remain unchanged at 45 years.[19]

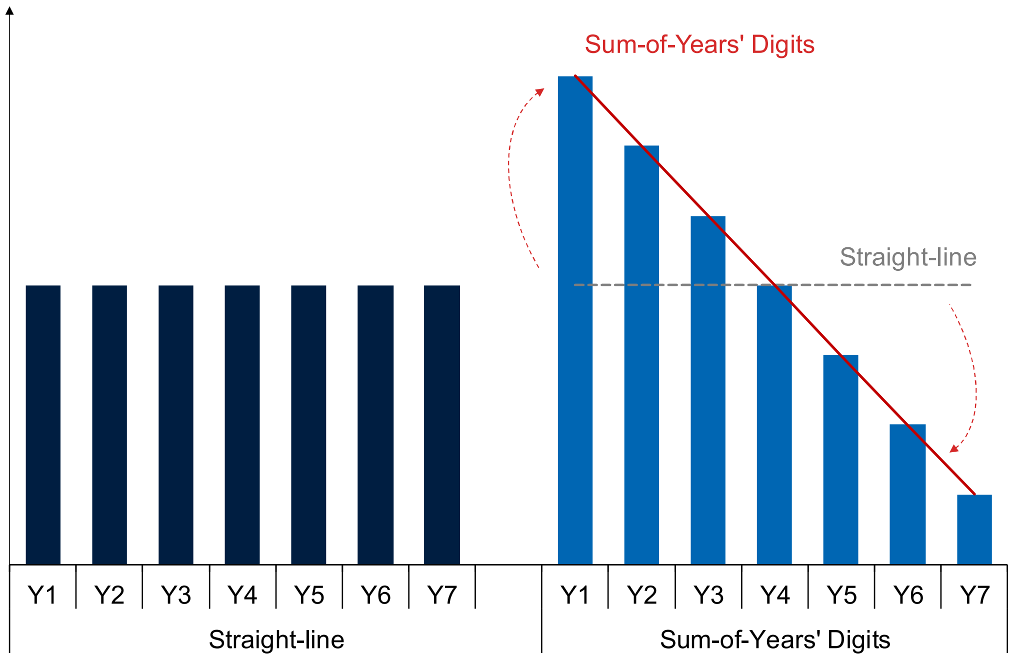
2.26 The type of front-loaded depreciation that Ofgem opted for is the Sum-of-Years' Digits depreciation policy. Intuitively, the annual depreciation under this method is calculated in two steps.

1. First, each year's digits are summed over the depreciation period (e.g. with an asset life of five years, this would be 1 + 2 + 3 + 4 + 5, which equals 15).
2. Then, the depreciation for each year is calculated by dividing the asset's number of useful years left (e.g. five in the first year, and four in the second), by the sum-of-years' digits (e.g. 15). The ratio is then multiplied by the gross book value of the asset[20]

Figure 2.4 illustrates the impact of the Sum-of-Years' Digits depreciation policy.

[19] Ofgem (2021), 'RIIO-2 Final Determinations – Finance Annex (REVISED)', 3 February, section 10, https://www.ofgem.gov.uk/sites/default/files/docs/2021/02/final_determinations_-_finance_annex_revised_002.pdf (last accessed on 20 August 2021).
[20] Ofgem (2010), 'Glossary of terms: RPI-X@20 review', page 20, https://www.ofgem.gov.uk/sites/default/files/docs/2010/07/rec-glossary.pdf (last accessed on 20 August 2021).

Figure 2.4 The impact of the Sum-of-Years' Digits depreciation policy on the annual depreciation allowances ($)



Source: Oxera.

2C RAB inflation indexation

2.27 The same principle of addressing asset stranding risk underpins the examples of shortening asset lives and changing the depreciation profile: cash flows are brought forward on an NPV-neutral basis.

2.28 Another regulatory parameter that could be used to bring cash flows forward is the RAB inflation indexation. As discussed below, the Dutch regulator, ACM, used this approach for the upcoming regulatory period, to manage asset stranding risk in the gas sector.

2C.1 The case of the Netherlands

2.29 In addition to front-loading depreciation charges, in its latest price control review for gas networks, the Dutch regulator, ACM, switched from a real to a nominal regulatory system from the start of the regulatory period 2022–26 to address the issues of the expected decline in the use of gas.[21] That means that the rate of return is now specified on a nominal basis and no inflation indexation is applied to RAB (nominal regulatory system). That is in contrast to

[21] ACM (2021), 'Method decision GTS 2022-2026', 1 February, paras 148–155, https://www.acm.nl/sites/default/files/documents/methodebesluit-gts-2022-2026.pdf (last accessed 20 August 2021).

specifying the rate of return on a real basis and indexing RAB with inflation (real regulatory system).

2.30 The nominal rate of return has an immediate upward effect on the allowed revenues at the beginning of the price control period (compared to the real rate of return), whereas not indexing the RAB has only a limited downward effect in the first years (compared to indexing the RAB with inflation). However, this effect increases as the years go by. Therefore, cash flow allowances will decrease in later years.

2.31 The ACM explains that an argument for applying the real system in the past was to ensure that, in real terms, current network users pay the same amount for the same services as future network users. With decreasing gas network use, this argument would no longer hold: a decreasing number of network users would pay the same fixed cost base in real terms, which is an increasing number per user. Therefore, to enable the current and future users to pay the same in real terms, cash flow allowances need to be brought forward.

2D Cost of capital uplift

2.32 Another way for a regulator to compensate networks for the risk of stranded assets is to make an upwards adjustment to the cost of capital allowance. By increasing the allowance, the regulator endows the network operators with additional resources to offset the risks of the uncertain legislative environment and thus the potential materialisation of stranded assets. In contrast to shortening asset lives or adjusting depreciation profiles, providing an uplift to the cost of capital does not lead to lower cash flows in the future.

2.33 Below, we outline examples of regulators providing a cost of equity uplift to compensate gas networks for volume risk (Austria) and asset stranding risk (France). The two types of risks are related—both of them reflect uncertainty around volumes of gas transported and/or the number of users connected to the grid.

2D.1 The case of Austria

2.34 In its 2021–24 price control period for gas transmission system operators (TSOs), the Austrian regulator, E-Control, continued including, as in previous periods, a 'capacity risk premium' to the cost of equity allowance.[22] This premium is linked to the volume risk assumed by operators, and consists of two parts:

- a sector-wide uplift equal to an extra 3.5% to the cost of equity allowance;
- an individual risk premium, based on the estimated capacity risk for a specific regulated network.

2.35 Although the Austrian regulator's practice is not explicitly associated with the risk of stranded assets (in the context of a transition to a low-carbon energy strategy), it is related to the same category of risk (i.e. uncertainty around volumes of gas transported and/or the number of users connected to the grid). Indeed, one of the consequences of the materialisation of the risk related to stranded assets is the decline of volumes. From this perspective, the capacity risk premium acts as partial compensation for the risk associated with underutilisation of gas transmission assets, if this were driven by volume uncertainty.

2.36 Notably, networks have to retain the additional income from the risk premium—i.e. it cannot be distributed to shareholders.[23]

> TSOs must ring-fence 100% of their risk premiums (both the 3.5% risk premium and individual risk premium) and reserve them for actual future capacity risk. These reserves may not be distributed to shareholders and thereby reduced. Otherwise, materialising capacity risks could put the company's financial stability in jeopardy.

2.37 The accumulated reserves are supposed to compensate networks for losses if the risk materialises.

2D.2 The case of France

2.38 In CRE's latest tariffs determination for the gas transmission and distribution networks,[24] applicable from 2020, the consideration of potential asset stranding

[22] E-Control, 'Methodology pursuant to section 82 Gaswirtschaftsgesetz (Gas Act, GWG) 2011 for the fourth period for transmission systems of Austrian Gas Transmission System Operators (TSOs)', p. 7.
[23] Ibid., p. 19.
[24] Commission de Régulation de l'Energie (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', 23 January, p. 42, https://www.cre.fr/en/Documents/Deliberations/Decision/tariffs-for-the-use-of-grtgaz-s-and-terega-s-natural-gas-transmission-networks (last accessed 23 August 2021). Commission de Régulation de l'Energie (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', 23 January, p. 34, https://www.cre.fr/en/Documents/Deliberations/Decision/equalised-tariff-for-the-use-of-grdf-s-public-natural-gas-distribution-networks (last accessed 23 August 2021).

risk has led to the calibration of a higher cost of capital. Specifically, the CRE has noted:[25]

> It [CRE's decision on cost of capital] also takes into account the significant increase in uncertainty concerning long-term gas prospects in France, particularly in the light of the anticipated drops in gas consumption envisaged in France and the risk of stranded costs within the framework of the draft multi-annual energy plan.

2.39 This is a precedent of a regulator allowing for a higher rate of return on capital in recognition of stranding risk and in addition to shortening asset lives. The detailed reasoning behind CRE's analysis is not disclosed.

3 Re-openers and innovation allowances

3.1 The asset stranding risk, as discussed in this note, relates to the known uncertainty about the future demand for the services provided by gas networks. However, this is not the only uncertainty associated with the energy transition to net zero.

3.2 In this section, we focus on two common types of net-zero regulatory tools that are being deployed in recent price controls, to accommodate other types of uncertainty related to the energy transition (e.g. uncertainty about optimal technologies). These are:

- price control re-openers (see section 3A), addressing a possibility of the need for a change during the price control period, when those are related to net-zero developments;
- innovation incentives and allowances (see section 3B), encouraging networks to undertake R&D projects over and above business-as-usual requirements.

3.3 Over the past decades, regulatory systems have mostly focused on achieving direct cost efficiencies, and providing stability and predictability for investors. The direct costs in this context are opposed to external or social costs, such as the impact of climate change.

3.4 In this environment, it is typically difficult to prove the benefits of long-term strategic investment that could be needed to achieve net-zero objectives. Such long-term investment would typically be challenged due to the potential risk of building unnecessary infrastructure that the consumer will ultimately pay for.

[25] Ibid., p. 34.

Overall, these dynamics can disincentivise longer-term strategic investments, the immediate benefits of which are less defined or depend on the materialised decarbonisation pathway.[26]

3.5 In the context of net-zero objectives and the associated uncertainty around the needs of the markets, regulators are seeking to ensure that networks secure sufficient and timely investment, without inflating the bills unduly.

3A Re-openers

3.6 Re-opener mechanisms allow for the prospective modification of revenue allowances over the course of the regulatory period. These mechanisms are intended to increase the flexibility of price controls that may need to be adapted to the changing environment of the energy transition—e.g. due to new net-zero policies or market requirements over the price control period.

3A.1 The case of the UK

3.7 Table 3.1 outlines the re-openers related to net-zero that are available to gas transmission (GT) and gas distribution (GD) networks in the ongoing RIIO-2 price control. We provide further details about specific cross-sectoral net zero re-openers—i.e. the first three rows in Table 3.1—below the table.

[26] A corresponding effect of this dynamic may be the substitution of long-term capital expenditure by more asset-light operational expenditure.

Table 3.1 RIIO-2 re-openers that are related to net-zero developments

Re-opener	Description	Sectors
Net zero re-opener	To allow changes in policy, the role of the network companies, as well as technological or market [developments] to be reflected in company allowances.	All sectors[1]
Net zero and re-opener development use-it-or-lose-it (UIOLI) allowance	To enable net zero-related development work and small value net-zero facilitation projects to go ahead.	All sectors[1]
Net zero preconstruction and small projects re-opener	To capture preconstruction projects and small value net-zero facilitation projects that are too big for the UIOLIA but too small to be captured by the larger Net Zero related re openers as it does not meet feasibility requirements.	GD & GT
Heat policy re-opener	To respond to policy decisions on the future of gas and heat.	GD
New large load connection(s) re-opener	To increase baseline allowances to fund specific network reinforcement driven by the connection of large loads and gas producers.	GD
Major projects re-opener	To assess funding for projects to reduce compressor emissions.	GT
Incremental capacity re-opener	To assess requests for capacity in GT.	GT

Note: [1] At this stage, 'all sectors' does not include electricity distribution (ED) because RIIO-ED2, the upcoming price control for the ED sector, will start two years later than RIIO-2 for the GD, GT and electricity transmission sectors.

Source: Ofgem (2020), 'RIIO-2 Final Determinations - Core Document', 8 December, Table 10, https://www.ofgem.gov.uk/publications/riio-2-final-determinations-transmission-and-gas-distribution-network-companies-and-electricity-system-operator (last accessed on 20 August 2021).

Net zero re-opener

3.8 The net zero re-opener has a wide scope of allowing for changes to the price control allowances related to the achievement of net zero. In its determination, Ofgem provides the following examples:[27]

> […] changes in government policy, the successful trial of new technologies or other technological advances, changes in the pace or nature of the uptake of low carbon technologies and new investment arising from the agreement of a Local Area Energy Plan (or equivalent arrangements).

[27] Ofgem (2020), 'RIIO-2 Final Determinations - Core Document', 8 December, para. 8.42, https://www.ofgem.gov.uk/publications/riio-2-final-determinations-transmission-and-gas-distribution-network-companies-and-electricity-system-operator (last accessed on 20 August 2021).

3.9 It can be triggered only by Ofgem—however, networks can draw issues to Ofgem's attention. The materiality threshold for the re-opener to be triggered is 0.5% of the average annual ex ante base revenue allowance, to ensure that the mechanism is used only for significant changes.

Net zero and re-opener development use-it-or-lose-it (UIOLI) allowance

3.10 'Net zero and re-opener development use-it-or-lose-it (UIOLI) allowance' is additional to the broader net zero re-opener and focuses on the early design and pre-construction work, as well as small net-zero facilitation projects. Accordingly, this re-opener covers the lower-cost initiatives.

Net Zero pre-construction and small projects re-opener

3.11 The 'Net zero pre-construction and small projects re-opener' closes the gap between the 'Net zero and re-opener development use-it-or-lose-it (UIOLI) allowance', which focuses on very low-cost initiatives, and the 'Net zero re-opener', which is designed only for very material changes. Ofgem expected the projects above c. £1m but below 0.5% of the annual base revenue to fall into the category eligible for the 'Net zero pre-construction and small projects re-opener'.

3B Innovation incentives and allowances

3.12 In addition to increasing the flexibility of regulatory frameworks with re-openers, regulators provide specific net-zero allowances at the price control review stage. These allow networks to recover the costs of innovative projects which will not be delivered as part of business-as-usual and there may be a risk that innovation will not be successful.

3B.1 The case of the UK

3.13 In its latest RIIO-2 price control review, Ofgem uses the Strategic Innovation Fund (SIF) and the Network Innovation Allowance (NIA).[28]

3.14 The **Strategic Innovation Fund** (SIF) focuses on high-value innovation projects of over £5m that would not otherwise be pursued by operators as business-as-usual activities or via the NIA funding. There is a default level of companies' compulsory contribution equal to 10% of the project costs. The

[28] Ofgem (2020), 'RIIO-2 Final Determinations - Core Document', 8 December, Table 10, paras 8.52–89, https://www.ofgem.gov.uk/publications/riio-2-final-determinations-transmission-and-gas-distribution-network-companies-and-electricity-system-operator (last accessed on 20 August 2021).

overall funding across the networks is limited to £450m—however, it could be expanded if necessary.

3.15 The **Network Innovation Allowance** (NIA) focuses on innovative projects related to the energy system transition and provision of support to vulnerable consumers. The overall funding across the networks is £209.4m. Ofgem has stated that it may increase GT and GD NIA funding for hydrogen innovation.[29]

3B.2 The case of Austria

3.16 In the latest price control review for gas TSOs, the Austrian regulator, E-Control, incentivised networks to contribute to the decarbonisation of energy systems. The regulator focused on enabling networks to carry out feasibility studies and pilot projects in the following areas:[30]

- efficient use of the existing TSO's capacity or creation of new services with new equipment and operational measures (e.g. digitalisation);
- feeding low-carbon, biogenic or synthetic gases into the grid;
- addressing sector coupling.

3.17 E-Control awards an annual lump sum for R&D projects in these areas if they satisfy a number of additional criteria. If the actual expenditure is different from the forecast, the amount is adjusted accordingly. The list of criteria includes expected reduction of CO_2, innovation, and the potential to generate net benefits.

3.18 Furthermore, two more distinct treatments are applied to these projects:

- separate, possibly shorter, depreciation profiles;
- a premium of 1.5% on the cost of equity (without the compensation of the capacity risk).[31]

[29] Ibid., p. 106.
[30] E-Control, 'Methodology pursuant to section 82 Gaswirtschaftsgesetz (gas act, gwg) 2011 for the fourth period for transmission systems of Austrian gas Transmission system operators (TSOs)', section VI.
[31] A sector-wide risk premium of 3.5% and an additional individual risk premium are typically added to the cost of equity to compensate networks for the capacity (volume) risk. However, these premia do not apply to the R&D projects, to which a different 1.5% premium applies. See section 2D.1 for details.

3B.3 The case of Italy

3.19 The Italian regulator (ARERA) is also considering, by means of public consultations,[32] creating a support mechanism to foster innovation in the fields of grid optimisation, infrastructure repurposing and the networks' technological development. The areas of innovation include, notably, the production, transportation, stocking and blending of hydrogen gas.

3.20 Said incentives, which are still in development, would be awarded through a selection process, presided by an ad hoc panel, and would be financed both through in-tariff and extra-tariff contributions, the latter capped at a maximum amount of around €35m–€40m.[33]

4 Concluding remarks

4.1 This note has reviewed a number of regulatory tools that European regulators have used to manage potential asset stranding risk to gas networks and to facilitate the delivery of net-zero targets. These regulatory tools are often used in combination.

4.2 Figure 4.1 summarises the tools, discussed in this note, that European regulators have used in recent price controls to manage asset stranding risk.

Figure 4.1 Selected policies for managing asset stranding risk by country

	UK	BE	NL	AT	FR
Asset lives	✖	✔	✖	✖	✔
Depreciation profile	✔	✖	✔	✖	✖
RAB inflation indexation	✖	✖	✔	✖	✖
WACC uplift	✖	✖	✖	✔	✔

Note: UK: the United Kingdom, which in this note refers to GB precedent; BE: Belgium; NL: the Netherlands; AT: Austria; FR: France.

[32] ARERA (2021), 'Infrastrutture del gas naturale: progetti pilota di ottimizzazione della gestione e utilizzi innovativi. Documento per la consultazione 250/2021/R/GAS', 15 June, https://www.arera.it/allegati/docs/21/250-21.pdf (last accessed on 20 August 2021).

[33] For context, the total allowed revenue of gas transmission networks in 2021 is €2.2bn. See ARERA (2020), 'Delibera 26 maggio 2020. 180/2020/R/gas', 27 March, https://www.arera.it/it/docs/20/180-20.htm (last accessed 25 August 2021).

Source: Oxera.

4.3 Figure 4.2 outlines further net-zero regulatory tools, such as re-openers and innovation allowances, that are being deployed, to accommodate uncertainty in relation to the energy transition.

Figure 4.2 Selected regulatory developments to accommodate the uncertainty in relation to the energy transition

UK	AT	IT
• net zero price control re-openers • Strategic Innovation Fund • Network Innovation Allowance	• R&D projects allowance and cost of equity uplift	• support mechanism to foster innovation via in-tariff and extra-tariff contributions (in development)

Note: UK: the United Kingdom, which in this note refers to GB precedent, AT: Austria, IT: Italy.

Source: Oxera.