Evidence-based assessment of accelerated depreciation of gas transmission and distribution networks

January 2026

Table of contents

Appendices

Tables

Figures

Boxes

Definitions

AER	Australian Energy Regulator
AMP	Asset Management Plan
CPI	Consumer Price Index
DPP	Default Price Path
EY	Ernst & Young
GDB	Gas Distribution Business
GIC	Gas Industry Company
GJ	Gigajoule
LNG	Liquified Natural Gas
LPG	Liquified Petroleum Gas
NPV	Net Present Value
PJ	Petajoule
RAB	Regulatory Asset Base
WACC	Weighted Average Cost of Capital

Executive summary

The DPP4 draft decision published by Commerce Commission on 27th November 2025 (referred as "DPP4 draft decision") adopts a highly conservative view of future gas demand, anticipating gas network asset stranding. Under DPP4 draft decision, the assumed economic life of transmission and distribution assets is significantly shorter than the standard economic life.

The Commerce Commission appears to justify its approach to depreciation by long-term demand modelling which posits that gas transmission and distribution will effectively end between 2050 and 2060. However, the Commission's approach to depreciation is both inconsistent with the evidence on gas market developments and is internally inconsistent with assumptions about future investment in the network:

- The long-term gas demand trajectory (carried out by Concept Consulting) published by the Commission does not take into account changes in Government policy and technological developments which will likely sustain demand for gas transmission and distribution networks well into the future
- The long-term model published by the Commission implies a "death spiral" in demand, yet it also assumes that both Firstgas and gas distribution businesses (GDBs) will continue making significant network investment necessary to keep the pipelines operating, even though these investments will become stranded
- Financial and volume forecast data submitted to the Commerce Commission by the GDBs is inconsistent with the actual market valuations of those networks. While the Commerce Commission considers accelerated depreciation as an NPV=0 adjustment, markets tend to value front-loading of cash flows. Hence, the networks clearly have an incentive to argue a pessimistic case to the Commerce Commission while presenting more realistic prospects to investors. In such situations of information asymmetry, it is important for the regulator to take broader market information into account.

Overall, while the Commission argues that accelerated depreciation is necessary to preserve the incentives for network owners to ensure the necessary re-investment and maintenance of the network, the Commission's approach risks causing the very stranding it seeks to address. Significant increases in network prices in the short term, combined with near-term constraints on gas supply, invite a dynamic demand response to accelerate the decline in gas usage instead of bridging the sector to alternative gas supplies.

In essence, the Government's recent decision with respect to LNG imports, together with the investment in potential alternative gas supplies, indicates likely long-term demand for gas transmission and distribution infrastructure well beyond 2050. Brookfield's recent acquisition of both transmission and distribution assets further indicates that investors do not share the Commission's assessment.

Overall, the Commission's approach to **asset stranding risk** is based on very particular assumptions about the gas sector. Given the risks to the sector from short-term price shocks, the Commission should take great care to avoid **regulatory settings based on low probability outcomes**.

1 Introduction

The Commerce Commission has expressed concern that the gas transmission and distribution networks face a heightened risk of asset stranding as New Zealand transitions away from natural gas. In response, starting in DPP3, the Commission applied adjustment factors to shorten the economic life of gas transmission and distribution assets, allowing gas pipeline businesses to accelerate their asset depreciation and recover capital costs over a shorter period.

Accelerated depreciation front-loads the annual depreciation allowance and therefore immediately raises the allowable revenue recovered through transmission and distribution charges. This approach results in higher near-term prices faced by consumers. Higher prices discourage industrial, commercial, and residential users from continuing to rely on gas, incentivising them to disconnect from the gas network.

Given these dynamics, it is critical that the regulatory settings strike the right balance between ensuring a fair return on investment for gas pipeline businesses and supporting price affordability and efficient utilisation of the network.

We have undertaken a detailed review of the assumptions that underpin DPP4 draft decision. **Our assessment indicates that the Commission's view of future gas demand is based on assumptions and information about the market that are not consistent with the incentives or the actual behaviours of the market participants.** The Commission's entire approach is based on a scenario in which the market essentially does not respond to the need for or the incentive to adjust to current market trends, such as efforts to remove regulatory barriers, investments in biogas, and the development of LNG import options.

In Section 2 of this report, we examine the internal logic of the Commission's long-term financial modelling assumptions. While the DPP4 draft decision naturally focuses on the next 5-year period, the Commission has itself developed data to examine whether its approach makes logical sense over the long term. We conclude that on the Commission's own analysis, its approach to accelerated depreciation does not work.

In Section 3, we examine the demand forecasts published by the Commission by comparison with the demand scenarios developed by Ernest & Young (EY) for the Gas Industry Company in thorough consultation with gas users. While GIC and the Commerce Commission obviously have different regulatory responsibilities, the sector overall is unlikely to achieve desirable outcomes if the two regulators act on the basis of materially divergent forecasts. Our review shows that the Commission has adopted a forecast that is closest to the least likely scenario.

In Section 4, we illustrate how regulatory decisions based on pessimistic demand assumptions, such as accelerated depreciation, risk creating a self-fulfilling decline in gas usage. By increasing prices today, accelerated depreciation can contribute to the very disconnection effects it seeks to guard against.

Finally, in Section 5, we examine the recent Brookfield/Clarus transaction to understand investor expectations regarding the future of the gas transmission and distribution network. We find that the market valuation of Firstgas is not consistent with investor perception of stranding risk or with the financial model adopted by the Commission.

2 Internal inconsistencies within the Commerce Commission analysis

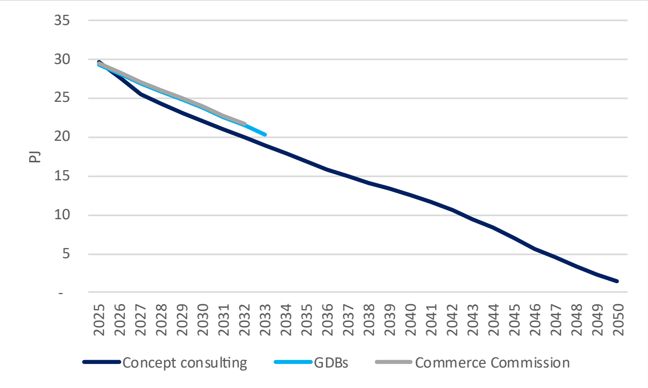
The draft decision places significant weight on the risk that gas transmission and distribution assets will become stranded. This risk assessment underpins the Commission's continued use of accelerated depreciation. For its analysis, the Commission has relied on data about future network investment decisions from the GDBs. and on long-term demand projections which, while independent, appear to rely on the GDBs' assessments. Box 2.1 discusses the various gas demand forecasts and explains our approach.

Box 2.1: Gas demand forecasts used in the DPP4 draft decision

In forming its view of future gas demand, the Commission has relied on several forecasting approaches:

- GDBs were asked to produce their own demand forecasts for the DPP4 period.
- The Commission engaged Concept Consulting to develop an independent forecast, which shows a similar trend but projects demand approximately 5 percent lower than the GDB forecasts. The forecast period is between 2026 and 2050.
- The Commission developed its own view for the DPP4 period, which is approximately 1 percent higher than the GDB forecasts.

All three forecasts imply similar levels and trends in gas demand. The Commission accepted both the GDB forecasts and the Concept Consulting forecast as reasonable.[1] The figure below shows forecasts undertaken by Concept Consulting, GDBs, and the Commission.



To compare the Commission's long-term view with more realistic forecasts, we assume that the Concept Consulting's forecast beyond the DPP4 period is a reasonable representation of the Commission's apparent long-term view on gas demand. This is the only long-term projection indicative of the Commission's view. Accordingly, we use a blended forecast which combines the Commission's figures for the DPP4 period and Concept Consulting's forecast for the period from 2033 to 2050. We refer to this blended projection as the "DPP4 forecast".

Source: Concept Consulting Gas DPP4 demand forecast; the Commerce Commission (2025), Price-Quality Regulation 1 October 2026 DPP Reset Draft decision - Constant price revenue growth model

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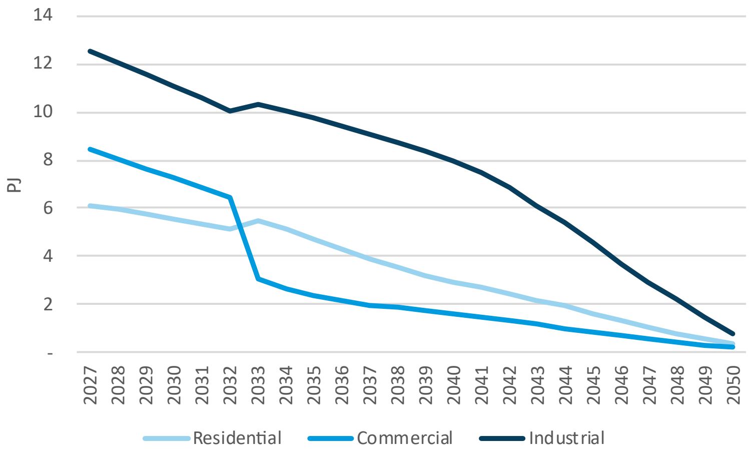
[1] Page 39. Commerce Commission (November 2025). "Gas DPP4 reset 2026- Default price-quality paths for gas pipeline businesses from 1 October 2026"

The Commission’s draft decision adopts a gas demand forecast in which residential, commercial, and industrial consumption declines rapidly and enters a “death spiral” dynamic. As shown in Figure 2.1, the DPP4 forecast implies a substantial reduction in gas demand over the DPP4 period and beyond, driven by assumed user disconnection and fuel switching.

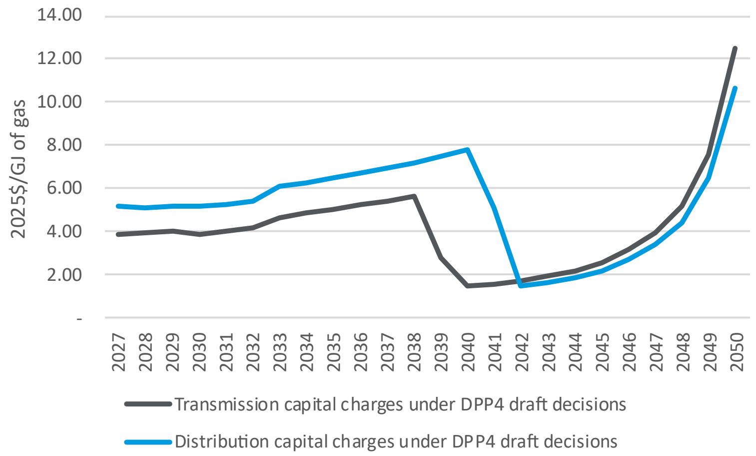
Figure 2.1: Gas distribution demand forecast



**We use the Commission’s figures for the DPP4 period and use Concept Consulting’s forecast for the period from 2033 to 2050.*
Source: Commerce Commission (November 2025) “Price-Quality Regulation 1 October 2026 DPP Reset Draft decision - Constant price revenue growth model” input tab; “Concept Consulting Gas DPP4 demand forecast” Concept tab

Such a sharp decline in gas demand has material implications for allowable revenue when combined with accelerated depreciation. While actual gas transmission and distribution pricing is obviously more complex, we use the DPP4 forecast to calculate an average capital charge per GJ over the long term. To ensure consistency, we calculate transmission capital charges for the residential, commercial and industrial users by excluding the part of the annual revenue requirement which will be recovered from the transmission-only users. Figure 2.2 shows the projected transmission and distribution capital charge (depreciation plus return on capital) for residential, commercial and industrial users per GJ of gas, expressed in real terms, using the Commission’s forecasts of future investment, demand, and its accelerated depreciation provisions.

Figure 2.2: Transmission and distribution capital charge under accelerated depreciation for residential, commercial and industrial users (in real terms)



Concept Consulting produces demand projection for gas distribution networks. To investigate the implications of the forecast, transmission-only users (such as petrochemical producers and electricity generators) are excluded by removing the share of transmission revenue attributable to these users and calculating per-GJ capital charges using residential, commercial, and industrial demand as the denominator. We note that transmission only customers account for 70% of volume but about 20% of revenue on the transmission network.
Source: Castalia analysis. See Appendix A for methodology.

In essence, based on the Commission's view on gas demand, the transmission and distribution capital charges per GJ rise until the existing asset bases, subject to accelerated depreciation, are fully depreciated. Then the charges fall steeply as the asset base re-adjusts and rise again as ongoing capital investments are incorporated into the regulatory asset base (RAB) and recovered over a diminishing user base. By 2050, transmission capital charges alone are forecast to reach approximately $12/GJ, more than three times the level at the beginning of DPP4. Distribution capital charges are forecast to reach $10/GJ, almost double the level at the beginning of DPP4. This pattern is characteristic of a death spiral, where rising prices drive users off the network, leaving remaining users to bear an ever-increasing cost burden.

Crucially, this outcome is not consistent with the investment planning assumptions of Firstgas and GDBs. For example, the Firstgas Asset Management Plan (AMP) outlines sustained and ongoing capital expenditure, including:

- Average capex of approximately $34 million per year between 2026 and 2035
- $22 million of planned capex in 2035 alone

In addition, Vector forecasts a total of $80 million of Capex between 2026 and 2035.[2] PowerCo also records over $130 million of capital expenditure for the next ten years. [3]

[2] Vector (2025). Gas Distribution Asset Management Plan. https://blob-static.vector.co.nz/blob/vector/media/vector-2025/04-june_gas-distribution-2025-amp-v0-6-2_updated-250625.pdf

[3] PowerCo (2025). Gas Asset Management Plan. https://www.powerco.co.nz/-/media/project/powerco/powerco-documents/who-we-are---pricing-and-disclosures/disclosures/gas-disclosures/1-gas-asset-management-plans/2025-gas-asset-management-plan_v2.pdf

Such levels of ongoing investment are inconsistent with the death spiral implied in the DPP4 draft decision. The projected capital charges would indicate that if the gas pipeline businesses believed in the demand forecast, it would be unlikely to expect to recover their investments undertaken in the 2030s. The pace of decline in demand past mid-2040s is inconsistent with the likely prices at that time. The projected rise in the capital charges would likely lead to more rapid transition away from gas than is implied in the demand forecast as it is unlikely that the remaining users in the 2045 to 2050 period would find gas affordable.

A network operator would not commit to sustained capital expenditure if it expected the network to become uneconomic or largely unused in a decade. If the AMPs of the gas pipeline businesses are correct, then the Commission's view on demand is overly pessimistic and materially overstates the risk of stranding.

3 Independent modelling indicates higher and more sustained gas demand

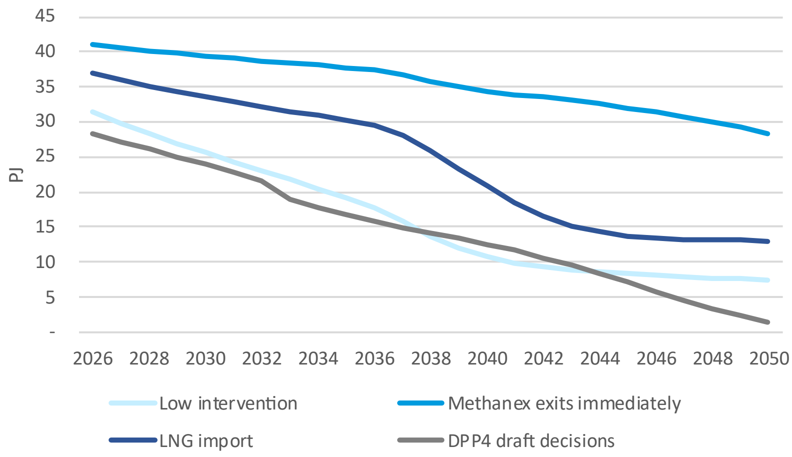
The Commission's draft decision relies on a gas demand forecast that assumes a rapid decline in consumption across residential, commercial, and industrial customer classes. This forecast underpins the Commission's view that transmission and distribution assets face a high risk of economic stranding. However, independent modelling prepared for the Gas Industry Company (GIC) by EY presents a materially different outlook. Across all scenarios modelled by EY, gas demand remains significantly higher than that assumed by the Commission.

EY developed three scenarios—Low Intervention, Methanex Exits Immediately, and LNG Import—to reflect different combinations of supply conditions and demand responses. In all cases, the modelling incorporates short-term supply constraints, long-term decarbonisation pressures, and opportunities for fuel switching. Despite these considerations, EY projects that substantial demand for natural gas will remain across all sectors for an extended period.

Figure 3.1 compares EY's demand forecasts with the DPP4 forecast. We note that the DPP4 forecast does not forecast demand from transmission-only users. To ensure consistency, we have adjusted the EY forecasts by removing such demand.

The contrast is pronounced: whereas the Commission bases its view of the future on the forecast accelerated, near-term decline in throughput, GIC is expecting declining but sustained consumption from industrial, commercial, and residential users even under its most pessimistic scenario.

Figure 3.1: Gas demand from residential, commercial, and industrial users



Source: EY gas supply and demand forecast, 2024. Demand from transmission-only users such as large petrochemicals, co-generation, and electricity generators are excluded.

Crucially, the Commission's view on gas demand is most similar to the GIC's "low intervention scenario"—a scenario in which the sector essentially allows itself to die out without taking economically justified and efficient adjustment measures.

Table 3.1 summarizes the assumptions in each scenario. In its work for GIC, EY first fits regression models to historical demand data, then incorporates scenario-driven policy, supply, and behavioural assumptions, and ultimately applies a Bass-diffusion model to shape the long-term decline trajectory.

Table 3.1: EY sectoral demand assumptions by scenario

Sector / End-use	Low Intervention	LNG Import Scenario	Methanex Exits Immediately
Supply conditions	Severe supply shortages; limited new supply investment	Supply shortfall to 2026, then new LNG supply added	Large supply freed by Methanex exit; demand for others remains high
Industrial – High-temperature heat	Significant cuts; many users close; demand forced down beyond low-temp uses	~25% reduction	Largely maintained; only gradual decline; high-temperature remains dependent on gas
Industrial – Medium & low-temperature heat	Substantial forced reductions due to shortage; exceeding low-temp demand	Switching occurs where feasible; moderate reductions	Low-temp processes switch away; medium-temp partially maintained
Commercial – Space heating	~50% reduction by 2035	~40% reduction by 2035	~30% reduction by 2035
Commercial – Water heating	~40% reduction by 2035	~25% reduction by 2035	~9% reduction by 2035
Residential – Space heating	~60% reduction by 2035	~45% reduction by 2035	~40% reduction by 2035

Sector / End-use	Low Intervention	LNG Import Scenario	Methanex Exits Immediately
Residential – Water heating	~40% reduction by 2035	~30% reduction by 2035	No reduction assumed
Overall demand trend	Sharp decline driven by supply shortages; widespread forced exit	Moderated decline due to restored supply and fuel-switching incentives	High sustained demand across sectors despite Methanex closure
Key drivers	Lack of supply forces early disconnection and process closures	LNG restores supply, allowing continued gas use but incentivising switching	Supply freed up enables stable demand by remaining sectors

Source: EY (2024). Gas Supply and Demand Study

EY's modelling shows that:

- Even under pessimistic assumptions (**Low Intervention scenario**), such as prolonged supply shortages, demand remains higher than in the Commission's view on gas demand because many industrial and commercial users maintain gas use for high-temperature or process-critical applications
- Under the **LNG Import scenario**, the introduction of LNG restores supply adequacy and supports continued gas use in both industrial and commercial sectors
- Under the **Methanex Exits Immediately** scenario, Methanex's departure frees up supply for other sectors, resulting in relatively stable demand from industrial users and modest declines in commercial and residential use.

3.1 LNG import policy supports continuing gas use

In October 2025, the Government announced policy support for developing an LNG import terminal at Taranaki. The purpose of this initiative is to address declining domestic gas production and improve resilience and security of supply

By supplementing domestic gas with LNG, the Government is signalling that gas will continue to have a material role in New Zealand's energy system for the foreseeable future. This policy direction is fundamentally inconsistent with the Commission's assumption that gas demand will decline to near zero.

If LNG importation proceeds, the transmission and distribution network will remain essential to transport LNG-sourced gas to industrial, commercial, and residential users and power stations. This would materially extend the economic life of the transmission and distribution system and significantly reduce stranding risk.

Regulation must remain aligned with government policy. A demand forecast implying imminent network obsolescence is inconsistent with active governmental steps that prolong gas availability and network utilisation.

The Government's announcement already shows that EY's "low intervention" scenario is unlikely compared to the LNG import scenario.

3.2 Alternative gases

The Commerce Commission has taken an ambiguous position with respect to the development of alternative gases (such as biogas). On the one hand, the Commission is of the view that its regulatory regime applies only to the transport of “natural gas”, which is distinct from alternative gases. The Commission also appears to consider that some admixture of alternative gases is consistent with this legal view and willing to allow inclusion of some investments associated with alternative gases into the regulatory asset base.

We are not able to comment on the Commission’s legal interpretation, but it is clear that the Commission’s concern about the need for accelerated depreciation is based on the assumption that the network only has economic value in the carriage of primarily natural gas. This is clearly not the case. Whatever the Commission’s view about the scope of its regulatory powers, there is no obvious reason why it should base its approach to depreciation on natural gas alone.

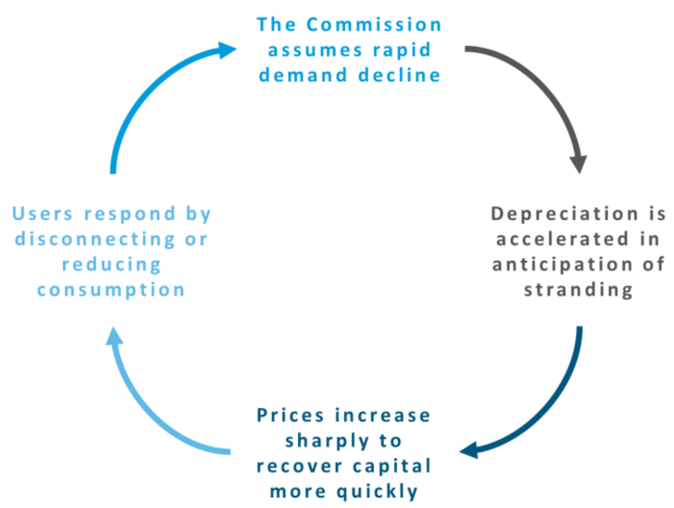
The likely availability of alternative gases in the future further underscores the Commission’s choice of a particularly unrealistic scenario.

4 Accelerated depreciation reinforces demand decline

Government policy and more realistic scenario modelling indicate that natural gas is likely to continue playing a meaningful role in New Zealand’s energy system. While gas demand will decline under all scenarios, a decline that is consistent with the users’ ability to cover the costs of the network should not be confused with a “death spiral”.

However, by acting as though a collapse in demand is inevitable, the Commission risks bringing about the very outcome it is trying to insure against. Accelerated depreciation substantially increases allowable revenue in the near term, raising gas transmission and distribution charges for all users. Higher prices, in turn, discourage continued gas use, particularly among commercial and industrial consumers with viable alternatives. This would accelerate disconnection and reduce throughput on the network.

Figure 4.1: A self-fulfilling prophecy

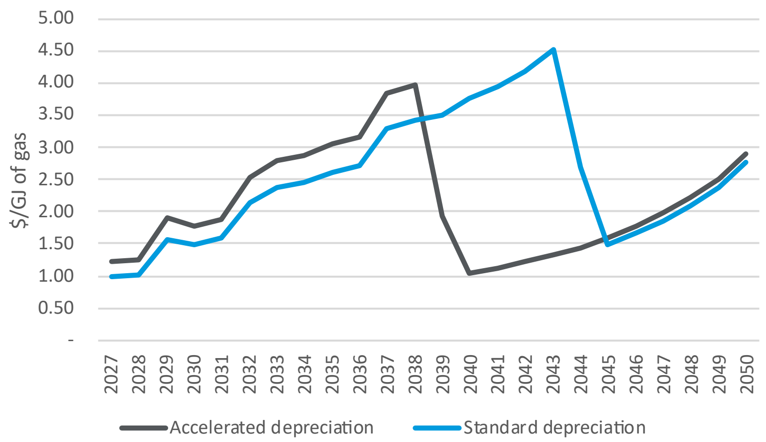


Our modelling confirms this dynamic. We compared system-wide transmission capital charges per GJ under accelerated and standard depreciation across different scenarios. We find that accelerated depreciation:

- Produces substantially higher transmission capital charges in the near term, before existing assets are fully depreciated
- Provides little benefit beyond bringing forward the price drop that occurs naturally once the existing RAB is fully depreciated.

Figure 4.2 shows the result under the DPP4 forecast for the transmission network.

Figure 4.2: Transmission capital charges per GJ of gas—DPP4 draft decision (in nominal terms)



**This figure estimates the system-wide capital charge per GJ. It includes all gas transported on the transmission network, not just the residential, commercial, and industrial users shown in Figure 2.2. Specifically, the Figure 4.2 calculation combines demand from residential, commercial, and industrial consumers forecast in the DPP4 forecast with demand for electricity generation, cogeneration, and petrochemical production forecast under EY's Low Intervention scenario. This approach provides the best available estimate of total system demand while remaining anchored to the DPP4 forecast assumptions.*

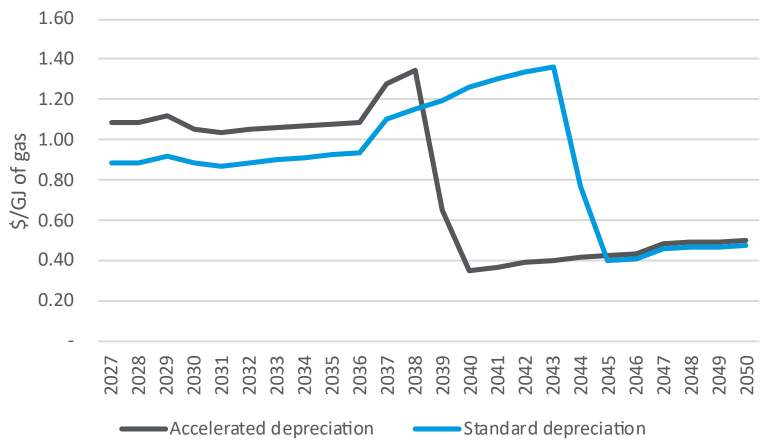
Source: Castalia analysis. See Appendix A for methodology.

Between 2027 and 2038, prices under accelerated depreciation are on average 19 percent higher than under standard depreciation. In 2039, prices under accelerated depreciation drop as the existing asset base is fully depreciated.

Prices under standard depreciation continue rising, reaching the accelerated-depreciation peak in 2041, and continue increasing for two years before eventually falling as the existing RAB is fully recovered.

Figure 4.3 shows the result of the more likely scenario of LNG import.

Figure 4.3: Transmission capital charges per GJ of gas—LNG import (in nominal terms)



Source: Castalia analysis. See Appendix A for methodology.

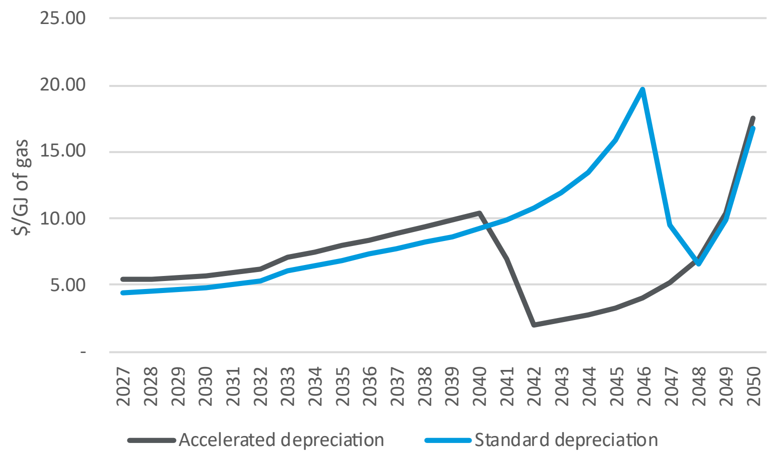
Under the more realistic LNG Import scenario, prices under accelerated depreciation are again significantly higher in the near term. After 2038, prices under standard depreciation continue rising, reaching the accelerated-depreciation peak in 2042, and continue increasing for one year before eventually falling as the existing RAB is fully recovered. For the remainder of the modelling period, prices under standard depreciation remain consistently lower than under accelerated depreciation.

Distribution capital charge also does not enter a death spiral

We examine the distribution capital charge trajectories faced by residential, commercial, and industrial users. For this analysis, we aggregate data across all distribution networks.

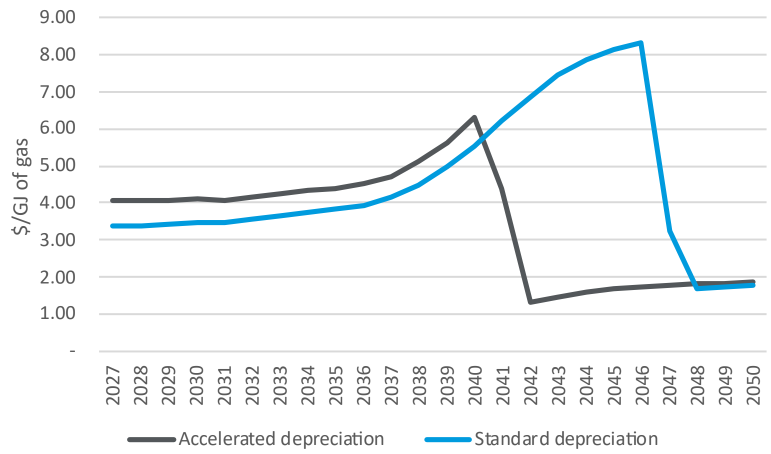
Figure 4.4 show the estimated capital charge for the distribution networks over the long term under both the DPP4 forecast and the more likely LNG import scenario.

Figure 4.4: Distribution capital charges per GJ of gas—DPP4 draft decision (in nominal terms)



Source: Castalia analysis. See Appendix A for methodology.

Figure 4.5: Distribution capital charges per GJ of gas—LNG import (in nominal terms)

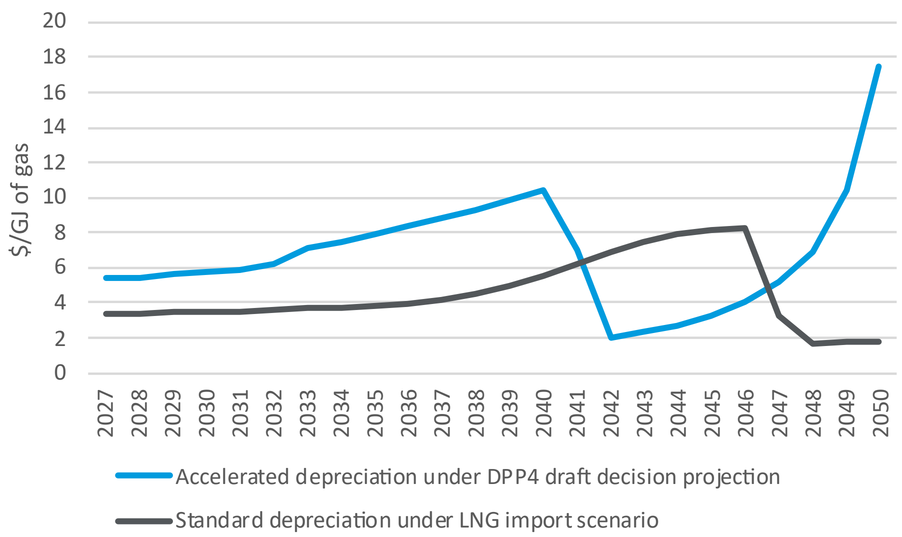


Source: Castalia analysis. See Appendix A for methodology.

While accelerated depreciation lowers the pricing peak under both demand scenarios, it again primarily has the effect of bringing forward a future price drop at the expense of materially higher prices in the near term.

To form an overall picture, we compare price trajectories under accelerated depreciation and the DPP4 draft decision projections with those under a more plausible demand scenario involving LNG imports and standard depreciation. Under the latter scenario, which reflects likely market developments, capital charges are materially lower than those implied by the DPP4 forecast and avoid destabilising swings.

Figure 4.6: Comparison between DPP4 forecast and LNG import scenario (in nominal terms)



For the distribution networks as a group, although accelerated depreciation changes the timing of cost recovery, it does not materially alter the long-run price path. Its primary effect is to bring forward the price drop that would occur naturally once the existing RAB is fully depreciated. The trade-off is that prices are significantly higher in the near term. These elevated prices discourage gas use and increase the likelihood of disconnection. In this way, accelerated depreciation can unintentionally reinforce the very demand decline it is designed to manage, creating a self-fulfilling dynamic in which short-term price shocks lead to long-term reductions in network viability.

5 Investor behaviour contradicts stranding narrative

The recent Clarus/Brookfield transaction provides an important real-world test of whether investors believe the gas transmission and distribution network faces the risk of stranding. Public reporting indicates that Brookfield acquired Clarus' gas portfolio, including Firstgas' transmission and distribution businesses, for approximately $2 billion.

As the valuation breakdown of the purchase price is not publicly disclosed, we used publicly available information to remove the non-gas-pipeline businesses within the $2 billion portfolio and infer the portion attributable to Firstgas' regulated transmission and distribution assets. The resulting implied valuation aligns closely with Firstgas' audited 2024 RAB. In other words, the market paid a price broadly equivalent to the regulatory value of the transmission and distribution assets. Table 5.1 shows our high-level breakdown of the Brookfield/Clarus transaction. Our approach is outlined in Appendix B.

Table 5.1: Breakdown of the Brookfield/Clarus transaction

Component	Valuation (in million)
Total acquisition price	NZ$2,000
Minus: Rockgas	NZ$325
Minus: Flexgas	NZ$178
Minus: Firstlight Network	NZ$273
Firstgas total	**NZ$1,224**
Firstgas distribution	NZ$235
Firstgas transmission	NZ$989

According to Firstgas' regulatory disclosures, the RAB for its transmission and distribution assets as of September 2024 is NZ$1,203 million, with the transmission RAB being NZ$983 million, and the distribution RAB being Z$232 million. This is very close to our estimate of the implied purchase prices above.

A purchase price equal to RAB indicates that investors do not believe the gas network will become stranded. One could argue that this valuation validates the approach taken by the Commission—on this interpretation, the market valuation shows that the Commission has successfully addressed the risk of asset stranding. However, this positive interpretation is inconsistent with the evidence:

- The transaction was closed—and hence the valuation was reached—prior to the DPP4 draft decision. In other words, at the very least, it shows that further acceleration of depreciation proposed in DPP4 would deliver a windfall gain to the investors
- As discussed previously in this report, the Commission's own modelling shows that the investors will be required to undertake sustaining capex from the mid-2030s which they—on the Commission's view on gas demand—would be unlikely to recover. A rational investor would anticipate that and would discount the current purchase price accordingly. By being willing to pay the equivalent of RAB, Brookfield signalled that they anticipate being able to recover both the current RAB and the future sustaining capex.

The Brookfield acquisition demonstrates confidence in the continued viability of the gas transmission and distribution network and provides no evidence that further acceleration of depreciation is required.

Appendix A: Technical note of comparing transmission and distribution capital charges under accelerated and standard depreciation

This appendix presents the methodology and results for estimating the per-GJ capital charges that Firstgas are permitted to recover from users of the gas transmission and distribution network under two different depreciation approaches:

- **Accelerated depreciation**, as allowed by the Commerce Commission under the DPP4 draft decision
- **Standard depreciation**, based on conventional asset lives for gas transmission infrastructure.

The analysis examines four gas demand scenarios: DPP4 forecast, low intervention (EY), Methanex exits immediately (EY), and EY LNG import (EY). Across all scenarios, a consistent pattern emerges: accelerated depreciation results in substantially higher per-GJ capital charges in the near term, while delivering little benefit beyond bringing forward the price reduction that would occur naturally once the existing RAB is fully recovered.

This note is structured as follows:

- Comparing accelerated depreciation and standard depreciation
- Approach and assumptions
- Results

The results section focuses on transmission capital charges rather than distribution for two reasons. First, the transmission network is an essential upstream component of the gas supply chain, and the pricing dynamics observed at the transmission level provide clear insight into the broader cost-recovery issues affecting gas users. Second, gas transmission is operated by a single regulated business (Firstgas), which allows the analysis to be undertaken with fewer assumptions and greater transparency. In contrast, gas distribution services are provided by multiple GDBs, and aggregating their capital charges requires additional assumptions that could obscure the core mechanisms being examined.

A.1 Comparing accelerated depreciation and standard depreciation

Under the DPP3 determination, the Commerce Commission allowed Firstgas to apply an accelerated depreciation approach to its gas transmission assets. In its recent DPP4 draft decision, the Commission proposes further acceleration.

Under both accelerated and standard approaches, depreciation is calculated on a straight-line basis. The key difference between DPP4 draft decision accelerated depreciation and standard depreciation lies in the assumed asset life:

- Under **standard depreciation**, gas transmission and distribution assets are assigned a standard economic life of 45 years
- Under **accelerated depreciation**:
  - For transmission network, the Commerce Commission applied an adjustment factor of 0.71 to both the life of new assets and the life of existing assets that had more than 20 years of service life remaining.[4]
  - For distribution network, the Commerce Commission applied four adjustment factors to Firstgas Distribution, GasNet, PowerCo, and Vector, ranging from 0.62 to 0.77. We calculate the weighted average adjustment factor based on the four GDBs' closing RAB in 2024, which results in an aggregate adjustment factor of 0.72.

Table A.1 shows the assumed asset life under both scenarios.

Table A.1: Assumed asset life under standard and accelerated depreciation

Item	Standard depreciation	Accelerated depreciation
Transmission network		
Standard asset life (in years)	45	32.0
Average remaining life for existing asset (at 31/9/2026) (in years)	16.8	14.0
Distribution network		
Standard asset life (in years)	45	32.4
Average remaining life for existing asset (at 31/9/2026) (in years)	17.8	12.9

Source: Commerce Commission Gas Transmission Input Methodologies; Gas Pipeline Businesses Price-Quality Regulation 1 October 2022 Reset DPP Financial Model; Gas Pipeline Businesses Price-Quality Regulation 1 October 2026 DPP Reset Draft decision Financial model

These differences in assumed asset life have a direct impact on annual depreciation charges. Under the building-block model, gas pipeline businesses are allowed to recover depreciation as part of their allowable revenue. A shorter asset life results in higher annual depreciation expenses, which in turn increases the prices charged to gas transmission users in the near term.

A.2 Approach and assumptions

A.2.1 Unit of comparison

We compare the system-level capital charges per GJ of gas transported. This is defined as the total capital charge allowance based on gas pipeline businesses' asset base divided by the volume of gas.

[4] Gas Pipeline Businesses Price-Quality Regulation 1 October 2026 DPP Reset Draft decision Financial model

Firstgas's pricing structure is complex. Its Maui transmission system has two pricing schemes, charging based on both GJ transported and GJ*km. The non-Maui transmission system is priced based on capacity reservation, throughput based on GJ, and overrun fees. Similarly, distribution network charges are composed of fixed charges, variable charges, and capacity charges.

Given this complexity, it is not possible to reliably trace how capital charges are distributed among the different tariff components for different users. For this reason, system-level capital charge per GJ is used as the indicator in this analysis. Although this is not the actual price that consumers pay, it represents the economic cost imposed on society to recover transmission and distribution network capital.

A.2.2 Capital charges allowance

The total capital charge allowance consists of two components:

- Return of capital (depreciation)
- Return on capital (regulated return on investment)

These are calculated annually within the model.

Return of capital (depreciation)

Depreciation is calculated using the straight-line method, based on the assumed asset life.

For existing assets, Firstgas's RAB at the start of DPP4 (1 October 2026) is forecast to be NZ$938 million, and the total RAB of the four GDBs is forecast to be NZ$1.1 billion. Annual depreciation is calculated as the opening RAB (inclusive of revaluation) divided by the implied remaining asset life.

The implied remaining asset life is derived by dividing the opening RAB by the forecast depreciation of the 2024 closing RAB, adjusted by the adjustment factor applied by the Commission.

The opening RAB in each year is calculated as:

$$\begin{aligned} Opening\ RAB\ &= Closing\ RAB\ (previous\ year) - depreciation + revaluation \\ &- asset\ disposals \end{aligned}$$

Revaluation adjusts the RAB for inflation in accordance with the Input Methodologies. For existing assets, revaluation is calculated as:

$$\begin{aligned} (\text{Opening RAB} \times \text{revaluation factor for existing assets}^{5} \\ - \text{disposed assets}) \times \text{revaluation rate}^{6} \end{aligned}$$

Asset disposals are taken directly from the Commission's financial model.

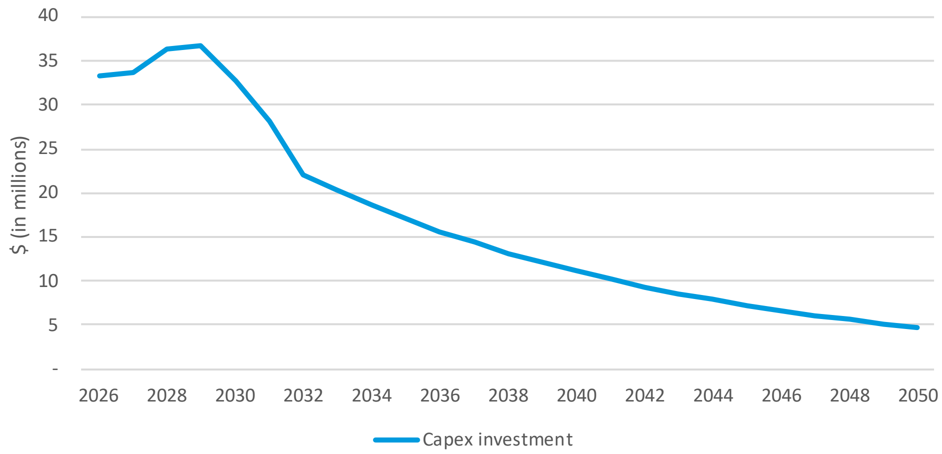
[5] The revaluation factor for existing asset is 0.999. Source: Gas Pipeline Businesses Price-Quality Regulation 1 October 2026 DPP Reset Draft decision financial model

[6] For Firstgas transmission, revaluation rate for 2025 is 3.0 percent; 2026: 2.2 percent; 2027 and onward: 2.0 percent. For the four GDBs, we use weighted average revaluation rate based on the GDB's closing RAB in 2024, which results in revaluation rate for 2025 being 3.0 percent; 2026: 2.7 percent; 2027 and onward: 2.0 percent. Source: Gas Pipeline Businesses Price-Quality Regulation 1 October 2026 DPP Reset Draft decision financial model.

For new assets, depreciation is calculated by dividing the commissioned asset value by the assumed asset life, commencing in the year the asset enters service.

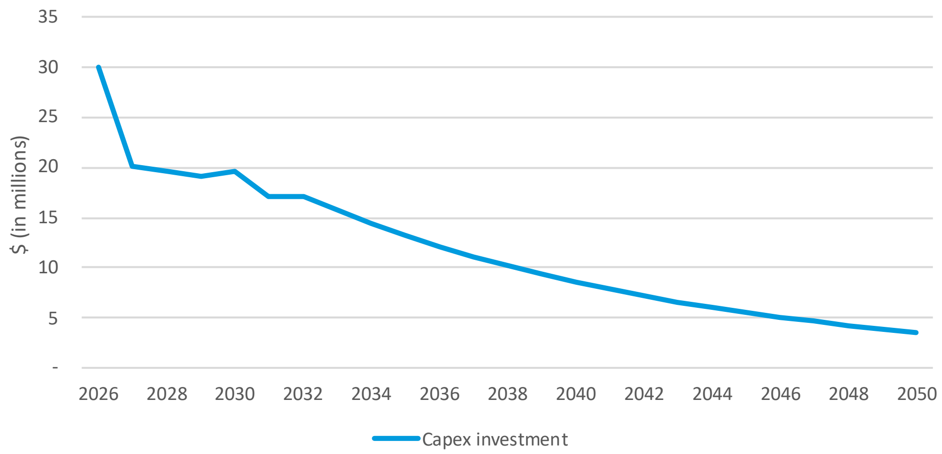
Figure A.1 presents Firstgas's capital investment programme. Figure A.2 presents the total capital investment programme of the four GDBs.

Figure A.1: Capex investment forecast—transmission (in nominal terms)



Source: Gas Pipeline Businesses Price-Quality Regulation 1 October 2026 DPP Reset Draft decision financial model

Figure A.2: Capex investment forecast—distribution (in nominal terms)



Source: Gas Pipeline Businesses Price-Quality Regulation 1 October 2026 DPP Reset Draft decision financial model

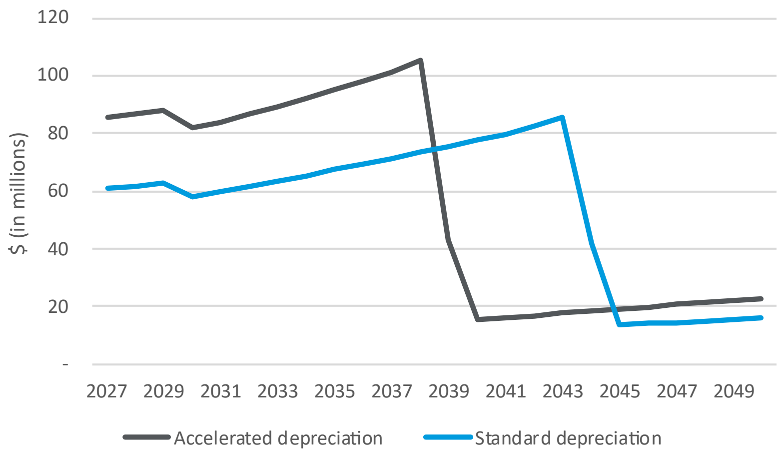
The capital investment profile for the period from 2026 to 2032 is based on the capital expenditure approved in the DPP4 draft decision. For the period beyond 2035, capital expenditure is forecast.

To do this, we calculated the rate of decline in the capital expenditure approved in the DPP4 draft decision for transmission and distribution network, both estimated at 8 percent per year. This rate is applied to extrapolate capital investment through to 2050.

In addition, we model a sensitivity scenario in which no further capital investment is undertaken after DPP4. While some ongoing investment would in practice be required to maintain safe and reliable operation of the pipelines into the 2050s, this scenario is used to test an extreme lower-bound case and assess the most conservative outcome.

Figure A.3 shows the resulting transmission asset depreciation profiles under the two scenarios, assuming capital investments continue until 2050.

Figure A.3: Depreciation profiles under accelerated and standard depreciation, assuming continued investment—transmission (in nominal terms)



The sharp decline in 2038 under accelerated depreciation and in 2042 under standard depreciation reflects the point at which the transmission asset base that existed at the start of DPP4 becomes fully depreciated. Although new assets continue to be commissioned through ongoing capital investment, the depreciation associated with these new assets is spread over longer asset lives and therefore does not restore the total depreciation charge to its original level.

Figure A.4 presents the transmission asset depreciation profiles under a sensitivity scenario in which no capital investment occurs after the DPP4 period. While the overall pattern remains similar, total depreciation allowances are lower than in the scenario with continued investment.

Figure A.4: Depreciation profiles under accelerated and standard depreciation, assuming no investment after DPP4—transmission (in nominal terms)

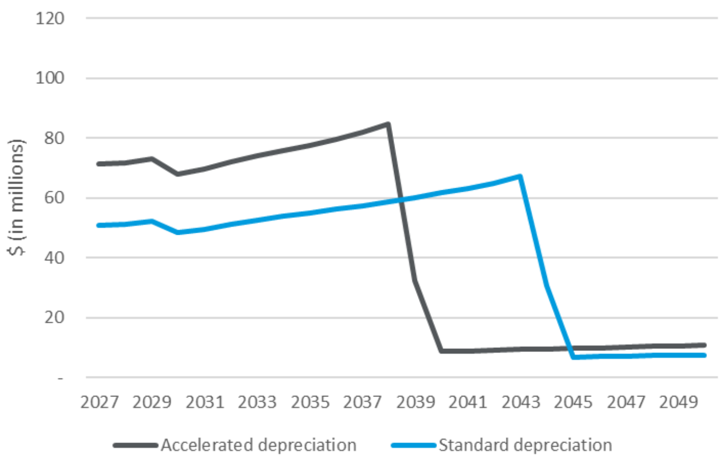


Figure A.5 shows the resulting distribution asset depreciation profiles under the two scenarios, assuming capital investments continue until 2050.

Figure A.5: Depreciation profiles under accelerated and standard depreciation, assuming continued investment—distribution (in nominal terms)

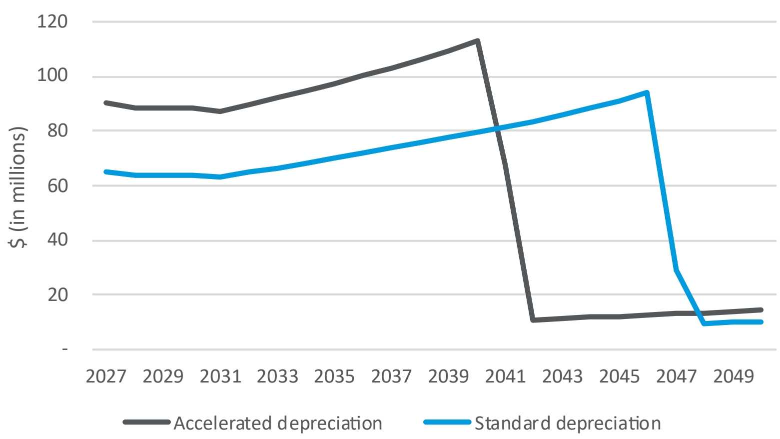
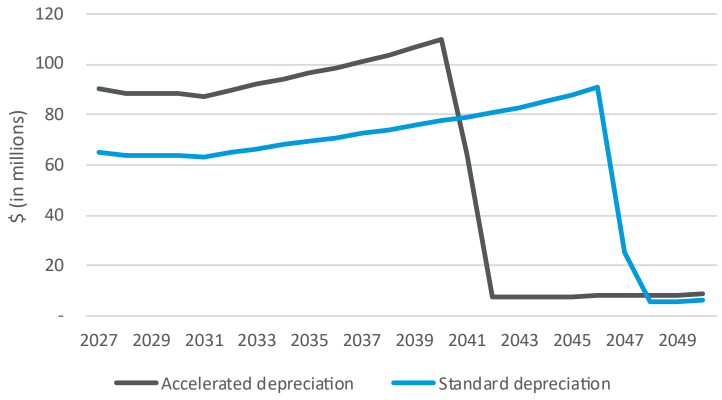


Figure A.6 presents the distribution asset depreciation profiles under a sensitivity scenario in which no capital investment occurs after the DPP4 period.

Figure A.6: Depreciation profiles under accelerated and standard depreciation, assuming no investment after DPP4—distribution (in nominal terms)



Return on capital

Return on capital is calculated as:

$$Return\ on\ opening\ RAB + return\ on\ newly\ commissioned\ assets - total\ revaluation$$

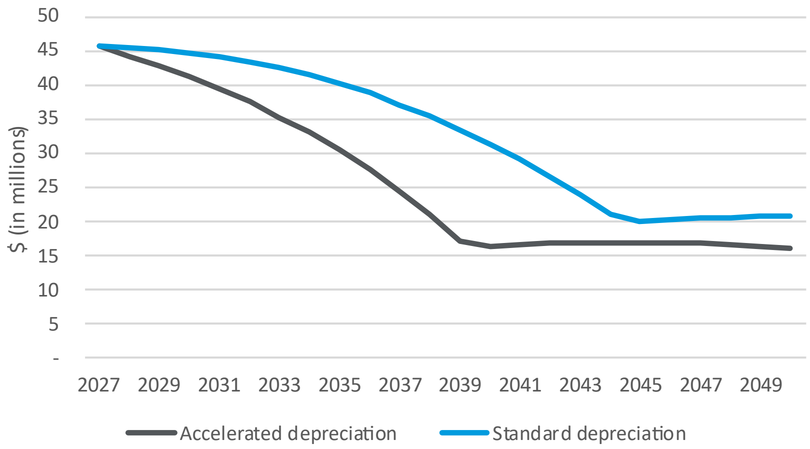
The return on opening RAB is calculated by applying the weighted average cost of capital (WACC) to the opening RAB.

The return on newly commissioned assets reflects the fact that assets are not in service for the full year. A mid-year timing adjustment is applied to the value of commissioned assets to account for this. Specifically, the return on commissioned assets is calculated as:

$$Return\ on\ commissioned\ assets = Value\ of\ commissioned\ asset * \left((1 + WACC)^{\left(\frac{182}{365}\right)} - 1\right)$$

Figure A.7 shows the evolution of the return on capital allowance for the transmission network from 2026 to 2050 under both depreciation scenarios, assuming continued capital investment.

Figure A.7: Return on capital under accelerated and standard depreciation, assuming continued investment—transmission (in nominal terms)



Return on capital is lower under the accelerated depreciation scenario than under standard depreciation, as the more rapid depreciation of assets leads to a faster decline in the RAB.

Figure A.8 shows the return on capital allowance for the transmission network, assuming no investment after DPP4. The trends remain similar, but the level of return on capital allowance is lower.

Figure A.8: Return on capital under accelerated and standard depreciation, assuming no investment after DPP4—transmission (in nominal terms)

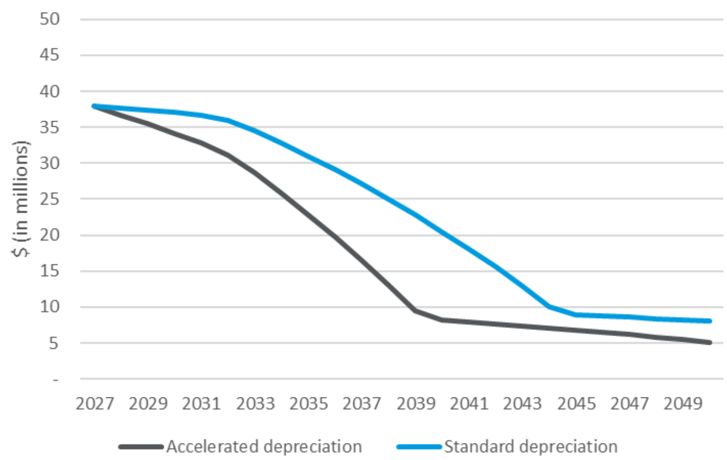


Figure A.9 shows the evolution of the return on capital allowance for the distribution network from 2026 to 2050 under both depreciation scenarios, assuming continued capital investment.

Figure A.9: Return on capital under accelerated and standard depreciation, assuming continued investment—distribution

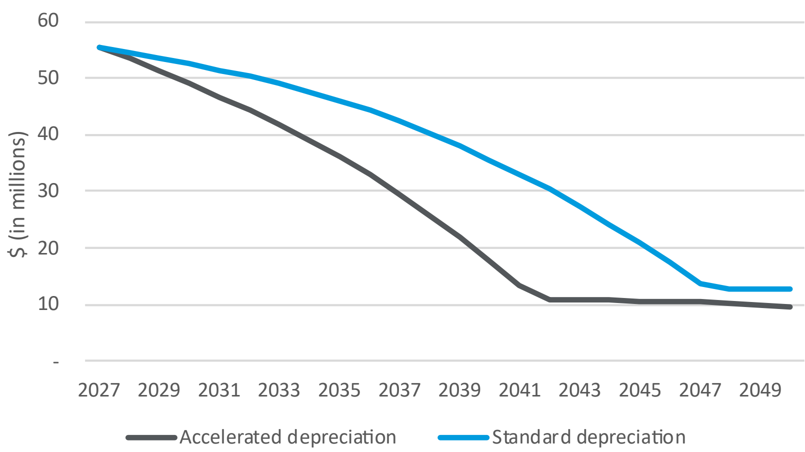
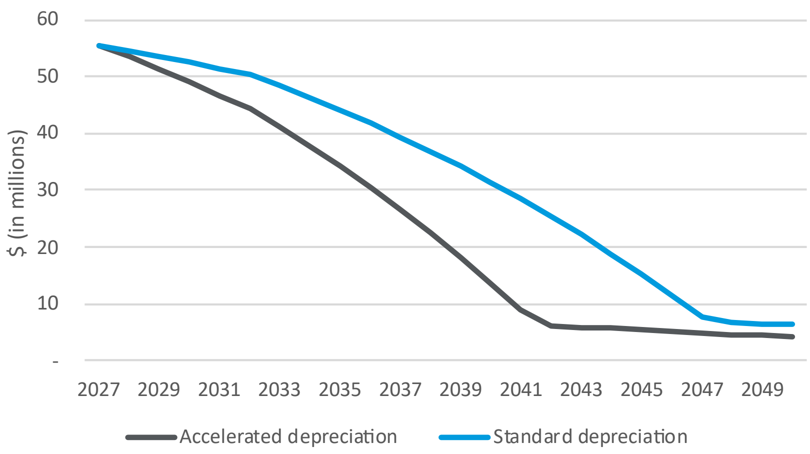


Figure A.10 shows the return on capital allowance for the distribution network, assuming no investment after DPP4.

Figure A.10: Return on capital under accelerated and standard depreciation, assuming no investment after DPP4—distribution (in nominal terms)



A.2.3 Volume forecast

To estimate capital charges on a per-GJ basis, a forecast of gas volumes transported on the transmission network is required.

The DPP4 draft decision publishes gas demand forecasts prepared GDBs and validated by Concept Consulting. These forecasts focus on demand from residential, commercial, and industrial users, excluding users that only use the transmission system, such as large petrochemical producers, co-generation users, and electricity generators.

In addition, EY developed independent gas supply and demand forecasts with a broader scope, covering all major categories of gas use, including petrochemical production, electricity generation, and cogeneration. EY modelled three alternative scenarios[7]:

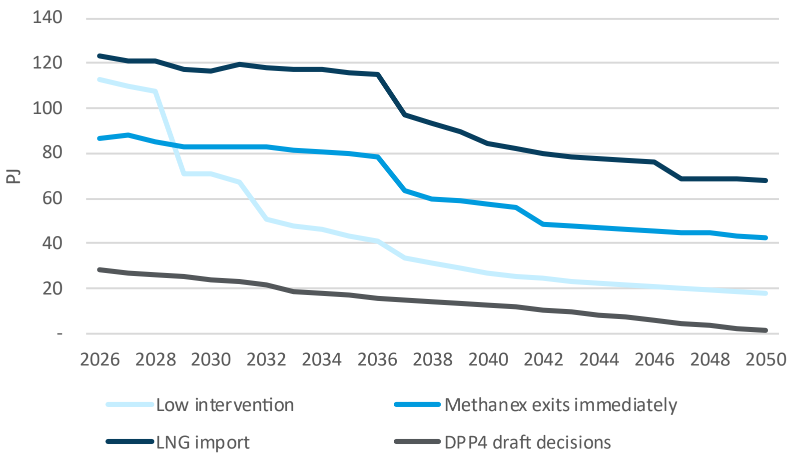
- **Low intervention:** This scenario assumes supply constraints persist and there is limited investment to develop new supply or accelerate fuel switching. As a result, several major industrial consumers reduce operations or exit the market.
- **Methanex exit immediately:** This scenario assumes the largest gas consumer exits abruptly, with production ceasing by the end of 2025. Because Methanex plays a key role in underwriting supply-side development, its exit leads to a substantial decline in gas supply. In this scenario, large remaining consumers are assumed to collaborate and enter into long-term contracts to partially underwrite future gas supply development.

[7] EY (2024). Gas Supply and Demand Study

- **LNG import:** This scenario assumes an LNG import terminal is developed to alleviate domestic supply constraints. This opens potential for higher future demand, particularly in the electricity and petrochemical sectors. This scenario also reflects the higher cost and emissions intensity of imported LNG when compared to domestic natural gas.

Figure A.11 presents the projected gas consumption trends under the DPP4 forecast and the EY scenarios.

Figure A.11: Projected gas consumption trends



Source: EY (2024). Gas Supply and Demand Study; Gas Pipeline Businesses Price-Quality Regulation 1 October 2022 Reset DPP Financial Model; Concept Consulting forecast

It is important to note that the DPP4 draft decision forecasts exclude demand from petrochemical production and electricity generation, which together currently account for over 70 percent of total gas demand in New Zealand. As a result, the trends shown in Figure A.11 are presented for context and are not directly comparable; they are used as inputs to calculate per-GJ capital charges rather than as like-for-like demand forecasts.

A.3 Results

This section presents the per-GJ transmission capital charge paths under accelerated depreciation and standard depreciation. Due to differences in the scope of the available demand data, two distinct sets of results are presented:

- The DPP4 draft decision forecast supports estimation of capital charges per GJ for residential, commercial, and industrial users only
- The EY forecasts support estimation of system-wide capital charges per GJ, covering all gas transported on the transmission network.

The results show that a consistent outcome: accelerated depreciation leads to significantly higher per-GJ capital charges in the near term, while offering little advantage beyond advancing the timing of the price decline that would occur once the existing RAB is fully recovered.

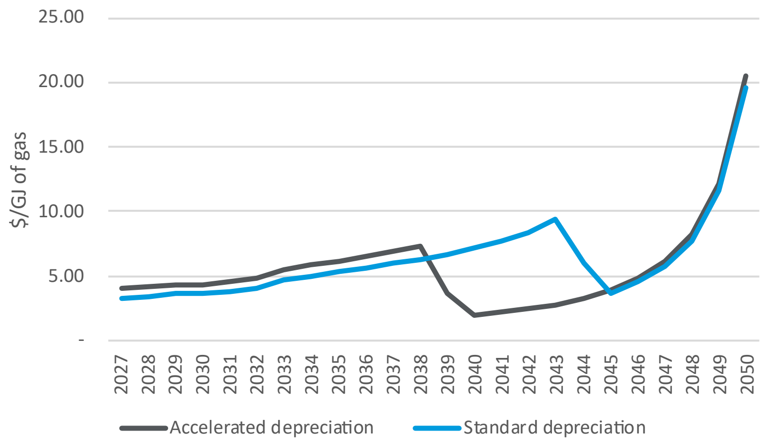
A.3.1 DPP4 draft decision

Because the DPP4 demand forecast excludes gas demand from petrochemical production and electricity generation, per-GJ transmission capital charges can only be calculated for residential, commercial, and industrial users.

According to Concept Consulting, residential, commercial, and industrial users accounted for approximately 83 percent of Firstgas's transmission revenue.[8] To derive per-GJ capital charges for these users, we exclude the portion of the total allowable revenue attributable to petrochemical production and electricity generation and allocate the remaining revenue across residential, commercial, and industrial demand. This proportion is assumed to remain constant across the forecast period.

Figure A.12 presents the resulting per-GJ capital charges for residential, commercial, and industrial users under accelerated and standard depreciation.

Figure A.12: Per-GJ capital charges for residential, commercial, and industrial users under accelerated and standard depreciation (in nominal terms)



Capital charges under accelerated depreciation are higher in the near term until 2038 when the existing RAB are fully depreciated. After 2038, prices under standard depreciation continue rising, reaching the accelerated-depreciation peak in 2041, and continue increasing for two years before eventually falling as the existing RAB is fully recovered. For the remainder of the modelling period, both scenarios enter a death-spiral dynamic, with capital charges under standard depreciation remaining slightly lower than those under accelerated depreciation.

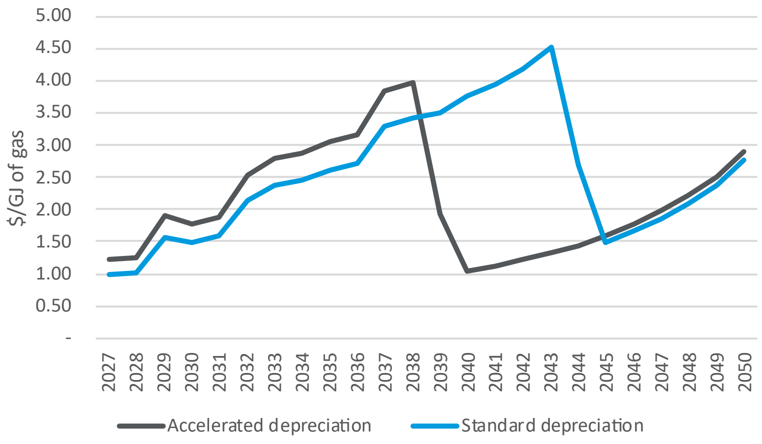
To enable an apples-to-apples comparison, we combine the DPP4 demand forecast with EY's forecasts for petrochemical production and electricity generation under the Low Intervention scenario. This approach provides the best available means of estimating total system demand

[8] Page 4, Concept Consulting (2025). "Gas demand projections to feed into the default price-quality path (DPP) regulation of gas distribution businesses"

and calculating system-level capital charges while remaining anchored to the DPP4 forecast assumptions.

Figure A.13 shows the system-level per-GJ capital charge paths for the combined DPP4+EY scenario.

Figure A.13: System-level per-GJ capital charges under accelerated and standard depreciation—DPP4+EY low intervention (in nominal terms)



In this scenario, prices under accelerated depreciation are higher in the near term until 2038 when the existing RAB are fully depreciated. After 2038, prices under standard depreciation continue rising, reaching the accelerated-depreciation peak in 2041, and continue increasing for two years before eventually falling as the existing RAB is fully recovered. For the remainder of the modelling period, prices under standard depreciation remain lower than under accelerated depreciation.

Scenario analysis: no capital investment after DPP4

We examine the transmission capital charges assuming no capital investment after DPP4. Under this assumption, per-GJ capital charges are lower overall due to the reduction in the asset base. However, the qualitative pattern remains unchanged: accelerated depreciation results in higher per-GJ capital charges in the near term, while providing little benefit beyond bringing forward the price decline that occurs once the existing RAB is fully recovered. Figure A.14 and Figure A.15 present the results.

Figure A.14: Per-GJ capital charges for residential, commercial, and industrial users under accelerated and standard depreciation—assuming no investment after DPP4 (in nominal terms)

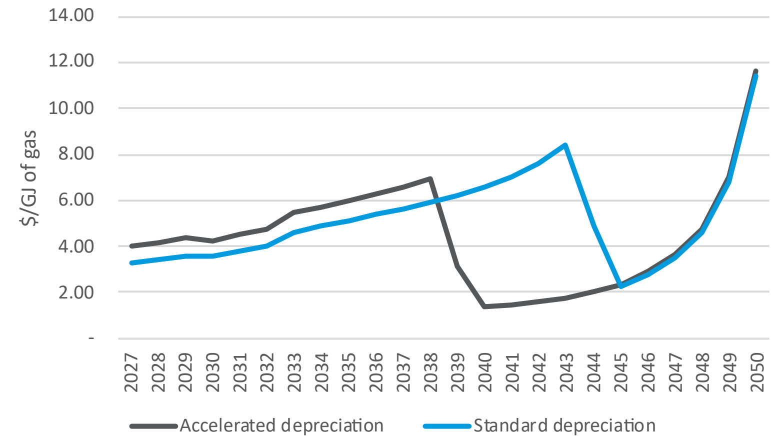
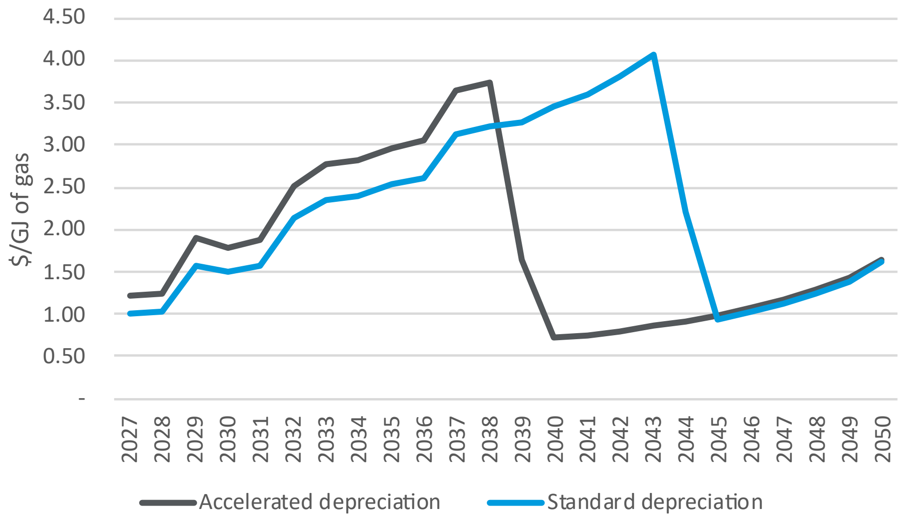


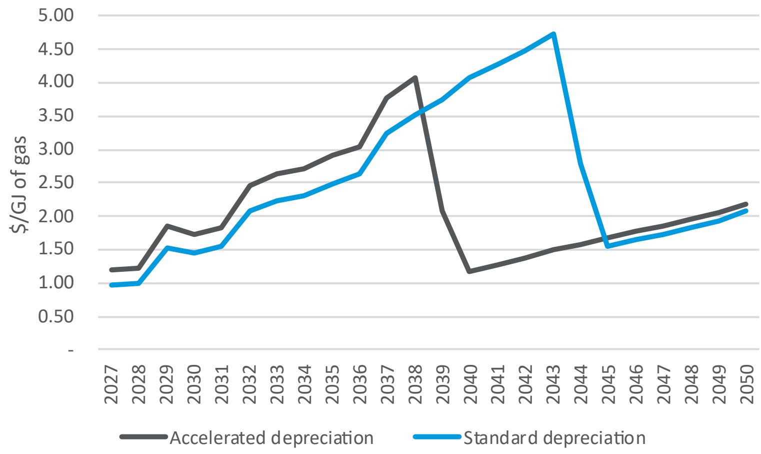
Figure A.15: System-level per-GJ capital charges under accelerated and standard depreciation—DPP4+EY low intervention—assuming no investment after DPP4 (in nominal terms)



A.3.2 Low intervention

Figure A.16 shows the system-level per-GJ capital charge paths under the Low Intervention scenario.

Figure A.16: System-level per-GJ capital charges under accelerated and standard depreciation—Low intervention (in nominal terms)



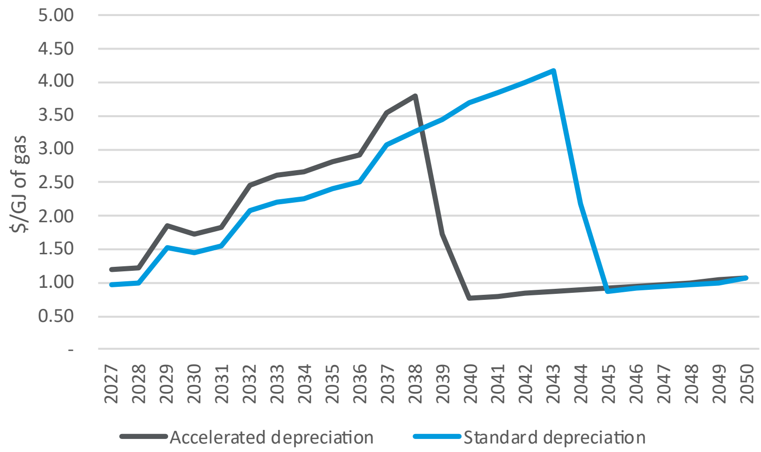
Under this scenario, gas consumption declines sharply over time, which drives capital charges upward in both cases as the asset base is recovered over an increasingly smaller volume of gas.

In this scenario, prices under accelerated depreciation are higher in the near term, until 2038 when the existing RAB are fully depreciated. After 2038, prices under standard depreciation continue rising, reaching the accelerated-depreciation peak in 2040, and continue increasing for three years before eventually falling as the existing RAB is fully recovered. For the remainder of the modelling period, prices under standard depreciation remain lower than under accelerated depreciation.

Scenario analysis: no capital investment after DPP4

We examine the transmission capital charges assuming no capital investment after DPP4. Figure A.17 present the results.

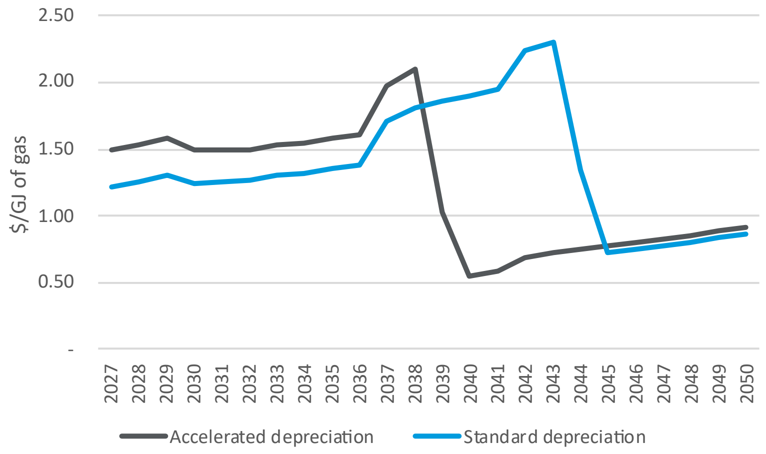
Figure A.17: System-level per-GJ capital charges under accelerated and standard depreciation—Low intervention, assuming no investment after DPP4 (in nominal terms)



A.3.3 Methanex exits immediately

Figure A.18 shows the per-GJ capital charge paths under the Methanex Exits Immediately scenario.

Figure A.18: System-level per-GJ capital charges under accelerated and standard depreciation—Methanex exit immediately (in nominal terms)



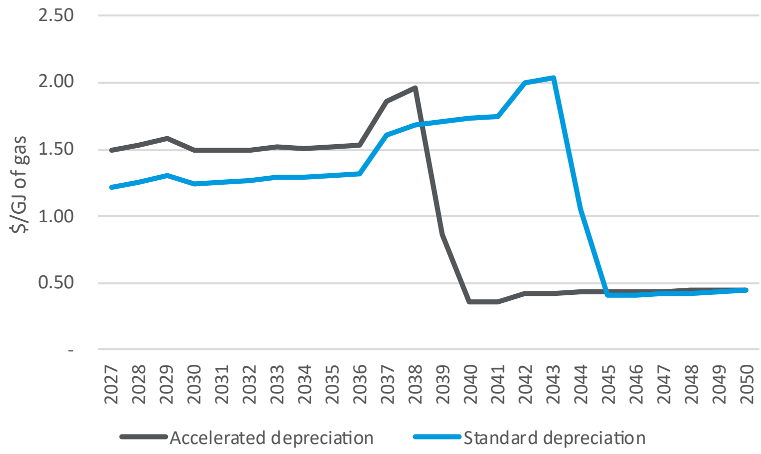
Under standard depreciation, capital charges are lower than under accelerated depreciation in most years. However, the sudden reduction in demand causes a pronounced temporary spike in capital charges before they decline again.

Under accelerated depreciation, this short-term spike is avoided, as a greater proportion of the asset base has already been depreciated. The trade-off, however, is that capital charges remain consistently higher throughout the earlier years of the period.

Scenario analysis: no capital investment after DPP4

We examine the transmission capital charges assuming no capital investment after DPP4. Figure A.19 present the results.

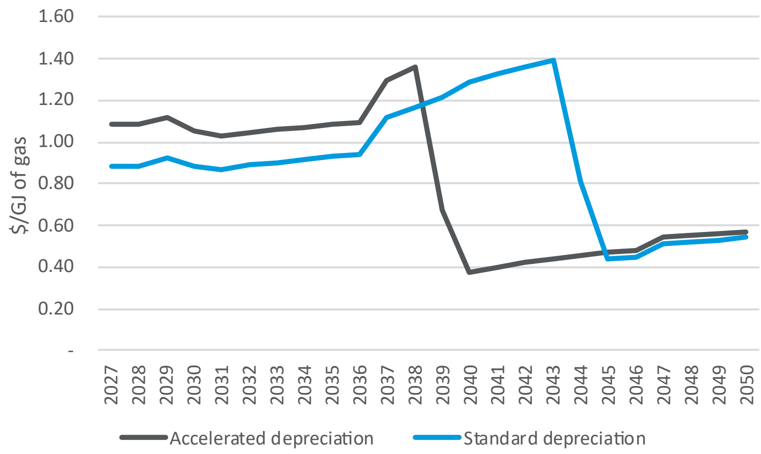
Figure A.19: System-level per-GJ capital charges under accelerated and standard depreciation—Methanex exits immediately, assuming no investment after DPP4 (in nominal terms)



A.3.4 LNG import

Figure A.20 shows the per-GJ capital charge paths under the LNG Import scenario.

Figure A.20: System-level per-GJ capital charges under accelerated and standard depreciation—LNG import (in nominal terms)

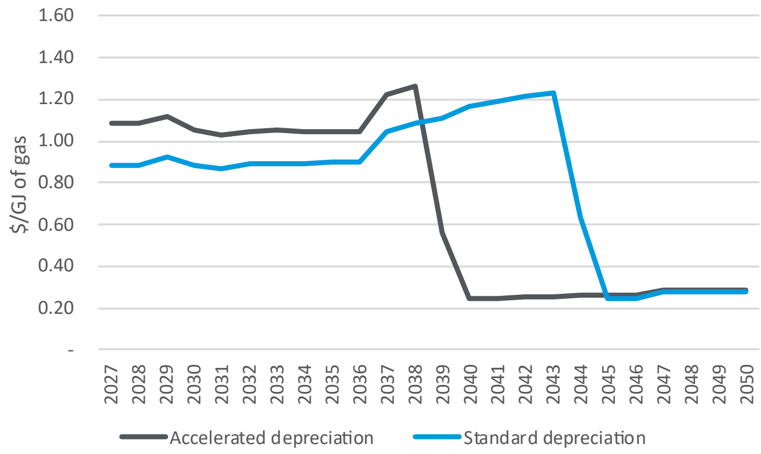


In this scenario, prices under accelerated depreciation are higher in the near term. After 2038, prices under standard depreciation continue rising, reaching the accelerated-depreciation peak in 2042, and continue increasing for one year before eventually falling as the existing RAB is fully recovered. For the remainder of the modelling period, prices under standard depreciation remain lower than under accelerated depreciation.

Scenario analysis: no capital investment after DPP4

We examine the transmission capital charges assuming no capital investment after DPP4. Figure A.21 present the results.

Figure A.21: System-level per-GJ capital charges under accelerated and standard depreciation—LNG import, assuming no investment after DPP4 (in nominal terms)



Appendix B: Methodology for estimating the Brookfield's valuation of Firstgas transmission and distribution

This appendix describes the methodology used to disaggregate the reported Brookfield/Clarus transaction value and infer the implied market valuation of Firstgas's regulated gas transmission and distribution assets.

B.1 Overview of approach

In assessing whether the market valuation of Firstgas's assets reflects expectations of asset stranding, we draw on principles set out in an analytical paper published by the Australian Energy Regulator (AER).[9] The AER defines a RAB multiple as the ratio of a firm's enterprise value to its RAB, measured at the same point in time and relating to the same regulated revenue and expenditure streams. While Firstgas is regulated under Part 4 of the Commerce Act 1986, these principles are equally relevant in establishing the conditions under which market valuations and regulated asset values can be meaningfully compared.

Firstgas's audited Closing Transmission RAB as of 30 September 2024 is NZ$982.9 million, and the Closing Distribution RAB is NZ$232 million.[10,11] Rolling this RAB forward to later years would require assumptions regarding asset commissioning, depreciation, revaluation, and disposals. In addition, there is no evidence of large greenfield transmission and distribution assets being commissioned between 30 September 2024 and the Clarus transaction that would materially alter the scale of the network.[12] Therefore, to avoid introducing additional uncertainty, we align the reported Clarus transaction value to the 2024 RAB year.

Public reporting indicates that Brookfield acquired Clarus' gas portfolio for approximately NZ$2 billion.[13] This portfolio includes multiple businesses that fall outside the regulated gas pipeline businesses, including LPG retail, gas storage, and electricity distribution. To isolate the portion of the transaction value attributable to Firstgas's regulated gas transmission and distribution

[9] Biggar, D. (2018, February 20). *Understanding the role of RAB multiples in regulatory processes*. Australian Energy Regulator. Retrieved from https://www.aer.gov.au/documents/aer-role-rab-multiples-regulatory-process-february-2018

[10] First Gas Limited. (2025, March 31). *Gas Transmission Information Disclosure 2024* (Schedule 4: Regulatory Asset Base). Retrieved from https://cms.firstgas.co.nz/assets/Uploads/Transmission-PDFs/Gas-Transmission-Information-Disclosure-2024.pdf

[11] First Gas Limited. *Gas Distribution Information Disclosure 2024*. Retrieved from https://cms.firstgas.co.nz/assets/Uploads/Distribution-PDFs-/Gas-Distribution-Information-Disclosure-2024.pdf

[12] First Gas Limited. (2025). *Firstgas Transmission Asset Management Plan 2025 Summary*. Retrieved from https://cms.firstgas.co.nz/assets/Uploads/Documents/AMPS/Firstgas-Transmission-2025-Asset-Management-Plan-Summary.pdf

[13] Macdonald-Smith, A. (2025, October 5). *Brookfield, Powerco to pay $1.8b for NZ energy distributor Clarus*. Australian Financial Review. Retrieved from https://www.afr.com/street-talk/brookfield-powerco-to-pay-1-8b-for-nz-s-energy-distributor-clarus-20251005-p5n06r (https://archive.md/fHX5z); The Australian. (2025, October 6). *Brookfield, Powerco snap up NZ pipeline giant Clarus for $2bn*. Retrieved from https://www.theaustralian.com.au/business/dataroom/brookfield-powerco-snap-up-nz-pipeline-giant-clarus-for-2bn/news-story/9468f17c15d9a977319debe0b8bf026a?amp (https://archive.md/azBdy); BusinessDesk. (2025, October 6). *Brookfield backs NZ gas market with $2B Clarus buy*. Retrieved from https://businessdesk.co.nz/article/energy/brookfield-backs-nz-gas-market-with-2b-clarus-buy (https://archive.md/GQVaI)

assets, we deduct the estimated market values of the non-pipeline businesses from the reported portfolio valuation.

All non-pipeline asset values are derived from publicly disclosed historical transaction prices and restated to 2024 New Zealand dollars using All Groups CPI. This ensures comparability with Firstgas's audited Closing Transmission and Distribution RAB as of 30 September 2024.

B.2 Inflation indices used

The following CPI indices are used for inflation adjustments[14]:

- CPI 2017 Q4 = 1,006
- CPI 2018 Q3 = 1,024
- CPI 2023 Q1 = 1,218
- CPI 2024 Q3 = 1,280

B.3 Valuation of non-pipeline assets

B.3.1 Rockgas LPG retail

Rockgas was sold in 2018 for NZ$260 million.[15] To restate this value in 2024 terms, we apply the ratio of CPI in 2024 Q3 to CPI in 2018 Q3, resulting in an estimated value of NZ$325 million.

B.3.2 Flexgas (Ahuroa Gas Storage)

The Ahuroa gas storage facility (Flexgas) was sold in 2017 for NZ$200 million.[16] This value is restated to 2024 terms using CPI from 2017 Q4 to 2024 Q3, resulting in an estimate value of NZ$254.5 million.

Subsequent disclosures indicate that the usable storage capacity at the Ahuroa gas storage facility has been revised downward relative to expectations at the time of the 2017 transaction. At the time of sale, Ahuroa was understood to have a maximum usable capacity of approximately 18 PJ. However, later public disclosures indicate that updated reservoir assessments place total available storage capacity at around 10–12 PJ. After accounting for gas reclassified as pad gas, the effective working capacity has been assessed at approximately 6–8 PJ.[17] These revised estimates imply a 30-65 percent reduction in usable capacity relative to the original expectations.

To reflect this, we apply a capacity-related haircut to the inflated value. To be more conservative, we adopt the lower bound of this range and apply a 30 percent haircut, resulting in an estimated 2024 valuation of NZ$178.1 million.

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14 Statistics New Zealand. (2025). *Consumer Price Index: All Groups (Quarterly)*. Infoshare Table CPI316601. Retrieved from https://infoshare.stats.govt.nz/ViewTable.aspx?pxID=398f8dc6-621a-4863-b5cb-336d125c1cc4

15 Contact Energy Limited. (2018, July 31). *Contact Energy to sell Rockgas for NZD 260 million* [NZX announcement]. Retrieved from NZX, New Zealand's Exchange - Announcements, Sale Of Contact's Lpg Business Rockgas

16 Contact Energy Limited. (2017, December 21). *Contact Energy to sell Ahuroa Gas Storage facility to Gas Services New Zealand for NZD 200 million* [NZX announcement]. Retrieved from NZX, New Zealand's Exchange - Announcements, Contact Energy To Sell Ags To Gas Services New Zealand

17 New Zealand's Exchange (2022, December, 21). Retrieved from https://www.nzx.com/announcements/404460

Sensitivity testing indicates that alternative haircut assumptions do not materially alter the conclusions of the analysis. Applying a larger haircut reduces the implied valuation of Flexgas and correspondingly increases the implied valuation of Firstgas' transmission and distribution assets. This would imply that Brookfield paid a premium for the gas network, which is inconsistent with an asset-stranding narrative. Meanwhile, a smaller haircut (for example, 20 percent) still results in a market valuation broadly aligned with the reported RAB.

B.3.3 Firstlight Network (electricity distribution)

In November 2022, Eastland Group and Trust Tairāwhiti announced the sale of Eastland Network (now Firstlight Network) to Firstgas Group for NZ$260 million.[18] The transaction was completed in March 2023 following Overseas Investment Office approval.[19]

The 31 March 2023 Information Disclosure reports a closing electricity distribution RAB of NZ$209 million, materially below the transaction price.[20] For the purpose of disaggregating the Clarus portfolio valuation, we therefore adopt the NZ$260 million transaction price and restate it to 2024 terms using CPI from 2023 Q1 to 2024 Q3, resulting in an estimated value of NZ$273 million.

B.3.4 Implied valuation of regulated gas networks

We subtract the restated values of Rockgas, Flexgas, and Firstlight Network from the reported NZ$2 billion portfolio valuation to estimate the implied market value of Clarus' regulated gas networks:

$$NZ\$2{,}000m - NZ\$325m - NZ\$178.1m - NZ\$273m \approx NZ\$1{,}224m$$

This residual reflects the combined market value of Firstgas' regulated gas transmission and distribution businesses.

B.4 Allocation between transmission and distribution

To arrive at the respective implied valuation of transmission and distribution assets, we apportion the NZ$1.224 billion residual between transmission and distribution based on their respective Closing RAB values as of 30 September 2024.

According to Information Disclosure:

- Closing Transmission RAB: NZ$982.9 million
- Closing Distribution RAB: NZ$232.2 million[21]

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18 Eastland Group & Trust Tairāwhiti. (2022, November 22). *Eastland Group and shareholder Trust Tairāwhiti announce sale of Eastland Network to Firstgas Group, owned by Igneo Infrastructure Partners, for $260 million*. Retrieved from https://www.eastland.nz/2022/11/22/eastland-group-and-shareholder-trust-tairawhiti-announce-sale-of-eastland-network-to-firstgas-group-owned-by-igneo-infrastructure-partners-for-260-million

19 Firstlight Network. (2023). *Firstgas Group acquisition of Eastland Network receives OIO approval and a new name is revealed*. Retrieved from https://firstlightnetwork.co.nz/tell-me-about/firstlight-network/network-news/firstgas-group-acquisition-of-eastland-network-receives-oio-approval-and-a-new-name-is-revealed

20 Firstlight Network. (2023, August 31). *Information Disclosure for year ended 31 March 2023* (Schedule 4: Report on value of the Regulatory Asset Base). Retrieved from https://www.firstlightnetwork.co.nz/assets/Documents/FNL-IDs-RY23-S1-15-FINAL-v2.pdf

21 First Gas Limited. (2025, March 31). *Gas Distribution Information Disclosure 2024* (Schedule 4: Regulatory Asset Base). Retrieved from https://cms.firstgas.co.nz/assets/Uploads/Distribution-PDFs-/Gas-Distribution-Information-Disclosure-2024.pdf

Transmission therefore represents approximately 80.8 percent of the combined regulated gas RAB.

We apply this share to the implied gas network valuation, resulting in an estimated value of NZ$989 million for the gas transmission asset, and NZ$235 million for the gas distribution asset.

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