Date:

3rd February 2023

Name of submitter:

Electricity Networks Association

Industry/area of interest:

Utilities/infrastructure

Contact details

Graeme Peters, Chief Executive

Address:

Level 5, Legal House

101 Lambton Quay

WELLINGTON 6011

Telephone:

027 6677 400

Email:

gpeters@electricity.org.nz

Submission on rate of return issues

To the Commerce Commission

From the Electricity Networks Association

Contents

1. Introduction

The Electricity Networks Association (**ENA**) appreciates the opportunity to make a submission to the Commerce Commission (the Commission) on the cost of capital. This submission is on behalf of ENA's members (listed in appendix A to this submission), the electricity distribution businesses (EDBs), of New Zealand.

EDBs are and will play a critical role in supporting and enabling the decarbonisation and electrification of the New Zealand economy, as the country responds to the challenges posed by climate change. It is essential that EDBs are appropriately compensated so they can deliver the long terms benefits that electrification and decarbonising the New Zealand economy will bring.

2. Executive summary

The Commission's rate of return framework is well established, and its application is generally appropriate for the purposes of part 4 of the Commerce Act. This submission highlights specific improvements to the framework to ensure it enables EDBs to support the electrification and decarbonisation of the New Zealand economy.

CEPA report

ENA supports the fundamental findings of the CEPA report. Specifically, ENA's view is that:

- the Commission should, given the compelling evidence that the risk/cost of underinvestment is higher as New Zealand progresses through its transition to a net zero carbon economy, consider an increase of the WACC percentile to the 75th. At a minimum, the 67th percentile should be maintained.
- the use of an asset beta of 0.35, gearing of 0.39 and BBB+ credit rating is appropriate.
- no adjustment should be made to the comparator sample for COVID impacts.

Other rate of return issues

The Commission has invited feedback on other cost of capital issues. There are a number of areas where the input methodologies approach to the cost of capital can be improved to deliver long-term benefits to consumers. Specifically, the ENA recommends that the Commission:

- use the comparator sample to set debt tenor. In the absence of the liquidity of a debt market for bonds of equal length to the comparator sample, the Commission should adopt a 10-year debt tenor;
- accompany the move to a 10-year debt tenor with a transition to the use of a trailing average cost of debt. The AER transition method should be used to make this transition;
- should it decide against the moving to a 10-year debt tenor and to retain the 5-year debt tenor, set the term credit spread differential (TCSD) at 0.91%;

- conduct a financeability assessment as part of its IM review and price-quality setting process which adopts the quantitative metrics used by Moody's and S&P Global Ratings against the benchmark efficient entity;
- include in its financial model an allowance for equity raising costs based on the AER approach;
- correct its calculation of the debt issuance allowance to include the time value of money;
- adopt the average of RBNZ CPI forecast and the 5-year break-even inflation derived from NZ government bonds as its forecast of inflation.

The Commission, when deciding if it should target a real or nominal return on capital and consequentially if the regulatory asset base (RAB) should be indexed, the key criteria must that it should be protecting consumers from inflation forecasting risk, maintaining NPV=0, and ensuring EDBs have sufficient financeability to allow them to achieve the Commission's targeted BBB+ credit rating.

Finally, ENA recommends that the Commission investigate the benefits of allowing EDBs to choose to use an indexed, un-indexed, or partially index (hybrid) RAB, as is the case for airports.

3. CEPA confirms 67th WACC percentile is a lower bound

The CEPA review[1], based on the Commission's empirical model developed by Oxera, quantifiably demonstrates that at minimum the 67th percentile be retained, and serious consideration be given to an increase in the WACC percentile.

ENA notes that the CEPA report doesn't take the updated Oxera modelling to its natural conclusion and quantify the percentile at which the marginal cost and benefit curves intersect.

The attached expert report from the Competition Economist Group (CEG), completed prior to the publication of the CEPA report updates the Commission/Oxera empirical model (Appendix B). Adjusting solely for the lower standard error would raise the WACC percentile that maximises consumer welfare to 69% (although the WACC uplift would effectively remain unchanged – with the higher WACC percentile offset by a narrower distribution of the WACC).

The findings of the CEG report corroborate CEPA's finding that the current percentile would be the lower bound of the estimates supported by the 2014 empirical model.

However, the world has not stood still since the Oxera model was adopted by the Commission in 2014. The two most significant influences likely to alter the intersection points of the Oxera marginal cost and marginal benefit curves are:

- higher demand growth and greater uncertainty around that demand growth in 2025 than in 2014
- the need for a transition of the EDB from a passive 'poles and wires' business to active distribution system operator (DSO).

The transition will introduce greater complexity into EDBs' operating environment however, working together within the regulatory framework, there is opportunity to set free a material amount of economic value and consumer benefit.

The CEPA review notes that some international regulators adopt a mid-point WACC estimate. It highlighted the UK Regulators Network recommendation that *"Regulators should only deviate from the mid-point of the CAPM cost of equity range if there are strong reasons to do so"*[2]. Both CEPA and CEG's updates of Oxera's model empirically demonstrate that the reasons for the adoption of a WACC percentile at 67th or above are strong, especially in the face of the increased opportunity cost to consumers from underinvestment.

[1] CEPA, 2022, Review of Cost of Capital 2022/2023

[2] UK Regulators Network, 2022, Guidance for regulators on the methodology for setting the cost of capital — consultation

Impact of higher growth and uncertainty on the WACC percentile

It is intuitive that higher demand growth and higher uncertainty about the pace of demand growth increase the risk of (and potential for) underinvestment, and that this would be especially likely if the WACC were materially lower than investors' actual perceived costs.

If expected demand growth is very low and has very little uncertainty there will, by definition, be little or no efficient growth capital expenditure. If there is low or zero efficient growth capital expenditure, it is not possible to materially underinvest in that category of expenditure. By contrast, the larger the required investment program, the greater scope for underinvestment if the WACC is set too low. Similarly, if that growth rate is highly uncertain (i.e., a high mean and a high standard error) then this will add to the risk of underinvestment.

ENA considers that the risk of underinvestment is driven by:

- the expected rate of demand growth (driving the magnitude of the expected investment requirement)
- the uncertainty around that the timing of the expected demand growth.

Both factors are materially higher in 2025 than in 2014. It follows that the marginal benefit curve will be "shifted up" in 2025 relative to its position in 2014. Exactly how much higher is difficult to quantify and will require exercise of judgement.

Shifting the marginal benefit curves to reflect faster and more uncertain demand growth

CEG modelled the increases in the expected cost of underinvestment associated with the higher demand growth/uncertainty faced in 2025, compared to 2014. The four scenarios modelled by CEG were where the marginal benefit curve (expressed as a percentage of RAB) is:

1. 25% higher than it was in 2014 (which is less than proportional to the increase in demand growth/uncertainty since 2014);
2. 50% higher than it was in 2014 (which is less than proportional to the increase in demand growth/uncertainty since 2014);
3. 100% higher than it was in 2014 (which is approximately proportional to the increase in demand growth/uncertainty since 2014);
4. 200% higher than it was in 2014 (derived from the ratio of Oxera's 'low' and 'high' cost of underinvestment estimates (being 6.8% and 20.4% of RAB)).

The results of CEG's modelling is summarised in Table 1 below.

Table 1: Welfare maximising percentile given a 1.01% standard error and various increases in the risk/cost of underinvestment since 2014

Threshold and 2014 starting point cost	Increase in cost/risk	Optimal percentile	2014 uplift (bp)**	2025 uplift (bp)**	Difference (bp)
		Standard error of WACC = 1.06% (2014 decision)			
0.5% and 4.0% of RAB	0%	67%	0.53	NA	NA
		Standard error of WACC = 1.01% (2016 IM)			
0.5% and 4.0% of RAB	0%	68%	0.53	0.56	0.03
0.5% and 4.0% of RAB	25%	75%	0.53	0.78	0.25
0.5% and 4.0% of RAB	50%	79%	0.53	0.92	0.40
0.5% and 4.0% of RAB	100%	85%	0.53	1.09	0.56
0.5% and 4.0% of RAB	200%	90%	0.53	1.35	0.83
		Standard error of WACC = 1.06% (2014 decision)			
1.0% and 6.7% of RAB	0%	67%	0.53	NA	NA
		Standard error of WACC = 1.01% (2016 IM)			
1.0% and 6.7% of RAB	0%	66%	0.53	0.42	-0.11
1.0% and 6.7% of RAB	25%	72%	0.53	0.59	0.06
1.0% and 6.7% of RAB	50%	75%	0.53	0.71	0.19
1.0% and 6.7% of RAB	100%	80%	0.53	0.85	0.32
1.0% and 6.7% of RAB	200%	86%	0.53	1.09	0.56
		Standard error of WACC = 1.01% (2016 IM)			
Midpoint scenario*	0%	69%	0.53	0.50	-0.03
Midpoint scenario*	25%	75%	0.53	0.68	0.15
Midpoint scenario*	50%	79%	0.53	0.81	0.29
Midpoint scenario*	100%	84%	0.53	1.00	0.48
Midpoint scenario*	200%	89%	0.53	1.24	0.71

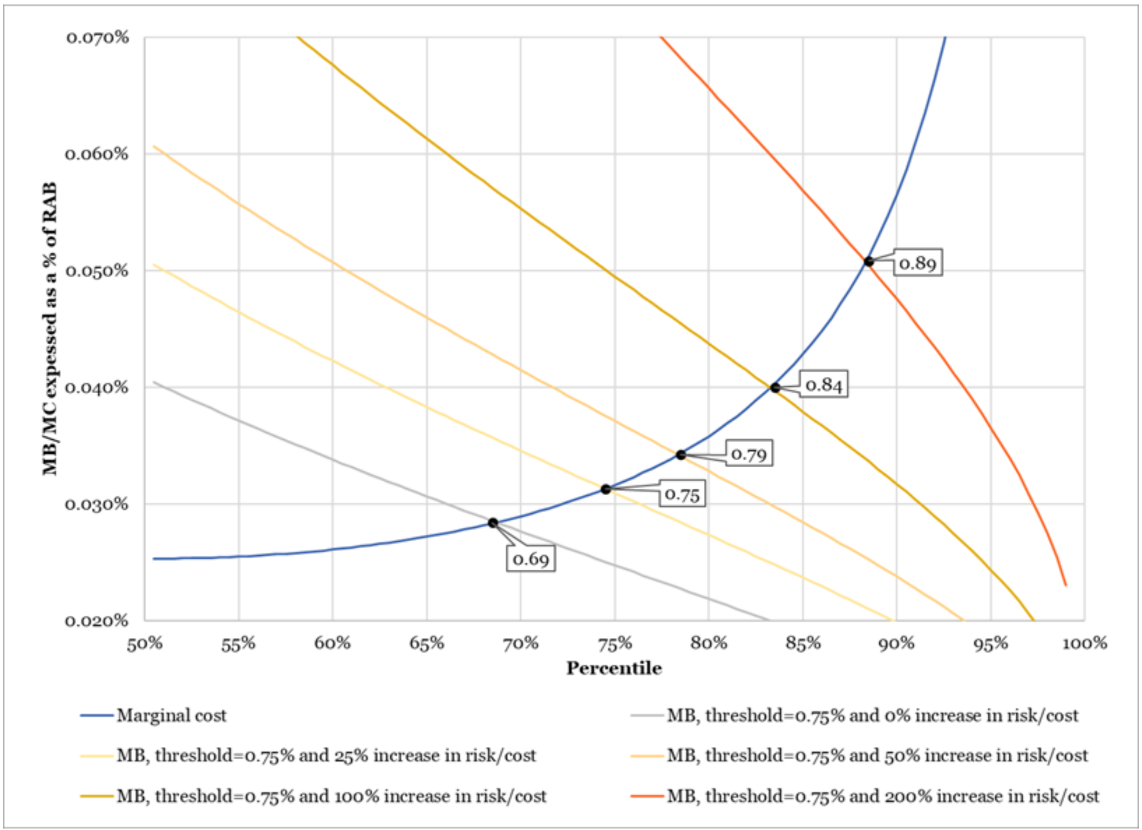
Source: CEG analysis. *The midpoint scenario applies a 0.75% threshold for triggering underinvestment (being the midpoint of 1.0% and 0.5%), and a 5.35% of RAB cost of underinvestment when it occurs (being the midpoint of the "2014 starting point" estimates of 6.7% and 4.0% derived in section 2). ** 2014 WACC uplift is based on 1.2% standard error and 67% percentile. 2025 uplift is based on 2016 IM standard error of 1.01% and varying percentiles.

Focussing on the midpoint scenarios, updating the standard error (from 1.06% to 1.01%) but leaving the marginal benefit assessment unchanged, results in a slightly higher estimated WACC percentile of 69% and a slightly lower WACC uplift (50bp) relative to 2014.

The average estimated WACC percentile rises to 75% (79%), if we assume that the risk/cost of underinvestment is 25% (50%) higher (as a percentage of RAB) in 2025 than was the case in 2014. This results in a relatively small 15bp (29bp) higher WACC uplift than in 2014. Similarly, if we assume that the risk/cost of underinvestment is 100%/200% higher in 2025 than in 2014 then the average percentile increases to 84%/89% and the WACC uplift increases by 46/68bp.

The results of this midpoint modelling are illustrated in Figure 1.

Figure 1: Midpoint marginal benefit curves intersections with marginal cost curve using a Standard Error of 1.01%



Source: CEG analysis

The impact of the evolving role of EDBs

Another critical difference between 2014 and 2025 is the changing role of EDBs driven by the integration of a greater share of intermittent distributed energy resources (DER). This transition, where well-handled by EDBs, regulators and other stakeholders (including the government), has the potential to unlock enormous long-term benefits for consumers. However, at the heart of this process are EDBs evolving from passive 'poles and wires' businesses into a DSO role.

Well-handled, this transition can be expected to result in both:

- a significant shift to electrification from fossil fuelled energy sources
- lower average costs per unit of energy consumed by households as consumers benefit from.

  a) lower cost electricity for existing uses and appliances
  b) replacing expensive to run fossil fuel appliances with their electric equivalents such as electric cars and electric heating/cooking.

Putting a dollar value on efficient DSO and flexibility services

Based on the best international evidence, CEG estimated the value of taking efficient actions to implement a DSO-type capability will be to reduce supply chain (grid plus generation) costs by 12% to 19%. As summarised in CEG's report (Appendix B), reasonable lower bound estimates of supply chain savings from the state-of-the-art US Department of Energy multidisciplinary study[3] are that the efficient operation of flexibility platforms delivers savings of at least:

- 4% to 8% for distribution hardware expenditure
- 10% for transmission expenditure
- 22% for generation expenditure.

These are the sources of benefit that give rise to the 12% lower bound estimate of total supply chain savings. The higher bound estimate of 19% is associated with deeper penetration of intermittent renewable generation (solar and wind) and, therefore, greater benefits from flexibility.

The benefits to customers of falling costs of renewable technology and switching from expensive fossil fuels to cheaper electricity are in addition to the supply chain savings. Including these savings, the whole of supply chain benefits to customers is likely more than 20% per annum of the current value of the electricity supply chain.

The conclusion of the evidence surveyed by CEG is that, even in the moderate renewables scenarios, average electricity retail bills for customers would be 12% to 14% per annum lower under the DSO model than the business-as-usual model. Under the scenarios with high penetration of renewables, the net benefits to final customers would be even larger (around 18% to 19% lower retail bills). There is a large number of other important findings, including distributional impacts associated with flexibility markets, also summarised in Appendix B.

The evidence provided by the US studies demonstrates that the marginal benefits quantified by Oxera and updated by CEPA are likely to materially understate the long-term benefits to consumers. This is further evidence that the use of the 67th percentile, while appropriate, does not maximise the benefit to consumers. The Commission should therefore give serious consideration to raising the percentile to the 75th to reflect the increased cost/risk of under investment.

Regulatory precedent from the United Kingdom

CEG's review also highlighted that regulators are beginning to take the evolving role of EDBs into account in their regulatory decision making. Ofgem's DSO strategy has developed over the last seven years through consultation and draft business plan guidance and is now documented in its RIIO-ED2 draft decision, where Ofgem states:[4]

> *"A key objective of RIIO-ED2 is to support the delivery of net zero at the lowest cost to the consumer; and* ***the efficient operation of the energy system at all voltages is essential if this vision is to be realised. Changes are required to the operation of electricity distribution networks to maximise the value of decentralised, local markets for flexibility services and to enhance the visibility of network data.*** *DSO is the set of*

[3] Pacific northwest national laboratory operated by Battelle for the United States Department of Energy, 2022, The Distribution System Operator with Transactive (DSO+T) Study

[4] Ofgem, Consultation - RIIO-ED2 Draft Determinations – Overview Document, p. 61.

> *activities that are needed to support this transition to a smarter, more flexible, and digitally enabled local energy system. (Emphasis added.)"*

UK EDBs (referred to as DNOs) proposed material expenditures on DSO activities. For example, both Scottish and Southern Electricity Networks and UK Power Networks have proposed spending roughly £150m (NZD$283 million) each over the regulatory period on DSO activities. Ofgem's June 2022 draft decision states that:[5]

In total, the proposed DSO spend across all companies in RIIO-ED2 was ~£890m, almost four times the forecast spend in RIIO-ED1.

Ofgem's draft decision also states:[6]

> *"We propose to accept the majority of the DNOs' DSO strategy proposals without amendment, with the exception of investments where we have found weak justification in the associated Engineering Justification Paper (EJP)."*

The availability of LV network data is a key enabler for DNOs delivering against their and the regulators' expectations. Ofgem states.[7]

> *"Access to more granular demand and voltage data will improve understanding of existing capacity on individual LV circuits, which will allow DNOs to produce enhanced forecasts. Better data and forecasting will also support DNOs in tendering for flexibility services on LV constraints."*

Prioritising EDBs developing plans for these capabilities, and being compensated for doing so, is an example of a "no regrets" policy that the Commission can promote. Ofgem's stated goal is for UK EDBs to achieve full network visibility by the end of RIIO-ED2, and Ofgem is proposing to include an outturn performance metric on network visibility (customer coverage in a new DSO incentive framework).

Even so, Ofgem is concerned that this timeframe may inappropriately delay the development of flexibility markets and, to this end, is setting out a re-opener provision within the regulatory period:[8]

> *"We also propose to introduce a Digitalisation re-opener to allow DNOs to provide the tools and services required for smart optimisation of the distribution networks during the price control period."*

The regulatory precedent established by Ofgem provides yet more evidence that the marginal cost of under-investment has increased since Oxera's original 2014 modelling, and that any move to reduce the percentile would be against the long-term benefits to consumers.

Based on the analysis of CEPA, CEG and the impact of the evolving role of EDBs, ENA recommends the Commission consider an increase of the WACC percentile to the 75th percentile to reflect the

[5] Ofgem, Consultation - RIIO-ED2 Draft Determinations – Core Methodology Document, p. 82.

[6] Ibid.

[7] Ofgem, RIIO-ED2 Draft Determinations – Overview Document, p.56.

[8] Ibid, p.57.

increased risk/cost associated with underinvestment as New Zealand decarbonises . At a minimum maintain, the 67th percentile should be maintained.

4. Comparator sample selection for asset beta and leverage

The Commission's covering letter has sought views of stakeholders on CEPA's findings on the comparator sample used to update the estimate of asset beta and leverage. **ENA supports the Commission's continued use of the compactor sample as the basis for establishing asset beta and leverage.**

ENA also supports CEPA's use of both gas and electricity businesses in the sample for energy businesses and the exclusion from the sample of de-listed companies.

The ENA does not support any COVID adjustments to the electricity and gas sample as the impact of COVID-19 on the utility sector was not material.

CEPA proposed two firms be excluded from the sample, on the basis of the proportion of their revenue generated from regulated activities. ENA does not support the removal of these firms from the sample but notes that their exclusion doesn't alter either the sample asset beta or leverage.

ENA notes that CEPA recommends the Commission has regard to an upward trend in asset betas.

The ENA supports the use of the asset beta of 0.35, leverage of 0.39 and BBB+ credit rating based on the comparator sample.

5. Use of comparator sample to set debt tenor

Internally consistent debt tenor

The Commission currently sets a cost of debt based on the assumption that the EDB maintains a staggered portfolio of 5-year debt. Large EDBs that issue longer tenor debt receive compensation of the higher debt risk premium (DRP) on that debt via the TCSD (discussed below).

However, as discussed above, the Commission sets the asset beta and leverage for all EDBs based on benchmarking against businesses that universally have a longer average tenor of debt. In fact, in the Commission's asset beta sample, the value-weighted average tenor of all bond issues is over 20 years.

The difference between the actual practice of the firms in the asset beta sample (20 years) and the Commission's assumption (5 years) is material. In this context, it is critical to understand why firms choose to issue longer-dated debt even though this is typically associated with a higher cost of debt and, in particular, a higher DRP.

In its report on non-percentile issues (Appendix C), CEG outlines the reason why the equity owners of a firm would choose to issue higher-cost, long-term debt, rather than lower-cost, short-term debt. This must be because doing so reduces the cost of equity. That is, any higher interest costs must be associated with an at least offsetting lower cost of equity – otherwise, it would be irrational to incur the higher costs associated with issuing long-term debt.

The capital asset pricing model (CAPM) used by the Commission to estimate the cost of equity, must manifest through a lower beta. That is, a firm-specific decision to issue longer-term debt can only reduce the cost of equity if it reduces the equity beta for any given gearing level (given that the market risk premium and risk-free rate are market-wide parameters).

This relationship between debt beta and equity beta is well understood and accepted by the Commission. The Commission explains why the existence of positive debt betas means internal consistency requires it to use the same benchmark gearing as the sample average gearing from the asset beta sample of firms. Otherwise, using a debt beta of zero and a value for benchmark gearing above the sample average would tend to overestimate the equity beta and create "the leverage anomaly" whereby WACC increases with gearing when the Modigliani Miller Theorem[9] argues that WACC should be independent of gearing (within reasonable ranges).

To this end, the Commission has stated:[10].

> *"We continue to consider that using the average leverage of the asset beta comparator samples is the best way of dealing with the anomaly. As we have estimated a notional leverage in line with the companies in our asset beta comparator samples, the resulting*

[9] Modigliani, F.; Miller, M. (1958). "The Cost of Capital, Corporation Finance and the Theory of Investment". American Economic Review. 48 (3): 261–297.

[10] Commerce Commission, Input methodologies review decisions, Topic paper 4: Cost of capital issues, December 2016, p. 144.

> *WACC will be the same for those services regardless of the value assumed for the debt beta."*

CEG found that the same principle of internal consistency applies in the context where the Commission uses the asset beta for firms with long-term debt and applies it to a benchmark where it assumes short-term debt is being used. Other things equal, this will create precisely the same sort of bias that the Commission is concerned about with the leverage anomaly.

CEG notes that the 'leverage anomaly' is a direct corollary of the 'tenor anomaly'. Choosing a different leverage to the sample average should not affect the WACC but, without accounting for debt beta, it does. Similarly, choosing a different tenor to the sample average should not affect the WACC but, without accounting for debt beta, it does. The Commission has correctly addressed the leverage anomaly, but the same logic means it should also address the tenor anomaly.

Table 2: Leverage anomaly vs tenor anomaly

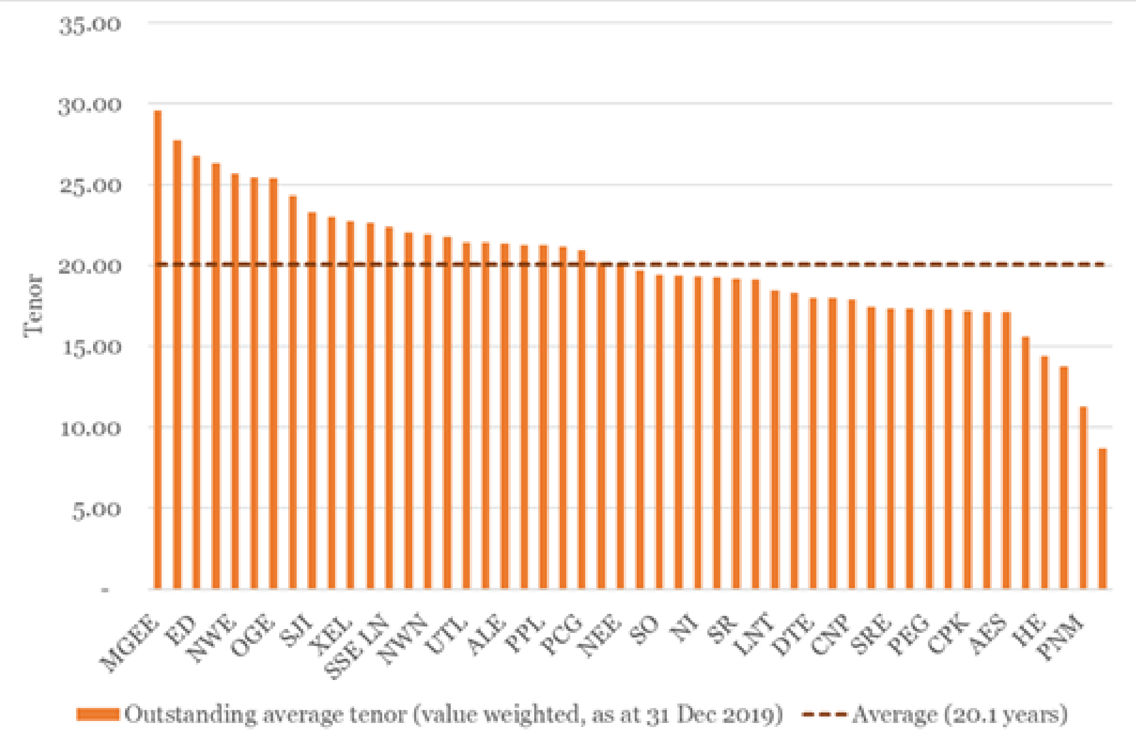
	Leverage anomaly	**Tenor anomaly**
Problem	The sample average equity beta reflects the sample average **leverage** and its effect on the (unknown) sample average debt beta. Debt beta is important. Therefore, setting the **benchmark gearing** different to the sample average gearing would require an accurate estimate of the value of the debt beta (and how it changes with **leverage**), but this is not available.	The sample average equity beta reflects the sample average **debt tenor** and its effect on the (unknown) sample average debt beta. Therefore, setting the **benchmark debt tenor** different to the sample average debt tenor would require an accurate estimate of the value of the debt beta (and how it changes with **debt tenor**) but this is not available.
Solution	Set the **benchmark leverage** equal to the **sample average leverage** to avoid any adjustments that require an estimate of debt beta.	Set the benchmark **debt tenor** having regard to the **sample average debt** tenor to avoid any adjustments that require an estimate of debt beta.

Source: CEG analysis

The main difference between these two problem/solution sets is that adopting the sample average gearing for New Zealand is not viable. The market for very long-dated New Zealand corporate debt is not sufficiently large for even actual or hypothetical large listed New Zealand EDBs to issue an average bond tenor of 20+ years.

Vector is the only New Zealand business in the Commission's asset beta sample and it has the smallest average tenor (8.7 years) reported in Figure 2.

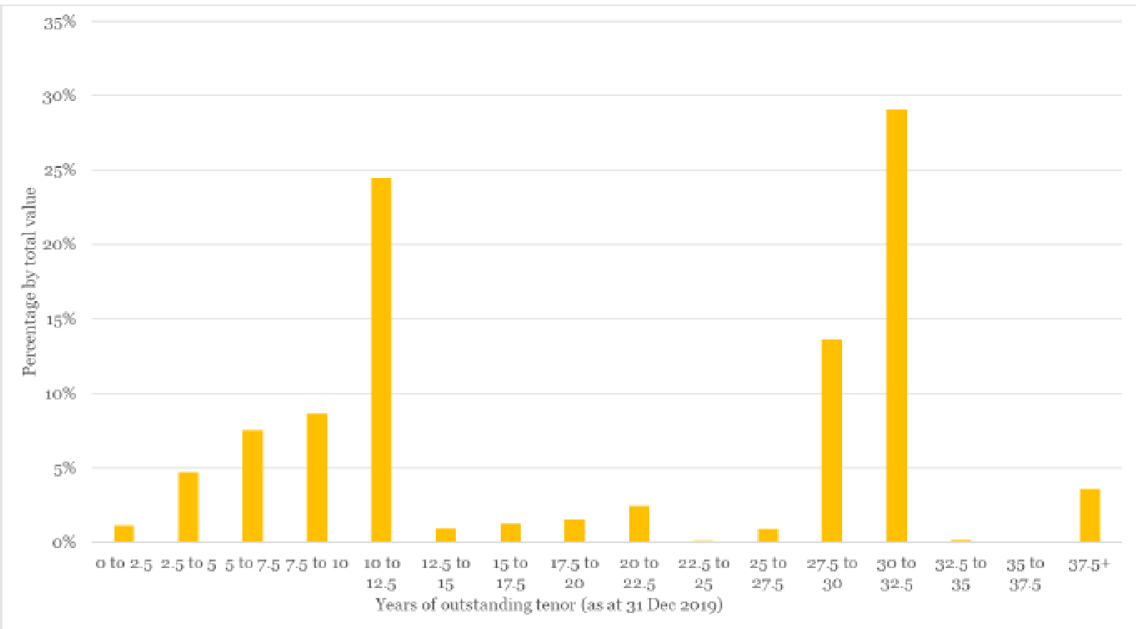
Figure 2: Average debt tenor of CEPA sample



Source: Bloomberg and CEG analysis

The figure below presents the data as a histogram over all maturity profiles (i.e., combine all debts for all firms in the sample before reporting the distribution of those debts). There are two poles of common debt issuance maturity – one at 10 years and one at 30 years. The 30-year maturity is not a realistic option for even a hypothetical large listed New Zealand EDB. However, maintaining a 10-year average debt tenor is a realistic option for a hypothetical large listed New Zealand EDB.

Figure 3: Histogram of all debts



Source: Bloomberg and CEG analysis

This would be consistent with the practice of regulators internationally. In the US and the UK, regulators set the cost of debt with respect to the observed yields on 10+ year maturity debts. In Australia, being the most similar to New Zealand in terms of access to debt funding, the AER has estimated that Australian EDBs have an average debt tenor of between 8 and 11 years and concludes:[11]

> *"Our decision is to maintain the benchmark return on debt term at 10 years. This aligns with the debt financing practices of regulated businesses to issue long-term debt. Our analysis of industry debt data also does not show clear evidence that the current benchmark of 10 years is no longer an appropriate benchmark term, or that there is a materially better alternative."*

ENA recommends the Commission use the comparator sample to set debt tenor. In the absence of the liquidity of a debt market for bonds of equal length to the comparator sample, the Commission should adopt a 10-year debt tenor.

Implementation of a 10-year tenor

If a 10-year tenor assumption was adopted, the Commission would then have two options for the implementation of the 10-year tenor:

1. Continue to assume that EDBs engage in an underlying swap strategy to reset the base rate of their debt portfolio to a 5-year rate at the beginning of each DPP. In this case, it would need to:
   - extend the timeframe for observations to 10 years from 5 years;
   - re-estimate the DRP at 10 years rather than 5 years;
   - reconsider its assumed swap strategy to take into account that EDBs would need to now use a 10-year pay fixed/receive floating swap to convert a 10-year debt issue into a floating rate instrument.
2. Adopt a trailing average approach to the cost of debt, as is the practice in Australia and internationally.

ENA recommends that the Commission adopt the second of these options and implement a trailing average approach which has the following beneficial attributes:

- it is hedgeable/implementable
- it has low transaction costs for the business
- the potential cost of estimation error is low
- it gives rise to relatively low price volatility and does not result in higher prices when customer budgets are under stress
- is consistent with standard business practice.

[11] AER, Draft Rate of Return Instrument Explanatory Statement, June 2022, p. 194.

In either case, it would be reasonable for the Commission to consider and consult on imposing a transition arrangement. The AER's transition methodology adopted for its move to the use of a trailing average cost of debt in 2013 is appropriate and should be adopted in New Zealand.

ENA recommends the Commission move a 10-year debt tenor should be accompanied by a transition to the use of a trailing average cost of debt. The AER transition method should be used to make this transition.

6. Term credit spread differential

The TCSD refers to the increase in Debt Risk Premium (DRP) as the tenor of the bond increases. This parameter is used by the Commission to capture the additional cost of network operators of holding bonds with tenor greater than 5 years. If the Commission adopts the ENA recommendation on debt tenor, this removes the issue of the TCSD.

Under the current approach, the Commission makes a TCSD adjustment to the allowed revenue for EDBs that have outstanding debt issued with an original tenor greater than the 5-year regulatory period.

In the 2016 IM final decision, the Commission reported an estimate of the TCSD of 4.5-6.0 bps using its own methodology. However, it also relied on an estimate calculated by CEG of 9.5-11.0 bps. In its final decision, the Commission chose a middle value of 7.5 bps.

The differences in the CEG and Commission methods were small. The most material difference is that CEG estimated the TCSD every month of the relevant historical period and then took an average of the monthly estimates. By comparison, the Commission determined that it would break the data into six monthly blocks, rather than monthly periods.

CEG has replicated the calculation of the Commission 2016 TCSD and updated the calculation using up-to-date data (Appendix C). CEG has however been unable to replicate the Commission's final 2016 TCSD estimate.

CEG's updated TCSD estimates to 2022 (using the Commission's description of its method and an updated sample of bonds) are very similar to its estimates in 2016 and its attempted replication of the Commission method in 2016 (see Table 3 below).

Table 3: Updated TCSD estimates*

	Excel software	R Software
Jan 2013 to June 2016	0.10%	0.11%
Jan 2013 to June 2022	0.09%	0.10%
Jan 2016 to June 2022	0.09%	0.10%
Jan 2018 to June 2022	0.10%	0.11%

* The use of NSS curve fitting applies an optimisation algorithm which can affect the result.

For completeness, CEG also calculated the TCSD that would result from aggregating monthly TCSD estimates, which was the method CEG proposed in 2016 in response to the Commission's draft decision (Table 4).

Table 4: Table: Six versus one monthly TCSD estimates, R software

	6 monthly regression (Commission)	Monthly regression (CEG)	Monthly regression (removing two outlier estimates)
Average TCSD from June 2016 July to 2022 June	0.091%	0.160%	0.094%

Source: Bloomberg, CEG analysis.

ENA's view is that CEG's analysis supports the Commission's decision to adopt a six-monthly estimation period in preference to a monthly estimation period. This approach result in a TCSD of 0.091%. On request, ENA will share with the Commission CEG's detailed calculations.

ENA recommends that if the Commission continues to adopt a 5-year debt tenor, a TCSD of 0.091% be used.

7. Financeability and equity raising costs

Financeability

The enablement of the electrification and decarbonisation of the New Zealand economy will result in increased expenditure by EDBs. The funding of this expenditure will put pressure on EDBs' cash flows. The attached report from NERA highlights (Appendix D) the impact this will have on EDBs' financeability.

ENA recommends the Commission incorporate financeability tests into its regulatory regime as a cross-check to ensure the internal consistency of its credit rating assumptions with the revenue allowance for the Benchmark efficient entities.

This cross-check should adopt the quantitative metrics used by rating agencies S&P Global Ratings and Moody's and be conducted at each price quality determination and review of the IMs.

Equity Raising Costs

Equity raising costs are transaction costs incurred when EDBs fund capital investment through equity. As EDBs' capital expenditure rises to enable New Zealand's decarbonisation, it is likely that EDBs may need to raise equity. The Commission's current WACC method does not compensate EDBs for transaction costs involved in the issuance of equity.

The Australian regulatory regime has explicitly incorporated an equity-raising cost since 2009. When introduced, the AER noted:[12]

> *"In raising new equity capital a business may incur costs such as legal fees, brokerage fees, marketing costs and other transaction costs. These are upfront expenses, with little or no ongoing costs over the life of the equity. Whilst the size of the equity a firm will raise is typically at its inception, there may be points in the life of a firm—for example, during capital expansions—where it chooses additional external equity funding (instead of debt or internal funding) as a source of equity capital, and accordingly may incur equity raising costs."*
>
> *"The AER has accepted that equity raising costs are a legitimate cost for a benchmark efficient firm only where external equity funding is the least–cost option available."*

ENA agrees with AER's view that "*equity raising costs are a legitimate cost for a benchmark efficient firm"* and should be included in the Commission's framework. We recommend that the AER approach to the calculation of this allowance be adopted in the Commission's financial model.

Calculation of equity raising costs

In order to fund capital expenditure, the first option for an EDB is to fund the equity portion of RAB growth utilising retained earnings - but with increases in retained earnings constrained by the need to

[12] AER TransGrid transmission determination 2009-10 to 2013-14, Final decision, 28 April 2009

maintain a minimum rate of dividend payout to shareholders (assumed by the AER to be 63% of taxable profit).

This source of funding is assumed to be costless by the AER. However, if this source of equity raising is exhausted, the EDB has the option of either:

- seeking reinvestment of dividends from its existing equity holders using a 'dividend reinvestment program' often referred to as a DRP. The AER assumes that up to 30% of the dividend is available for reinvestment and that the cost of this option is 1% of the size of the amount reinvested (known as 'Dividend Reduction').
- seek new equity investors via what is known as a 'seasoned equity offer' (or SEO - which distinguishes equity raising for an existing listed firm from the initial public offering for a newly listed firm). The AER assumes that the cost of an SEO is 3% of the amount of equity raised.

The AER assumes that higher-cost funding is relied on only when the available lower-cost funding is exhausted.

A detailed description of the AER's approach to the estimation is set in the CEG report at Appendix C.

The AER approach can be adopted directly into the Commission's financial model. Attached to this submission (Appendix E) is a modified version of the Commission's financial model prepared by CEG that incorporates equity raising costs for each price-quality regulated EDB.

ENA recommends the Commission include in its financial model an allowance for equity raising costs based on the AER approach.

8. Amortisation of debt issuance costs

CEG has identified a potential error (Appendix B) in the Commission is collation of debt issuance cost in its final 2016 decision, which understated transaction costs by around 0.5bp (assuming a 5-year tenor and a 5% discount rate). This mathematical error should be simple to correct.

In the final Topic 4 paper the Commission states:[13]

> *"Amortisation of upfront costs*
>
> *CEG submitted that upfront debt costs need to be amortised over time using a cost of capital to take into account the time value of money.*
>
> *"We disagree with this conclusion because suppliers typically issue some debt each year to manage refinancing risk. They therefore incur some debt issuance costs each year. Assuming that firms issue a consistent amount each year with similar costs, there is no need for a present value adjustment in respect of a portfolio of debt."*

The Commission notes that:

- *"a firm operating a trailing average debt 5-year tenor strategy will refinance 20% of total debt each year;*
- *every year it will incur 20% of the total transaction costs associated with raising its entire debt RAB; and*
- *if it simply provides an ongoing annual allowance for 20% of the total transaction costs associated with raising its entire debt RAB, then the allowance will fully cover ongoing debt issuance costs. "*

This is mathematically correct (assuming a constant value for the RAB). However, it does not follow that this means no NPV adjustment is required. If the Commission were correct, it would imply that in a competitive market: there is no need for a firm to earn a return on its investment in inventory (no holding cost of inventory).

In the regulatory context, we can think of the entire debt RAB as the inventory of debt that is being used up (maturing) and replenished (refinanced) at a rate of 20% per year. The Commission's approach to compensate only for the costs of new debt as it is incurred amounts to, in effect, refusing to compensate for the costs of prior building and holding of that debt inventory.

If the Commission speculates each year's total debt issuance compensation to the debt that has just been raised in that year (being one-fifth of the RAB), then that leaves the other four-fifths of the RAB uncompensated.

[13] Commerce Commission, Input methodologies review decisions, Topic paper 4: Cost of capital issues, December 2016, p. 56.

That is, at any given time there is an "inventory" of old debt-raising costs that is uncompensated. This uncompensated inventory issue can be addressed by simply adding a NPV adjustment to debt issuance costs.

ENA recommends that the Commission include an NPV adjustment to its estimate of debt issuance cost.

9. Inflation and targeting a real return

Intrinsically and inseparably linked to the calculation of the WACC is how inflation is treated within the regulatory regime. The key inflation related questions for the regulatory model and its WACC calculation are:

- how should expected inflation be estimated; and
- to what extent should the model target a real versus a nominal return?

Estimating expected inflation

The Commission in its 2016 IM determined that expected inflation should be estimated from the RBNZ CPI forecast produced at the time closest to the determination window used to estimate the risk-free rate and then trend to the mid-point of the RBNZ inflation target by the end of year 5.

The Commission decided to not give weight to measures of expected inflation derived from the difference in yields between nominal and inflation-indexed New Zealand government.

Accuracy of the Commission's inflation forecast method

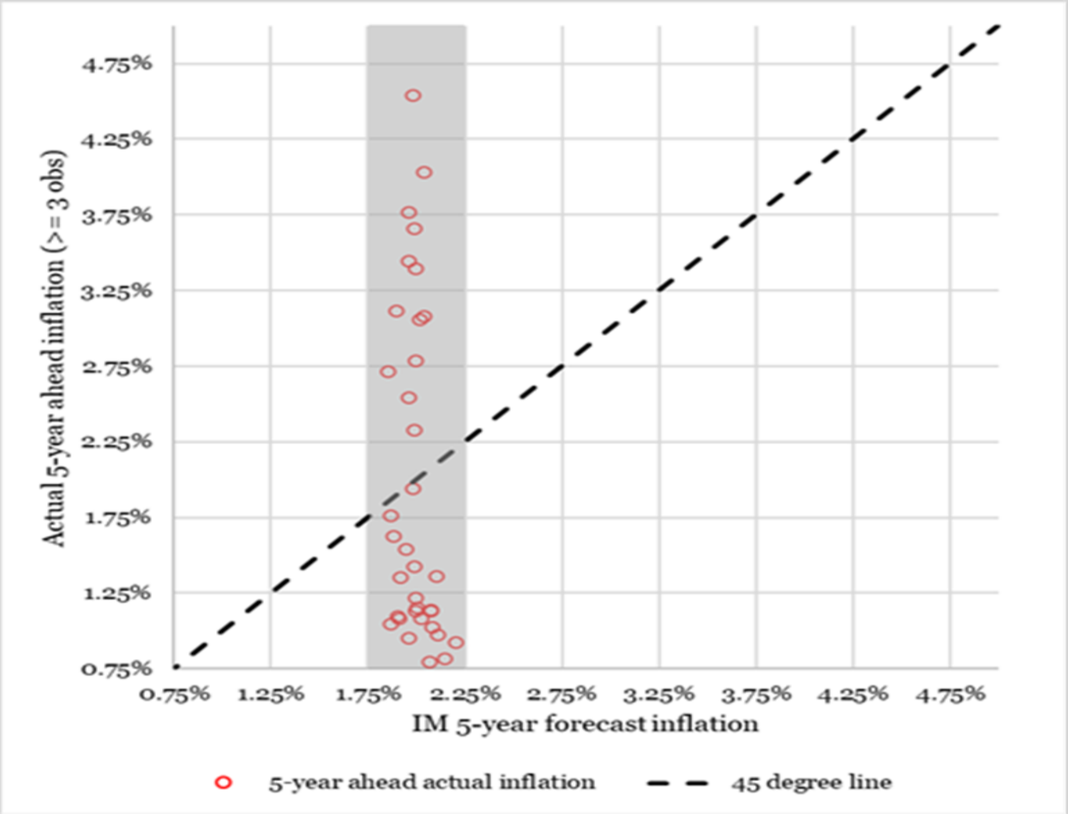
In this section, we examine evidence on the magnitude of inflation forecast error since 2016. This evidence shows larger inflation forecast errors since 2016 than pre-2016. The Commission may wish to recalibrate its assessment that the existing methodology creates only "small" inflation forecast risks.

In the 2016 IM process, the Commission expressed the view that inflation forecasting error was relatively small and would tend to "wash out" if it was unbiased. However, recently experience tends not to support such a conclusion. In summary, the Commission's five-year inflation forecasts have:

1. Either
    a. overestimated actual inflation; or
    b. underestimated actual inflation; but
2. almost never accurately estimated actual inflation.

Figure 4 shows the Commission's 5-year forecast inflation on the horizontal axis and actual 5-year inflation (over the same forecast period) on the vertical axis. If forecast inflation was accurate, then the red dots would be spread up and down the dotted 45-degree line.

Figure 4: The Commission's forecast vs actual 5-year inflation since 2010



Source: Commerce Commission forecast methodology, RBNZ quarterly inflation forecasts, CEG analysis.

It can be seen that the Commission's 5-year forecast is universally (100%) within a narrow band of 1.75% to 2.25%. By contrast, actual inflation is only twice (5.6%) within that narrow band and, instead, is spread relatively evenly from 0.75% to 4.75%.

The experience of actual inflation since 2016 is inconsistent with the view expressed by the Commission in its 2016 IM decision that inflation forecast error is likely to be small.

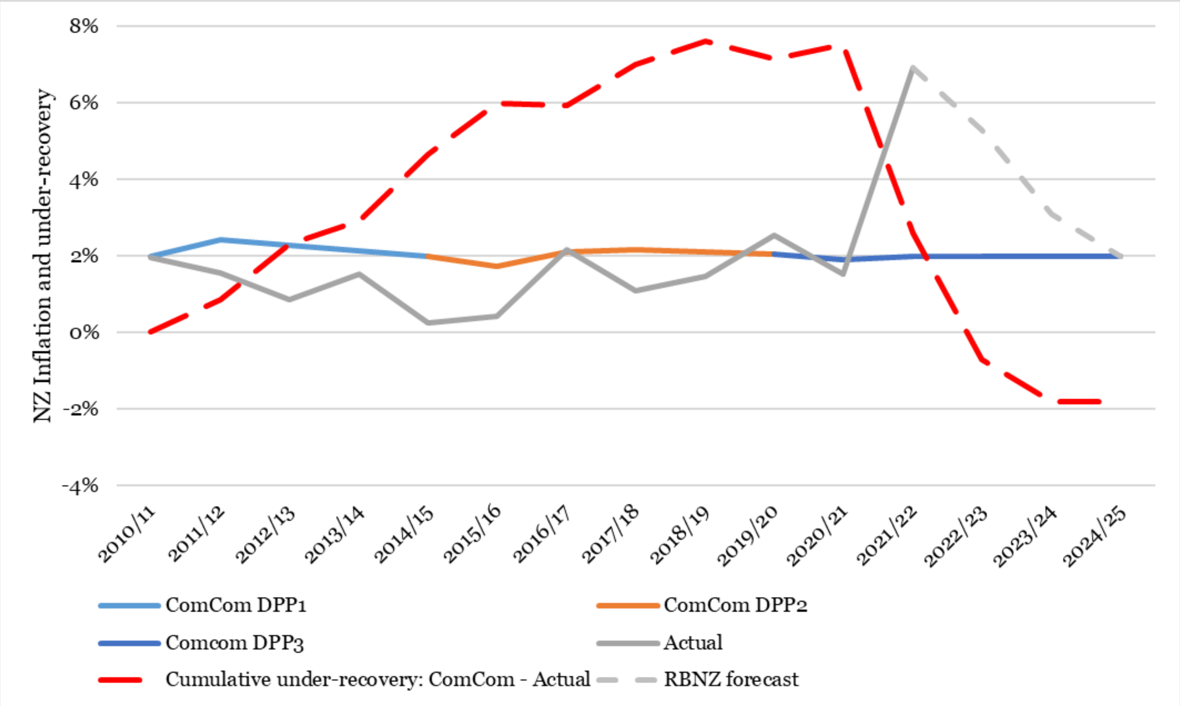
The Commission's view is that forecast errors "will wash out over time" provided that the forecast of inflation is unbiased. The result is that when the Commission overestimates inflation, customers end up under compensating EDBs for their nominal debt costs. And when the Commission understates inflation, EDBs are over compensated. That is, when we talk about "under" and "over" compensation for costs, we are focussed on the cost of debt – which all parties agree is efficiently incurred in nominal terms.

The statement that forecast errors "wash out" in the long run can only ever be true if the period of "time" being referred to is the very long run. This is because the Commission only makes one forecast every 5 years. Thus, after 50 years there will be only 10 sets of forecasts to average. Even if the Commission's forecast is unbiased with no autocorrelation with previous forecast errors, it will still take many decades before the law of large numbers takes effect and one can confidently talk about errors "washing out". For many customers/investors this would not be expected to occur over their remaining life/investment horizon.

When looked at over the last 15 years from 2010 to 2025 (DPP1 to DPP3)), which could be considered short run as compared to a 50 year long run horizon, there has been an approximate "wash out" (as shown in Figure 5) with:

- very large cumulative under-recovery of inflation for EDBs (over-recovery for customers) over the 10 years to 2020-21 which has been almost fully offset by
- a single year of very high over-recovery of inflation for EDBs (under-recovery for customers) in 2021-22
- current forecasts until the end of DPP3 in 2024-25 imply more material over-recovery for EDBs such that over 15 years they can expect to have substantially over-recovered actual inflation (without adjusting for discounting or changes in RAB).

Figure 5:Cumulative forecast error over DPP1 to DPP3



Source: RBNZ, Commerce Commission and CEG analysis

The above shows forecast CPI used by the Commission (colour coded by DPP) and actual inflation (grey line) extended out to 2024-25 by the current RBNZ forecasts (4.5% to June 2023, 2.64% to June 2024 and 1.93% to June 2025). The dotted red line is the cumulative sum of the difference between the Commission forecasts and actual CPI over past years.

Over the 10 years to 2020/21, the cumulative forecast error was over 7% (implying that debt costs during that period went uncompensated by over 7% of the debt portion of the RAB). This period is likely to be followed by massive overcompensation for debt costs in DPP3, which is expected to more than fully reverse the previous 10 years' forecast errors.

However, rather than providing comfort that the current regime it can be assumed to inevitably result in forecast errors "washing out", the opposite lesson can be drawn. If DPP3 looked more like DPP2 and

DPP1 (which could easily have occurred if the forecasts are unbiased) then cumulative under-compensation would be over 10%. If DPP4 and DPP5 look like DPP3 then customers will overcompensate EDBs by more than 20% of the debt portion of the RAB.

An improved measure of forecast inflation

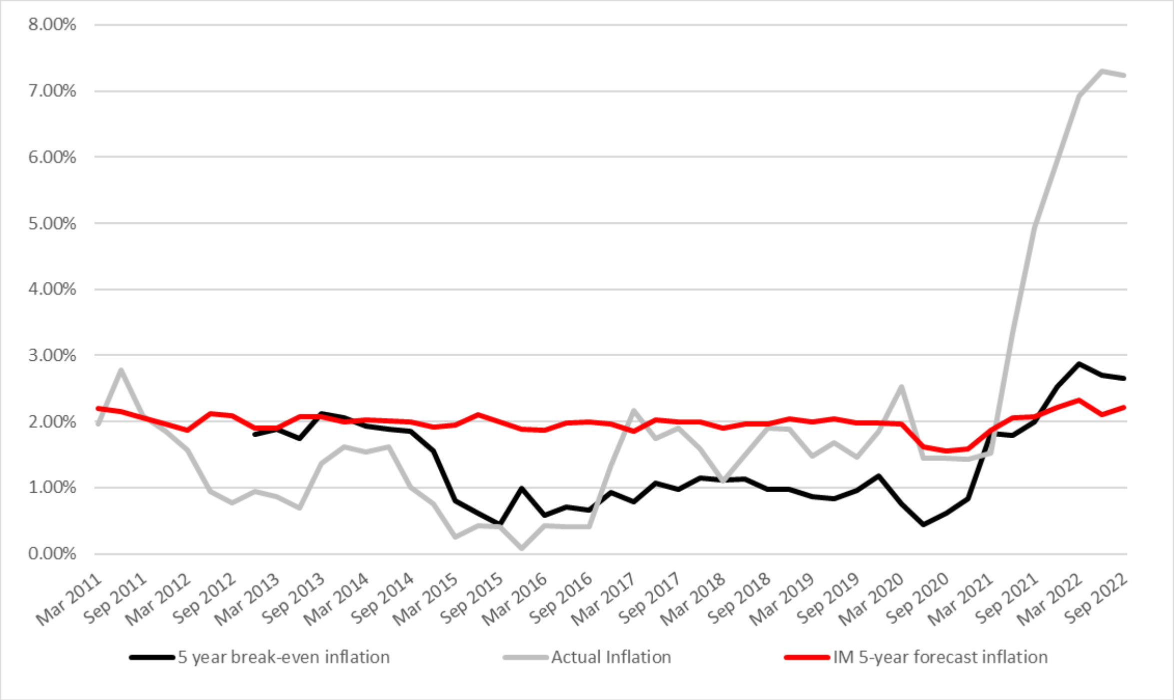
The assumption in the IMs that inflation will return to the midpoint of the RBNZ's target range over the short term is at odds with the evidence surveyed above. Since the global financial crisis, actual inflation in developed countries has been below central bank targets until the post-Covid period when it has been way above target.

Market-based estimates of expected inflation derived from the difference between the yield on nominal and inflation-indexed debt issued by the New Zealand Government provide an alternative to the Commission mechanically assuming inflation is always expected to trend to 2% over the RBNZ forecast period.

This difference is a measure of investors' inflation expectations because, if investors believed that inflation would be higher/lower than this difference, they would rationally sell/buy nominal debt and buy/sell inflation-indexed debt. The difference between nominal and CPI-indexed debt is known as the 'break even' inflation rate.

Pre Covid, 5-year break-even inflation rates were well below the mid-point of central bank target ranges globally, and New Zealand was no exception. This was a more accurate predictor of actual inflation, and was below the midpoint of central bank targets. Post Covid, 5-year break-even inflation responded more aggressively to the high inflation outbreak than the Commissions' method for forecasting 5-year inflation, and now sits above the forecast from the Commissions' method. This is illustrated in Figure 6.

Figure 6: Break-even inflation vs midpoint of RBNZ target range



Source: RBNZ b2 daily publication, CEG analysis.

This evidence suggests that some weight should be given to break-even inflation. In the 2016 IMs, the Commission argued that[14]:

> *"294.1 The shortest dated NZ government inflation-linked bond matures in 2025. Therefore any implied inflation would be an average over the period until the bond matures and would not necessarily correspond to the five-year regulatory period;"*

There are currently four inflation-indexed New Zealand government bonds (maturing in 2030, 2035 and 2045). This means that in 2025, at the time of the DPP4 reset, there will be an approximately 5-year maturity bond, as will be the case at the DPP5 reset. The above argument against giving any weight to break-even inflation falls away.

The Commission has also argued that break-even inflation might be biased by other factors (such as illiquidity premium in inflation-indexed bonds and an inflation premium in nominal bonds). This may be true but there is no theoretical reason to believe that the net effect of these results in a material net expected bias (noting that the former would increase indexed yields and the latter would increase nominal yields).

While all approaches to the forecasting of inflation give rise to forecasting error, this can, and should be, minimised to the extent possible. ENA believes inflation forecasting risk can be reduced by utilising both RBNZ inflation forecasts and the break-even rate for New Zealand bonds.

[14] Commerce Commission, Input methodologies review decisions, Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower December 2016, p. 68.

Therefore, ENA recommends that the Commission adopt the average of RBNZ CPI forecast and the 5-year break-even inflation derived from New Zealand government bonds as the forecast of inflation.

Targeting a real vs nominal return

In the 2016 IM, the Commission determined that it should target real returns for EDBs and GPBs but nominal returns for Transpower.

The Commission's current approach for EDBs involves targeting a real cost of capital by:

- estimating the nominal required return on capital;
- deducting forecast of inflation;
- indexing RAB using actual inflation.

The current regime does not protect customers from inflation forecasting risk

As shown above, the Commission's forecasts of inflation have consistently proved to be inaccurate and given rise to substantial inflation forecast errors. This results in either EDBs being over or undercompensated based on the differential between forecast and actual inflation.

Neither consumer or regulated businesses are able to influence inflation, or the forecasts of inflation, and should therefore bear as little inflation forecasting risk as possible. Inflation forecasting risk can be eliminated in its entirety through the use of an unindexed RAB or materially reduced by adopting a hybrid approach where the debt-funded portion of the RAB is unindexed.

NPV =0 can be achieved by targeting a real or nominal return

As demonstrated by Frontier Economics in its report submitted to the Commission by Transpower, the use of an unindexed RAB, a fully indexed RAB, or partially indexed RAB (the hybrid approach) can all theoretically achieve NPV=0.

Financeability is equally important

As discussed by NERA in its report (Appendix D), financeability is a concern for EDBs facing increased expenditure to facilitate of New Zealand's transition to a net zero carbon economy. The choice to target a real or nominal return on capital can have implications for the financeability of EDBs. The Commission, when making the choice to target a real or nominal WACC, must be careful to ensure the allowable revenues calculated under either approach are sufficient to allow the benchmark efficient entity to achieve the BBB+ credit rating assumed in the WACC.

The IMs should not proscribe a single approach to indexation

The Commission's, when deciding the if it should target a real or nominal return on capital and consequentially if the regulatory asset base (RAB) should be indexed the key criteria must that it should; protecting consumers from inflation forecasting risk, maintaining NPV=0 and ensuring EDBs have sufficient financeability to allow them to achieve the Commission's targeted BBB+ credit rating.

There are benefits for EDBs facing large investment programmes driven by decarbonisation investment, and the consequential financeability impacts being able to elect to have their RAB unindexed. The Commission's adopted the unindexed approach to Transpower RAB in 2010 for similar reasons noting in 2016 it considered *"this was appropriate in 2010 given their relatively large investment programme, since an unindexed approach would likely lead to higher revenues in the near-term that better matched their investment needs[15]".*

ENA recommends that the Commission investigate the benefits of allowing EDBs to choose to use an indexed, un-indexed, or partially index (hybrid) RAB, as is currently the case for airports.

10. Contact

Thank you again for the opportunity to submit on this important topic. The ENA's contact person for this submission is Keith Hutchinson.

Email: Keith@electricity.org.nz

Phone: (04) 555 0074.

[15] Commerce Commission, Input methodologies review decisions, Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower December 2016, p.70

Appendix A – ENA members

The Electricity Networks Association makes this submission with the support of its members, listed below.

Alpine Energy

Aurora Energy

Buller Electricity

Centralines

Counties Energy

Eastland Network

Electra

EA Networks

Horizon Energy

MainPower NZ

Marlborough Lines

Nelson Electricity

Network Tasman

Network Waitaki

Northpower

Orion New Zealand

Powerco

PowerNet

Scanpower

The Lines Company

Top Energy

Unison Networks

Vector

Waipa Networks

WEL Networks

Wellington Electricity Lines

Westpower

Appendix B – CEG report, Updating the 2014 WACC percentile

Appendix C – CEG report, Estimating the WACC under the IMs

Appendix D – NERA report, Financeability considerations under the DPP

Appendix E – Revised financial model incorporating equity issuance costs

CEG Asia Pacific
www.ceg-ap.com

Memorandum

To:	NZ ENA
From:	CEG – Asia Pacific
Date:	26 January 2023
Subject:	**CEPA and CEG's analysis of the percentile**

1 Purpose

1. In October 2022 CEG finalised a report for the New Zealand Electricity Networks Association entitled "Updating the 2014 WACC percentile". Since then the New Zealand Commerce Commission released a report by CEPA[1] that, amongst other things, addressed the issue of updating the percentile. This memo briefly contrasts the findings of the two reports.

2 Findings

2. The CEG report concluded, by applying the 2014 framework developed by Oxera, that the optimal percentile would have increased. This was based on both:

   - Materially higher investment needs post 2025 compared to 2014 driven by growth in peak demand due to decarbonisation and the changing role of distribution networks as they transition to be "DSOs";[2]
   - Materially higher uncertainty around the median projection for demand growth and required investment.

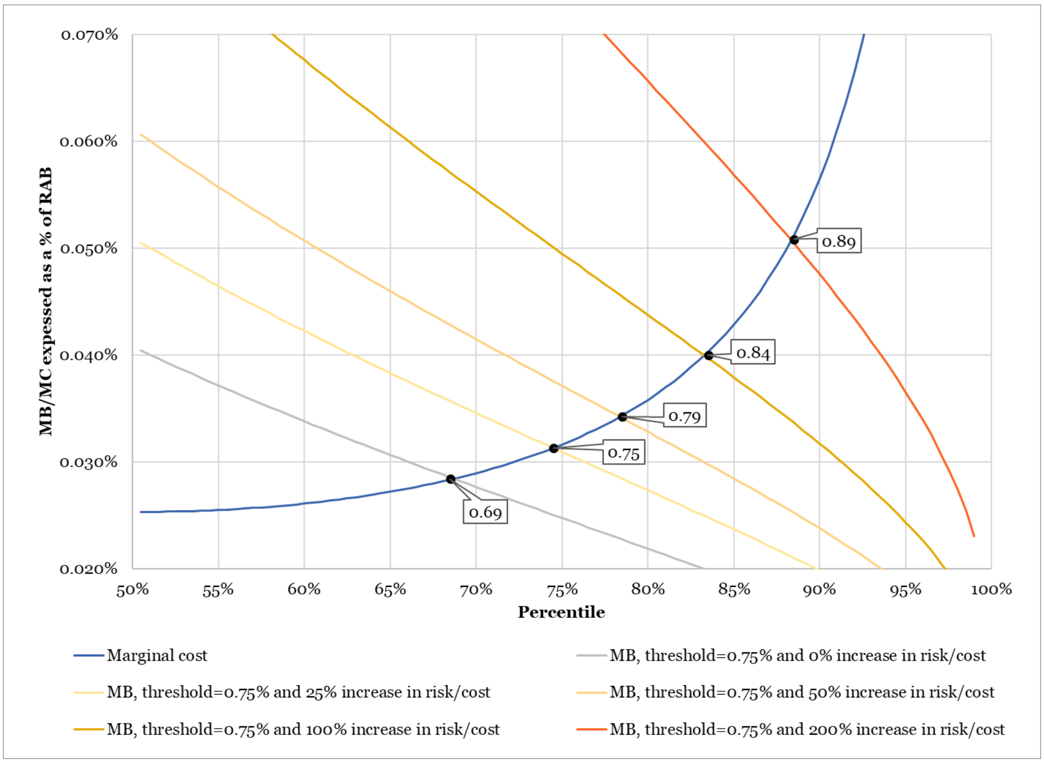
3. On this basis, we conclude that the percentile would increase from 67% to be at least 75%. This was summarised in Figure 7-1 by the intersection of:

   - the marginal cost to customers of paying a higher percentile (which can be mathematically derived from the WACC distribution and the industry RAB); and
   - the marginal benefit to customers of a higher percentile – which is the reduction in the probability (and, therefore, expected cost) of underinvestment.

[1] CEPA, Review of Cost of Capital 2022/2023, 29 November 2022.

[2] Distribution System Operator – responsible for monitoring and helping manage load and generation on the distribution network.

Reproduction of Figure 7-1: Midpoint marginal benefit curves intersections with marginal cost curve using a SE of 1.01%

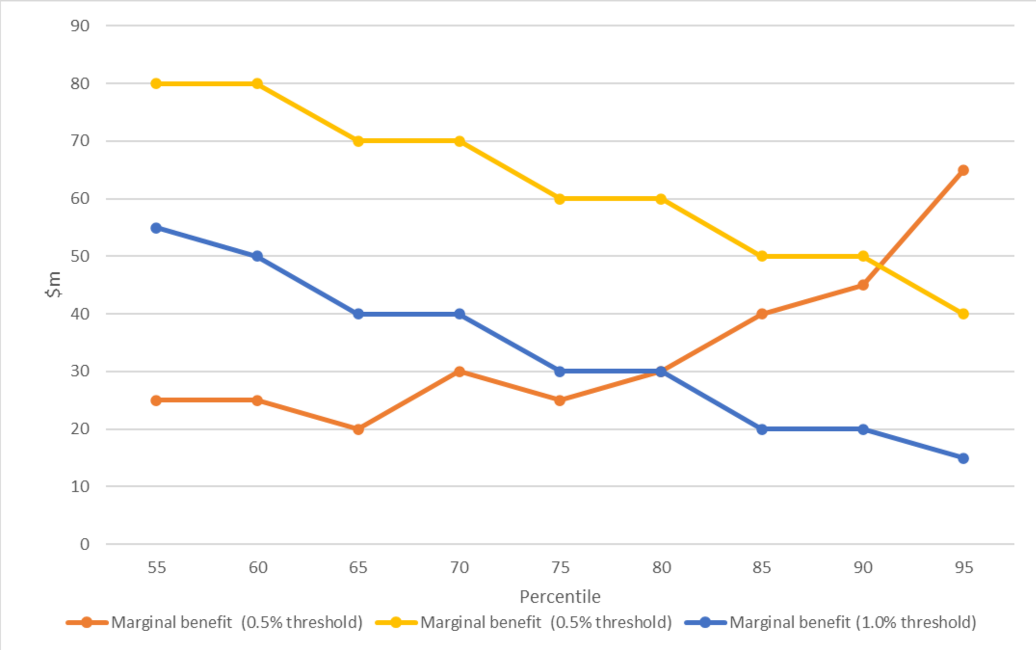


4. The marginal benefit curve depends on the expected cost of underinvestment and the threshold of WACC error that it's assumed to be necessary to generate underinvestment. For the purpose of the summary in Figure 7-1 we used a threshold of 0.75% (which is the midpoint of the thresholds Oxera and the Commission focussed on in 2014).

5. For the reasons set out in paragraph 2 above we concluded that the marginal benefit of a higher percentile would be at least 25% higher in 2025 than was the case in 2014 and could reasonably be assumed to be 100% higher. This would result in a corresponding percentile range of 75% to 84%.

6. CEPA arrived at a similar conclusion. CEPA's marginal cost and marginal benefit curves can be calculated from Tables 4.17 and 4.8 of its report. This is done by subtracting the total cost (benefit) amounts at each percentile from the total cost (benefit) amount at the preceding percentile. However, because CEPA reports percentiles in 5% increments and total costs/benefits rounded to the nearest $5m the resulting curves are not smooth.

Figure 2-1: CEPA marginal cost and benefit curves



Source: CEPA tables 4.17 and 4.8.

7. It can be seen that the optimal percentile based on these curves is in the range of 80% to 90%. This is similar, albeit higher, than the range recommended by CEG.

8. CEPA has arrived at this conclusion in a different manner to CEG.

   - The CEG report assumes that, other things equal, the benefit of avoiding underinvestment grows with the RAB as does the cost of underinvestment. Therefore, the only reason for an increase in the percentile is the greater risk of underinvestment due to the reasons summarised at paragraph 2 above.
   - By contrast, CEPA places zero explicit weight on the factors summarised at paragraph 2 above. However, CEPA assumes that the cost of underinvestment grows in line with New Zealand GDP and the value of lost load which CEPA regards as capturing in part the effect of decarbonisation increasing the value of the electricity network.[3] This leads to a 90% increase in the estimated benefits of avoiding underinvestment relative to 2014. However, because the RAB has

3 CEPA states on page 24 "*Oxera's links between underinvestment and a loss of network reliability. Instead, we scaled Oxera's estimate for the cost of network outages if underinvestment were to occur accounting for New Zealand's increase in GDP and the change in the value of lost load in New Zealand, which we consider a proxy for changes in reliance on electricity driven by electrification and decarbonisation. Once these two effects are accounted for, the estimated annualised cost of a loss of network reliability resulting from underinvestment is NZ$1.9bn. Oxera's estimate was NZ$1.0bn.*"

grown by around 30% (i.e., less than 90%)[4] since 2014 the optimal percentile increases (marginal cost increases by less than marginal benefit).

9. A reasonable summary of the difference between CEPA and CEG is that:

- CEPA focussed on changes between 2014 and 2021 in the form of GDP and the value of lost load growing faster than RAB. CEPA attributed the faster growth in the value of lost load as capturing to some extent the growing importance of the electricity sector in the context of decarbonisation and electrification; and
- CEG focussed on a comparison between EDB's operating environments post 2014 versus post 2025. CEG's analysis was predicated on much higher expected investment post 2025 due to decarbonisation and a radically different role for EDBs facilitating the transition to functioning distribution system operators (DSOs). This is what led to an increased assessed risk (probability) and cost of underinvestment due to an error in the WACC post 2025 compared to post 2014.

10. Arguably, both sets of changes are relevant which suggests that both CEPA and CEG's analysis is conservative in terms of the recommended percentile.

4 CEPA Tables 4.6 and 4.10.

Updating the 2014 WACC percentile

October 2022

COMPETITION ECONOMISTS GROUP

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1 Overview

1. The 2014 framework applied to estimate the optimal WACC percentile was set out in both an Oxera expert report[1] to the NZCC and the NZCC's final decision.[2] In this report we adopt as a starting point: a) that framework; and b) the assumption that the 67th percentile was a correct application of that framework in 2014.

2. We then examine the impact of various changes since 2014 that can be expected to alter the selection of the WACC percentile that maximises expected net benefits to consumers. The changes we examine are:

   a. The reduction in the NZCC estimate of the standard error of the WACC from 1.06% in 2014 to 1.01% in the 2016 IMs. (Under the 2014 framework a change in the standard error of the WACC can be expected to change the optimal WACC percentile);

   b. The imminent energy transition which involves both much higher expected demand growth now than in 2014 and greater uncertainty around that demand growth (both upwards and downwards).

   c. The fact that EDBs roles and services are changing to play a much more direct role in coordinating efficient operation of distributed generation assets and also demand side response (in coordination with national wholesale market driven flexibility responses). In effect, EDBs are in the process of becoming distribution system operators (DSOs). This materially increases the value that EDB's investment can provide to the entire supply chain and, consequently, increases the costs of underinvestment.

3. We conclude that the reduction in the standard error would not materially affect the WACC percentile. However, we conclude that the other two factors justify a further increase to between 75% and 84% and we recommend a value of 79%.

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[1] Oxera, Review of the '75th percentile' approach, June 2014.

[2] NZCC, Amendment to the WACC percentile for price-quality regulation for electricity lines services and gas pipeline services, Reasons paper, October 2014.

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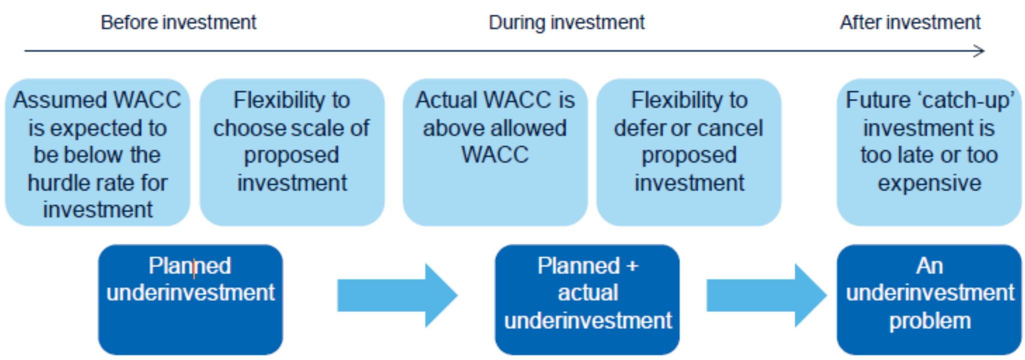
2 The 2014 framework and "starting points" for our analysis

4. The 2014 NZCC/Oxera framework is neatly summarised using Oxera's Figure 7.1 (reproduced below).

Figure 7.1 What is the underinvestment problem?



Source: Oxera.

5. Oxera describes the underinvestment problem as existing in circumstances where:

   a. an EDB's required return is higher than the regulatory WACC; and

   b. the firm has some flexibility to choose the scale and type of investment program – and will choose to underinvest if the allowed WACC is sufficiently below firm's actual WACC; and

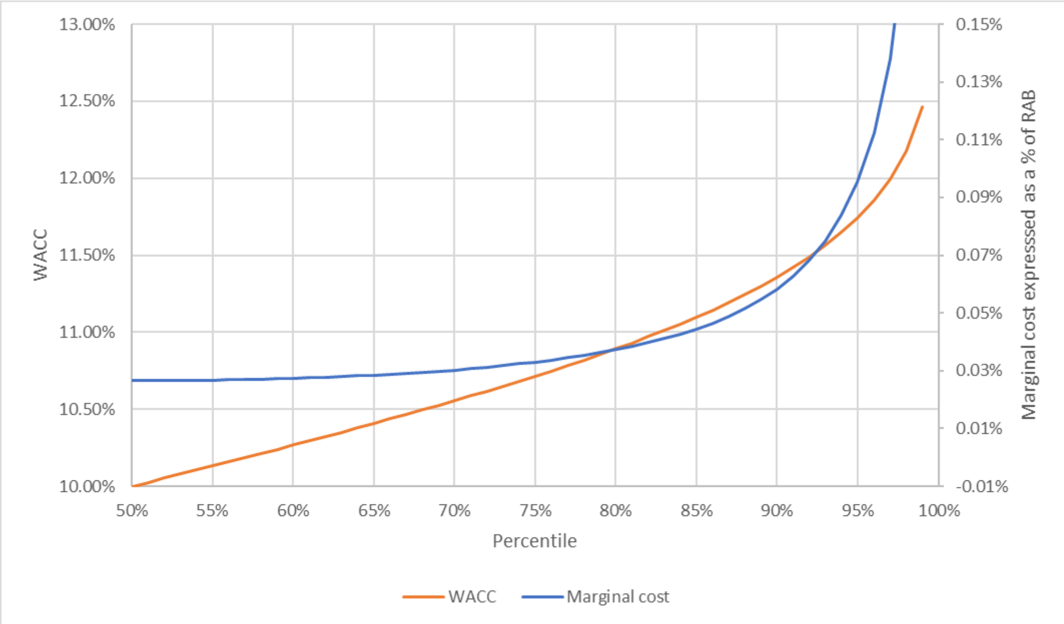
   c. by the time underinvestment is apparent, it is higher cost to solve this via "catch up" investment (due to costs of supply interruptions in the meantime and/or higher costs of "catch up" investment versus prudently planned investment).

6. Setting the regulatory WACC above the midpoint delivers benefits to customers by reducing the probability (expected level of) underinvestment and reducing the attendant costs of that underinvestment. However, this comes at a cost to customers because it results in a higher price of delivered electricity (for any given value of the RAB). (The NZCC framework consciously gives no weight to the fact that many consumers are also owners of EDBs. If the NZCC framework factored this in then the optimal percentile would be higher than that estimated in 2014.)

7. The marginal cost to customers of a higher percentile increases with level of the percentile WACC chosen. This is because, given an assumed normal distribution of the true WACC around the midpoint estimate, each increase in the percentile results in a larger increase in WACC the further above the midpoint the WACC is set. This is

illustrated below in a scenario where the midpoint WACC is 10% and the standard deviation is 1.06% (being the EDB standard error estimate in 2014).

Figure 2-1: Illustration of relationship between the percentile, the WACC and percentile (midpoint = 10%, standard error=1.06%) and the marginal cost of a percentile increase (as a % of RAB)



Source: CEG illustration

8. The marginal cost to customers starts off fairly stable at around 3bp per percentile. That is, raising the percentile above 50% raises the WACC by around 3bp for each percentile between the 50th and the 80th percentile. However, the marginal cost starts to increase rapidly as the percentile increases beyond the 80th percentile. This is because, as the percentile enters the tail of the normal distribution, ever larger increases in the WACC are required to achieve a unit increase in the percentile.

9. The shape and the position of the marginal cost curve is relatively uncontroversial to estimate. All that is required is an estimate of the standard error of the WACC (and an assumption of a normal distribution for the WACC) and the value of the RAB. The annualised marginal cost of an increase in the percentile is simply the value of the RAB multiplied the change in WACC required to achieve a unit increase in the WACC percentile.

10. It is also possible to mathematically model the marginal benefit to consumers of increasing the percentile. However, this involves more uncertainty and stronger assumptions about how underinvestment responds to errors in the WACC and also the probabilistic costs of underinvestment.

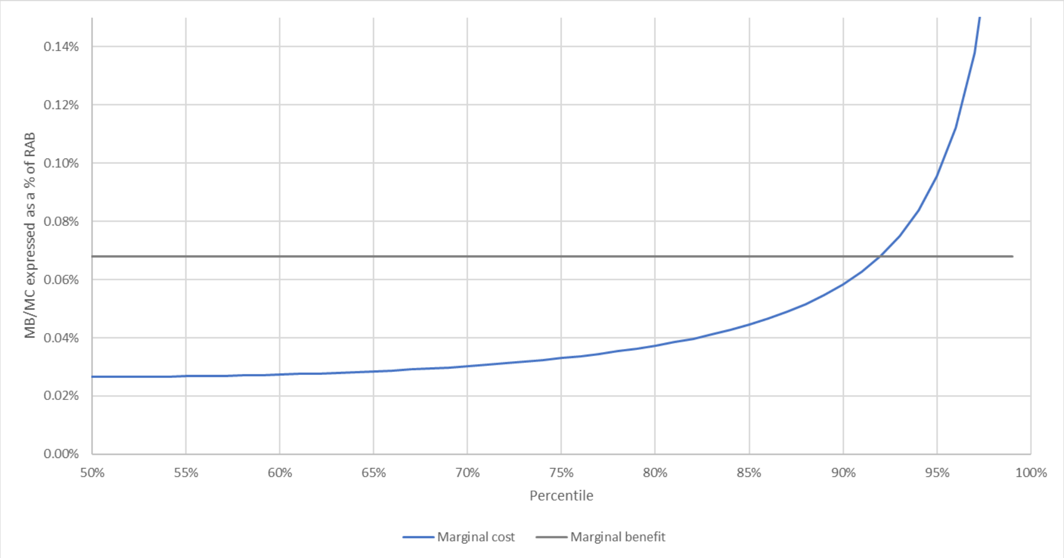
11. In 2014 Oxera estimated a low (high) cost of underinvestment at around \$1bn pa (\$3bn pa). Expressed as a percentage of the 2014 industry RAB this translated to 6.8% (20.4%). (Note, we express costs of underinvestment as a percentage of RAB because the costs of increasing the WACC percentile are expressed in the same terms (being the WACC uplift multiplied by RAB). In addition, on the assumption that the RAB grows more or less in line with the value of the electricity supply chain this allows for a simple comparison across periods with different RABs.)

12. For the sake of a stylised illustration, we initially ignore gradations in the underinvestment problem, and assume that underinvestment will occur whenever the allowed WACC is below the true WACC and that, whenever underinvestment occurs, it has the same expected cost. In that case, increasing the percentile by 1% decreases the probability of underinvestment by 1%. It follows that the marginal benefit of increasing the WACC percentile by 1.0% is a flat (constant) value of 1.0% times the cost of underinvestment if it occurs. Using the low end of the Oxera estimates of the cost of under-investment (6.8% of RAB pa) this implies a marginal benefit of increasing WACC percentile of 0.068% of the RAB (6.8%×1.0%).[3]

13. Combing this estimate of the marginal benefit of raising the WACC percentile with the marginal cost curve derived in Figure 2-1 results a point of intersection between these curves at a WACC percentile of just over 90% as shown in Figure 2-2 below. The intersection of the marginal cost and marginal benefit curves is the percentile that maximises expected welfare for customers because at any lower percentile customers will benefit more from increasing the percentile than it costs them to do so (and *vice versa* at any higher percentile than the intersection of the curves).

3 By definition, increasing the percentile by one percentage point reduces the probability of the allowed WACC being too low by 1.0%. By further assumption this reduces the probability of underinvestment by 1.0% and, therefore, reduces the expected cost of underinvestment by 1.0%×6.8%×RAB (0.068%×RAB).

Figure 2-2: Marginal cost and marginal benefit of increase in percentile (standard deviation=1.06%, zero threshold before underinvestment is triggered, cost of underinvestment is 6.8% of RAB)



Source: CEG illustration.

14. This is clearly materially higher than the percentile range recommended by Oxera and the 67th percentile ultimately set by the NZCC. Moreover, had Oxera's high estimate of costs (20.4% of RAB) been adopted then the optimal percentile would have been 98%.

15. This difference can be explained by the overly simplistic assumption underpinning the marginal benefit curve in Figure 2-2; namely that underinvestment is triggered immediately the allowed WACC is below the actual WACC and that the same cost of underinvestment occurs whether the WACC is 1bp too low or 100bp too low. Oxera noted that this was unrealistic and contemplated an alternative approach[4] where it was assumed that underinvestment is only triggered when the underestimate of the WACC exceeds a given threshold (Oxera and the NZCC focussed on thresholds of 0.5% or 1.0%).

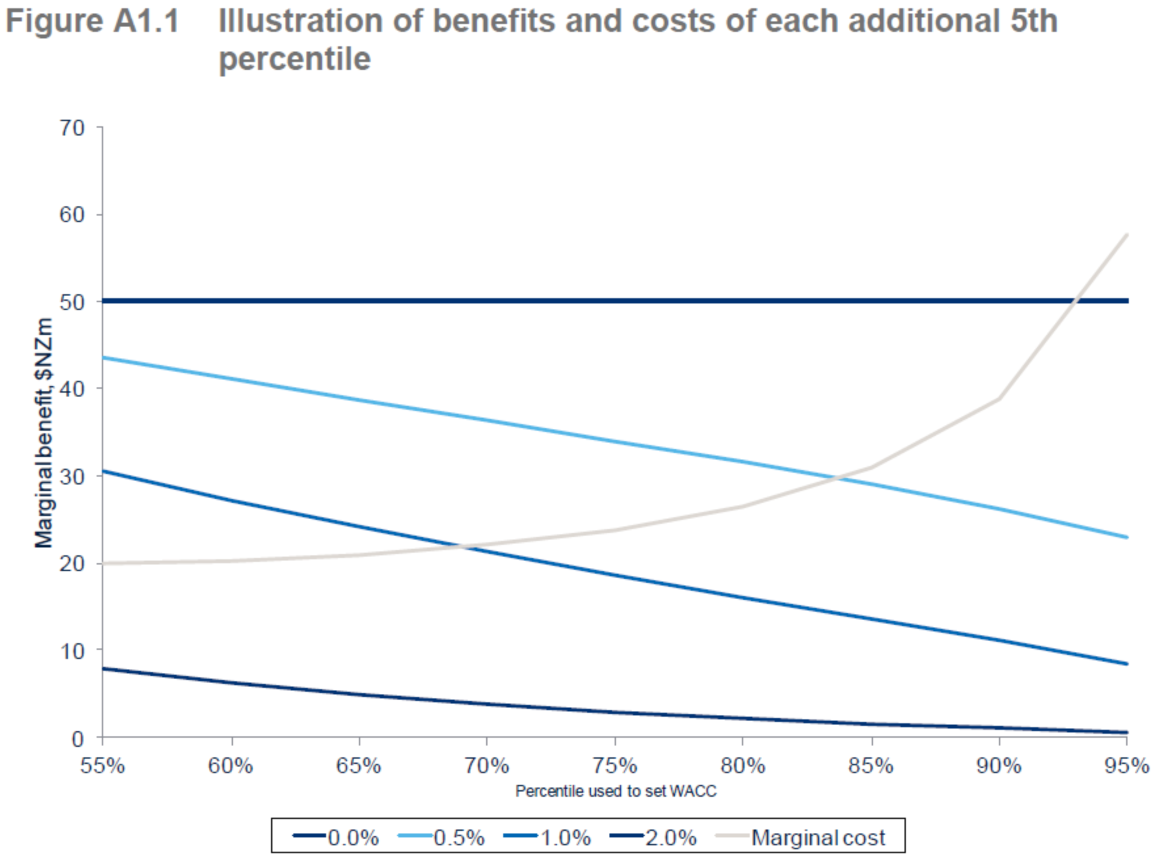
16. In this case, the marginal benefit curve ceases to be flat but, rather, slopes downward. This is because, even at the 50th percentile WACC, the threshold for underinvestment (the true WACC plus 0.5%/10%) is already likely to be towards the upper tail of the estimated WACC distribution. Thus, even though a 1% increase in the percentile reduces the probability that the allowed WACC is lower than the true WACC by 1% (by definition) it reduces the probability that it is 0.5%/1.0% lower than the true WACC by less than 1%. n As the percentile increases it gets pushed further into the tail of the distribution – such that there is smaller and smaller benefit (in terms of

4 For example, see Table 7.3 on page 69 of Oxera 2014.

lower probability of the threshold being surpassed) from each increase in the percentile WACC.[5]

17. In its Appendix A1, Oxera modelled 0.0%, 0.5%, 1.0% and 2.0% as four possible thresholds for an error in the WACC that could trigger material underinvestment (although in section 7 Oxera focused on the 0.5% and 1.0% thresholds).

Figure 2-3: Oxera modelling of 6.8% of RAB cost of underinvestment and 1.06% standard error of WACC, various thresholds for triggering underinvestment



Source: Oxera (also replicated by CEG)

5 By definition, a 1% increase in the percentile results in a 1% reduction in the probability the allowed WACC is below the true WACC. However, if there is a threshold error required to trigger underinvestment, then what matters is the change in the probability that the threshold is triggered and this will be both lower than 1% and declining as the base percentile increases. By way of illustration, imagine that the standard deviation of the WACC is 1.0%. A move from the 50th to the 51st percentile reduces the probability that the allowed WACC is below the true WACC from 50% to 49%. However, it reduces the probability that the allowed WACC is at least 0.5% below the true WACC from 30.9% to 30.0%. The base line probability of underinvestment is already lower (30.9% vs 50.0%) due to the threshold and the reduction in that probability is similarly lower (0.9% vs 1.0%).

18. It can be seen that second lowest marginal benefit curve intersects the marginal cost curve very close to the 67th percentile (it is actually the 68the percentile). This marginal benefit curve is associated with the scenario with a 1.0% threshold before underinvestment is triggered.

19. It is important to note that there are a large number of other modelling assumption that can also generate a percentile close to 67%. In particular, the 67th percentile can be generated by combining:

- a smaller assumed threshold before underinvestment is triggered; with
- a smaller cost of underinvestment; or
- *vice versa*.

20. However, it is clear from both the Oxera and NZCC analysis that there was a focus on two values for the threshold (0.5% and 1.0%). For example, the NZCC states:[6]

> *It will be difficult to identify a probability that a particular value for the assumed WACC directly results in under-investment. However, it is instinctively consistent with the workings of financial markets and the competition for capital that a shortfall of 0.5–1% (or more) is likely to increase the risk of triggering a rebalancing of medium-term investment plans, and a move by investors towards deferring investment as far as possible.*

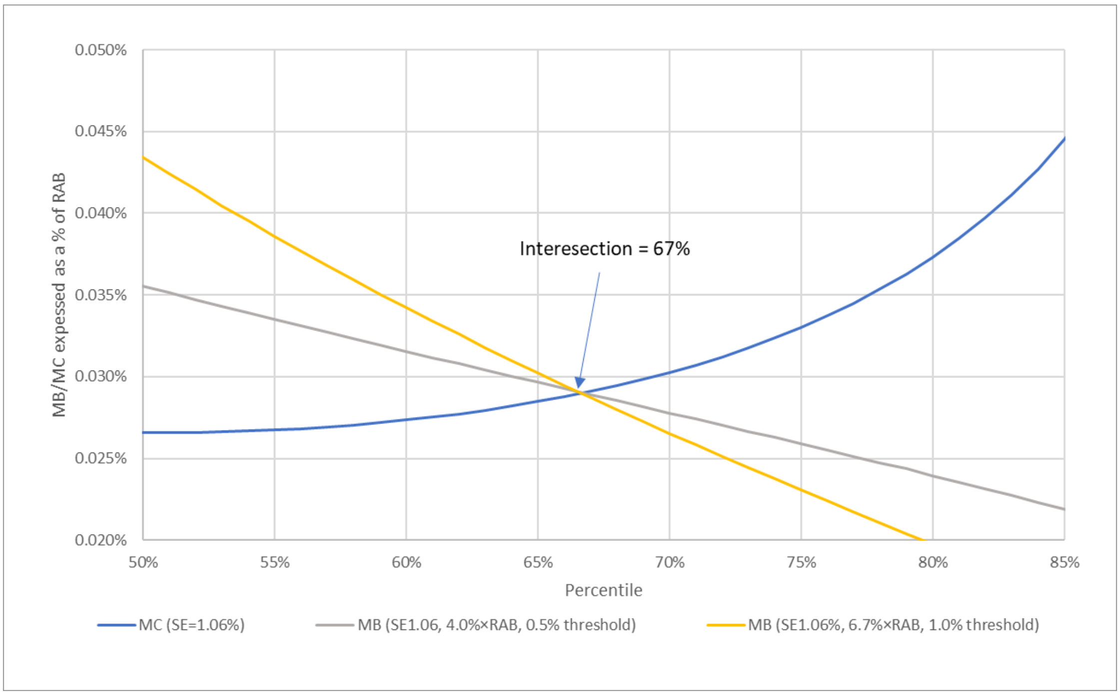
21. When we combine these two thresholds with the 2014 WACC standard error estimate (1.06%) we can estimate the cost of underinvestment that is internally consistent with the NZCC's then adoption of the 67th percentile. This results in a cost of underinvestment of:

- 6.7% of RAB associated with a threshold error in the WACC of 1.0%; and
- 4.0% of RAB associated with a threshold error in the WACC of 0.5%.
  - We note that 4.0% is over a third lower than Oxera's low estimate of underinvestment costs in 2014 (6.8% of RAB). However, this is necessary to be consistent with a 67th percentile estimate when the threshold is 0.5%.

22. These stylised "2014 starting points" for the analysis are illustrated graphically in Figure 2-4 below. By construction, both sets of assumptions about the marginal benefit curve result in intersection with the marginal cost curve at the 67th percentile – although they do so with different shaped marginal benefit curves.

6 NZCC, Amendment to the WACC percentile for price-quality regulation for electricity lines services and gas pipeline services Reasons paper, October 2014, p. 76-77.

Figure 2-4: Graphical illustration of stylised 2014 "starting points"



Source: CEG illustration.

23. In the next section we use these marginal cost and marginal benefit curves as an illustrative "2014 starting point". We then explore reasons why these curves may have shifted their position since 2014 and illustrate the impact of various shifts on the optimal WACC percentile.

24. Adopting this approach allows us to be clear and transparent about the assumptions we are making and the basis of our recommendations. It is important to emphasise that we do not suggest that this "2014 starting point" precisely describes how the NZCC arrived at the 67th percentile. However, it is a useful mathematical rendering of the framework and the kind of analysis that Oxera and the NZCC relied on. Put simply, there must have been some implicit marginal benefit curve underpinning the NZCC's 2014 decision – even if was not exactly one or the other of the two depicted in Figure 2-4.

3 Impact on demand and uncertainty of the energy transition

25. By the time the 2023 IMs are first implemented in 2025, more than a decade will have passed since the NZCC's 2014 WACC percentile decision. Moreover, another decade will pass before the 2030 IMs first apply to a DPP period beginning in 2035. The period from 2025 to 2035 is expected to be a period of great upheaval in the New Zealand and global electricity markets. In this context, it is relevant to ask to what extent these changes are likely to alter the calculus used in 2014 to arrive at an estimate of the percentile that best serves the purpose of Part 4 of the Commerce Act.[7]

26. The most significant change since 2014 is the immediacy and the size of the "energy transition" under which renewable sources of electrical energy will replace fossil fuel as a source of energy. This energy transition is driven by both private commercial incentives (as renewable energy costs fall below those of fossil fuels) and policy changes aimed at limiting global warming.

27. Figure 3-1 below illustrates the dramatic (and ongoing) decline in solar and wind generating costs (point 68.a.i above) and is based on data from IRENA.[8]

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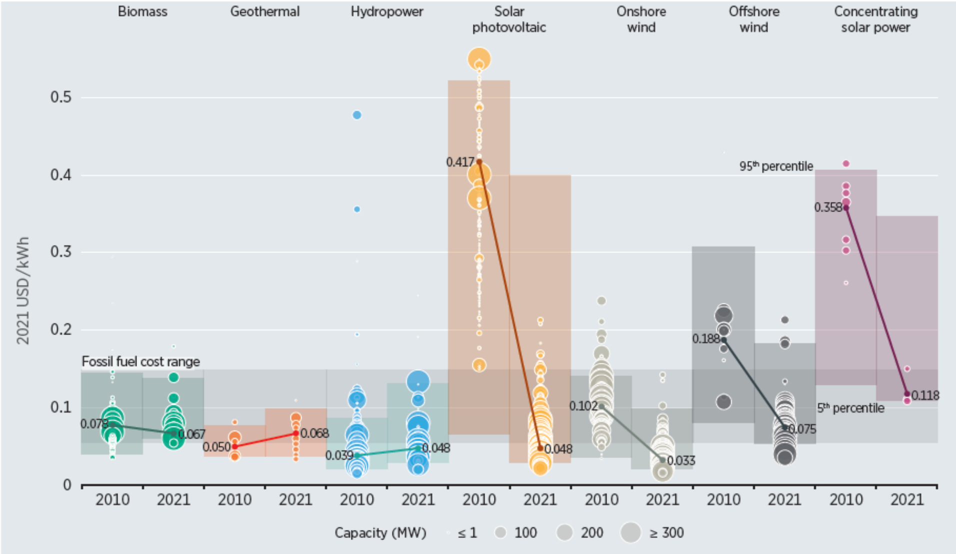
7 Specifically, that best promotes the long-term benefit of consumers by promoting outcomes that are consistent with outcomes produced in competitive markets such that suppliers of regulated goods or services:
(a) have incentives to innovate and to invest, including in replacement, upgraded, and new assets; and
(b) have incentives to improve efficiency and provide services at a quality that reflects consumer demands; and
(c) share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and
(d) are limited in their ability to extract excessive profits.

8 We note that IRENA has separately estimated falls of at 13% to 15% in solar and wind generation costs across 2021 to 2022. Although IRENA have noted this trend may be temporarily disrupted in 2022-23 by materials and supply chain issues – which will equally affect other generation technologies

Figure 3-1: Global weighted average LCOEs from newly commissioned, utility-scale renewable power generation technologies, 2010-2021



Source: IRENA Renewable Cost Database.

28. Some of this replacement will be for energy that is already delivered over the electricity networks (i.e., replacement of gas fired electricity generation by renewables). But most of the transition will be associated with the replacement of fossil fuels currently burnt in the transport sector (largely cars and trucks) and to directly produce heat (both space heating and for industrial processes). The rapid reduction in lithium ion battery costs used in electric vehicles (estimated at 16% per annum ongoing)[9] is an example of the impact of technological change driving electrification with or without the assistance of climate change policies.

29. In 2021 The New Zealand Climate Change Commission estimated that by 2025 electric cars will be on a private parity with internal combustion engine (ICE) cars and would be lower cost by 2030. Consistent with this, the Climate Change Commission estimated the following market penetration of light electric vehicles in its "demonstration path" modelling (associated with net zero CO_2 emissions by 2050).

9 https://mackinstitute.wharton.upenn.edu/2021/electric-vehicle-battery-costs-decline/

Figure 3-2: Penetration of EV (Reproduction of NZCCC* Figure 7.7)

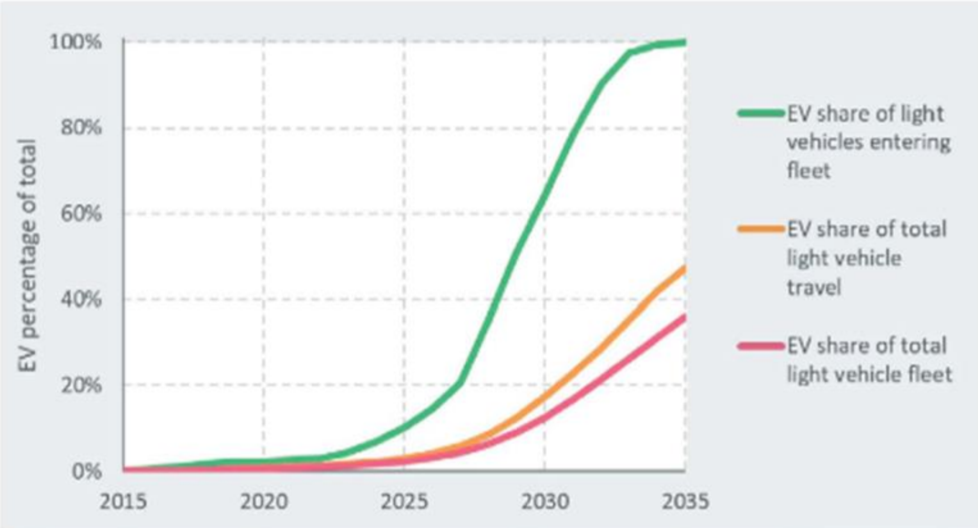


Figure 7.7: Uptake of light EVs in the demonstration path
Source: Commission analysis

Source: Ināia tonu nei: a low emissions future for Aotearoa, May 2021

30. This and other aspects of the energy transition are expected to dramatically increase electricity consumption and generation. The New Zealand Climate Change Commission reports both historical growth in New Zealand electricity generation and projected future growth under its "demonstration path". From this data it is possible to compare projected growth in electricity generation in New Zealand historically and from 2025 to 2035. This is summarised in the below table.

Table 3-1: Projected vs historical growth in electricity generation

Start year	End year	CAGR
2025	2035	2.16%
1990	2020	1.05%
2010	2020	-0.10%
2014	2020	0.26%
1990	2019	1.12%
2010	2019	0.01%
2014	2019	0.53%

Source: CEG analysis of data underlying NZ Climate Change Commission, "Figure 7.10: Electricity generation by fuel in the demonstration path" contained in "Data for figures in the Commission's 2021 final advice to Government, Ināia tonu nei: a low emissions future for Aotearoa" published 24 June 2021

31. It can be seen that projected growth in the 10 years from 2025 is materially higher (more than double) historical ranges for growth. At the time of the 2014 decision, it is reasonable to assume that the NZCC and Oxera took the view that the electricity

sector was, and would remain, in a relatively stable equilibrium over the medium term – as indeed turned out to be what happens. However, in the context of the 2023 IM review this is clearly not the case and is a major difference to the 2014 decision.

32. Moreover, the nature of the generation used to serve this electrification is going to change dramatically. Consistent with the IRENA evidence in Figure 3-1 there is expected to be a large increase in the share of intermittent generation (wind and solar PV).

Figure 3-3: Penetration of wind and solar generation (Reproduction of NZCCC* Figure 7.10)

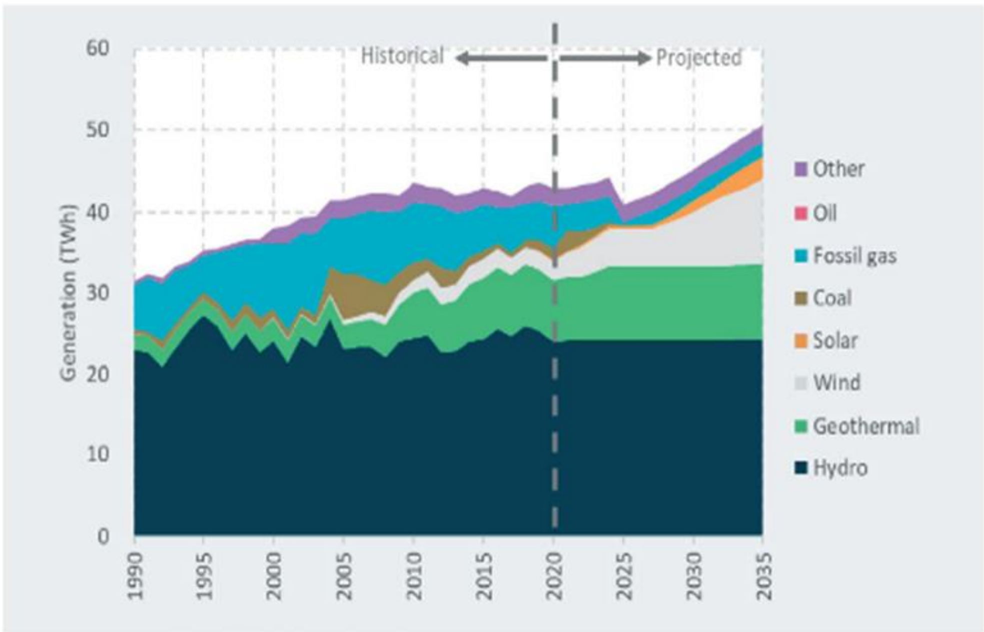


Figure 7.10: Electricity generation by fuel in the demonstration path
Source: Commission analysis

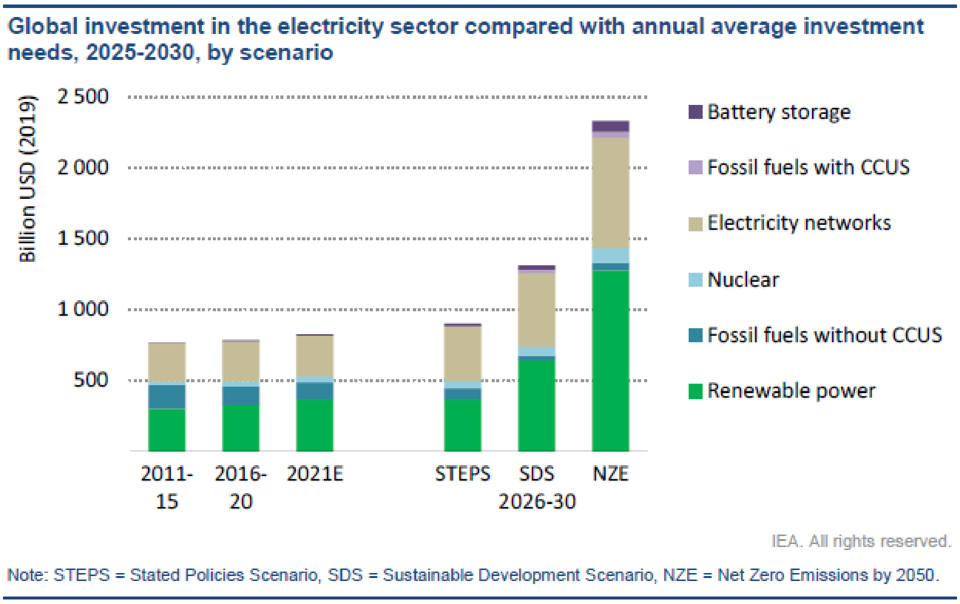
Source: Ināia tonu nei: a low emissions future for Aotearoa, May 2021

33. This increasing reliance on intermittent generation along with the rapid rates of advancement in battery storage and smart devices will also result in a radical change in the way EDBs operate (discussed further in section 5 below)

34. Altogether, the above factors mean that there will be a commensurate increase in the need for growth in network capacity to efficiently deliver the growing demand for electricity. This growth in network capacity will be a global phenomenon and has the potential to place strains on global supply chains that New Zealand EDBs rely on.

35. The International Energy Agency (IEA) estimates a more than doubling in global grid and generation capacity investment over 2026-30 if a net zero by 2050 target is to be achieved.

Figure 3-4: IEA estimates of grid and generation investment 2026-30



36. The energy transition is associated with both:

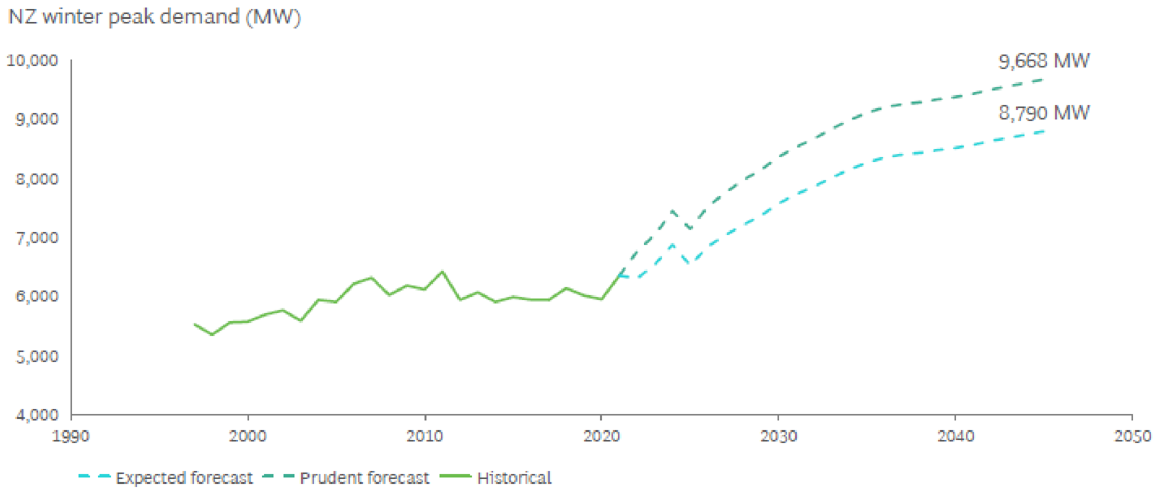
- higher median expectations of growth in electricity demand; and
- critically, higher variance around the median expectation.

37. Boston Consulting Group (BCG) reports Transpower estimates of peak demand and their analysis is replicated in Figure 3-5 below. [10] It can be seen that the demand growth environment from 2025 to 2035 is expected to be radically different to the environment from 2014 to 2025.

[10] BCG, The Future is Electric a Decarbonisation Roadmap for New Zealand's Electricity Sector,2022, p.58.

Figure 3-5: Replication of BCG Exhibit 33

Exhibit 33: Transpower's forecast increases to peak demand

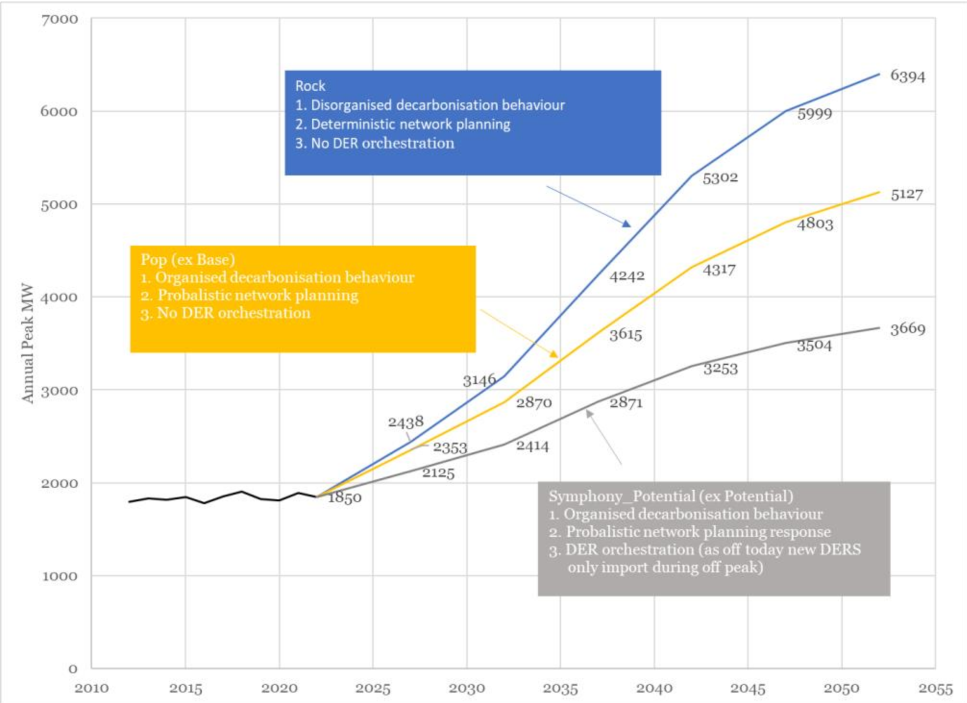


Source: Transpower, BCG analysis

38. BCG estimates that this peak demand will drive annual network costs will be 30% higher per year from 2026 to 2050 than they are today.[11] Consistent with this, Vector is forecasting commensurate acceleration in network maximum demand. The following figure provided by Vector has a range of projections for maximum demand. These depend on the extent to which the transition of energy demand to electricity is coordinated in a manner that minimises, to the extent efficient, the demand for network capacity.

[11] BCG, The Future is Electric a Decarbonisation Roadmap for New Zealand's Electricity Sector,2022, p.76

Figure 3-6: Replication of Vector's Figure 3



39. Under the most disorderly transition ("Rock") maximum demand grows at a 5.4% pa CAGR between 2022 and 2042. Achieving this requires the EDB invest in becoming a distribution system operator (DSO) as discussed in section 5. Under the most orderly transition ("Symphony") maximum demand still grows at 2.9% CAGR over the same period. To put this in context, maximum demand grew at a CAGR or 0.3% between 2012 and 2022. That is, even under the most optimistic scenario for an orderly transition to electrification, network capacity will need to grow at roughly 10 times the rate that was required over the decade to 2022.

4 Impact of higher growth and uncertainty on the WACC percentile

40. It is intuitively obvious that higher demand growth and higher uncertainty about demand growth increase the risk of (potential for) underinvestment relative to demand growth and that this would be especially likely if the WACC were materially lower than investors actually perceived costs.

41. If expected demand growth is very low and has very little uncertainty there will, by definition, be little or no efficient growth capital expenditure. If there is low or zero efficient growth capital expenditure it is not possible to materially underinvest in that category of expenditure. By contrast, the larger the required investment program the greater the scope for underinvestment if the WACC is set too low. Similarly, if that growth rate is highly uncertain (i.e., a high mean and a high standard error) then this will add to the risk of underinvestment.

4.1 A simple model where higher uncertainty implies greater risk of underinvestment

42. It is intuitively obvious that an EDB is more likely to underinvest when future demand is more uncertain than when it is more certain. However, it is useful to explore this with a simple model in which:

- Prudent investment planning today (T=0) involves targeting capacity in year T=N to meet levels of demand from the upper half of the possible distribution of maximum demand in year T=N. For example, this might be one standard deviation above the median level of expected demand in T=N.
  - For example, it might be prudent to plan for higher than median growth in order to avoid the risk that demand gets above capacity and/or to avoid the need to engage in more expensive "emergency catch up" measures to add capacity.
- If EDBs perceive that the allowed WACC is:
  - at or above the actual WACC, they will undertake the optimal planning strategy;
  - materially below the actual WACC, they will target the midpoint of projected demand in year N (or a value closer to the midpoint of projected demand). That is, EDBs prefer to take on some risks that future demand exceeds capacity rather than make a certain loss on the efficient/prudent level of investment.

43. In this simple model of EDB behaviour, when the allowed WACC is materially below the perceived WACC, EDBs target capacity at closer to what is "most likely" to be needed not what is prudent to plan for given the uncertainty in the path of future demand. As uncertainty about the future path of demand increases, the gap between these values increases commensurately. Consequently, for any given error in the WACC, the level of underinvestment (relative to prudent levels) increases with the level of uncertainty about future demand.

44. The cost of underinvestment in this simple model will, in most scenarios, never be realised. Even when being undercompensated, the EDB is unlikely plan its investments such that the *most likely* outcome is large scale blackouts and/or high cost "catch up" investments. (An EDB that targets capacity in year T=N to the midpoint of projected maximum demand will, by definition, have planned for the most likely eventuality.) However, in this model:

- An EDB will take greater risk that demand will "get away" from capacity if the EDB is being undercompensated for investment; and
- When demand growth is high and uncertain, the expected cost of taking those risks will be higher. That is, potential for large scale service interruptions and the need for large scale (high cost) "catch up" investment are a direct function of the upper tail of demand growth. The wider the distribution of possible demand growth the higher the expected cost of underinvestment.

45. As noted by Oxera, the cost of underinvestment is not just in the form of higher probability of service interruptions but also manifests in the potential need for high cost "catch up" investment. For example, scrambling to put infrastructure in place at inefficient scale/location relative to a prudently planned investment program.

46. Moreover, variation around the median pace of electrification in New Zealand is likely to be strongly correlated with similar variation in the pace of electrification globally. For example, faster than expected reductions in the cost of electric vehicles (EVs) would lead to faster take up of EVs globally and, therefore, faster rates of electrification in New Zealand and globally. In this circumstance, attempting to solve emerging capacity constraints in New Zealand via "catch up" investment may be likely to run into constraints in global supply chains relied on by EDBs.

47. All of the above conclusions are true holding constant the rate of expected demand growth. That is, for any level of expected demand growth the risk of underinvestment is higher the higher the uncertainty around that expected demand growth. The next section examines the impact of variations in the level of expected demand growth on the cost of underinvestment.

4.2 Higher demand growth increases the likely magnitude of underinvestment (for any given underestimate of WACC)

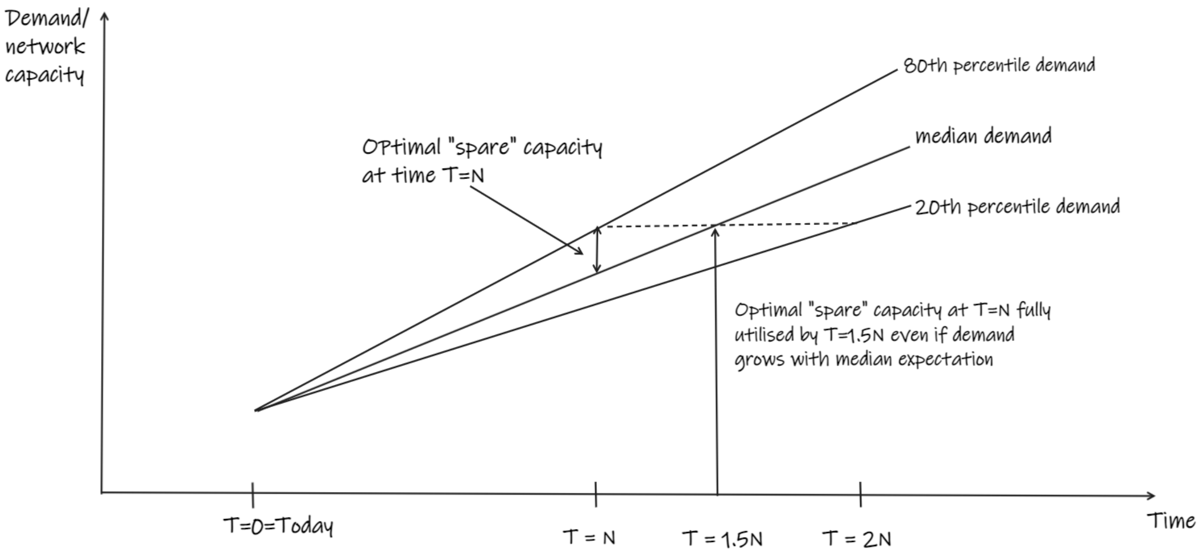
48. It is obviously true that material underinvestment in growth capex is only possible if the efficient level of growth capex is materially above zero. However, it is once more useful to illustrate these issues with a simple model that holds the level of uncertainty about future demand growth constant and shows that the expected level of underinvestment will tend to be higher when demand is growing faster (other things equal).

49. This can be illustrated within the simple behavioural model described in 40 above. With strong underlying demand growth, the cost of building in a "prudency margin" for capacity in year T=N will be lower because, even if demand grows at (or below) median expectations, this capacity will still be utilised relatively quickly (compared to a scenario with lower underlying demand growth).

50. This is illustrated in Figure 4-1 below which shows a stylised illustration of the $80^{th}/50^{th}/20^{th}$ percentiles of expected demand growth. In the illustration it is assumed that meeting the 80^{th} percentile for expected demand in period T+N is efficient. This largely eliminates the risk of service interruptions and the need for "catch up" investment is limited to all but the highest 20% (=100%-80%) of demand growth scenarios.

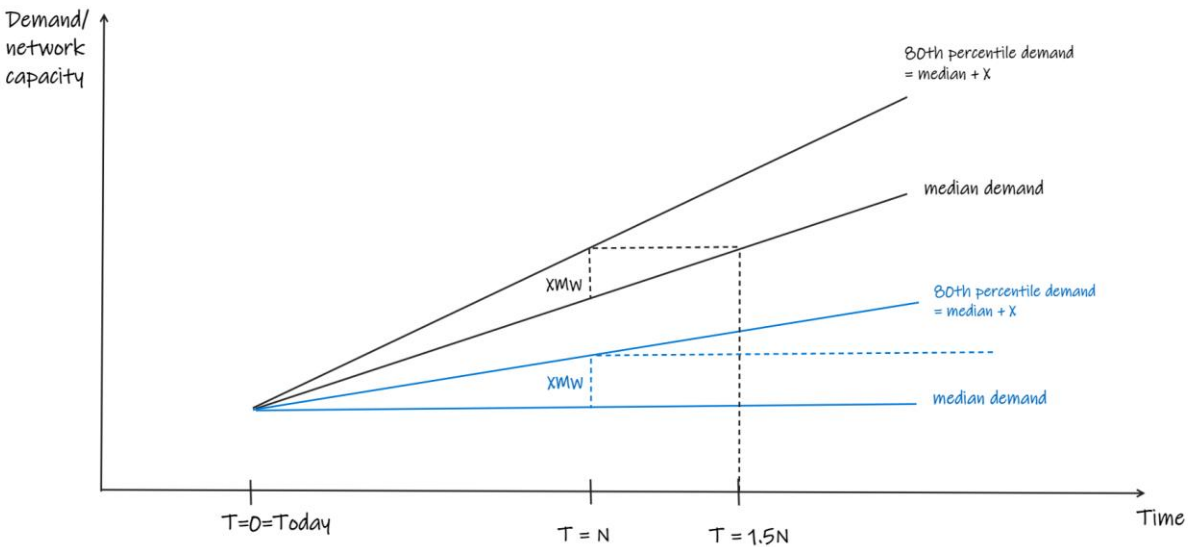
51. Importantly, even if demand grows at median (or lower) projections the additional capacity will be utilised relatively quickly (i.e., is not wasted investment). As drawn, prudently planned excess capacity is absorbed after an additional 0.5N years of median expected growth and after 1.0N additional years of 20^{th} percentile expected growth.

Figure 4-1: Absorption of "spare" capacity under high demand growth



52. By contrast, if underlying demand growth were flat but there was the same distribution of demand around the median then building to the 80th percentile of projected demand would result in excess capacity that was never likely to be absorbed. This is illustrated in Figure 4-2 below. The black lines represent respectively the median and 80th percentile demand projection under the high growth circumstance. The blue lines represent the median and 80th percentile demand projection under the low demand growth scenario. In both cases, the 80th percentile line is the same (XMW) absolute distance above the median demand scenario (i.e., both have the same standard deviation of demand around the midpoint).

Figure 4-2: Absorption of "spare" capacity high and low demand growth



53. If investment is built to target the 80th percentile of demand in year T+N then:

- In the high demand growth scenario, even if demand only grows at the 50th percentile, the "spare" XMW is fully absorbed by year T+1.5N; but
- In the flat demand growth scenario, the XMW is never fully absorbed if demand only grows at 50th percentile.

54. It follows that, holding the level of uncertainty about future demand constant, it is more efficient to target a higher "prudency margin" when underlying demand growth is higher. However, it is precisely the "prudency margin" that is most at risk when the allowed WACC is too low. It follows that, for any given level of uncertainty about demand growth, the expected level of underinvestment will be higher (for any given WACC misestimation) the higher is underlying demand growth.

55. The discussion above is based on a rational model of behaviour where EDB management knowingly accept higher risks associated with underinvestment as the level of under compensation for investment increases.

56. However, perhaps equally, or even more importantly, there is simply greater scope for errors when demand is growing faster. Larger investment programs put pressure on planning resources at EDBs which, in an ideal world, is resolved by the organisation increasing the planning budget commensurately. However, if the allowed WACC is materially below the true WACC this commensurate increase in planning resources may not be forthcoming. As a result, in addition to rational "risk taking" underinvestment (from the perspective of the EDB) there can be expected to be an increase in irrational underinvestment. That is, unintended risk taking may take place due to a failure to adequately resource investment planning.

57. This is especially likely in the context of both:

- Material under compensation for the cost of investment (including investment planning); and
- Pressure associated with national (and global) competition for planning resources due to the global nature of the energy transition.

58. Fast growing global demand will add to the overall complexity of developing an investment program by making input costs more volatile (noting that NZ EDBs will be competing with each other and foreign EDBs to source the skills and resources).[12]

4.3 Quantification of the impact on the percentile

59. In the previous two sections we have explained why we consider that the risk of underinvestment is driven by:

12 Both human (e.g., engineers) and physical (e.g., transformers) input costs

- the expected rate of demand growth (driving the magnitude of the expected investment requirement); and
- the uncertainty around that expected demand growth.

60. Based on the evidence surveyed in this report (including the evidence supplied by EDBs) we consider that both of these factors (mean demand growth and uncertainty around that mean) to be more than twice as high in 2025 as they were in 2014. It follows that, other things equal, the marginal benefit curve will be "shifted up" in 2025 relative to its position in 2014. Exactly how much higher is difficult to quantify and will require the exercise of judgement – which we explore in the next section.

4.4 Shifting the marginal benefit curves to reflect faster and more uncertain demand growth

61. We now turn our minds to modelling increases in the expected cost of underinvestment associated with the higher demand growth/uncertainty faced in 2025 than 2014. We model four scenarios where the marginal benefit curve (expressed as a percentage of RAB):

- is 25% higher than it was in 2014 (which is less than proportional to the increase in demand growth/uncertainty since 2014);
- is 50% higher than it was in 2014 (which is less than proportional to the increase in demand growth/uncertainty since 2014);
- is 100% higher than it was in 2014 (which is approximately proportional to the increase in demand growth/uncertainty since 2014);
- is 200% higher than it was in 2014 (derived from the ratio of Oxera's "low" and "high" cost of underinvestment estimates being 6.8% and 20.4% of RAB (where 2014 is 200% higher than 6.8)).

62. The results are summarised in Table 4-1 below.

Table 4-1: Welfare maximising percentile given WACC standard error and various increases in the risk/cost of underinvestment since 2014

Threshold and 2014 starting point cost	Increase in cost/risk	Optimal percentile	2014 uplift (bp)**	2025 uplift (bp)**	Difference (bp)
Standard error of WACC = 1.06% (2014 decision)					
0.5% and 4.0% of RAB	0%	67%	0.53	NA	NA
Standard error of WACC = 1.01% (2016 IM)					
0.5% and 4.0% of RAB	0%	68%	0.53	0.56	0.03
0.5% and 4.0% of RAB	25%	75%	0.53	0.78	0.25
0.5% and 4.0% of RAB	50%	79%	0.53	0.92	0.40
0.5% and 4.0% of RAB	100%	85%	0.53	1.09	0.56
0.5% and 4.0% of RAB	200%	90%	0.53	1.35	0.83
Standard error of WACC = 1.06% (2014 decision)					
1.0% and 6.7% of RAB	0%	67%	0.53	NA	NA
Standard error of WACC = 1.01% (2016 IM)					
1.0% and 6.7% of RAB	0%	66%	0.53	0.42	-0.11
1.0% and 6.7% of RAB	25%	72%	0.53	0.59	0.06
1.0% and 6.7% of RAB	50%	75%	0.53	0.71	0.19
1.0% and 6.7% of RAB	100%	80%	0.53	0.85	0.32
1.0% and 6.7% of RAB	200%	86%	0.53	1.09	0.56
Standard error of WACC = 1.01% (2016 IM)					
Midpoint scenario*	0%	69%	0.53	0.50	-0.03
Midpoint scenario*	25%	75%	0.53	0.68	0.15
Midpoint scenario*	50%	79%	0.53	0.81	0.29
Midpoint scenario*	100%	84%	0.53	1.00	0.48
Midpoint scenario*	200%	89%	0.53	1.24	0.71

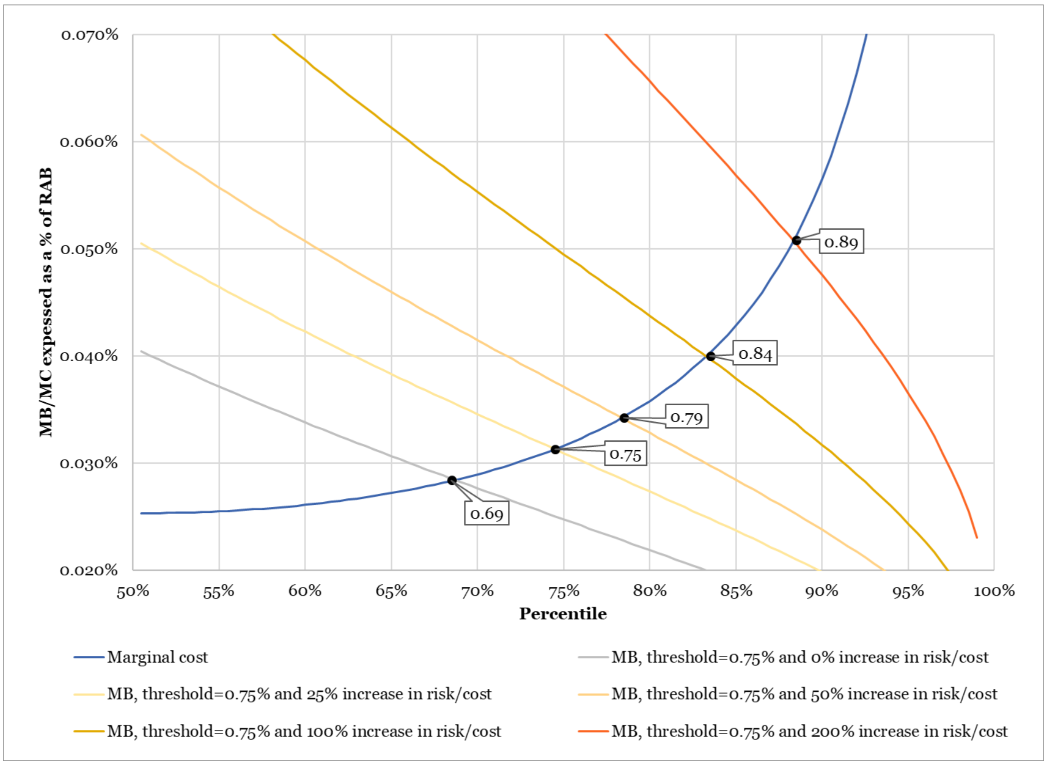
Source: CEG analysis. *The midpoint scenario applies a 0.75% threshold for triggering underinvestment (being the midpoint of 1.0% and 0.5%); and a 5.35% of RAB cost of underinvestment when it occurs (being the midpoint of the "2014 starting point" estimates of 6.7% and 4.0% derived in section 2). ** 2014 WACC uplift is based on 1.2% standard error and 67% percentile. 2025 uplift is based on 2016 IM standard error of 1.01% and varying percentiles.

63. Focussing on the midpoint scenarios, updating the standard error (from 1.06% to 1.01%) but leaving the marginal benefit assessment unchanged, results in a slightly higher estimated WACC percentile of 69% and a slightly lower WACC uplift (50bp) relative to 2014.

64. The average estimated WACC percentile rises to 75% (79%) if we assume that the risk/cost of underinvestment is 25% (50%) higher (as a percentage of RAB) in 2025 than was the case in 2014. This results in a relatively small 15bp (29bp) higher WACC uplift than in 2014. (Similarly, if we assume that the risk/cost of underinvestment is 100%/200% higher in 2025 than 2014 then the average percentile increases to 84%/89% and the WACC uplift increases by 46/68bp.)

65. The results of this midpoint modelling are illustrated in Figure 4-3 below.

Figure 4-3: Marginal cost and marginal benefit curves with SE=1.01% and assuming a 0.75% threshold and 5.3% of RAB cost of underinvestment



5 Changing role of EDBs transitioning to be DSOs

66. Another critical difference between 2014 and 2015 is the changing role of EDBs driven by the integration of a greater share of intermittent distributed energy resources (DER). This process, if well-handled EDBs, regulators and other stakeholders (including government) has the potential to unlock enormous long-term benefit for consumers. However, at the heart of this process are EDBs evolving from passive "poles and wires" into a distribution system operator (DSO) role.

67. In this section we describe what the DSO role is and provide estimates of the potential latent long-term benefit to consumers from this innovation. In section 6 we describe the implications of this for the WACC percentile.

5.1 The potential value to consumers of smart energy grids

68. This section describes the development over time of optimal interactions between:

   a. **Technological innovation in generation, storage and digitalisation of appliances and the grid**. A transformation in technology and costs which has to some degree already occurred but is continuing. Namely:

      i. Low and falling electric generation costs – especially photovoltaic (PV) and wind generation costs per MWh but also potential future low cost technologies such as enhanced geothermal systems (EGS);

      ii. Falling costs of electric energy storage. Especially grid connected battery energy storage systems (BESS) forecast to grow globally at a 16% CAGR (doubling every 5 years). To date this is mainly lithium ion BESS but extensive R&D means promising potential for many other storage technologies to become economic (flow batteries and hydrogen storage etc).

      iii. Falling costs and improving quality of electric vehicle (EV) and other appliances (HVAC, hot water, cooktops etc); and

      iv. The digital revolution allowing a combination of "smart appliances" and a "smart grid" (allowing generation, storage, and time of use to be optimised to maximise the value of generation and minimise the grid investment require to deliver it).

   b. **Flexibility in unlocking further value**. New Zealand, like other countries around the globe, will need to adapt to make the most of these low and falling costs. This involves:

i. Investing in development of a "smart grid" (including cyber security) and "smart appliances/charging" enabling supply chain "flexibility". And creating the platforms and incentives necessary to:

  - Save on energy generation costs by: a) storing energy when its plentiful (when the wind is blowing and the sun shining) to use when it is scarce and expensive; b) shifting flexible consumption (EV charging, HVAC[13], pool pump/heating, irrigation etc) away from periods of generation scarcity to periods of plentiful periods of supply ("demand side response" or DSR);
  - Save on distribution and transmission by: a) building a smart grid and using DSR for smart appliances including EV charging, to shift load away from periods of network congestion; and b) generating (rooftop solar PV) and/or storing (BESS) energy closer to where it is consumed;
  - Build the distribution grid to accommodate higher peak load (to the extent this cannot be avoided – see previous point) and periods of high distributed generation;
  - Reduce outages and system stability costs by: a) having a fully digitised grid and detailed models (including forecast models) of electricity flows not just on the transmission network but also on the distribution network; b) using control over batteries and smart appliances to ensure balance between supply and demand even during extreme conditions.

ii. In doing so, allow dispatchable generation (e.g., hydro and gas to save their limited supply (especially in dry years) to the periods when the wind is not blowing and the sun is not shining.

69. Well-handled, this process can be expected to result in both:

- electrification of (nearly) all energy use is in the future; and
- lower average costs per unit of energy consumed by households.

  i. Consumers will benefit from lower cost electricity for existing uses and appliances; and

  ii. Consumers will benefit by replacing expensive to run fossil fuel appliances with their electric equivalents. Namely, electric cars and electric heating/cooking.

70. Figure 3-1 above has already illustrated the dramatic (and ongoing) decline in solar and wind generating costs (point 68.a.i above). Similarly, Figure 3-4 above has already described the IEA's estimate of the investment burden required to integrate these new lower cost forms of electricity generation.

[13] Heating, ventilation, and air conditioning.

71. The "good news story" here is that this investment will make New Zealanders better off by lowering their overall energy costs. But this is only necessarily true if the full power of the technological revolution is harnessed via investment in a smart grid and associated flexibility in the supply chain.

72. A graphical illustration of the points made in 68.a to 69 is provided in Figure 5-1 below. The generation layer of Figure 5-1 includes new sources of intermittent low cost generation (solar PV and wind) only recently available and the cost of which is intended to keep falling. The "Grid" includes transmission and distribution connecting, respectively, distant and embedded generation to customers.

73. The "flexibility platform" layer of Figure 5-1 reflects the potential for organising the kinds of efficient actions described in paragraph 68.b above. This platform coordinates the "responsive assets" layer to optimally match consumption/storage to when generation is plentiful (and *vice versa*). Naturally, this layer already exists in some form via the operation of grid-connected generation and large DER which are currently managed by the security-constrained economic dispatch run by Transpower as the system operator.

74. Signals to all parties – grid-connected and DER, generation and load – are provided by the real-time LMPs that are produced by that dispatch schedule. Recent market design enhancements by the Authority, to be implemented early next year ("Dispatch Notification"), are motivated by the desire to have even more DER operate in accordance with the needs of the interconnected power system.

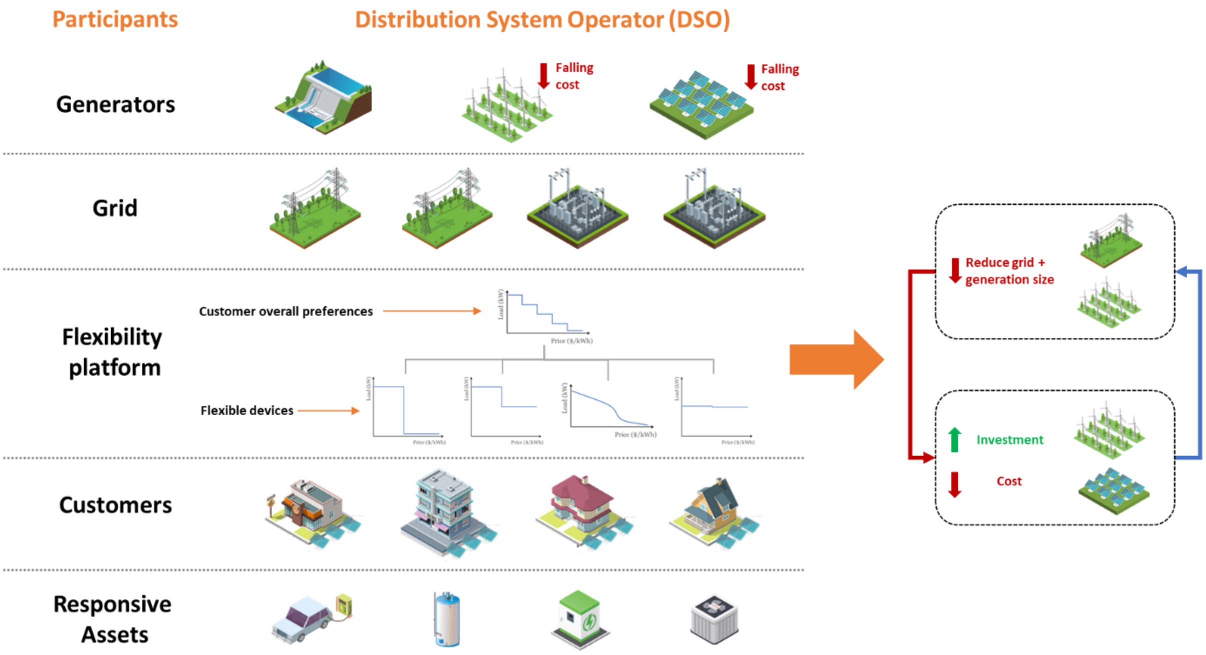
75. This, currently, does not require a DSO. However, importantly, as congestion on EDB networks increases dispatch of DER (by Transpower and/or other parties) will require coordination by a DSO to continue realising those benefits.

76. More importantly, high scale penetration of smaller DER at all scales, but especially at the scale of individual households investing in smart controllable appliances, will require compensation from, and coordination by,[14] EDBs if the full value of flexibility responses.

77. This will be especially valuable as more low cost intermittent generation is added to the generation layer and/or peak demand grows with electrification (e.g., from EV charging). In doing so, the "flexibility platform" means less generation and a smaller grid is needed to reliably serve a given number of customers. That is, the flexibility platform lowers whole of supply chain costs for the final consumers of electricity.

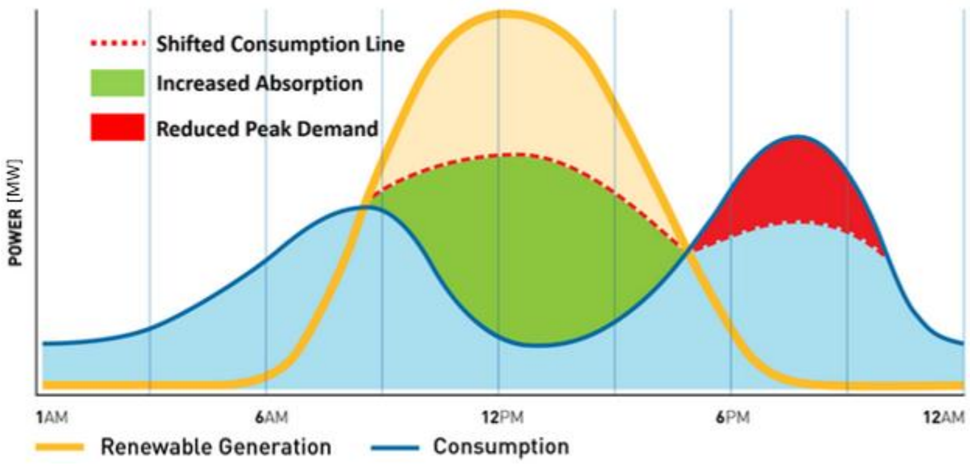
[14] Even if it is via a third party and/or the TSO.

Figure 5-1: Graphical illustration



78. Within the flexibility platform layer sits a range of different actors efficiently adapting their energy use, storage, generation to circumstances on a seasonal/daily/minute by minute basis. A stylised illustration of how flexibility can extract the most value from intermittent generation is provided in Figure 5-2.

Figure 5-2: Graphical illustration role of flexibility in efficiently matching supply and demand (in general and in specific locations on the distribution grid)



79. In this illustration, the cheapest (low short run marginal cost) renewable generation occurs in the middle of the day (consistent with high PV output) but could equally occur in the middle of the night (e.g., with high wind generation). This creates a mismatch between peak generation and peak demand. Moreover, this can create a new strain on network capacity in the locations where generation is highest. If energy generated at specific locations on the distribution grid cannot be used/stored/transferred across the grid to other locations then it must be curtailed. (Noting that curtailment of distributed generation is a new cost associated with insufficient network capacity that was not envisioned in 2014.)

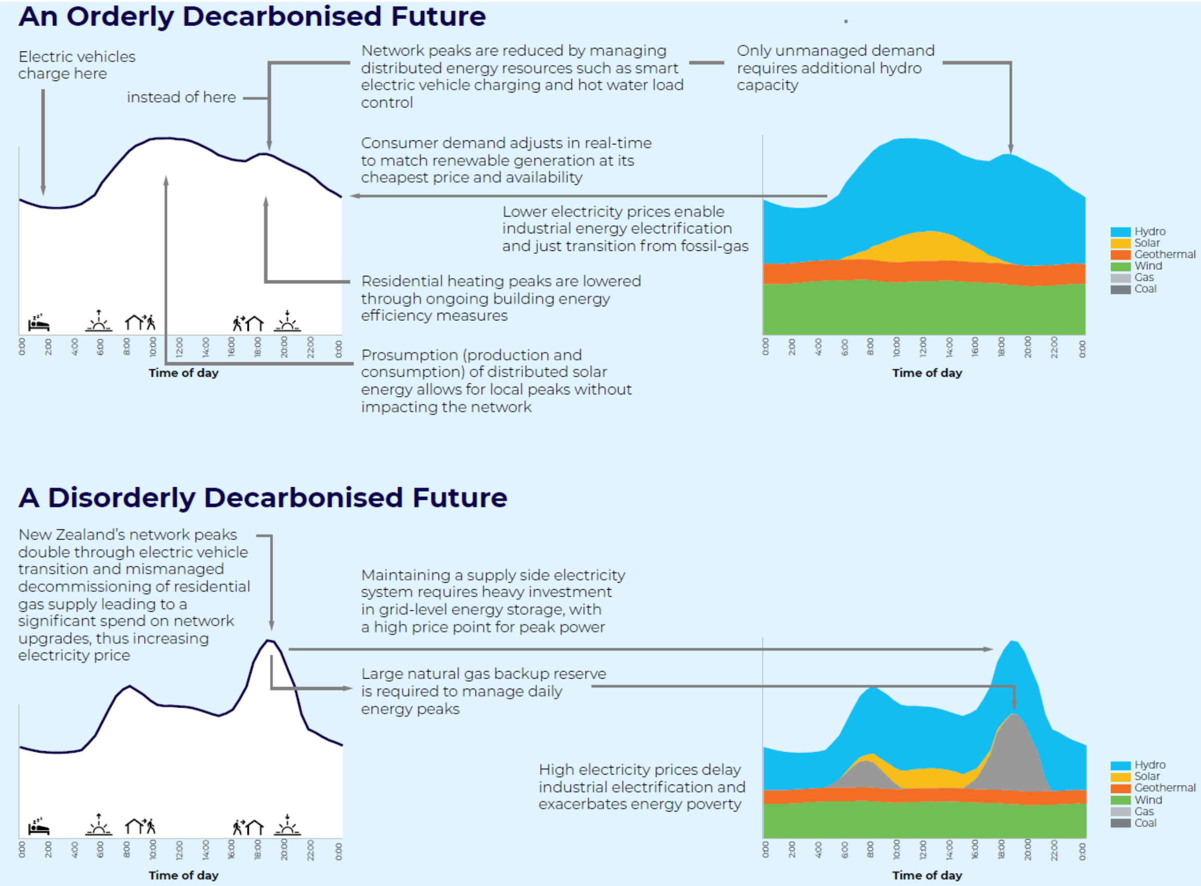
80. The optimal solution to high levels of intermittent generation involves transporting energy within the distribution and transmission grid to distributed BESS or more widely to other forms of storage (e.g., pumped hydro) when prices are low and releasing that energy when prices are high. Similarly, it requires the coordination of smart appliances (smart EV chargers, HVAC and hot water heaters, pool pumps etc) to shift load to when generation prices are low and to ameliorate grid constraints. Actually, facilitating this requires:

- Requisite distribution grid capacity and information on real-time and near term forecasts of distribution grid constraints;
- An institutional environment that appropriately rewards investments in BESS ("in front of meter" and "behind meter") and smart appliances – including location specific investments. Noting that BESS and smart appliances can deliver both:
  - "wholesale market" benefits (storing cheap generation and substituting for expensive generation); and
  - "grid benefits" (avoiding investments in grid capacity to deal with peak generation/load in specific locations).
- An institutional environment that appropriately encourages the efficient operation of BESS/smart appliances. Noting that this might involve minute-by-minute price signals to some "high information" customers (e.g., owners of in front of the meter BESS) but will probably involve other institutional arrangements more suited to allowing "low information" customers to maximise the value of BESS/smart appliances. This might involve a household agreeing that a third party have some rights to control behind the meter BESS/appliances (where that third party might be an EDB or another party that the EDB contracts with).

81. If the institutional environment is well managed then there will be a form of "virtuous circle" between the "flexibility platform" and the addition of low cost intermittent generation. By shifting demand towards the low cost renewable generation, the "flexibility platform" improves the economics of investment in renewables which, in turn, improves the economics of the flexibility platform – all of which results in lower unit supply chain costs for the final consumers of electricity.

82. The following graphic developed by Vector provides a neat comparison of the way in which the electricity transition could work with and without a functioning a DSO capability supported by the associated institutional arrangements.

Figure 5-3: Vector's description of the energy transition with and without DSO capabilities and associated institutional support



Source: Vector's journey to a new energy future" document published in August 2022

5.2 Putting a dollar value on efficient DSO and flexibility services

83. We estimate the value of taking the efficient actions described in 68.b. will be to reduce supply chain (grid plus generation) costs by 12% to 19% based on the best international evidence.[15] As summarised in Appendix A, reasonable lower bound estimates of supply chain savings from the state of the art US Department of Energy

15 The US Department of Energy engaged Pacific Northwest National Laboratory to undertake detailed technical and cost modelling of the overall supply chain benefits to end customers associated with developing DSO capabilities. This study is discussed in detail in Appendix A.

multidisciplinary study are that the efficient operation of flexibility platforms delivers savings of at least:

- 4% to 8% for distribution hardware expenditure;
- 10% for transmission expenditure; and
- 22% for generation expenditure.

84. These are the sources of benefit that give rise to the 12% lower bound estimate of total supply chain savings. The higher bound estimate of 19% is associated with deeper penetration of intermittent renewable generation (solar and wind) and, therefore, greater benefits from flexibility.

85. The benefits to customers of falling costs of renewable technology (68.a.i and 68.a.ii.) and from switching from expensive fossil fuels to cheaper electricity (68.a.iii) are additional to this. Including these savings, the whole of supply chain benefits to customers are likely in excess of 20% pa of the current value of the electricity supply chain.

86. The headline conclusion of the evidence surveyed in Appendix A is that, even in the moderate renewables scenarios, average electricity retail bills for customers would be 12% to 14% pa lower under the DSO model than under the business as usual model. Under the scenarios with high penetration of renewables the net benefits to final customers would be even larger (around 18% to 19% lower retail bills). There are large number of other important findings, including distributional impacts associated with flexibility markets, also summarised in Appendix A.

5.3 EDB investment is a "choke point" for the realisation of these benefits

87. The vision encompassed in the above virtuous circle is only achievable (at least in its most efficient form) with a radical change in the role of the EDB and the concomitant required investments.

    a. Investment in building DSO capability is necessary to unlock the relevant value in the electricity supply chain. Moreover, if this is not done then:

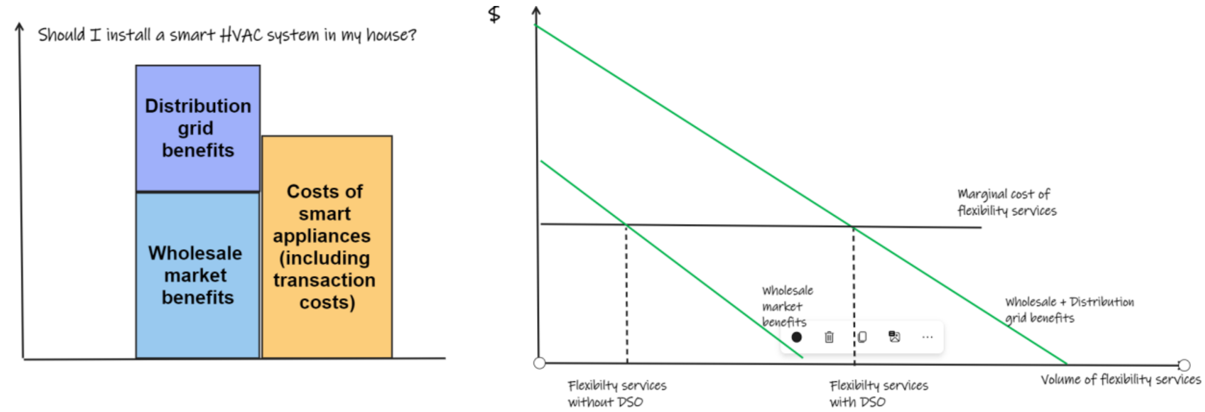
        i. EDB costs will be roughly the same (because "savings" on DSO expenditure will need to be spent on grid expansion – see Appendix A); and

        ii. Generation costs and transmission costs will be materially higher (at least 10% to 20% -see Appendix A).

    b. EDBs need to move first to build the platforms for "flexibility markets" before the supply chain benefits are unlocked. That is, EDB spending is a "choke" point for the entire supply chain.

88. This is not to suggest that there will be no flexibility response without the development of DSO capabilities. However, the level of response can be expected to be inefficiently low unless EDBs are signalling capacity constraints and customers are responding to those signals as illustrated below.

Figure 5-4: Illustration of the need for DSO signals



89. The left hand panel of Figure 5-4 illustrates an example where the cost of installing and operating an individual smart controllable appliance does not “stack up” for the consumer without a contribution from the expected value it would deliver to the distribution grid. In that case, the device is unlikely to be installed.

90. The right hand panel illustrates the potential impact across the entire possible market for flexibility services. The lower downward sloping line is the marginal benefit from a flexibility service in reducing wholesale market costs. The higher downward sloping line represents the sum of wholesale and grid benefits. The flat black line is the marginal cost of supplying flexibility services. It can be seen, at least as drawn, that absent grid benefits from the equation their will be around a quarter of the flexibility services actually provided.

91. In order to provide these signals EDB investments will be required to deal with any increases in peak load from electrification plus voltage stability and other power quality issues associated with accommodating both increased PV and battery output as well as the high loads associated with electric vehicle charging and increased penetration of heat pumps.

92. EDBs will also need to invest in improved monitoring of low voltage networks for forecast purposes. For example, measuring low voltage feeders in the context of take-up of EVs will help determine how (and when) individual charging behaviour and natural diversity will combine to result in peak demand needs. More accurate

forecasts[16] will be valuable to EDBs for the purpose of network planning (e.g., avoiding mistakes in upgrading substation capacity too early/late based on inaccurate forecasts). Improved monitoring can also facilitate experiments with distribution charging regimes and the efficient operation of “flexibility markets”.

93. Exactly what institutional model for procurement of flexibility services will be adopted in New Zealand (or, indeed, in all other international jurisdictions) is not clear. However, the critical point is that, under any institutional arrangement, there will be an EDB/DSO at the heart of the local flexibility market. The EDB/DSO will need to identify the need for and value of specific flexibility services at specific times and locations on their network. They will need to procure those flexibility services and, therefore, will need to establish the platforms (including information technology and information systems) for doing so. At its simplest, the EDB/DSO needs to be able to:

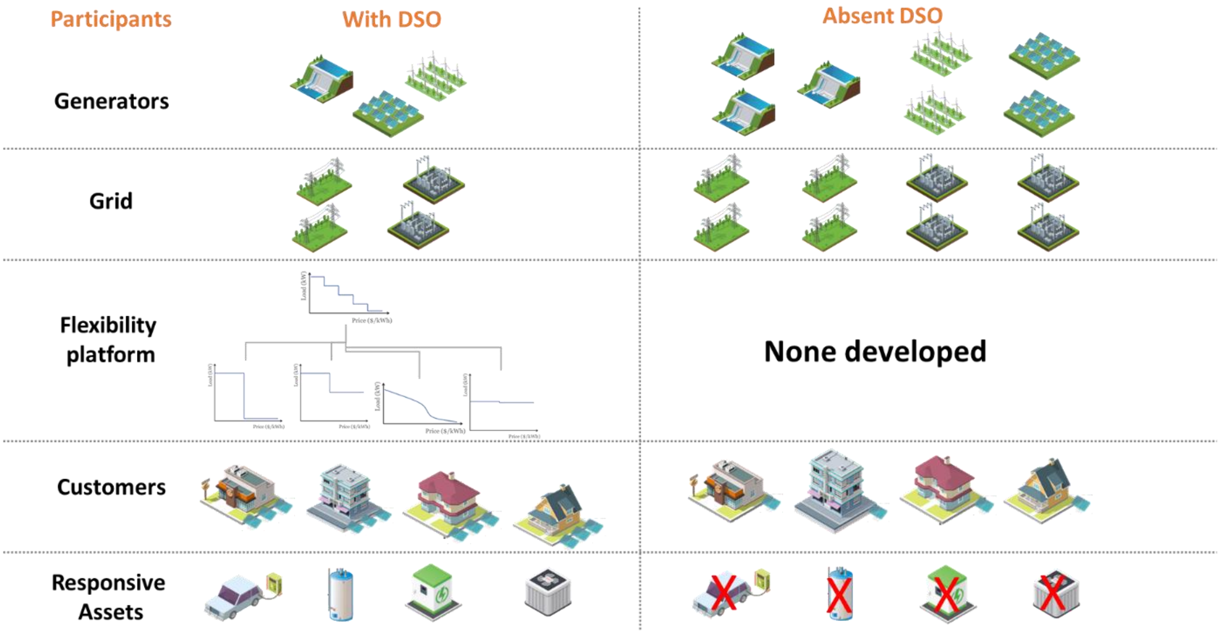
- Estimate the economic value of flexibility services at each point on its network;
- Communicate this both in real time and via forecast, to potential providers of flexibility services;
- Have a means to exercise the desired control to ensure delivery of those flexibility services; and
- Have a means to compensate for flexibility services.

94. The costs of developing the DSO capability to fully realise the value of flexibility services will be non-trivial and will take time. However, the benefits to customers will be substantial.

95. Figure 5-5 below uses the same graphics as Figure 5-1 above to illustrate the supply chain differences associated with having a DSO capability at the EDB level versus not (i.e., versus a business as usual supply chain). Absent a DSO capability there are fewer smart appliances and the generation/transmission sector needs to be larger while the distribution sector is roughly the same (but spends more money on “dumb” infrastructure and less on “smart” infrastructure and personnel). In addition, the generation sector has a smaller percentage of intermittent renewables absent the DSO function because the DSO function is valuable to efficiently integrating intermittent generation. The whole of supply chain costs are 12 to 20% higher absent the DSO function.

[16] Here a more accurate forecast is one that has a more accurate midpoint or, more importantly, a narrower uncertainty bound. A narrowing uncertainty band avoids an EDB overbuilding capacity “just in case”.

Figure 5-5: Graphical illustration – supply chain costs with and without a DSO capability



96. In order for flexibility platforms to efficiently develop (especially for small customers) EDBs need to develop a DSO capability first. This is needed in order that EDBs themselves can measure and communicate (and ultimately, compensate) for the benefits that flexibility providers supply to the distribution grid.

97. Moreover, much of the value that flexibility providers can provide elsewhere in the supply chain (i.e., transmission and generation) require a DSO platform to be realised. For example, investing in a smart demand side response (DSR) capable appliance (be that a HVAC system, a smart EV charging system or a behind the meter controllable battery) delivers benefits across the supply chain. A DSO capability is essential to incentivising DSR that provides distribution grid benefits but, also, for many customers, in providing a platform for the compensation of transmission and transmission connected generation benefits.[17]

98. This is why investment in DSO capability is a potential "choke point" for the development of flexibility benefits across the supply chain. EDBs need to move first to build the platforms for "flexibility markets" before the supply chain benefits more broadly are unlocked. The fact that there is not currently a broad based market for

17 While industrial and some large commercial businesses may have the means, and be incentivised, to pursue these benefits absent a DSO, this will generally not be true of smaller customers on the distribution network. Moreover, even if come customers could separately access benefits accruing to the transmission and transmission connected generation components of the supply chain, the economics of investing in DSR may not "stack up" without compensation from the distribution grid benefits they could supply.

flexibility services is **not** an argument against investing in building DSO capability. Quite the opposite is the case, the absence of a broad based market for flexibility services is the reason to develop DSO capability.

99. Given that these benefits are estimated to be in the order of 19% of the future entire supply chain this implies potentially billions of dollars of savings lost as a result of a single year delay in developing DSO activities.

100. The cost of such delay is high even if that delay is 10 years into the future. For example, delaying one billion real dollars of benefit from 2032 to 2033 implies a 0.6bn cost when discounted to 2022 at a 5.0% real (7.0% nominal) discount rate. Thus, even if the most realistic estimate is that flexibility platforms will, once started, take a decade to evolve to their full potential, the costs of delaying their development now could easily run to the billions of dollars of value in 2022 dollars.

5.4 Regulatory precedent from the UK

101. Appendix B provides details on Ofgem's DSO related strategy as developed over the last seven years (starting with its September 2015 Ofgem position paper "Making the electricity system more flexible and delivering the benefits for consumers"). This has been followed continuously with consultations and draft business plan guidance and now its RIIO-ED2 draft decision. Where Ofgem states:[18]

> *A key objective of RIIO-ED2 is to support the delivery of net zero at the lowest cost to the consumer;* ***and the efficient operation of the energy system at all voltages is essential if this vision is to be realised. Changes are required to the operation of electricity distribution networks to maximise the value of decentralised, local markets for flexibility services and to enhance the visibility of network data****. DSO is the set of activities that are needed to support this transition to a smarter, more flexible and digitally enabled local energy system.* (Emphasis added.)

102. UK EDBs (referred to as DNOs) proposed material expenditures on DSO activities. For example, both SSEN and UKNP have proposed spending **roughly £150m** each over the regulatory period on DSO activities (see Appendix B.2 below). Ofgem's June 2022 draft decision states that:[19]

> *In total, the proposed DSO spend across all companies in RIIO-ED2 was* ***~£890m****, almost four times the forecast spend in RIIO-ED1.*

[18] Ofgem, Consultation - RIIO-ED2 Draft Determinations – Overview Document, p. 61.

[19] Ofgem, Consultation - RIIO-ED2 Draft Determinations – Core Methodology Document, p. 82.

103. Ofgem's draft decision also states:[20]

> *We propose to accept the majority of the DNOs' DSO strategy proposals without amendment, with the exception of investments where we have found weak justification in the associated Engineering Justification Paper (EJP).*

104. Ofgem's DSO incentive framework and its outturn performance metrics are summarised in Figure 7-3 and Figure 7-4 in Appendix B.1 below.

105. The availability of LV network data is a key enabler for DNOs delivering against the DSO baseline expectations. Ofgem states.[21]

> *Access to more granular demand and voltage data will improve understanding of existing capacity on individual LV circuits, which will allow DNOs to produce enhanced forecasts. Better data and forecasting will also support DNOs in tendering for flexibility services on LV constraints.*

106. Prioritising EDBs developing plans for these capabilities, and being compensated for doing so, is an example of a "no regrets" policy that the NZCC can promote. Ofgem's stated goal is for UK EDBs (DNOs) to achieve full network visibility by the end of RIIO-ED2 and Ofgem is proposing to include an outturn performance metric on network visibility customer coverage in a new DSO incentive framework (see Figure 7-4 in Appendix B below).

107. Even so, Ofgem is concerned that this timeframe may inappropriately delay the development of flexibility markets and, to this end, are setting out a re-opener provision within the regulatory period. [22]

> *We also propose to introduce a Digitalisation re-opener to allow DNOs to provide the tools and services required for smart optimisation of the distribution networks during the price control period.*

5.5 Summary

108. The promotion of distributed flexibility services has the potential to create a "virtuous circle" whereby the combination of growing investment in renewables and flexibility services go hand-in-hand to lower overall supply chain costs.

- New Zealand consumers benefit from new low cost wind and solar generation;

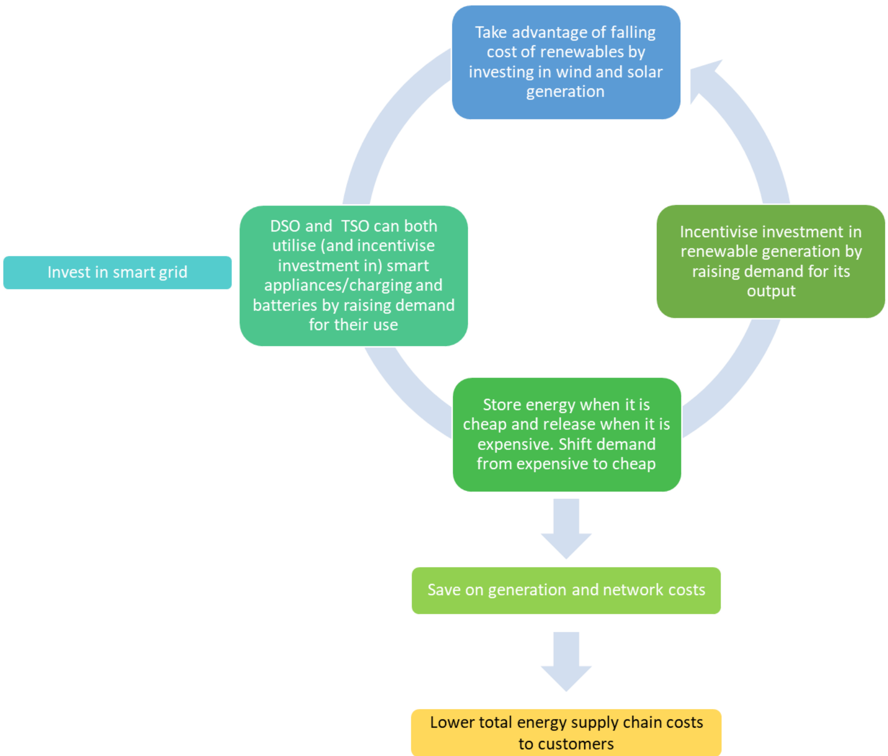
[20] Ibid.

[21] Ofgem, RIIO-ED2 Draft Determinations – Overview Document, p.56.

[22] Ibid, p.57.

- But this only takes New Zealand Inc "so far" without flexibility (because the value of wind and solar generation is constrained if New Zealand Inc isn't able to shift load or transport/store excess production where/when generation is plentiful);
- With flexibility the true potential of renewable generation is unlocked which both lowers grid and generation cost;
  - Consumers and investors have incentives to invest in batteries and smart appliances because the mechanisms exist by which they are compensated for the services provided;
  - This action by consumers and investors not only lowers system cost immediately but, by shifting demand to make the most of low cost renewables, this incentivises more investment in renewables.
  - This in turn incentivises more provision of flexibility services.
  - And so on, in a virtuous circle.

Figure 5-6: Graphical illustration of "virtuous circle" with flexibility markets enabling growth in renewables and vice-versa



109. Credible estimates from the US Department of Energy put these the benefits of this at 19% pa of the total electricity supply chain.

110. But as Figure 5-6 makes clear, the full realisation of this vision relies on the existence of distributed flexibility services at the disposal of the electricity supply chain including the EDB/DSO but also the transmission system operator (TSO).

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6 Implications of DSO transition for the WACC percentile

111. In 2014, the potential cost of underinvestment by EDBs was more or less purely related to standard quality of service considerations largely associated with interruptions to supply. For the reasons described in section 3, with at least double the rates of demand growth and the uncertainty around demand growth, these issues loom much larger in 2025 than they did in 2014.

112. However, the focus of this section is on quantifying additional (not existing in 2014) costs of underinvestment. Specifically, the failure of EDBs to invest in building DSO capability would have supply chain costs to consumers unrelated to the costs of service interruptions. As summarised in section 5 and Appendix A, reasonable lower bound estimates of supply chain savings from the state of the art US Department of Energy multidisciplinary study are that the efficient operation of flexibility platforms (which require DSO capability) delivers savings of at least:

- 4% to 8% for distribution hardware expenditure;
- 10% for transmission expenditure; and
- 22% for generation expenditure.

113. These are all costs that customers would have to pay if EDBs fail to invest in transitioning to DSO capability. The US Department of Energy study discussed in Section 5 and Appendix A puts the value of these at around 19% of total supply chain costs in the scenario with high penetration of renewables.

114. Total EDB revenues in New Zealand are 27% of the average retail bill[23] and the total EDB RAB is around 1.4 times total EDB revenues.[24] It follows 19% of total supply chain costs, when expressed as a percentage of the EDB RAB, is around 50% (=19%/(27%*1.4))

115. This is important in the context of the WACC percentile estimate because it means that a large new source of underinvestment cost, not envisioned in 2014, exists. If a too low WACC resulted in a failure of EDBs to invest in DSO capabilities the annual cost of this can reasonably be estimated at 50% of the EDB's RAB. To put this in context, a cost of underinvestment equal to 50% of the RAB is an order of magnitude larger than:

23 Electricity Authority, Electricity in New Zealand, 2018, p. 13.

24 NZCC, DPP3 financial model (does not include Powerco due to lack of data).

- Oxera's estimate of the cost of underinvestment due to potential service interruptions of around $1bn pa (or 6.8% of the 2014 RAB).
- The we modelled estimates in section 2 of the cost of underinvestment that were consistent with the adoption of the 67th percentile in 2014. These resulted in
  - 6.7% of RAB (associated with a threshold for error in the WACC before underinvestment is triggered of 1.0%); and
  - 4.0% of RAB (associated with a threshold for error in the WACC before underinvestment is triggered of 0.5%).

116. That said, it is probably reasonable to believe that a too low WACC is more likely to impede/delay the development of DSO capabilities rather than to cause them never to be developed. It is also the case that, even if there was no error in the WACC, it would take time for NZ EDBs to fully develop DSO capabilities and, therefore, it would take time for the attendant flexibility benefits to materialise. One way to model these issues is to assume that:

- Full development of DSO capabilities would only generate the kind of benefits estimated by the US Department of Energy one decade after the transition begins (specifically, the benefits would increase by 5% of RAB each year from 0% to 50% after 10 years); and
- If the NZCC sets too low a WACC this would delay the full development of DSO capabilities by a further decade.

117. In this case, at a 6% discount rate, the NPV cost of delayed investment would be 275% of today EDB RAB. If this loss was annualised over perpetuity at the same discount rate it would imply a 16% annual cost of underinvestment. This loss is roughly 3 times the "2014 starting point" estimates of the cost of underinvestment associated supply interruptions.

118. This result along with other sensitivities to the calculation (using different discount rates and periods of delay) are summarised in Table 6-1 below. It can be seen that in all cases modelled the estimated cost of under/delayed investment in DSO capabilities are higher than the modelled 4.0%/6.7% magnitude of the costs of service interruptions underpinning the 2014 WACC percentile.

Table 6-1: Estimates of the cost of delay in developing DSO capabilities (estimated as an annual perpetuity expressed as a % of RAB)

Discount rate	Period of delay		
	5 years	**10 years**	**15 years**
6%	6.9%	15.1%	19.3%
7%	7.8%	16.5%	20.8%
8%	8.5%	17.6%	21.9%

119. Of course, it might be that the US Department of Energy study overestimated the benefits to flow from DSO investment (or overestimated the benefits for New Zealand of such investment). However, even if the values in Table 6-1 were halved, they would still be associated with a substantial increase in the risks/costs of underinvestment that did not realistically exist in 2014.

7 Recommendations

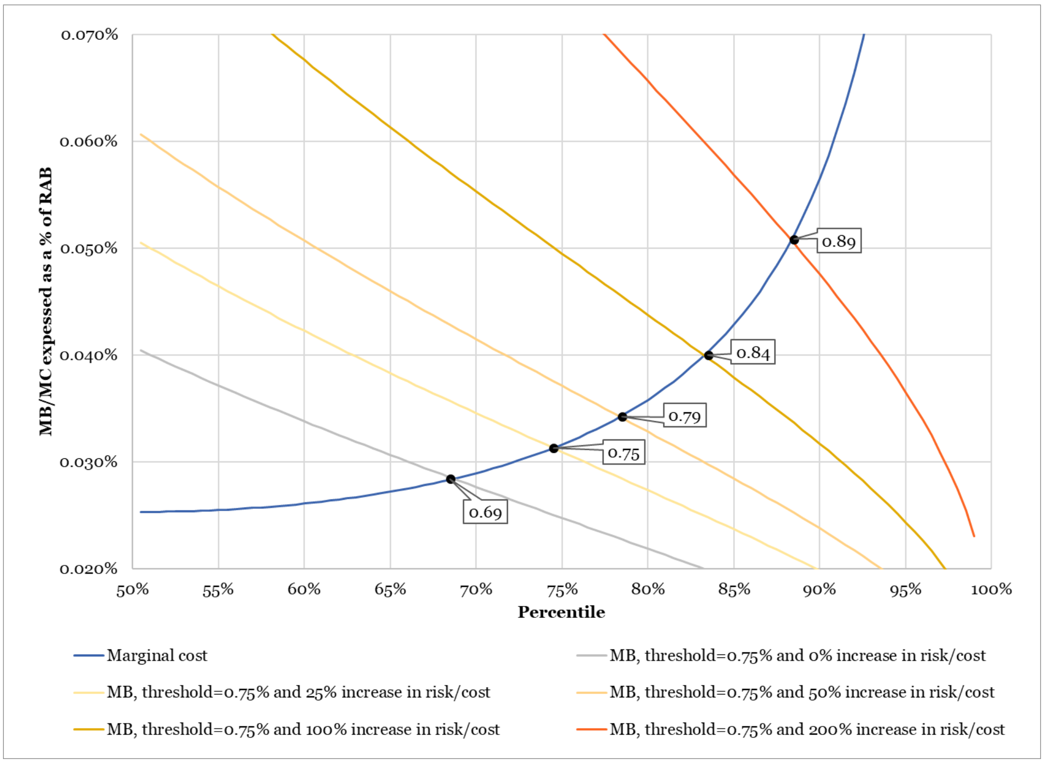
120. This report identifies three sets of changed circumstances that suggest a higher WACC percentile should be set today than that which was set in 2014. These are:

- A lower standard error today than in 2014;
- Higher demand growth and greater uncertainty around that demand growth in 2025 than in 2014; and
- The need for a transition of the EDB from a passive "poles and wires" business into an active DSO.

121. Figure 4-3 provides a useful way to consider the impact of these three factors on the optimal WACC percentile. Recall that Figure 4-3 shows the estimated marginal cost of increasing the RAB percentile (assuming a 1.01% standard error) and also shows the intersection of this marginal cost curve with various marginal benefit curves. All of the marginal benefit curves are associated with a standard error of 1.01% and the midpoint of:

- the threshold for triggering underinvestment (0.75% being the midpoint of 1.0% and 0.5%); and
- a baseline probabilistic cost of underinvestment when it occurs (5.35% of RAB being the midpoint of the "2014 starting point" estimates of 6.7% and 4.0% derived in section 2).
- with the differences between these curves due to a scaling factor applied to the baseline probabilistic cost of underinvest (scaling factors: 1.0, 1.25, 1.5, 2.0 and 3.0).

Figure 7-1: Midpoint marginal benefit curves intersections with marginal cost curve using a SE of 1.01% (reproduction of Figure 4-3)



Source: CEG analysis

122. Based on this figure, solely adjusting for the lower standard error would raise the WACC percentile that maximises consumer welfare to 0.69% (although the WACC uplift would nonetheless fall by 3bp – with the higher WACC percentile more than offset by a narrower distribution of the WACC).

123. If one were also to raise the estimated cost of underinvestment by a factor of 25%/50%, then the WACC percentile would increase to 75%/79%. Raising the estimated cost of underinvestment by a factor of 100%/200% would increase the WACC percentile to 84%/89%.

124. We consider that reasonable interpretations of the evidence in this report could result in a conclusion that the risk/cost of underinvestment in 2025 is likely to be in the order of 25% to 100% higher than it was in 2014 (scaled relative to the respective RAB values).

125. In our view, the middle of this range would imply a reasonable balance of the costs and benefits to consumers of allowing a higher WACC percentile. This would result in a 79% WACC percentile (associated with a 50% estimated increase in the cost of underinvestment relative to 2014).

Appendix A US Department of Energy Study

126. The most extensive modelling of the costs and net benefits of DSO capabilities has been undertaken for the US Department of Energy who engaged Pacific Northwest National Laboratory to undertake detailed technical and cost modelling of the overall supply chain benefits to end customers associated with developing DSO capabilities. The first four volumes of this study were released in January 2022 and the final fifth volume with the most detailed results was recently released which confirms and expands on the finds of the previous 4 volumes..[25] We consider that this is the "state of the art" in modelling of DSO costs and benefits.

127. The following is relevant background to the US Department of Energy study.

- First, the study makes a fundamental assumption that the adoption and deployment the DSO strategy occurred in the past and has reached steady state. That is, the modelling is of the benefits of a DSO strategy once it is up and running.
- Second, the study compares a DSO strategy with a "business as usual" (BAU) strategy;
- Third, the study considers various future market scenarios:
  - MR vs HR - being "moderate renewables" (15% combined PV and wind generation) vs "high renewables" (42%) as proportion of generation;
  - Case FL vs Case Batt – Case FL being a scenarios where most of the flexibility response comes from flexible demand response (EV charging, control of HVAC etc) while Case Batt being a scenarios where most of the flexibility response comes from control of behind the meter (consumer owned) batteries. These scenarios allow comparison of:
    i. BAU with MR and HR;
    ii. DSO Case FL with MR and HR; and
    iii. DSO Case Batt with MR and HR.
- Fourth, the DSO flexibility market is integrated with the wholesale market.[26]

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25 The first four volumes can be found here: https://www.pnnl.gov/projects/transactive-systems-program/dsot-study

26 This is covered in the third volume of the study. The mechanics by which this was modelled are interesting to understand but are specific to a given type of wholesale market. However, the authors note that the final results are applicable more generally – all that is important is that DSO and wholesale market signals are reflected in an integrated manner to participating customers.

- Fifth, it was assumed that participating customers could choose the level of flexibility between zero and one – where zero (prioritises convenience) and one (prioritises cost savings). This is a "set and forget" decision with an algorithm determining the responsiveness of the assets based on the customer setting.[27] [28]

128. Also critically important, and covered in the US DoE study, is that the development by the DSO of flexibility platforms is critical to the success of, and integration with, supply chain wide flexibility benefits. A single "market" means signalling/rewarding/factoring in the benefits of an action across the entire supply chain. For example, shifting load from (discharging a battery during) a period of peak demand on the local distribution network delivers benefits across the wholesale generation, transmission, and distribution systems. In order to obtain the optimal flexibility response (and investment in flexibility responses) all of these benefits need to be combined and signalled to flexibility providers.

129. The US DoE study design is calibrated to the Texan ERCOT system. While ERCOT is obviously different to the New Zealand system (e.g., larger, summer peaking, no hydro and higher wind penetration), it is not obvious that the benefits of a DSO led flexibility market will be materially different in New Zealand. ERCOT has more wind generation than New Zealand currently 15% vs 6% in 206 - but New Zealand wind generation is likely to grow strongly and can be expected to match or overtake ERCOT within a decade.

130. In any event, the authors note that their results are only calibrated to ERCOT in 2016 in order to gauge the accuracy of their modelling. They state: "*ERCOT data are used to gauge how well we have done, but the ultimate goal is to capture nationally representative behavior, not accurately model ERCOT behavior in 2016*".

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27 The authors engaged in detailed modelling of how this system would work in reality. For instance, if an HVAC unit had not met its minimum on/off time, it will not change state (on to off or vice-versa) even if signaled to do so by a supervisory control temperature setpoint change.

28 It is worth noting that, in the longer term, improved participation rates in flexibility markets could be achieved by, for example, making "high participation" the default customers to opt out of and/or by having the lowest level of participation still include some level of participation.

Table 7-1: Key results from US Dept. of Energy DOS study volume 4

Impact on	Result
	Average impact on customers
Retail energy bill savings to customers	12% to 14% under MR, 18% to 19% under HR
	Distributional impact on customers
Key conclusion	*"Ultimately the benefits seen by customers is a function of the overall cost savings seen by the DSO that serves them, which is in turn a function of peak load reduction. Beyond this trend, however, this study has shown that the average customer in practically every subclass sees a meaningful reduction in their annual electrical bill."*
Participating vs non-participating customer	Participating customers (those providing flexibility) benefit by more (in % terms) than non-participating customers. However, non-participating customers still share materially in the benefits (e.g., 10% reduction vas 15% reduction in the MR Case FL scenario).**
Urban/suburban/rural EDBs	Customers of urban and suburban EDBs tend to experience the largest percentage reduction in costs but benefits to rural EDBs' customers are only modestly lower.
Customers in apartments vs standalone houses	Both sets of customers benefit materially but stand-alone housing customers benefit more.
	System load impacts
Daily total system load	DSO models dramatically reduced daily system load variations (reducing these 20% to 44%) – driving significant savings in network and generation capital costs.
Variation in average local marginal prices	Consistent with the above, DSO models dramatically reduced daily system LMP variations (reducing these 31% to 78%) – driving significant savings in network and generation capital costs
	Impacts on EDB specific expenditures
EDB hardware expenditure (pa)*	Consistent with the above, the study estimated an ongoing saving of around **4%** pa on capex (primarily on substations) and **8%** pa savings on O&M materials/replacement capex.
EDB IT and IS expenditure (pa)*	Consistent with the focus of the DSO role these expenditures are **21%** higher relative to the BAU scenario. In terms of absolute $ this is around the same value as the savings on substations.
EDB other DSO labour costs (AMI network and cybersecurity and DER related) (pa)*	These labour costs can't be expressed as a % increase because they are, often, entirely new categories. However, these additional expenditures are estimated to be around **75%** of the expenditure savings on hardware.
Total EDB expenditures (pa)*	Total EDB expenditures are modelled to be roughly the same under the BAU and the DSO scenarios. The savings on traditional hardware expenditures are mostly offset by higher expenditures on DSO activities. The modelled net effect is around a reduction in total expenditures of **2%.**
	Impacts on transmission/generation/whole supply chain costs

Total transmission costs (pa)*	Total transmission expenditures are modelled to be **10%** lower under DSO scenarios.
Total wholesale/generation costs (pa)*	Total transmission expenditures are modelled to be around **22%** lower under DSO scenarios.
Total whole of supply chain expenditure reduction (pa)*	Total supply chain costs are modelled to be **13.5%** lower under DSO scenario.*
USD savings for a region the size of ERCOT (pa)	Total supply chain savings of USD 2.3 to 5.0 bn (noting that Texas' electricity consumption is roughly 10 times that of New Zealand).
Other key conclusions	
Key sensitivities	The existence of net economic benefits was not sensitive to assumptions. "*Of greatest importance is the fact that there is a still a net economic benefit of $1.7-2.9B/year even when assuming the low end of regional capacity prices for 2030.*"[29] "*…the overall benefits are insensitive to implementation costs. Even a doubling in DSO implementation cost only represents 2-6% of the total economic benefit seen by DSOs.*"
Benefits of DSO likely underestimated	*… the wholesale market model captured overall price trends but did not capture price excursions. This resulted in a substantial underprediction in the average daily price range, likely resulting in a conservative estimate of the wholesale energy market benefits of demand flexibility.*[30]
Net benefit increase as renewables increase	*… the need and benefit of transactive energy coordination schemes will only increase with the increasing deployment of renewable generation sources and load growth from the electrification of space heating and transportation*
Net benefits likely maximised with a mix of battery and other flexible assets.	*The annual simulation of both cases across the moderate and high renewable scenarios provides insights into the relative suitability and potential of various flexible assets to manage load. Flexible loads provided effective flexibility when grid constraints and price incentives aligned with their operation. … Flexible loads were found to be less effective when grid needs did not align with the assets' availability or operation. … Batteries provided much greater flexibility and resulting reductions to daily system load variation during these times. This suggests the need for a mix of flexible assets: flexible loads that can alleviate their contributions to system peak loads and local delivery constraints; and batteries and other storage mechanisms that can address excess renewable generation that does not align with nominal loads…*

* The EDB/Transmission/Wholesale specific results summarised in this table are for the BAU vs DSO in the moderate renewables (MR) scenario in the Case Batt scenario and are for an urban EDB. The results in other scenarios are similar (or higher cost savings in the high renewables (HR) scenarios).

** The study design specifically included a tariff design aimed at sharing the benefits of flexibility more widely. Specifically, the tariff design principle is that nonparticipating customers pay an amount expected to be equal to what would have been collected had they been paying a "dynamic" rate that reflected locational marginal cost pricing. This means that any reduction in locational marginal costs as a result of customers providing flexibility services also is reflected in lower retail bills for nonparticipating customers (i.e., they also benefit from the reduced overall cost basis of their DSO.

29 The authors method assumes the wholesale market has a capacity and energy component. However, as noted, the results are generalisable across other wholesale market structures.

30 Given that wholesale energy savings was the key differentiator of individual DSO benefits, improved representation of wholesale price volatility, and the specific market features and transmission constraints that drive them is needed.

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Appendix B Ofgem DSO precedent

B.1 Ofgem processes and draft decision

131. Ofgem's approach to encouraging development of DSO capabilities has evolved over the last at least 7 years of consolation and information papers leading up to the current draft decision. In September 2015 Ofgem released its position paper "Making the electricity system more flexible and delivering the benefits for consumers" followed two years later by its 2017 decision document "Upgrading our Energy System – smart systems and flexibility plan". This has been followed by continual updating of its business plan guidance which sets out Ofgem's expectations for EDBs to develop DSO strategies.[31]

132. Ofgem's RIIO-ED2 decision is in draft form at the moment (with consultation still open until 25 August 2022). However, Ofgem and UK EDBs have made significant efforts to elicit, develop and compensate plans to develop DSO capabilities. In its June 2022 (currently open for consultation) draft decision as follows, Ofgem states:[32]

> *A key objective of RIIO-ED2 is to support the delivery of net zero at the lowest cost to the consumer;* ***and the efficient operation of the energy system at all voltages is essential if this vision is to be realised. Changes are required to the operation of electricity distribution networks to maximise the value of decentralised, local markets for flexibility services and to enhance the visibility of network data****. DSO is the set of activities that are needed to support this transition to a smarter, more flexible and digitally enabled local energy system.* (Emphasis added.)

133. Ofgem summarises its approach as per Figure 7-2 below.

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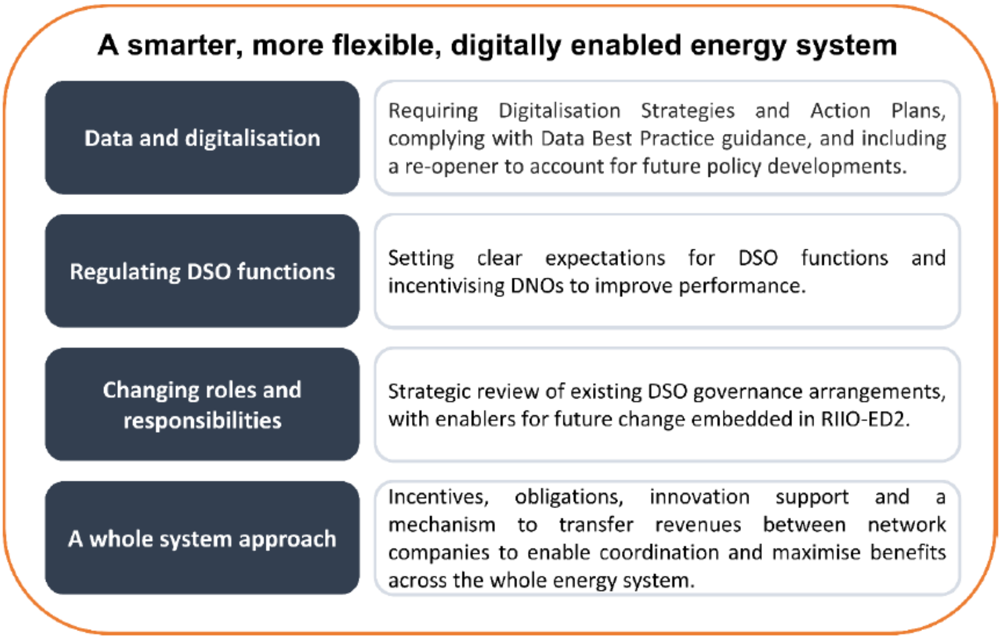
31 Some of the relevant documents can be found in the following links. Ofgem decarbonisation programme action plan 2020
https://www.ofgem.gov.uk/sites/default/files/docs/2020/02/ofg1190_decarbonisation_action_plan_revised.pdf
Ofgem RIIO-ED2 Methodology Decision: Overview
https://www.ofgem.gov.uk/sites/default/files/docs/2020/12/ed2_ssmd_overview.pdf
June 2022 draft decisions
Ofgem RIIO-ED2 Draft Determinations https://www.ofgem.gov.uk/sites/default/files/2022-06/RIIO-ED2%20Draft%20Determinations%20Overview.pdf
Ofgem RIIO-ED2 Draft Business Plan Guidance
https://www.ofgem.gov.uk/sites/default/files/docs/2020/08/ed2_draft_business_plan_guidance_-_august_reissue.pdf

32 Ofgem, Consultation - RIIO-ED2 Draft Determinations – Overview Document, p. 61.

Figure 7-2: Ofgem summary graphic



134. Ofgem summarises its draft decision prosaically as follows (emphasis added): [33]

> *Our Draft Determinations proposals are summarised below.*
>
> - *Baseline **investment of £2.7bn in network upgrades to support the rollout of EVs, HPs** and the connection of more local, low carbon generation including solar and wind*
> - *An agile package of **uncertainty mechanisms** that will allow investment to adapt quicky to support higher volumes of low carbon technologies if networks are faced with sharper uptakes in demand for new connections*
> - *…*
>
> ***Supporting a smarter, more flexible energy system***
>
> - *A new framework of outputs and incentives for Distribution System Operation (DSO) with clearer executive level accountability for neutral decision-making between DSO and DNO business activities*
> - *This includes a new **DSO financial output delivery incentive (ODI-F)** to drive DNOs to more efficiently develop and use their network, considering flexible and smart alternatives, to defer the need for reinforcement and ultimately reduce customer bills*

[33] Ofgem, Consultation - RIIO-ED2 Draft Determinations – Overview Document, p. 11.

- ***Funding to improve the DNOs' monitoring of their networks**, including through the installation of network monitoring equipment and through improved use of data analytics*
- *New licence requirements for all DNOs to ensure that they communicate flexibility requirements for the future and the detailed information about the outcome of their procurement of flexibility services annually to Ofgem, to benefit those businesses able to respond.*

135. UK EDBs (referred to as DNOs) proposed material expenditures on DSO activities. For example, both SSEN and UKNP have proposed spending **roughly £150m** each over the regulatory period on DSO activities. Ofgem's June 2022 draft decision states that:[34]

> *In total, the proposed DSO spend across all companies in RIIO-ED2 was ~**£890m**, almost four times the forecast spend in RIIO-ED1.*

136. Ofgem's draft decision also states:[35]

> *We propose to accept the majority of the DNOs' DSO strategy proposals without amendment, with the exception of investments where we have found weak justification in the associated Engineering Justification Paper (EJP).*

137. Ofgem's DSO incentive framework and its outturn performance metrics are summarised in Figure 7-3 and Figure 7-4 below.

[34] Ofgem, Consultation - RIIO-ED2 Draft Determinations – Core Methodology Document, p. 82.

[35] Ibid.

Figure 7-3: Ofgem DSO incentive framework

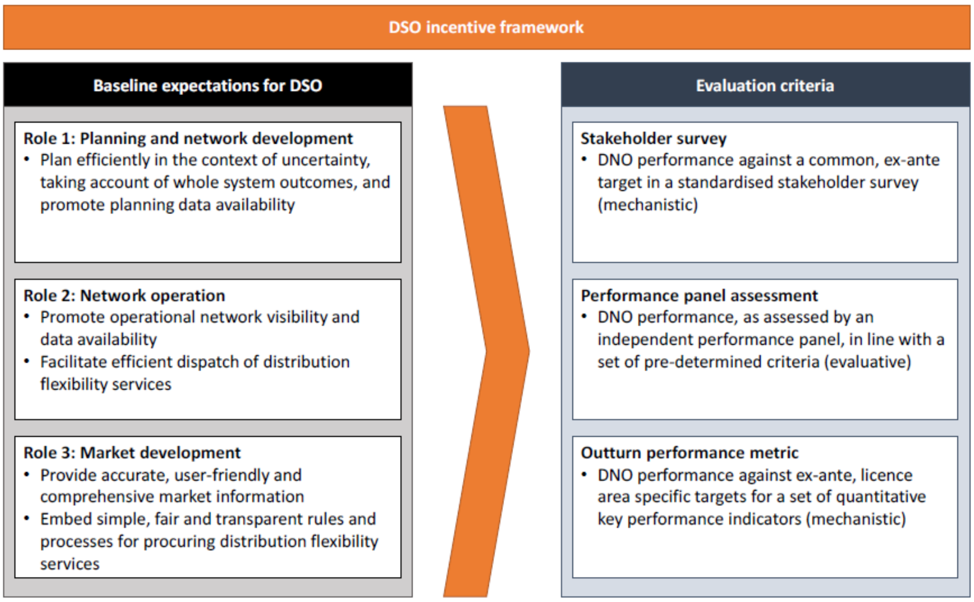


Figure 7-4: Ofgem DSO outturn performance metrics

Table 10 DSO outturn performance metrics

Metric	Definition
Flexibility market testing	The metric will validate the extent to which a DNO is undertaking comprehensive quantitative assessments when determining if distribution flexibility services are the most economic solution with respect to reinforcement decisions across the LV, HV and EHV networks: $Flexibility\ market\ testing\ \% = \frac{\sum MVA\ of\ network\ reinforcements\ market\ tested\ for\ flexibility}{\sum MVA\ of\ network\ reinforcements\ subject\ to\ DNOA} * 100$
Network visibility	The metric will consider the extent to which there is near real time, aggregate monitoring of LV network load data: $Network\ visibility = \frac{\sum T_i N_i}{N_t} * 100$ where T_i takes the value of 1 if location i is visible to the DNO and 0 otherwise, N_i is the number of customers connected to location i, and N_t is total number of customers.
Curtailment efficiency	The metric will consider the extent to which a DNO is limiting curtailment of users on non-firm connections resulting from actions taken by the DNO to restrict the conditions of a connection in response to a constraint on the distribution system: $Curtailment\ efficiency = \frac{\sum H_i A_i}{A_t}$ where H_i is duration of curtailment in hours for user i, A_i is the MVA reduction in access for user i, and A_t is total MVA access for all users on non-firm connections.

B.2 Extracts from UK EDB DSO spending proposals

B.2.1 Scottish & Southern Electricity Networks

OVERARCHING AMBITION				
Enabling LCT connections	SSEN Aim	Ready the network for net zero, consistent with up to 1.3m electric vehicles and up to 800,000 heat pumps connecting by 2028.	£100m carbon benefits and £112m customer financial benefits over RIIO-ED2, enabled by ensuring LCT customers are able to connect on time.	£510.2m baseline load and connections-driven reinforcements with additional uncertainty mechanism funding in period*
Enabling LCT connections	SSEN Aim	Ready the network for net zero, consistent with a total of 8GW of distributed energy resource (including windfarms, solar, and energy storage) connecting by 2028.		

DSO Strategy				
DSO Strategy	**LO ODI-F**	Define a DSO strategy that will be reviewed and refreshed annually with an action plan to deliver against it, including changes to IT systems, processes, and people.	Our DSO strategy will provide significant benefits across our plan: • Through flexible connections saving £417.6m in reinforcement costs, offsetting 1.8mtCO_2. • Deferred reinforcement and avoided capital expenditure saving customers up to £46.3m.	**£73.1m**
Facilitating participation in flexibility markets	**LO ODI-F**	Set up an annual flexibility providers forum and survey enabling regular feedback.		
Transparency of information	**LO ODI-F**	Provide timely, accurate and accessible DSO data across all DSO roles.		
Improving provision of forecasting information	**LO ODI-F**	Continually improve the provision of forecast information for both new and existing flexibility markets.		
Deploying flexible solutions	**SSEN Aim**	Target 5GW of Constraint Managed Zone services across multiple service types and grow our flexible connections to 3.7GW of capacity across 35 zones by 2028.		
CVPs				
Energy efficiency accelerator for smarter networks	**CVP**	Proactively work with Local Authorities and partners to identify and implement energy efficiency measures across our customer base that can release network capacity, with an aim to prioritise fuel poor customers and those in vulnerable circumstances.	• £7.1m net positive value and an SROI of £0.21 benefit delivered in excess of every £ spent. • Supporting all our customers in the energy transition. • Our blended CVP approach will actively promote a localised, balanced energy system, with wider societal benefits (e.g. carbon savings). • Communities will be empowered to participate in flexibility markets, benefiting from the energy system transition, and resulting in lower customer bills through the reduced need for reinforcement and energy efficiency. • Support the fair distribution of benefits from smart technology.	**£36.8m**
Local and community flexibility market stimulation	**CVP**	Partner with local organisations, aggregators and energy suppliers and other relevant organisations to actively promote recruitment of flexibility in areas of low market growth.		

LO: Licence Obligation; **PCD:** Price Control Deliverable; **ODI:** Output Delivery Incentive (**F:** Financial, **R:** Reputational), **CVP:** Consumer Value Proposition, **SSEN Aim:** Company Goal

Cost area	Forecast position at end of RIIO-ED1
Load-related expenditure	We are forecasting to spend 71% or more of our load-related allowance across SHEPD and SEPD as a result of three key factors: • Lower than anticipated peak load: driven by slower economic growth, the roll-out of domestic energy efficiency, offsetting of demand by distributed generation (DG). • Innovative solution: we have been able to use innovative solutions such as flexibility and Active Network Management (ANM) schemes to reduce the costs of managing load and generation increases (see below). • Lower than anticipated transmission reinforcement: very little transmission reinforcement has been triggered by our DG connections and we have used ANM schemes to help mitigate constraint costs for customers.

DEPLOYING FLEXIBILITY IN RIIO-ED1

During RIIO-ED1, we achieved significant benefits for our customers through flexibility solutions such as Active Network Management (ANM) and Constraint Managed Zones (CMZ). Overall, we have delivered savings of around £60m in deferred reinforcement through our CMZ (flexibility procurement) and ANM schemes:

- We have contracted in excess of 468MW of flexibility services delivering an operational saving of £251k and avoiding 3,250tCO_2e.
- The use of flexible connections (ANM) has enabled 679GWhr of renewable energy onto the network and avoided £58m of network reinforcement, saving customers 90.6 years of connections delays.

These benefits have been predominantly focused on the connection of generation, but it is already becoming clear that flexible connections for LCTs, such as public EV charging infrastructure, will be even more valuable.

USING FLEXIBILITY TO ADDRESS LOAD-MANAGED AREAS (LMA)

LMA is a legacy system used to manage network capacity in the SHEPD licence area. LMAs reduce the maximum demand on circuits and at substations by controlling customer space heating and water heating load at different times during the day and night via Long Wave Radio Tele-Switching (RTS). LMAs cover approximately 93,000 customers in rural areas. They were historically introduced as an alternative to traditional reinforcement in rural parts of the network where costs are prohibitively expensive.

Our approach in RIIO-ED2 will be to use market flexibility services to replace LMA-mandated switching patterns – including activities to define, develop and stimulate the market – alongside, and in accordance with, development and facilitation of flexibility markets to support DSO.

Solutions to provide additional capacity to support the uptake of LCT will be co-optimised with those to remove LMA restrictions – using the principle of 'flexibility first' We will also ensure that other reinforcement or flexibility procurement for other (non-LCT) needs or requirements provides for LMA removal, as a matter of course.

It is anticipated that the load-related investment in RIIO-ED2 will ease or lift around 30% of the LMA restrictions by the end of the RIIO-ED2 period, with the potential for up to 50% of restrictions lifted if higher levels of LCT materialise. The aim is to remove all remaining LMA restrictions during the RIIO-ED3 period.

More detail on our proposed approach to removal of LMA restrictions is provided in *Load Related Plan Build and Strategy (Appendix C of Annex 10.1)*.

138. The following quotes are how SSEN describes their plan to evaluate themselves. It will be based on a combination of volume and customer feedback.

> *We will employ both qualitative and quantitative approaches as part of this performance metric. To measure our success in facilitating participation in the flexibility markets we operate and the flexible connections we selected a range of measurement points covering different stages and touchpoints in our DSO customer journey. We will seek feedback from participants who completed those stages or touchpoints. This feedback will identify our performance in each stage or touchpoint. We would then measure how our performance improves over time and publish an annual stakeholder report on*

our DSO performance. This could be through individual service standards or collectively via a customer satisfaction score or balanced scorecard.

We will also report the volume of market participant enrolments, connection applications, market actions and inquiries and other data points from the various stages and touchpoints of our customer journey. This compliments the feedback from stakeholders.

B.2.2 UK Power Networks

139. The following sets out UKPN's plans on introducing flexibility on its network. Similar to SSEN, these costs involve customer engagement, improving data management and forecasting such that outages can be predicted.

Commitment WS1

We will engage with all 127 regional local planning authorities on their climate plans each year of RIIO-ED2, offering a three-tiered support service utilising a framework to assess, develop action plans and deliver investments where a prescribed level of certainty is achieved in period. **NEW**

Resource and expenditure	Regulatory treatment	Customer benefit	Stakeholders / customers said
£9.3m. Establish a local area planning team of 20 full time employees. They will work with local authorities to assess their energy plans and develop CBAs. Included in this team is dedicated resource focused on Community Energy progression. We will regularly review our approach to make sure it remains proportionate, transparent and appropriate.	Included in baseline DSO allowances.	Enables pro-active engagement with all local authorities whilst minimising unnecessary effort on both sides. Prioritises effort in areas where investment decisions are most needed to reduce delays. Provides clear guidance on the minimum requirements agreed across all parties to share knowledge and support the development of all local plans.	Our stakeholders proposed that we should carry out local energy planning and zoning. To support the transition to Net Zero, customers and stakeholders believe that we should focus on: information provision; and collaboration (particularly with local authorities). Stakeholders told us that this resource should also support capability and capacity building across local authorities. (See Insight I-FNZ1, I-FNZ5, I-FNZ7, I-FNZ8, I-FNZ13, I-DSO/WS8 in our supporting document Line of Sight – Whole systems)

Commitment WS2

By 2024, we will provide core planning datasets via an on-line, self-service energy planning tool to support the planning process for our local authorities, helping them make the best choices for their communities.

Resource and expenditure	Regulatory treatment	Customer benefit	Stakeholders / customers said
£2.02m.	Included in baseline allowances.	Improved customer experience by enabling local authorities to make the best choices for their communities. Improved support for local authorities. Increased participation in flexibility markets.	To support the transition to Net Zero, customers and stakeholders believe that we should focus on: information provision, collaboration (particularly with local authorities), and relieving capacity constraints to enable supporting infrastructure like EV charging points. (See Insight I-FNZ1, I-FNZ5, I-FNZ7, I-FNZ8, I-FNZ9, I-FNZ11 and I-FNZ13, I-DSO/WS6 in our supporting document Line of Sight – Whole systems)

Commitment WS3

We will provide proactive services to our DER by expanding our digital outage planning and automatic restoration tools, to minimise disruption and maximise their system access throughout RIIO-ED2.

Resource and expenditure	Regulatory treatment	Customer benefit	Stakeholders / customers said
£0.6m	Included in baseline DSO allowances.	Increased system access for DER. Increased opportunity to access system services Increased satisfaction and maximised revenue opportunities for connected DER.	"If UKPN know about regular maintenance or planned outages then this information should be made public." DG focus group. (See Insight I-FNZ1, I-FNZ8, I-FNZ11, I-FNZ16, I-DSO/WS7 in our supporting document Line of Sight – Whole systems)

Commitment WS5

We will expand the geographic area of our South East Regional Development Programme (RDP) in RIIO-ED2 and deliver a RDP in East Anglia by 2024, as agreed with the ESO. We will unlock up to £130m of whole system benefits during RIIO-ED2.

Resource and expenditure	Regulatory treatment	Customer benefit	Stakeholders / customers said
£3m IT CAPEX. £1.5m FTE costs during RIIO-ED2.	Included in baseline DSO allowances.	Up to £130m of whole system benefits.	Stakeholders want transparency to understand why decisions are being made and view this as critical for enabling market participation. (See Insight I-FNZ1, I-DSO/WS2, I-DSO/WS8 and I-DSO/WS9 in our supporting document Line of Sight – Whole systems)

Commitment WS7

Over RIIO-ED2 we will deliver 1GW of distributed energy resources (DER) capacity at no more than £8m, using smart interventions and new innovations, reporting progress in our annual business plan.

Resource and expenditure	Regulatory treatment	Customer benefit	Stakeholders / customers said
£7.6m capex for targeted distributed generation enhancements.	Included in baseline DSO allowances.	Greater volumes of local renewable energy provision. See ED2-EJP-NP-004. Reduced connections costs for DER. Increased market opportunity for DER.	Stakeholders think that we should ensure sufficient network capacity ahead of need, and coordinate network reinforcement so that we only "dig the road once". (See Insight I-FNZ1, I-FNZ7, I-FNZ8, I-FNZ15 and I-FNZ16, I-DSO/WS2, I-DSO/WS13 and I-DSO/WS16 in our supporting document Line of Sight – Whole systems)

Commitment WS10

We will develop an energy efficiency flexibility product, running tenders every 6 months, starting in 2023. **NEW**

Resource and expenditure	Regulatory treatment	Customer benefit	Stakeholders / customers said
Costs have been included in our DSO Cost build up.	Included in baseline DSO allowances.	Supports lower energy bills. Provides a revenue opportunity for customers that can provide energy efficiency services.	Customers support the need for smart technology and want us to support the roll out of energy efficient technology, and local authorities want to improve energy efficiency of housing stock and stakeholders want us to enable markets to be successful. (See insight I-DSO/WS11 and I-DSO/WS16 in our supporting document Line of sight – Whole systems)

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Commitment DSO2

We will deliver operational transparency by publishing our day-ahead operational plan and schedule of flexibility services and curtailment, and a monthly control room dispatch decision report from the start of RIIO-ED2.

Resource and expenditure	Regulatory treatment	Customer benefit	Stakeholders / customers said
£5.7m investment in operational forecasting, scheduling support and dispatch tools. £22.1m IT operating costs and Indirects.	Included in baseline allowances.	Providing visibility of planned curtailment and flexibility services will enable customers to plan their operations, and wider system operators to coordinate dispatch. Transparency of dispatch will promote competition and market participation, thereby reducing the costs to operate the system for all customers.	Stakeholders support improvements in our operational planning and requested increased transparency of control room actions to build confidence in DSO actions. Stakeholders support ambitious options on outage planning, including further network sectionalisation to reduce outage impact. (See key insights in our Line of Sight – DSO and Line of Sight – Whole systems)

Commitment DSO3

Our DSO function will deliver up to a £410m reduction in load related expenditure during RIIO-ED2 through increased competition and use of LV flexibility, including at the domestic level.

Resource and expenditure	Regulatory treatment	Customer benefit	Stakeholders / customers said
£13.2m investment in forecasting, decision support and control system tools. £34.3m IT operating costs and Indirects.	Included in baseline allowances.	An open and transparent network development process will promote competition and maximise the use of service, smart network and whole-system solutions thereby delivering the lowest cost network solutions.	Stakeholders told us that they see using flexibility markets and technology to deliver benefits for customers and flexibility as the core DSO role. (See key insight I-DSO/WS10, I-DSO/WS19, I-FNZ1 in our Line of Sight – DSO and Line of Sight – Whole systems)

Commitment DSO4

We will keep our costs down by taking a "flexibility and energy efficiency first" approach over RIIO-ED2 and will "market test" all network needs before considering reinforcement. These needs will be procured through a range of long-term and short-term markets and products, which are inclusive by design and ensure no customer is left behind in the energy transition.

Resource and expenditure	Regulatory treatment	Customer benefit	Stakeholders / customers said
£9.5m investment in control systems and market operations capabilities (via third parties). £12m IT operating costs and Indirects (including third party platform support).	Included in baseline allowances.	Delivering real-time market operations will enable the most efficient use of the network. Focusing on inclusive design will ensure all customers are able to experience the benefits of the energy transition.	Stakeholders have said that we must demonstrate flexibility is on a level playing field with all other options, promote greater use of flexibility at lower voltage levels, and enable 3rd party platforms to flourish and deliver benefits. (See key insight I-DSO/WS4, I-DSO/WS9, I-DSO/WS10, I-DSO/WS11, I-DSO/WS14, I-DSO/WS16, I-FNZ9, I-FNZ10 in our Line of Sight – DSO and Line of Sight – Whole systems)

Commitment DS05			
We will collect real time data through monitoring in all LV networks where we are forecasting constraints over RIIO-ED2, and will target 100% coverage of the rest of the network through advanced analytics using smart meter data. This will give us better insight to run the network at higher utilisation and to defer reinforcement actions for as long as possible.			
Resource and expenditure	**Regulatory treatment**	**Customer benefit**	**Stakeholders / customers said**
£38.6m in network monitoring costs and software based network data. £4.4m of indirect costs.	Included in baseline allowances.	Provision of improved visibility of network constraints will provide customers and stakeholders valuable insight to help plan and manage their operations. It will also enable us to maximise utilisation of the existing network and keep bills as low as possible for consumers.	Stakeholders say that developing proactive LV network monitoring that goes beyond the traditional peak power demand management approach is key to preparing for a smarter network. Participants want market data to be provided in a useable manner, and strongly support as much being provided as possible. (See key insight I-DSO/WS12, I-DSO/WS15, I-DSO/WS17, I-DSO/WS18, I-FNZ11 in our Line of Sight – DSO and Line of Sight – Whole systems)

B.2.3 S&P Energy Networks

140. The following describes S&P Energy's current capabilities in tracking DERs on their network and predict their usage or generation.

> Therefore over the course of RIIO-ED1, we've developed a new and industry-leading approach to developing investment plans. This involved developing and combining two separate innovations.
>
> First, through our award-winning Network Constraints Early Warning System (NCEWS) innovation project, we built a full model of all 48,000km of our LV network. We've combined it with our existing HV and EHV network models, so we now have a complete connectivity model of our entire distribution network. We hosted this connectivity model within an analytical platform – our Engineering Net Zero (ENZ) Model.
>
> Second, we've developed two enhanced forecasting tools. They're called EV-UP and Heat-Up, and they use spatial, demographic, and socioeconomic data to forecast EV and heat pump uptake for every customer we serve. This is relevant as these are the two drivers of increasing demand.
>
> These forecasting tools are complementary to our low, baseline, and high scenario forecasts. The scenarios consider a range of macro factors (such as legislation and technology development) to forecast total EV and heat pump volumes across our whole licence area. EV-Up and Heat-Up show, for any scenario, how these are likely to roll-out across the network – they forecast which individual households will get them and in what timescales.

141. The following describes S&P Energy's previous attempt to engage customers to attempt to sign them up to provide demand flexibility. It also provides information on S&P Energy's plan to repeatedly re-engage with remaining customers to convince them to sign up

In developing our RIIO-ED2 intervention plan, we used our ENZ Model to establish network capacity requirements (*Pg 38*). We tendered for flexibility services for every RIIO-ED2 network capacity shortfall identified by this process, including all HV/LV substation constraints. We did this through two large flexibility tenders in autumn 2020 and spring 2021, which sought 1.5GW of flexibility across 1,557 sites (see table opposite).

These tenders showed the availability and cost of flexibility, so we could develop a well-justified plan and put in place flexibility contracts for RIIO-ED2. The bid responses from these flexibility tenders were assessed in detail alongside all other viable solutions.

In RIIO-ED2 we will use flexibility to defer reinforcements, including major schemes, where this is in the best interests of customers. For example, in the Carrington–Fiddlers Ferry group we will defer £10.5m of 132kV circuit upgrades, and at Redhouse we are able to defer replacing a 132/33kV transmission transformer, saving our customers £2.8m in exit charges. In Merseyside, we will combine flexibility with network monitoring and automation to defer replacing 10km of the 132kV cable that runs into the centre of Liverpool – as well as deferring £9m, this avoids significant disruption for residents.

Our plan is robustly built by testing the market for every network capacity shortfall identified in RIIO-ED2.

Scheme Voltage	Flexibility Tendered	Market Response	RIIO-ED2 Baseline
132kV	81.8MW *(3 sites)*	282.4MW *(3 sites)*	75.8MW *(3 sites)*
33kV	720.2MW *(22 sites)*	736.9MW *(20 sites)*	212.7MW *(19 sites)*
11kV	222.4MW *(55 sites)*	335.5MW *(55 sites)*	166.3MW *(55 sites)*
LV	454.4MW *(1,477 sites)*	563.8MW *(1,473 sites)*	95.6MW *(1,275 sites)*
Total	1,478.8MW *(1,557 sites)*	1,918.6MW *(1,551 sites)*	550.3MW *(1,352 sites)*

Where flexibility services are not yet available and we have had to assume the use of network reinforcement, we will re-tender for flexibility within RIIO-ED2 before the reinforcement starts to ensure we are using the most efficient intervention. We plan to run our tender process on a twice annual basis. This will have several beneficial effects including improving service provider confidence, challenging market costs, and increasing certainty on the level of flexibility we can procure in RIIO-ED2.

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Estimating the WACC under the IMs

Tom Hird
Ker Zhang
Samuel Lam

February 2023

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1 Executive summary

1. This report addresses a number of issues related to estimating the WACC under the IMs and proposes a number of reforms to the 2016 IMs. These can be summarised below.

1.1 Debt tenor and trailing average

2. The 2016 IMs involve a fundamental inconsistency between the asset beta estimate the debt tenor assumption which creates a downward bias in the WACC estimate. This inconsistency can, and should, be corrected by adopting a benchmark tenor of 10 years for debt (rather than the current 5 year benchmark).

3. This inconsistency is analogous to the "debt leverage anomaly" that the NZCC already recognises and which is the reason it sets the benchmark leverage in the WACC consistent with the average leverage in the asset beta sample. For precisely the same reasons, a "debt tenor anomaly" exists which the NZCC needs to address by adopting an average debt tenor consistent with the average debt tenor in the asset beta sample.

4. We also consider that the NZCC should adopt a trailing average estimate of the 10 year cost of debt. However, this issues is separable from the tenor assumption. That is, the NZCC could logically address the "debt tenor anomaly" without adopting a trailing average. If the NZCC does adopt a trailing average it would be reasonable to consult on applying a transition.

1.2 Term Credit Spread Differential (TCSD)

5. The TCSD compensates for the higher cost of long term debt for those EDBs that issue long term debt. The TCSD would not be necessary if the NZCC adopts a 10 year tenor. However, if the NZCC does not adopt a 10 year tenor the TCSD will need to be updated.

6. In the process of updating the TCSD we have attempted to replicate the NZCC's 2016 estimate. We have been unable to do so and consider that there is a high probability that the estimate was made in error. Our estimate of the NZCC 2016 methodology is that the TCSD:

   - The 2016 TCSD should have been estimated at 10bp (i.e., a 10bp increase in DRP per year of tenor above 5 years);
   - The updated application of this method also results in a 10bp estimate.

7. This compares to the NZCC stated estimate of around 5bp (which was increased to 7.5bp based on CEG estimates).

1.3 RAB indexation and CPI forecasting

8. We consider that new evidence since 2016 should lead the NZCC to reconsider its approach to targeting compensation for a real cost of debt. Given the cost of debt is efficiently incurred in nominal terms, targeting compensation to a real cost of debt creates risk for customers and EDBs that would simply not exist if a nominal cost of debt was targeted.

9. In the 2016 IM decision, the NZCC accepted that there would be risk mitigation advantages for EDBs but rejected reform on the basis that:

   a. The status quo was established and changing it would involve some effort and that the inflation forecasting errors were not so large as to warrant that effort; and

   b. Reducing EDB risk would "transfer" that risk to customers.

10. The first point has been demonstrated to be empirically wrong since 2016. The second point was always conceptually wrong (see paragraph 8 above) but has also been proved to be empirically wrong by recent high inflation outcomes. These have the effect of resulting in customers paying substantially more than the efficient costs for debt funding (even if we take the average over DPP1 to DPP3).

11. We also describe empirical evidence that suggests that, to the extent that the NZCC still needs a forecast of inflation, it should give some weight to break-even inflation estimates derived from the yields on inflation indexed government bonds.

1.4 Amortisation of issuance costs

12. In 2016 the NZCC determined that it would not amortise issuance costs on the grounds that:

> *…suppliers typically issue some debt each year to manage refinancing risk. They therefore incur some debt issuance costs each year. Assuming that firms issue a consistent amount each year with similar costs, there is no need for a present value adjustment in respect of a portfolio of debt.*

13. We explain that this logic is flawed. It amounts to taking the money allocated to compensate for past costs and using it to fund current costs. It is true that this will "adequately" compensate for current costs but it does so by leaving past costs completely uncompensated. That is, if the NZCC hypothecates each year's total debt issuance compensation to the debt that has just been raised in that year (being one fifth of the RAB) then that leaves the other four fifths of the debt RAB uncompensated. That is, at any given time there is an "inventory" of old debt raising costs that is uncompensated.

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2 Tenor of debt and use of a trailing average

2.1 Internally consistent tenor of debt

14. The NZCC currently sets a cost of debt based on the baseline assumption that the EDB maintains a staggered portfolio of 5-year debt. Large EDBs that issue longer tenor debt receive compensation of the higher debt risk premium (DRP) on that debt via the TCSD (discussed in section 3).

15. However, the NZCC sets the asset beta for all EDBs based on benchmarking against businesses that universally have a longer average tenor of debt. In fact, in the updated NZCC asset beta sample from 2016, the value weighted average tenor of all bonds issues is over 20 years.

Figure 2-1: Average tenor of bonds issued for firms in asset beta sample

Source: Bloomberg and CEG analysis. 31 December 2019 is chosen to reflect pre Covid impacts. There is significant evidence that during the Covid period long term corporate debt was difficult to finance [Ref] and the subsequent rapid inflation escalation has also tended to the available of long term nominal debt funding.[1]

1 Ropele, Gorodnichenko and Coibion, Inflation expectations and corporate borrowing decisions: new causal evidence, NBER working paper series, Working Paper 30537, October 2022.

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16. The difference between the actual practice of the firms in the asset beta sample (20 years) and the NZCC's assumption (5 years) is highly material. In this context it is critical to understand why firms choose to issue longer dated debt even though this is typically associated with a higher cost of debt and, in particularly, a higher DRP.

17. There is only one reason why the equity owners of a firm would choose to issue higher cost long term debt rather than lower cost short term debt. This must be because doing so reduces the cost of equity. That is, any higher interest costs must be associated with an at least offsetting lower cost of equity – otherwise it would be irrational to incur the higher costs associated with issuing long term debt.

18. Moreover, in the capital asset pricing model (CAPM), used by the NZCC to estimate the cost of equity, this must manifest through a lower beta. That is, a firm specific decision to issue longer term debt can only reduce the cost of equity if it reduces the equity beta for any given gearing level (given that the market risk premium and risk free rate are market wide parameters).

19. Longer term debt reduces the equity beta precisely because longer term debt absorbs some of "equity like" risk. Equity is infinitely lived (or, at least, as long lived as the firm) while debt funding is made for discrete periods of time. The longer debt funding is provided for the more like equity funding it is. The longer a debt instrument is the more exposed is the lender to the long-term viability of the firm. That is exposure raises the "debt beta" for the debt instrument and, in doing so, the equity beta is reduced.

20. This is formalised in the following commonly used relationship between asset beta, equity beta and debt beta ().

$$\beta_e = \frac{\beta_a - \beta_d}{1 - L}$$

Where:
β_e is the equity beta
β_a is the asset beta
β_d is the debt beta
L is the leverage/gearing

21. This is at the well-known Modigliani Miller theorem that the WACC should be more or less invariant to the level of debt leverage.[2] This is also sometimes described as the "conservation of risk" theorem (drawing a parallel from the law of the conservation of energy in physics). It states that the fundamental risk of a firm cannot be changed by the funding strategy of the firm – it can only be allocated in different ways between

[2] The Modigliani Miller theorem is a cornerstone of modern finance theory. It states that if financial markets are efficient and there are no transaction costs, then a firm's WACC is not affected by its capital structure. Modigliani, F.; Miller, M. (1958). "The Cost of Capital, Corporation Finance and the Theory of Investment". American Economic Review. 48 (3): 261–297.

funders. In this context, this means issuing low cost short term debt rather than high cost long term debt cannot lower the WACC for a firm. All that is happening when a firm issues low cost short term debt is that it is retaining more of the risk for equity holders that it would otherwise have passed onto long term debt funders.

22. Such a relationship between debt beta and equity beta is well understood and accepted by the NZCC. Indeed, the NZCC carefully explains why the existence of positive debt betas means internal consistency requires it to use the same benchmark gearing as the sample average gearing from the asset beta sample of firms. Otherwise, using a debt beta of zero and a value for benchmark gearing above the sample average would tend to overestimate the equity beta and create "the leverage anomaly" whereby WACC increases with gearing when the Modigliani Miller Theorem argues that WACC should be independent of gearing (within reasonable ranges).

23. To this end the NZCC states:[3]

> *562. We continue to consider that using the average leverage of the asset beta comparator samples is the best way of dealing with the anomaly. As we have estimated a notional leverage in line with the companies in our asset beta comparator samples, the resulting WACC will be the same for those services regardless of the value assumed for the debt beta.*

24. But the same principle of internal consistency applies in the context where the NZCC uses the asset beta for firms with long term debt and applies it to a benchmark where it assumes short term debt is being used. Other things equal this will create precisely the same sort of bias that the NZCC is concerned about with the leverage anomaly.

25. That is, the "leverage anomaly" is a direct corollary of the "tenor anomaly". Choosing a different leverage to the sample average should not affect the WACC but, without accounting for debt beta it does. Similarly, choosing a different tenor to the sample average should not affect the WACC but, without accounting for debt beta it does. The NZCC has addressed the leverage anomaly but the same logic means it should also address the tenor anomaly.

[3] NZCC, Input methodologies review decisions, Topic paper 4: Cost of capital issues, December 2016, p. 144.

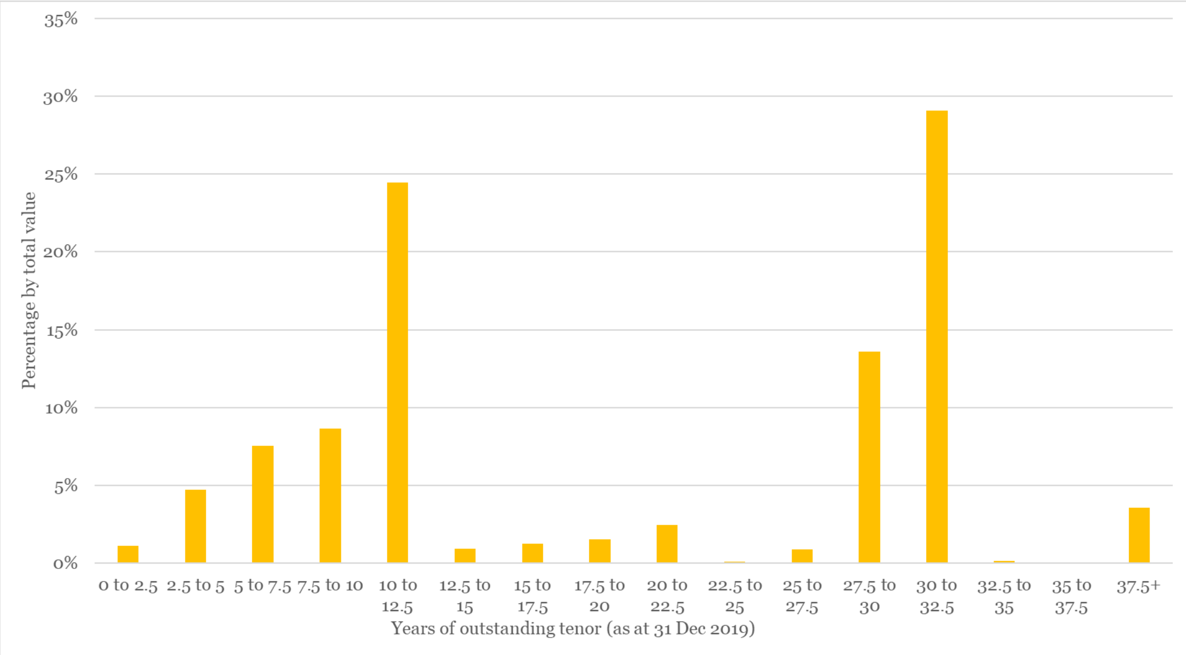
Table 2-1: Leverage anomaly vs tenor anomaly

	Leverage anomaly	Tenor anomaly
Problem	The sample average equity beta reflects the sample average **leverage** and its effect on the (unknown) sample average debt beta. Debt beta is important. Therefore, setting the **benchmark gearing** different to the sample average **gearing** would require an accurate estimate of the value of the debt beta (and how it changes with **leverage**) but this is not available.	The sample average equity beta reflects the sample average **debt tenor** and its effect on the (unknown) sample average debt beta. Therefore, setting the **benchmark debt tenor** different to the sample average **debt tenor** would require an accurate estimate of the value of the debt beta (and how it changes with **debt tenor**) but this is not available.
Solution	Set the **benchmark leverage** equal to the **sample average leverage** to avoid any adjustments that require an estimate of debt beta.	Set the **benchmark debt tenor** having regard to the **sample average debt tenor** to avoid any adjustments that require an estimate of debt beta.

26. The main difference between these two problem/solution sets is that adopting the sample average gearing for New Zealand is not viable. The market for very long dated New Zealand corporate debt is not sufficiently large for even actual or hypothetical large listed New Zealand EDBs to issue an average bond tenor of 20+ years.

27. In this context, it is worth noting that Vector is the only NZ business in the NZCC asset beta sample and it has the smallest average tenor (8.7 years) reported in Figure 2-1 above. In this context it is useful to present the data in Figure 2-1 as a histogram over all maturity profiles (i.e., combine all debts for all firms in the sample before reporting the distribution of those debts).

Figure 2-2: Histogram of all debts



Source: Bloomberg and CEG analysis

28. It can be seen that there are two poles of common debt issuance maturity – one at 10 years and one at 30 years. The 30 year maturity is not a realistic option for even a hypothetical large listed New Zealand EDB to issue a large proportion of their debt at. However, maintaining a 10 year average debt tenor is a realistic option for a hypothetical large listed New Zealand EDB.

29. This would also be consistent with the practice of regulators internationally. In the US and the UK regulators set the cost of debt with respect to the observed yields on 10+ year maturity debts. In Australia, being the most similar to New Zealand in terms of access to debt funding, the AER has estimated Australian EDBs have average debt tenor of between 8 and 11 years and concludes:[4]

> *Our decision is to maintain the benchmark return on debt term at 10 years. This aligns with the debt financing practices of regulated businesses to issue long term debt. Our analysis of industry debt data also does not show clear evidence that the current benchmark of 10 years is no longer an appropriate benchmark term, or that there is a materially better alternative.*

30. We note that the AER's estimate of the average tenor of debt is, if anything, biased downwards by excluding some long dated instruments (such as callable debts) and including some instruments that are better characterised as liquidity facilities rather than debt funding. In any event, its estimate of 8 to 11 years is broadly reflective of

[4] AER, Draft Rate of Return Instrument Explanatory Statement, June 2022, p. 194.

actual practice. We also note that Australian EDBs often issue long term debt in USD (and other currencies) and swap the interest costs back into AUD. We would expect the same practice to be undertaken by the hypothetical benchmark large, listed NZ EDB.

2.1.1 Implementation of a 10 year tenor

31. If a 10-year tenor assumption was adopted then the TCSD allowance would no longer be needed. The NZCC would then have two options:

- Continue to assume that EDBs engage in an underlying swap strategy to reset the base rate of their debt portfolio to a 5 year rate at the beginning of each DPP. In this case it would need to:
  - Lengthen the number of observations for the DRP from 5 to 10 years into the past;
  - Re-estimate the DRP at 10 years rather than at 5 years;
  - Reconsider its assumed swap strategy to take into account that EDBs would need to now use a 10 year pay fixed/receive floating swap to convert a 10 year debt issue into a floating rate instrument.
- Adopt a trailing average approach to the cost of debt (as is the practice in Australian and internationally.

32. In either case it would be reasonable for the NZCC to consider and consult on imposing a transition arrangement.

33. In our view, the trailing average approach is to be preferred because it is simpler to hedge to and is more stable (which benefits both EDBs and customers).

3 Term Credit Spread Differential

3.1 Overview

34. Term Credit Spread Differential (TCSD) refers to the increase in Debt Risk Premium (DRP) as the tenor of the bond increases. This parameter is used by the NZCC to capture the additional cost of network operators of holding bonds with tenor greater than 5 years.

35. The NZCC makes a TCSD adjustment to the allowed revenue for EDBs that have outstanding debt issued with an original tenor greater than the 5 year regulatory period.

36. In the 2016 IM final decision the NZCC reported an estimate of the TCSD of 4.5-6.0 bps using its own methodology. However, the NZCC also relied on CEG's estimate of 9.5-11.0 bps. The final decision chose a value in the middle of 7.5 bps.

37. The differences in our methods, as we understand them based on the NZCC's description, were relatively small. The most material difference is that we proposed to estimate the TCSD every month of the relevant historical period and then take an average of the monthly estimates. The NZCC determined that it would break the data up into 6 monthly periods rather than monthly periods. Otherwise, we understood that our methods were very similar.

3.1.1 Inability to replicate NZCC 2016 final decision.

38. In the process of preparing this report CEG attempted to replicate the NZCC's TCSD estimate of "4,5 to 6 bps" [5] from its final decision and are unable to do so. Subsequently, the ENA requested the data underlying Figure 31 from the NZCC final decision and was supplied with the NZCC's TCSD estimate for each of the NZCC's 6 monthly estimation windows (but not the underlying data/calculations for how that estimate was arrived at). [6]

39. We have also been unable to replicate those estimates. For example, following the methodology that the NZCC set out in its 2016 Topic Paper 4, we estimate an TCSD of 11 bps for second half of 2015, and NZCC estimate is only 4 bps.[7] While there is

5 See Paragraph 909 in NZCC Input Methodologies Review Decisions – Topic paper 4 – Cost of Capital Issues, 20 December 2016

6 ENA_CEG_TCSD_Query (4502834.1).xlsx in email from Geoff Brooke to Keith Hutchinson 27 September 2022

7 ENA_CEG_TCSD_Query (4502834.1).xlsx in email from Geoff Brooke to Keith Hutchinson 27 September 2022

some uncertainty in the NZCC method, all the interpretations we that appear consistent with the NZCC description result in us estimating a TCSD of around 10bp.

40. We note that the NZCC did estimate a 6bp TCSD in their draft decision which we can replicate. However, the methodological changes agreed in the final decision[8] imply a materially higher TCSD.

3.1.2 Updated estimates

41. Our updated estimates to 2022 (using the NZCC description of its method and an updated sample of bonds) are very similar to our estimates in 2016 and our attempted replication of the NZCC method in 2016.

Table 3-1: Updated TCSD estimates*

	Excel software	R Software
Jan 2013 to June 2016	0.10%	0.11%
Jan 2013 to June 2022	0.09%	0.10%
Jan 2016 to June 2022	0.09%	0.10%
Jan 2018 to June 2022	0.10%	0.11%

* The use of NSS curve fitting applies an optimisation algorithm which can affect the result. We have tested the algorithms used within both R and Excel.

42. For completeness, we also report the result of aggregating monthly TCSD estimates which was the method we proposed in 2016 in response to the NZCC draft decision. The NZCC's response to that submission was to agree that the TCSD should be estimated as the average over multiple sub-periods rather than by pooling all data into a single period. but was to propose that 6 monthly estimates rather than monthly estimates be adopted.[9] However, in the final decision the NZCC concluded that 6 monthly estimates should be relied on because monthly estimates were prone to outliers in months with few data points.[10]

43. Table 3-2 compares the average of 6 monthly regression estimates of TCSD to the average of monthly regression estimates. In both cases we are using the last 6 years of data and using R software. It can be seen that the monthly average results in a higher estimate 0.16 vs 0.09 but that this is largely explained by two monthly

8 Para 902 to 908 of the 2016 Topic paper 4. The only way we can generate a TCSD closer to 6bp is if we include pre 2013 data – something that the NZCC explicitly agreed should not be done (see para 908 of Topic paper 4).

9 See Paragraph 902 of NZCC Input Methodologies Review Decisions – Topic paper 4 – Cost of Capital Issues, 20 December 2016

10 See Paragraph 903 of NZCC Input Methodologies Review Decisions – Topic paper 4 – Cost of Capital Issues, 20 December 2016

estimates of TCSD, between 2020 May and 2020 June, reached over 2%. Removing these two outliers results in similar estimates.

Table 3-2: Six versus one monthly TCSD estimates, R software

	6 monthly regression (NZCC)	Monthly regression (CEG)	Monthly regression (removing 2 outlier estimates)
Average TCSD from June 2016 July to 2022 June	0.091%	0.160%	0.094%

Source: Bloomberg, CEG analysis.

44. In our view, this analysis supports the Commission's decision to adopt a 6 monthly estimation period in preference to a monthly estimation period.

3.2 NZCC Methodology

3.2.1 Draft Decision

45. In NZCC's 2016 Input Methodology Draft Decision, the first step to determining the TCSD of Electricity Distribution Business is to calculate the DRP of a BBB+ 5 year bond. This is constructed using a sample of 17 BBB+ bonds issued by the following firms:[11]

- Genesis Energy,
- Mighty River Power,
- Vector,
- Meridian Energy, and
- Christchurch International Airport

46. To calculate the DRP of these bonds, the NZCC takes their yield estimates from Bloomberg and subtracts an estimate of the risk-free rate (interpolated from the yields on the nearest maturity NZ Government bonds).[12]

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11 See NZCC Input Methodologies Review – Response to NSS data request, 27 July 2016

12 NZCC first estimates the risk-free rate for each of these bonds. This is achieved using the yields of NZ government bonds with the closest maturity before and after the maturity of each of these bonds. For example, to calculate risk-free rate for a bond maturing on September 15th 2016, the NZCC would first find the closest maturing government bond before September 15th 2016 and the closest maturing

47. The next stage is to estimate the DRP for a generic 5 year BBB+ bond. The estimation uses the sample of 17 bonds covering the periods January 2010 to March 2016. Bonds with maturity of less than 1 year are dropped.[13]

48. The estimation is achieved by regressing the DRP against tenor using a functional form known as Nelson-Siegel-Svensson (NSS). NSS is a very flexible function form allowing the yield curve to have a hump and trough in the yield curve structure. For example, it allows the DRP to increase, then decrease and then increase again as the tenor increases.

49. The estimated 5 year DRP in the draft decision is 1.69%.[14] This is a single estimate that is assumed to apply for the entire 6.25 year estimation period. (It was this aspect of the draft decision that CEG was most critical of. We argued that instead of estimating a single 5-year DRP for the whole period, the NZCC should break its estimation into a series of shorter periods and estimate separate 5-year DRPs and TCSDs for each of these periods.)

50. Once the 5 year DRP is calculated using the estimated parameters, the next step is to calculate the TCSD. This is done in the following steps

- exclude bonds with a tenor of less than 5 years.[15]
- calculate the differential in tenor and DRP for each of the remaining bonds relative to the previously estimated hypothetical 5 year BBB+ bond with 1.69% DRP.
- regress differential in DRP against the differential in tenor assuming a linear function form with zero intercept.

government bond after September 15th 2016. This would be the NZ government bonds maturing on 15th April 2015 and 15th December 2017.

The next step is to calculate the risk-free rate. The risk free rate is calculated using a weighted average of the two government bonds with weight based on the differences between maturity dates. The NZ government bond with the closer maturity date will have the higher weight.

Using the daily yields of the government bonds, the daily risk-free rate with the same maturity as the BBB+ bonds is calculated. The difference between the daily yields of the BBB+ bonds and its associated daily risk-free rate is the DRP. The monthly average DRP of each BBB+ bond is calculated.

13 Paragraph 684 in NZCC Input Methodologies Review Draft Decisions – Topic paper 4 – Cost of Capital Issues, 16 June 2016

14 See NZCC Input Methodologies Review – Response to NSS data request, 27 July 2016

15 See NZCC Input-methodologies-Review-Draft-Decisions - Response-to-TCSD-data-requests,-15-July-2016

51. The estimated slope of the regression line is the TCSD and was 0.0559%(5.6bp) in the draft decision.[16]

3.2.2 NZCC adjustments in final decision

52. In NZCC's final determination, in response to comments by CEG[17], the NZCC removed bonds of firms that were 100% percent owned by the government.[18]

> *We also agree with CEG that the yields on bonds issued by companies with 100% government ownership appear to behave differently and have lower debt premiums than other equivalent bonds. Therefore, we have excluded bonds from the sample that were issued by 100% government-owned companies.*

53. The NZCC also agree that instead of estimating a single 5 year DRP and TCSD over the 6.25 year period from January 2010 to March 2016, NZCC adopted an alternative approach of estimating for every 6 months of data.[19]

> *We agree with CEG that there are some concerns with pooling across the whole sample. To account for these concerns, we have broken the full dataset into semi-annual periods to estimate spread premiums before calculating the average spread premium over the sample.*

54. In addition, NZCC estimation produced negative TCSDs in datasets prior to 2013, therefore it has focused its results from the period 2013 to 2016.[20]

> *We have focussed on the period from 2013-2016 due to some anomalously high debt premium's estimates prior to 2013 – leading to negative spread premium estimates on longer-term bonds.*

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[16] Paragraph 734 in NZCC Input Methodologies Review Draft Decisions – Topic paper 4 – Cost of Capital Issues, 16 June 2016 and NZCC Input-methodologies-Review-Draft-Decisions - Response-to-TCSD-data-requests,-15-July-2016

[17] CEG (report prepared for ENA) submission on IM review draft decisions papers "Review of the proposed TCSD calculations", 4th August 2016

[18] Paragraph 904 in NZCC Input Methodologies Review Decisions – Topic paper 4 – Cost of Capital Issues, 20 December 2016

[19] Paragraph 902 in NZCC Input Methodologies Review Decisions – Topic paper 4 – Cost of Capital Issues, 20 December 2016

[20] See Paragraph 908 in NZCC Input Methodologies Review Decisions – Topic paper 4 – Cost of Capital Issues, 20 December 2016

55. Based on these changes the NZCC final decision reported an estimated range of 4.5 to 6bps – similar or even lower than its draft decision estimate of 5.59 bps. However, the NZCC adopted a 7.5 bps estimate by giving some weight top CEG estimates.[21]

> *There is a common range between around 4.5 – 6 bps p.a. for the Commission estimates, and around 9.5 – 11 bps p.a. for the CEG slope. Giving a greater weight to the [sic] our estimates, we consider that a spread premium of 7.5 bps p.a. is a reasonable estimate.*

56. In Figure 31 of the final decision, NZCC produced two sets of estimates. One set of estimates is said to be based on NZCC's own estimate of 5 year semi-annual DRP and another set is based on what is claimed to be CEG's estimate of the 5 semi-annual year DRP.[22]

Figure 3-1: NZCC comparison of TCSD estimates

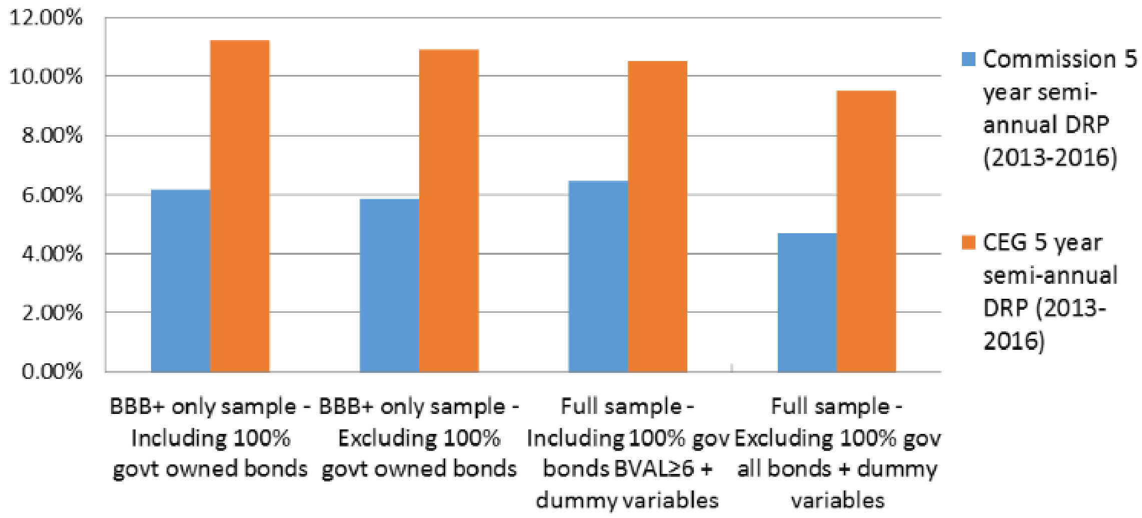

Figure 31: Comparison of spread premiums estimates using CEG and Commission estimates of the five-year debt premium. From NZCC Input Methodologies Review Decisions – Topic paper 4 – Cost of Capital Issues, 20 December 2016[23]. Note that we believe the vertical axis ought to be labelled as bps rather than %

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21 See Paragraph 909 in NZCC Input Methodologies Review Decisions – Topic paper 4 – Cost of Capital Issues, 20 December 2016

22 See also paragraph 908 in NZCC Input Methodologies Review Decisions – Topic paper 4 – Cost of Capital Issues, 20 December 2016 which refers to "comparison between spread premium estimates using the Commission and CEG's five-year debt premium estimate in regard to four different samples".

23 *Figure 31: Comparison of spread premiums estimates using CEG and Commission estimates of the five-year debt premium. From NZCC Input Methodologies Review Decisions – Topic paper 4 – Cost of Capital Issues, 20 December 2016*

57. However, there were no semi-annual 5 year DRP estimates in the CEG report.[24] The orange bars in the above figure are similar to the TCSD estimates we would derive when implementing what we understand to be the NZCC's method for estimating the TCSD. Under our understanding of the NZCC method:

- a 5 year DRP is estimated for each 6 month ("semi-annual") period (using the NSS curve); and
- a linear regression is fitted through this 5 year DRP value and the DRPs for the sample of bonds with maturity greater than 5 years in that 6 month period;
- the resulting slope is the TCSD for that period.

58. This is essentially the method from our report but applying that method over 6 monthly periods rather than over monthly periods. We should, therefore, get the same result so long as we are using the same sample (which appears to be being assumed in Figure 31). We do not understand what the methodology might be that gives rise to the blue bars in Figure 31 from the final decision.

3.2.3 Replication of final results

59. We asked the NZCC for the calculations underlying Figure 31 but were only provided with a hard-coded series 6 monthly estimates of the TCSD. We were not provided with the underlying calculations The table below presents those estimates for each semi-annual period in a NZCC response to our data request. The first and second columns of data in relate back to the first and second blue bars in Figure 31 from the final decision. The third and fourth columns of data relate to the first and second orange bars shown in the Figure 31 from the final decision.

24 CEG (report prepared for ENA) submission on IM review draft decisions papers "Review of the proposed TCSD calculations", 4th August 2016

Table 3-3: NZCC final decision TCSD estimates

	NZCC estimate based on NZCC 5 year DRP *BBB+ only sample; Including 100% govt owned bonds*	NZCC estimate based on NZCC 5 year DRP BBB+ only sample; excluding 100% govt owned bonds	NZCC estimate based on CEG 5 year DRP BBB+ only sample; Including 100% govt owned bonds	NZCC estimate based on CEG 5 year DRP BBB+ only sample; excluding 100% govt owned bonds
2013 Jan-Jun	0.01%	-0.02%	0.07%	0.07%
2013 Jul-Dec	0.04%	0.02%	0.09%	0.08%
2014 Jan-Jun	0.08%	0.03%	0.11%	0.10%
2014 Jul-Dec	0.06%	0.06%	0.10%	0.10%
2015 Jan-Jun	0.03%	0.04%	0.10%	0.10%
2015 Jul-Dec	0.04%	0.08%	0.13%	0.13%
2016 Jan-Mar	0.16%	0.13%	0.19%	0.19%
Average	0.06%	0.05%	0.11%	0.11%

ENA CEG TCSD Query (4502834.1).xlsx in email from Geoff Brooke to Keith Hutchinson 27 September 2022

60. In order to understand the large discrepancies in the estimated TCSDs between the two ranges, we have attempted to replicate the TCSD estimates produced by the NZCC.

61. We first attempt to replicate semi-annual NZCC's results which includes 100% government owned bonds because this approach has the least number of modifications from NZCC's draft decision. Then we attempt to replicate the set of results with 100% government owned bonds remove because this is the approach in which NZCC has accepted in its final decision to modify from the draft report.

62. The first column of Table 3-4 shows the TCSDs reported by the NZCC.[25] The remaining columns are replications estimated by CEG using the debt premium data provided by the NZCC in its draft decision information release.[26] The NZCC data is used to reduce the number of possible varying factors. The first set of results calculates the TCSD using bi-annual estimates of the 5 year DRP. The second set of results uses a single pooled estimate of the 5 year DRP (1.62%) using data from 2013 to 2016.[27]

[25] ENA_CEG_TCSD_Query (4502834.1).xlsx in email from Geoff Brooke to Keith Hutchinson 27 September 2022

[26] NZCC Input Methodologies Review – Response to NSS data request, 27 July 2016

[27] This is replicated by first calculating a 5 year DRP of 1.62% using all the data for the period from 2013 to 2016. Then we, in every 6 month period, place 1.62% it into cell M36 of the "Figure 23" sheet in the NZCC Input methodologies review draft decisions – Response to TCSD data requests – 15 July 2016.xlsx for each of the bi-annual periods.

Table 3-4: CEG replication of NZCC final decision (Incl 100% govt owned)

	NZCC estimate based on NZCC 5 year DRP	CEG replication of Bi-annual approach		Alternative replication assuming constant 5 year DRP	
	BBB+ only sample; Including 100% govt owned bonds	5 year DRP	TCSD	5 year DRP (2013-2016)	TCSD
2013 Jan-Jun	0.01%	1.85%	0.08%		0.15%
2013 Jul-Dec	0.04%	1.73%	0.08%		0.12%
2014 Jan-Jun	0.08%	1.75%	0.10%		0.14%
2014 Jul-Dec	0.06%	1.56%	0.09%	1.62%	0.07%
2015 Jan-Jun	0.03%	1.51%	0.09%		0.05%
2015 Jul-Dec	0.04%	1.48%	0.11%		0.04%
2016 Jan-Mar	0.16%	1.62%	0.17%		0.17%
Average	0.06%		0.10%		0.11%

CEG Analysis using data from NZCC

63. Table 3-5below shows the same comparison when bonds issued by 100% government owned firms are removed. This attempted replication has an even larger gap between our attempted replication and the estimates provided by the NZCC.

Table 3-5: CEG replication of NZCC final decision (Excl 100% govt owned)

	NZCC estimate based on NZCC 5 year DRP	CEG replication of Bi-annual approach		Alternative replication assuming constant 5 year DRP	
	BBB+ only sample; excluding 100% govt owned bonds	5 year DRP	TCSD	5 year DRP (2013-2016)	TCSD
2013 Jan-Jun	-0.02%	1.77%	0.12%		0.20%
2013 Jul-Dec	0.02%	1.74%	0.06%		0.12%
2014 Jan-Jun	0.03%	1.72%	0.09%		0.14%
2014 Jul-Dec	0.06%	1.56%	0.09%	1.58%	0.07%
2015 Jan-Jun	0.04%	1.51%	0.09%		0.05%
2015 Jul-Dec	0.08%	1.48%	0.11%		0.04%
2016 Jan-Mar	0.13%	1.62%	0.17%		0.17%
Average	0.05%		0.11%		0.11%

CEG Analysis using data from NZCC

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64. In order to clearly illustrate our method, the following describes the modifications to the NZCC published spreadsheets[28] for the draft decision that we have used to attempt to replicate the NZCC's final decision. The description below describes the attempt to replicate the results for the second half of 2015. However, we've conducted the same replication for the other bi-annal periods.

65. First, we use the NZCC Input methodologies review – Response to NSS data requests – 27 July 2016.xlsx model to generate a 5 year NSS DRP for the 2nd half of CY2015 using the "NSS – BBB+ only" sheet by:

   a. Sorting the data by column E and D;

   b. Removing all data not from the 2nd half of CY2015 (There are 60 bonds remaining in the spreadsheet after removing the bonds from other periods. The number of bonds remaining for each bi-annual period is shown in Table 3-6); and

   c. For estimates with 100% government owned bonds removed, the data are sorted by column B and additional bonds are removed:

      i. Genesis 2014 June and prior

      ii. Mercury 2013 May and prior

      iii. Meridian 2013 October and prior

   d. Rerunning the Commission's solver function to generate NSS parameters in cells L6 to L13 that are specific to 2nd half of CY2015 and which generate the new 1.48% 2nd half of CY2015 5-year DRP found in cell H67. The starting parameters of the solver are the parameters estimated by the NZCC in its draft decision.

66. When we repeat this same process in all other half year periods from January 2015 (and one quarter year period to March 2016) we have the following bonds used in each of the NZCC spreadsheets.

[28] NZCC Input Methodologies Review – Response to NSS data request, 27 July 2016 and NZCC Input-methodologies-Review-Draft-Decisions - Response-to-TCSD-data-requests,-15-July-2016

Table 3-6 Number of bonds in each bi-annual period in the NZCC spreadsheet

	Number of bonds in NSS spreadsheet		Number of bonds in TCSD spreadsheet	
	Incl 100% govt owned bonds	Excl 100% govt owned bonds	Incl 100% govt owned bonds	Excl 100% govt owned bonds
2013 Jan-Jun	68	12	38	9
2013 Jul-Dec	78	44	54	36
2014 Jan-Jun	84	54	56	38
2014 Jul-Dec	84	84	51	51
2015 Jan-Jun	76	76	36	36
2015 Jul-Dec	60	60	24	24
2016 Jan-Mar	31	31	13	13

CEG Analysis using data from NZCC

67. Returning to our 2nd half of CY2015 illustration, we the 1.48% 5 year DRP estimated value and input it into cell M36 of the "Figure 23" sheet in the NZCC Input methodologies review draft decisions – Response to TCSD data requests – 15 July 2016.xlsx. We then apply the same steps from 65.a and 65.b above to remove all data not from the 2nd half of CY2015.

68. This leaves us with a slope value in cell M38 of the "Figure 23" sheet of 11 bps per year of maturity above 5 years. This contrasts with the corresponding 4bps value in the spreadsheet provided by NZCC in the information request.[29] We note that the estimate of 11bp using the above NZCC models is similar to the 13 bps NZCC estimated based on CEG debt premium estimates.

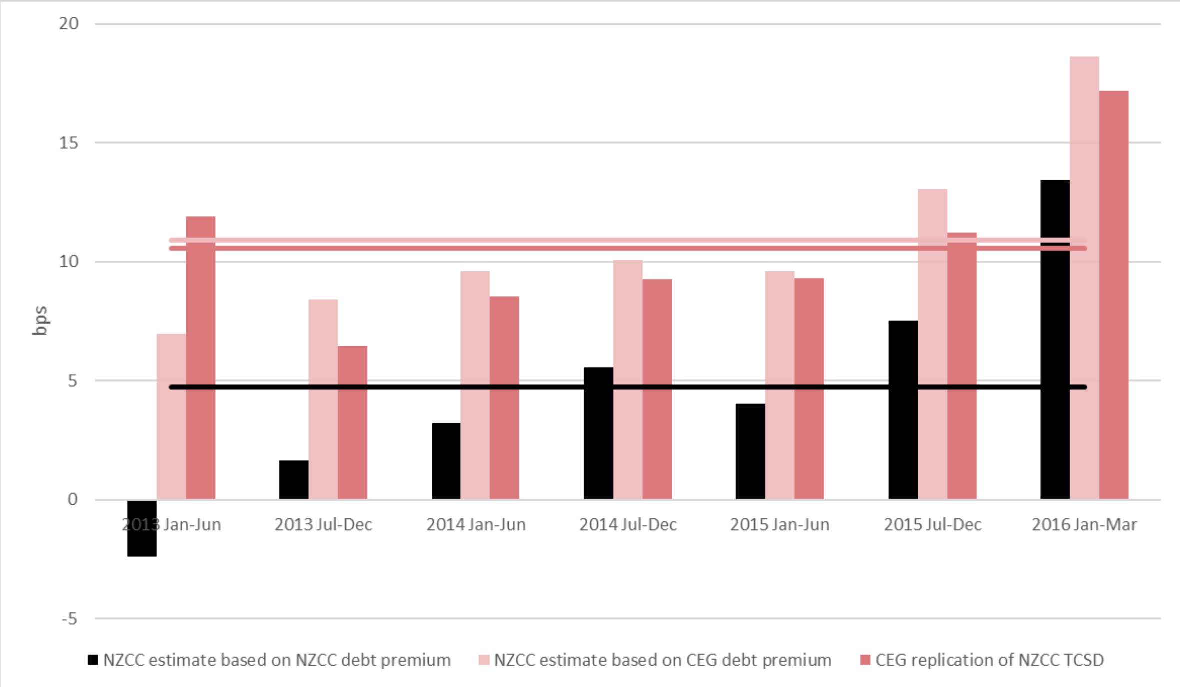
69. The results in Table 3-5 are shown graphically in the Figure 3-2 below. Figure 3-2 shows the 6 monthly NZCC TCSD estimates

- **Black bars**: that the NZCC describes as using its 5-year DRP in the 2016 final decision (sourced data provided to us following the ENA data request in this process);
- **Light pink bars**: that the NZCC describes as using CEG's 5-year DRP in the 2016 final decision (sourced data provided to us following the ENA data request in this process); and
- **Dark pink bars**: that are our attempted replication (using the method described above) of these results.

[29] cell C11 of the "Semi-annual slope results" sheet in ENA_CEG_TCSD_Query (4502834.1).xlsx in email from Geoff Brooke to Keith Hutchinson 27 September 2022. This value can also be seen in the 2015 Jan-Jun row of Table 3-4.

70. The horizontal lines are the averages for each of the three sets of results with the relevant colours matched. .

Figure 3-2: Replication comparison against estimates in final decision (BBB+ only, excl 100% govt owned bonds)



CEG Analysis using data from NZCC

3.3 Updated TCSD result to 2022

71. In this subsection, we update the TCSD results based on recent data and our best understanding of the NZCC stated methodology (noting that this fails to replicate NZCC estimates)

72. In the 2016 determination, the bond with the latest maturity is due to mature in March 2023. Therefore, the 2016 sample of bonds is no longer capable of calculating a TCSD in recent years given a tenor of 5 year is required to form the sample to calculate the TCSD. We update the sample based on the criteria set out previously by the NZCC. This results in a sample that includes all the bonds the NZCC identified in its August 2022 cost of capital update.[30]

73. However, the August 2022 update did not include a number of recently issued bonds. As a result, the three longest dated bonds in the August 2022 update sample had only

30 NZCC Cost of capital determination for disclosure year 2023 for information disclosure regulation

one bond with a maturity greater than 5 years as at June 2022. The three longest dated bonds were:

- MCYNZ 1.56 14/09/27,
- MCYNZ 2.16 29/09/26, and
- CHRINT 5.53 05/04/27

74. For our analysis we have included a number of additional bonds and, most importantly for the analysis, three additional bonds maturing in 2028 (2 from Genesis and 1 from Christchurch International Airport) and one additional bond maturing in 2030 (Mercury). The longer tenor of these bonds provides a more robust estimate of how DRP increases with tenor when the tenor is beyond 5 years.

Table 3-7: List of additional BBB+ bonds

Additional BBB+ bonds	Issue Date
GENEPO 4.17 03/14/28	14/03/2022
CHRINT 5.18 05/19/28	19/05/2022
MCYNZ 1.917 10/09/30	9/10/2020
GENEPO 1.32 07/20/22	20/07/2020
GENEPO 3.65 12/20/28	20/12/2021

75. It can be seen that with the expanded sample the estimated TCSD is relatively stable but with the sample from the NZCC's August 2022 disclosure year 2023 cost of capital update the estimated TCSD is very unstable (consistent with having very few bonds more than 5 year maturity).

Table 3-8: TCSD estimation based on NZCC stated method

	Excel software		R Software	
Estimation window	**NZCC (incomplete) August 2022 sample**	**CEG expanded sample**	**NZCC (incomplete) August 2022 sample**	**CEG expanded sample**
2010 1st Half	0.067%	0.067%	0.0347%	0.0347%
2010 2nd Half	0.052%	0.052%	0.0192%	0.0192%
2011 1st Half	-0.054%	-0.054%	-0.0552%	-0.0552%
2011 2nd Half	-0.025%	-0.025%	-0.0407%	-0.0407%
2012 1st Half	0.035%	0.035%	0.0089%	0.0089%
2012 2nd Half	0.135%	0.135%	0.1645%	0.1645%
2013 1st Half	0.064%	0.064%	0.0961%	0.0961%
2013 2nd Half	0.087%	0.087%	0.0777%	0.0777%
2014 1st Half	0.102%	0.102%	0.1131%	0.1131%
2014 2nd Half	0.096%	0.096%	0.0920%	0.0920%
2015 1st Half	0.091%	0.091%	0.0878%	0.0878%
2015 2nd Half	0.121%	0.121%	0.1146%	0.1146%
2016 1st Half	0.141%	0.144%	0.1574%	0.1610%
2016 2nd Half	0.077%	0.077%	0.0746%	0.0735%
2017 1st Half	0.066%	0.067%	0.0626%	0.0670%
2017 2nd Half	0.050%	0.049%	0.0547%	0.0456%
2018 1st Half	0.060%	0.060%	0.0560%	0.0589%
2018 2nd Half	0.107%	0.110%	0.1045%	0.1088%
2019 1st Half	0.106%	0.111%	0.0931%	0.1059%
2019 2nd Half	0.083%	0.100%	0.1299%	0.1337%
2020 1st Half	0.238%	0.204%	0.2255%	0.2131%
2020 2nd Half	0.192%	0.042%	0.1664%	0.0382%
2021 1st Half	0.025%	0.052%	-0.0249%	0.0514%
2021 2nd Half	0.009%	0.097%	-0.0387%	0.0934%
2022 1st Half	-0.139%	0.112%	-0.1426%	0.1065%
Average of last 6 years	**0.073%**	**0090%**	**0.063%**	**0.091%**

Source: Bloomberg, CEG analysis

76. In our view, sole focus should be given to the "CEG expanded sample".

77. Our updated estimates to 2022 (using the NZCC description of its method and an updated sample of bonds) are very similar to our estimates in 2016 and our attempted replication of the NZCC method in 2016.

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Table 3-9: Updated TCSD estimates*

	Excel software	R Software
Jan 2013 to June 2016	0.10%	0.11%
Jan 2013 to June 2022	0.09%	0.10%
Jan 2016 to June 2022	0.09%	0.10%
Jan 2018 to June 2022	0.10%	0.11%

* The use of NSS curve fitting applies an optimisation algorithm which can affect the result. We have tested the algorithms used within both R and Excel.

78. For completeness, we also report the result of aggregating monthly TCSD estimates which was the method we proposed in 2016 in response to the NZCC draft decision. The NZCC's response to that submission was to agree that the TCSD should be estimated as the average over multiple sub-periods rather than by pooling all data into a single period. but was to propose that 6 monthly estimates rather than monthly estimates be adopted. [31] However, in the final decision the NZCC concluded that 6 monthly estimates should be relied on because monthly estimates were prone to outliers in months with few data points. [32]

79. Table 3-2 compares the average of 6 monthly regression estimates of TCSD to the average of monthly regression estimates. In both cases we are using the last 6 years of data and using R software. It can be seen that the monthly average results in a higher estimate 0.16 vs 0.09 but that this is largely explained by two monthly estimates of TCSD, between 2020 May and 2020 June, reached over 2%. Removing these two outliers results in similar estimates.

Table 3-10: Six versus one monthly TCSD estimates, R software

	6 monthly regression	Monthly regression	Monthly regression (removing 2 outlier estimates)
Average TCSD from June 2016 July to 2022 June	0.091%	0.160%	0.094%

Source: Bloomberg, CEG analysis.

80. In our view, this analysis supports the Commission's decision to adopt a 6 monthly estimation period in preference to a monthly estimation period.

31 See Paragraph 902 of NZCC Input Methodologies Review Decisions – Topic paper 4 – Cost of Capital Issues, 20 December 2016

32 See Paragraph 903 of NZCC Input Methodologies Review Decisions – Topic paper 4 – Cost of Capital Issues, 20 December 2016

4 CPI forecasting and RAB indexation

81. At high level, there are two issues associated with the treatment of inflation in a regulatory model:

- To what extent should the model target a real versus a nominal return; and
- To the extent that the model targets a real return, and assuming the regulator starts with an estimate of returns based on observed returns on nominal bonds, how should expected inflation be estimated (i.e., what inflation value should be removed from those nominal returns to arrive at an estimate of real returns?

4.1 The mechanics of targeting a real vs nominal return

82. By way of example, if the prevailing cost of debt is 5% in nominal terms at the beginning of a DPP and a business borrows (enters into interest rate swap contracts) at this rate then the business is bound to pay its lenders (counterparties) 5%. However, the current IMs do not provide a 5% return in cash-flows. Rather the current IMs provide:

- a 5-X% return in cash-flows - where “X”% is the Commission’s forecast of inflation; plus
- a “Y”% indexation of the RAB at the time of the next DPP – where “Y”% is actual inflation.

83. The business will consequently receive actual nominal compensation that is equal to 5% plus Y%-X% - where Y%-X% is the Commission’s inflation forecast error. For example, if inflation is forecast to be 2%, but is actually 0%, then the business will only receive a nominal return of 3% - despite having nominal contracts that require it to pay 5%.

84. This inflation forecast error can be eliminated by simply setting both X and Y to be equal to zero. That is, removing revaluations for the RAB in both the Commission’s financial model and the RAB roll forward. However, this is not the only way to remove inflation forecast error. So long as the rate of revaluation provided in the RAB roll-forward is the same as that assumed in the Commission’s financial model inflation forecasting will be removed.

85. We consider that removing inflation forecasting error is unambiguously the correct approach for that portion of the RAB which is debt funded - assuming that businesses fund themselves with nominal debt. In addition, funding with nominal debt appears to be the standard practice of businesses and, therefore, can be assumed to be efficient. On this basis, we recommend that inflation forecast error should be removed from the RAB.

86. We also note that the case for eliminating inflation forecast error is more ambiguous for that portion of the RAB that is equity funded. Equity contracts do not promise either a real or a nominal return and, consequently, do not provide guidance as to what the regulatory policy should be.

4.2 The 2016 IM position

4.2.1 Targeting a real versus nominal return

87. In the 2016 IM the NZCC determined that it should target real returns for EDBs and GPBs (but nominal returns for Transpower). The reason for the different treatment of EDBs/GPBs vis-à-vis Transpower appeared to come down largely to a preference for the *status quo*. EDBs/GPBs (Transpower) were already regulated under a regime that targeted a real (nominal) return and the NZCC did not consider the potential benefits of a change outweighed the costs, including transaction costs, of a change in regime.

88. When explaining its decision not to apply the EDB/GPB regime to Transpower the NZCC stated:

> *Following submissions we decided not to introduce the annual capital charge adjustment. This is because we consider it would be an additional complication that is unlikely to result in significant benefits to suppliers or consumers in the current low inflation environment.*

89. When describing why the NZCC would not target a nominal return on debt for EDBs/GPBs (even though EDBs/GPBs cost of debt is incurred in nominal terms) the NZCC stated (emphasis added):

> *257. Our approach also exposes equity holders to some risk that they will not achieve a real return when inflation outcomes are different to forecast and the supplier has issued debt in fixed nominal terms. This is true even if our inflation forecast and the forecast inherent in the WACC are aligned. However, we consider that:*
>
> *257.1* ***over the long-term this risk is small*** *and will wash out over time if the forecast of inflation is unbiased; and*
>
> *257.2 the risk does not expose* [sic] *affect equity and debt holders collectively (ie, the total return to all capital is an ex-post real return) and suppliers can potentially manage any inflation risk to some extent through their debt-financing practices.*

And

298. An alternative potential option put forward by CEG (on behalf of the ENA) would be to apply a 'weighted average approach' in which the compensation for the cost of equity would be based on a real return and compensation for the cost of debt would be based on a nominal return.[188]

299. This approach has some attraction in that it reduces the potential for equity holders not to achieve a real return. However, we have not been convinced to introduce the weighted average approach because we consider:

299.1 ***It adds complexity to the overall approach both conceptually and in practice which is not justified by the existence of significant problems with the existing methodology****.*

299.2 We consider that pricing that remains constant in real terms over time is consistent with allocative efficiency in workably competitive markets. A change in our approach which provides compensation for debt fixed in nominal terms ***would transfer inflation risk from suppliers to consumers****. However, because debt-financing practice is in the control of suppliers we consider that it is most appropriate for suppliers to bear this risk, and be incentivised to undertake efficient financing arrangements.*

4.2.2 Estimating expected inflation

90. The 2016 IM determined that expected inflation should be estimated by using the RBNZ CPI forecast produced at the time closest to the determination window used to estimate the risk-free rate and then trend to the mid-point of the RBNZ inflation target by the end of year 5.

91. The NZCC decided that it would not give weight to measures of expected inflation derived from the difference in yields between nominal and inflation indexed NZ government bonds on the grounds that:

there are a number of issues which mean that this does not necessarily provide a more appropriate estimate of inflation than the RBNZ forecasts. For example:

294.1 The shortest dated NZ government inflation-linked bond matures in 2025. Therefore any implied inflation would be an average over the period until the bond matures and would not necessarily correspond to the five-year regulatory period;

294.2 *Yields on nominal government bonds can include a premium for bearing inflation risk which can distort the implied inflation forecast; and*

294.3 *Yields on CPI-indexed government bonds can include a liquidity premium, given the relative scarcity of this type of bonds. This can distort the implied inflation forecast.*

4.3 Evidence since 2016 relevant to the NZCC decisions

92. In this section we examine evidence on the magnitude of inflation forecast error since 2016. This evidence shows larger inflation forecast errors since 2016 than pre-2016. The NZCC may wish to recalibrate its assessment that the existing methodology creates only "small" inflation forecast risks. We also critique the belief expressed in the above quote that targeting a nominal cost of debt transfers inflation risk from suppliers to consumers.

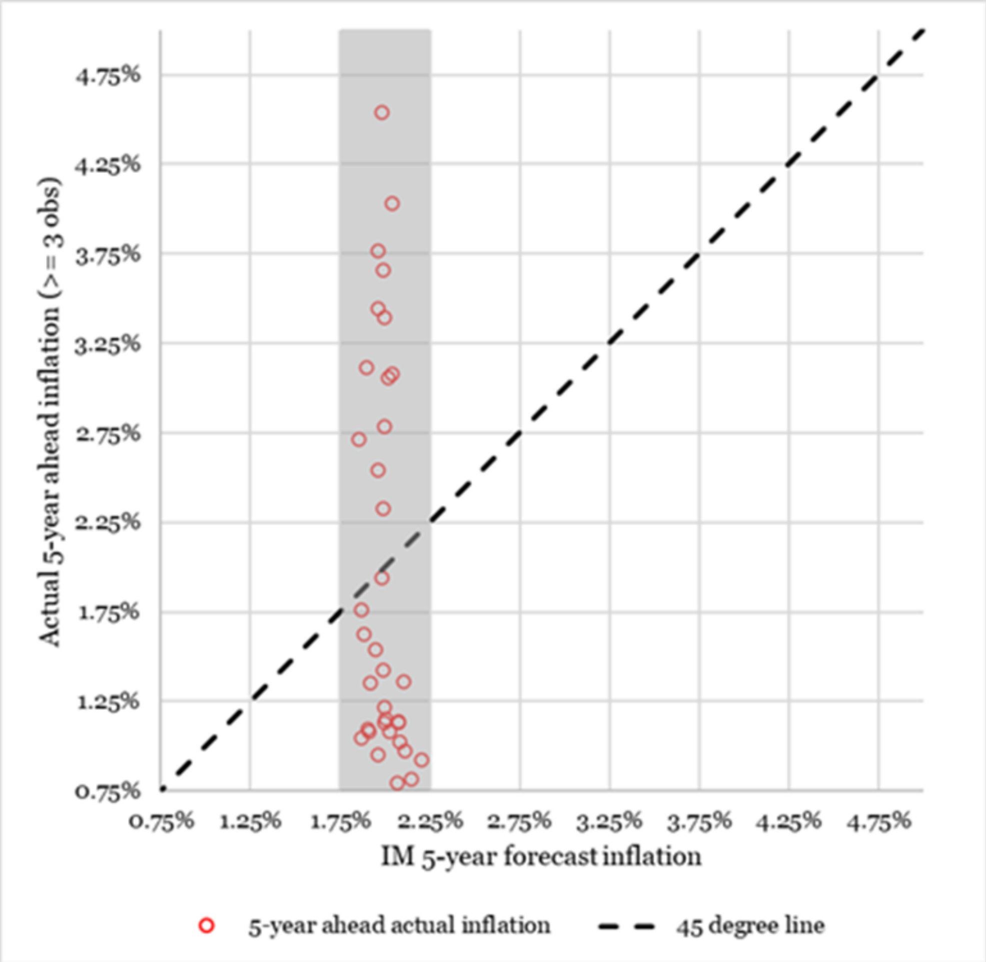
4.3.1 Accuracy of the NZCC inflation forecast method

93. In the 2016 IM process the NZCC expressed the view that inflation forecasting error was relatively small and would tend to "wash out" if it was unbiased. However, recent experienced tends not to support such a conclusion. In summary, the NZCC five year inflation forecasts have:

- Either
  - wildly overestimated actual inflation; or
  - wildly underestimated actual inflation; but
- almost never accurately estimated actual inflation.

94. This is illustrated in Figure 4-1 below. This figure shows the NZCC's 5 year forecast inflation on the horizontal axis and actual 5 year inflation (over the same forecast period) on the vertical axis. If forecast inflation was accurate then the "red dots" would be spread up and down the dotted 45 degree line.

Figure 4-1: NZCC forecast vs actual 5 year inflation since 2010

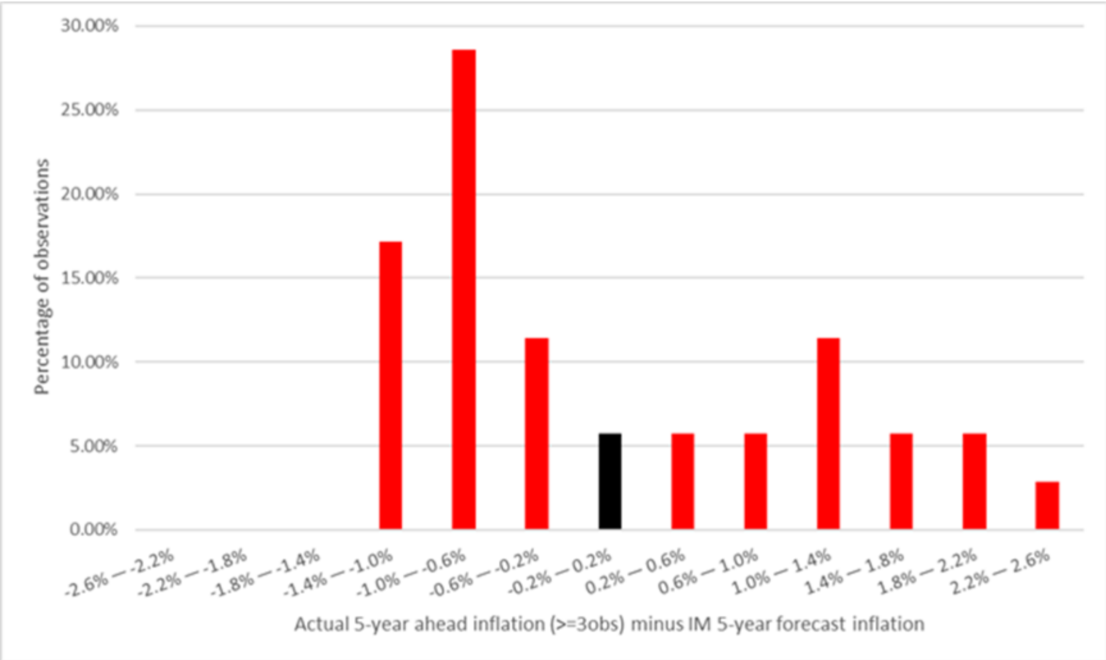


Source: NZCC forecast methodology, RBNZ quarterly inflation forecasts, CEG analysis.

95. It can be seen that the NZCC 5 year forecast is universally (100%) within a narrow band of 1.75% to 2.25%. By contrast, actual inflation is only twice (5.6%) within that narrow band and, instead, is spread relatively evenly from 0.75% to 4.75%.

96. Consistent with this, a histogram of forecast errors shows that not only is the distribution not bell shaped, it is, if anything, more heavily weighted to the extremes. This histogram is provided in Figure 4-2 below.

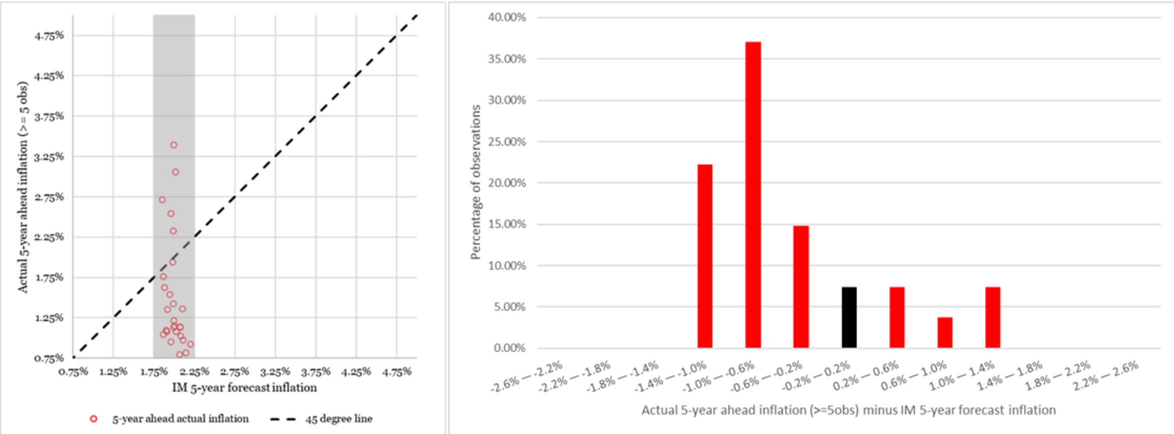
Figure 4-2: Histogram of forecast errors



Source: NZCC forecast methodology, RBNZ quarterly inflation forecasts, CEG analysis.

97. The latest actual inflation is to June 2022. In the above analysis we require that at least 3 years of actual inflation be available – which means our forecasts stop at June 2019. For forecasts made between June 2017 and June 2019 we assume that actual inflation beyond June 2022 will match the latest (August 2022) RBNZ forecast. However, a very similar outcome results when we require that 100% of actual inflation must be available (which means all forecasts stop in June 2017). This can be seen in

Figure 4-3: Figure 4-1 and Figure 4-2 with forecasts stopping in 2017



Source: NZCC forecast methodology, RBNZ quarterly inflation forecasts, CEG analysis.

98. The experience of actual inflation since 2016 is clearly inconsistent with any view that inflation forecast error is likely to be small – which was the NZCC view in 2016.

99. We now turn to the NZCC's 2016 IM view that forecast errors "will wash out over time" provided that the forecast of inflation is unbiased. In what follows we focus on the fact when the NZCC over-estimates inflation this means that customers end up undercompensating EDBs for their nominal debt costs and *vice versa*. That is, when we talk about "under" and "over" compensation for costs we are focussed on the cost of debt – which all parties agree is efficiently incurred in nominal terms.

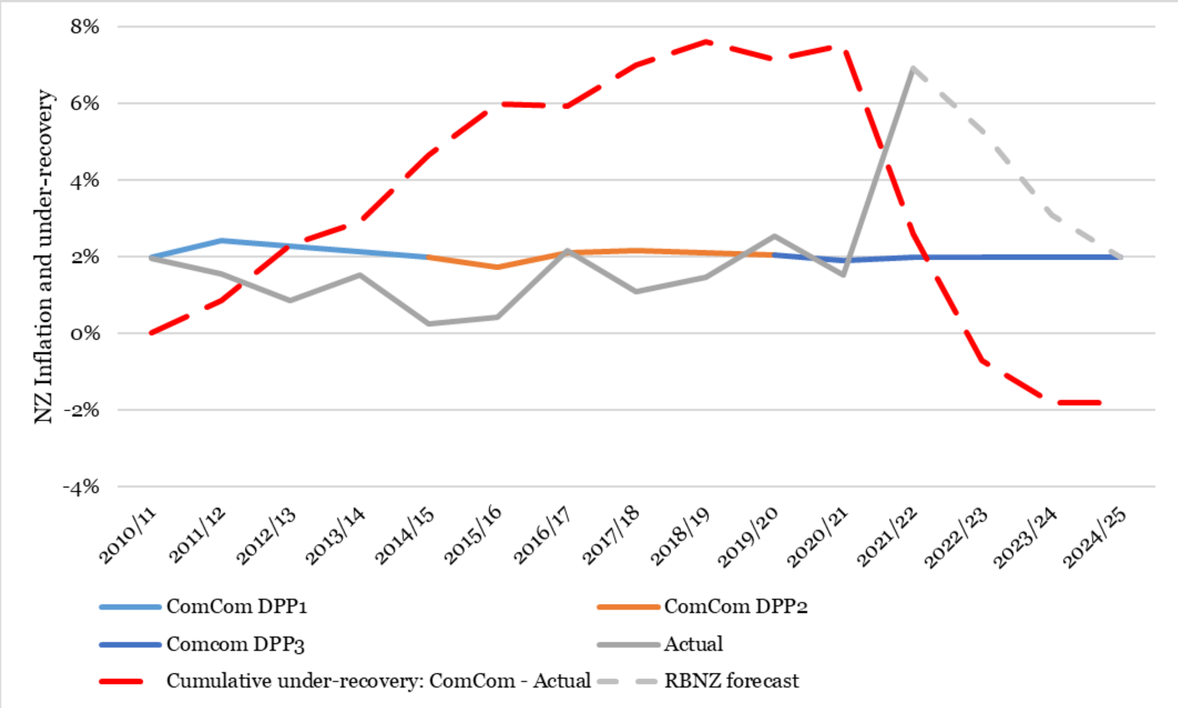
100. First, the statement that forecast errors "wash out" in the long run can only ever be true the period of "time" being referred to is the very long run. This is because the NZCC only makes one forecast every 5 years. Thus, after 50 years there will only be 10 sets of forecasts to average over. Even if the NZCC forecast is unbiased with no autocorrelation with previous forecast errors, it will still take many decades before the law of large numbers takes effect and one can confidently talk about errors "washing out". For many customers/investors this would not be expected to occur over their remaining life/investment horizon.

101. As it happens, when looked at over the last 15 years from 2010 to 2025 (DPP1 to DPP3) there has been an approximate "wash out" with:

- very large cumulative under-recovery of inflation for EDBs (over-recovery for customers) over the 10 years to 2020-21 has been almost fully offset by:
- a single year of very high over-recovery of inflation for EDBs (under-recovery for customers) in 2021-22; and
- current forecasts until the end of DPP3 in 2024-25 imply more material over-recovery for EDBs such that over 15 years they can expect to have substantially over-recovered actual inflation (without adjusting for discounting or changes in RAB).

102. This can be seen in Figure 4-4 below.

Figure 4-4: Cumulative forecast error over DPP1 to DPP3



Source, RBNZ, NZCC and CEG analysis

103. Figure 4-4 shows forecast CPI used by the NZCC (colour coded by DPP) and actual inflation (grey line) extended out to 2024-25 by the current RBNZ forecasts (4.5% to June 2023, 2.64% to June 2024 and 1.93% to June 2025). The dotted red line is the sum of the difference between NZCC forecasts and actual CPI over past years. (Geometrically, the height of the dotted red line is the area between the NZCC forecast and actual inflation series over past years).

104. The path of the dotted red line illustrates how easy it can be for forecast errors to accumulate over time. Over the 10 years to 2020/21 the cumulative forecast error was over 7% (implying that debt costs during that period went uncompensated by over 7% of the debt portion of the RAB). As it happens this period is likely to be followed by massive overcompensation for debt costs in DPP3 which is expected to more than fully reverse the previous 10 years forecast errors.

105. However, rather than providing comfort that the current regime can be assumed to inevitably result in forecast errors "washing out" the opposite lesson can be drawn. If DPP3 looked more like DPP2 and DPP1 (which could easily have occurred if the forecasts are unbiased) then cumulative under-compensation would be over 10%. If DPP4 and DPP5 look like DPP3 then customers will overcompensate EDBs by more than 20% of the debt portion of the RAB.

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4.3.2 The current regime does not protect customers from inflation risk

106. If there was a good economic reason for exposing customers and EDBs to this risk then that would be one thing. However, other than preserving the *status quo*, there is no good reason for exposing customers and EDBs to inflation forecasting error on the cost of debt. That is, there is no reason to target a real return on debt when it is universally agreed that debt is efficiently incurred as a nominal cost.

107. As noted above, in the 2016 IMs the NZCC did proffer one reason (apart from *status quo* bias) for why the regulatory regime should target a real return on debt. This was that targeting a nominal cost of debt woul*d "would transfer inflation risk from suppliers to consumers".*

108. We do not consider that this is correct. The only economically correct conclusion is that targeting a nominal cost of debt eliminates risk that is otherwise borne by both consumers and EDBs. That is, targeting a real cost of debt when debt costs are not incurred in real terms creates risk for all stakeholders – where risk is defined in terms of whether customers pay (EDBs receive) an amount different to efficiently incurred costs.

109. Over, DPP3 customers are expected to over-compensate EDBs by almost 10% of the debt portion of the RAB. Moreover, this is occurring when (and precisely because) their daily expenses are running at a much higher rate than previously expected. It is difficult to understand how such a regime is protecting customers from "inflation risk".

110. In truth, the current treatment of debt costs is creating inflation risk for both EDBs and customers. Changing the regime from targeting real to nominal debt costs would eliminate this risk for both parties (not transfer it from one to the other).

111. This is no different from if the NZCC set regulatory revenues in USD rather than in NZD. This would create currency risk for EDBs and customers. Changing the regulatory regime to target NZD costs instead of USD would not "transfer" currency risk from suppliers to consumers – it would eliminate currency risk for all stakeholders. That is, it would eliminate an artificially created currency risk – one that only existed because the regulatory regime incorrectly targeted compensation in a form that was not tied to efficient costs.

4.4 Correct measure of forecast inflation

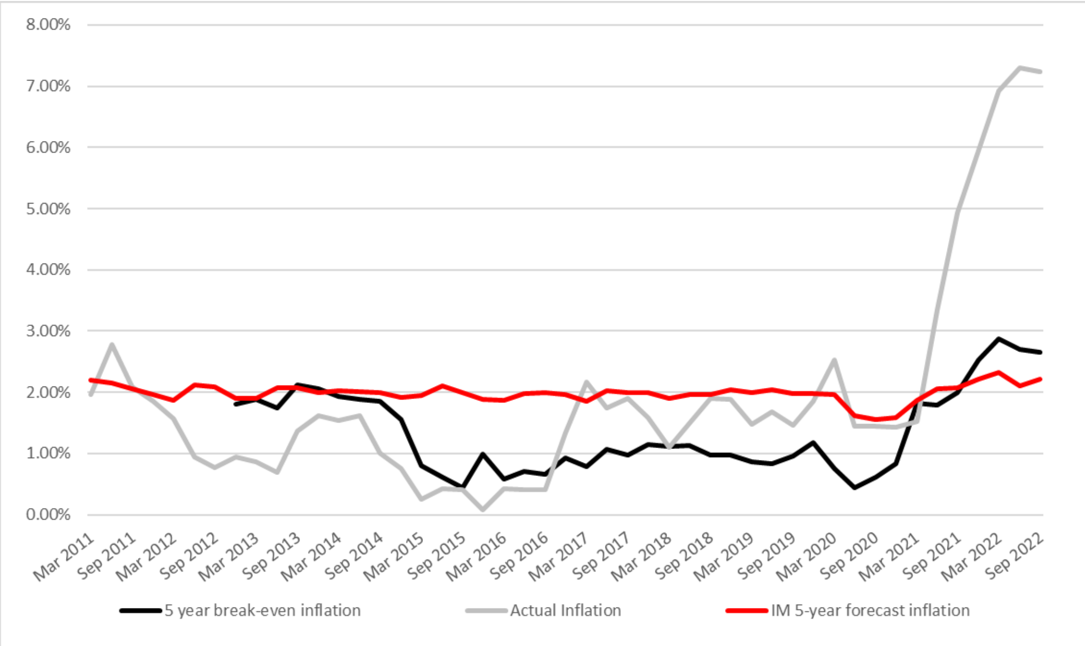
112. The assumption in the IMs that inflation will return to the midpoint of the RBNZs target range over the short term is at odds with the evidence surveyed above. Since the global financial crisis, actual inflation in developed countries have been below central bank targets until the post Covid period when it has been materially above target.

113. Market-based estimates of expected inflation derived from the difference between the yield on nominal and inflation indexed debt issued by the New Zealand Government provide an alternative to the NZCC mechanically assuming inflation always is expected to trend to 2% beyond the RBNZ forecast period. .

114. This difference is a measure of investors' inflation expectations because, if investors believed that inflation would be higher/lower than this difference, they would rationally sell/buy nominal debt and buy/sell inflation indexed debt. For this reason, the difference between nominal and CPI indexed debt is known as the 'break even' inflation rate - the rate at which there is no difference between a strategy of holding nominal as opposed to CPI indexed debt.

115. Pre Covid, 5-year break-even inflation rates were well below the mid-point of central bank target ranges globally, and New Zealand was no exception. This was a more accurate predictor of actual inflation which was also below the midpoint of central bank targets. Post Covid, 5-year break-even inflation responded more aggressively to the high inflation outbreak than did the NZCC method for forecasting 5 year inflation and now sits above the forecast from the NZCC method. This is illustrated in Figure 4-5 below.

Figure 4-5: Break even inflation vs midpoint of RBNZ target range



Source: RBNZ hb2 daily publication, CEG analysis.

116. This evidence is not conclusive because, ultimately, we do not know what inflation expectations investors have (and nor do we know what actual inflation will be over the next 5 years). However, it is at least *prima facie* evidence that some weight should be given to break-even inflation (noting that an average to the two series would more accurately have predicted pre Covid inflation than either series alone).

117. In the 2016 IM's the NZCC argued that:

> *294.1 The shortest dated NZ government inflation-linked bond matures in 2025. Therefore any implied inflation would be an average over the period until the bond matures and would not necessarily correspond to the five-year regulatory period;*

118. However, there is currently four inflation indexed NZ government bonds (maturing in 2030, 2035 and 2045). This means that in 2025, at the time of the DPP4 reset, there will be an approximately 5 year maturity bond as will be the case at the DPP5 reset. The above argument against giving any weight to breakeven inflation falls away.

119. The NZCC has also argued that breakeven inflation might be biased by other factors (such an illiquidity premium in inflation indexed bonds and an inflation premium in nominal bonds). This may be true but there is no theoretical reason to believe that the net effect of these results in a material net expected bias (noting that the former would increase indexed yields and the latter would increase nominal yields).

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5 Amortisation of issuance costs

120. We consider that the NZCC has made an error which lowers compensation for debt transaction costs by around 0.5bp (assuming a 5 year tenor and a 5% discount rate).

121. While minor, the 2016 IM final decision made what is, effectively, a mathematical error which should be simple to clarify and correct. In the final Topic 4 paper the NZCC states:

> *Amortisation of upfront costs*
>
> *CEG submitted that upfront debt costs need to be amortised over time using a cost 241.of capital to take into account the time value of money.*
>
> *We disagree with this conclusion because suppliers typically issue some debt each year to manage refinancing risk. They therefore incur some debt issuance costs each year. Assuming that firms issue a consistent amount each year with similar costs, there is no need for a present value adjustment in respect of a portfolio of debt.*

122. In this passage the NZCC's correctly noting that:

- a firm operating a trailing average debt 5-year tenor strategy will refinance 20% of total debt each year;
- every year it will incur 20% of the total transaction costs associated with raising its entire debt RAB; and
- if the NZCC simply provides an ongoing annual allowance for 20% of the total transaction costs associated with raising its entire debt RAB then the allowance will fully cover ongoing debt issuance costs.

123. This is mathematically correct (assuming a constant value for the RAB). However, it does not follow that this means no NPV adjustment is required. If the NZCC were correct it would imply that in a competitive market there is no need for a firm to earn a return on its investment in inventory (no holding cost of inventory).

124. To see why, imagine a firm that is importing $1m of product every year and selling it with an average one year lag. In effect, in every year the firm is selling stock imported the previous year and then replenishing those sales with new imports.

125. The Commissions logic would imply that, so long as that firm's price is covering its costs of importing the product in that year it is being fully compensated. This is clearly wrong; the firm needs to recover its costs of importing in the previous year *plus* the time value of money (and any other holding costs) over the time since it imported the stock it is selling.

126. In our context, we can think of the entire debt RAB as the inventory of debt that is being used up (maturing) and replenished (refinanced) at a rate of 20% per year. The NZCC's proposal to only compensate for the costs of new debt as it is incurred amounts to, in effect, refusing compensate for the costs of prior building and holding of that debt inventory.

127. Put another way, it amounts to taking the money allocated to compensate for past costs and using it to fund current costs. It is true that this will "adequately" compensate for current costs but it does so by leaving past costs completely uncompensated. That is, if the NZCC hypothecates each year's total debt issuance compensation to the debt that has just been raised in that year (being one fifth of the RAB) then that leaves the other four fifths of the RAB uncompensated. That is, at any given time there is an "inventory" of old debt raising costs that is uncompensated.

6 Equity Raising Cost

128. Equity raising costs are transaction costs incurred when EDBs fund capital investment through equity. According to the AER when it first applied equity raising cost in 2009:[33]

> *In raising new equity capital a business may incur costs such as legal fees, brokerage fees, marketing costs and other transaction costs. These are upfront expenses, with little or no ongoing costs over the life of the equity. Whilst the size of the equity a firm will raise is typically at its inception, there may be points in the life of a firm—for example, during capital expansions—where it chooses additional external equity funding (instead of debt or internal funding) as a source of equity capital, and accordingly may incur equity raising costs.*
>
> *The AER has accepted that equity raising costs are a legitimate cost for a benchmark efficient firm only where external equity funding is the least–cost option available.*

129. CEG has implemented an equity raising cost model based on the AER's current approach[34] to equity raising costs within the context of the NZCC financial model. The AER's current approach was formulated as part of its own revenue model to provide transparency and consistency.[35]

130. If applied in the current DPP period we estimate the following equity raising costs would have been estimated.

Table 6-1: Equity raising costs associated with AER method aggregated over 2021-2025 ($thousands, real 2019/20)

	Aurora	Orion	Unison	Vector	Wellington
Total Equity Raising Cost	628	1,141	402	2,003	126

Powerco not available due to lack of data on Powerco capex in the NZCC financial model.

131. In order to fund its capital expenditure, the first option for an EDB is to fund the equity portion of RAB growth utilising retained earnings but with increases in

33 AER TransGrid transmission determination 2009-10 to 2013-14, Final decision 28 April 2009

34 Page 90 in AER, "Electricity Distribution Network Service Provider – Post-Tax Revenue Model, Version 4, April 2019

35 Page 5 in AER, "Electricity transmission network service providers, Post-tax revenue model - Amendment - Final Decision," December 2010

retained earnings constrained by the need to maintain a minimum rate of dividend payout to shareholders (assumed by the AER to be 63% of taxable profit).

132. This source of funding is assumed to be costless by the AER. However, if this source of equity raising is exhausted, the EDB has the option of either:

- seeking reinvestment of dividends from its existing equity holders using a "dividend reinvestment program" often referred to as a DRP. The AER assumes that up to 30% of dividend is available for reinvestment and that the cost of this option is 1% of the size of the amount reinvested ("Dividend Reduction").
- seek new equity investors via what is known as a "seasoned equity offer" (or "SEO" - which simply distinguishes equity raising for an existing listed firm from the initial public offering for a newly listed firm). The AER assumes that the cost of an SEO is 3% of the amount of equity raised.

133. The AER assumes that higher cost funding is only relied on once the available lower cost funding is exhausted.

6.1 Methodology

134. This section demonstrates how the equity raising cost are calculated by us within the NZCC's existing financial model.[36]

135. Whenever the RAB grows equity must grow in proportion to the RAB in order to maintain the NZCC target gearing. Some of this growth in equity can be funded at zero cost via retained earnings. However, beyond some point costly forms of equity raising must be undertaken. Namely:

- dividend reinvestment program (DRP) – incentives are provided to existing equity holders to reinvest some of the dividend paid out to fund capital expenditure; and
- seasoned equity offerings (SEOs) – in which fresh equity are sought publicly from potential investors.

6.1.1 Estimating maximum retained earnings available

136. The first step is to calculate the minimum dividend payout for each year of the regulatory period and the amount of profit that is available to be retained. The minimum dividend payout is calculated based on a percentage of taxable income (loss).

[36] NZCC Electricity Distribution Business Price-Quality Regulation 1 April 2020 DPP Reset Financial model Final Determination, 27 November 2019

137. The model sets a normal distribution rate and assumes it is costless for firms to lower dividends down to that level. We have adopted a 63% of taxable profit, based on AER assumption[37], as the minimum dividend payout ratio. This is approximately equal to 65% to 80% of post-tax profit.[38] This range is reasonable based on a survey of industry averages. According to Damodaran, its survey of "General Utilities" industries in US finds the average dividend payout ratio to be 81%.[39] It also finds the dividend payout ratio for "Power" related industries to be 82%.

138. The next step is to calculate the retained cashflow available to the network operator in each year of the regulatory period after its dividend payout.

139. Retained Cashflow of the network operator is calculated as follows

$$\begin{aligned} & Retained\ Cash - flow \\ & \qquad = Revenue - Opex - Interest\ Payment - Tax\ Payable - Dividend \end{aligned}$$

The data for revenue, opex, interest payment and tax payable are obtained from NZCC's existing financial model.

140. Retained Cash-flow is assumed to be costless for the EDB to use to fund its capital expenditure.

6.1.2 Estimating the equity raising requirement

141. The next step is to calculate the equity funding required.

142. Capex Funding Requirement is the amount of capex expenditure forecasted by EDB according to the NZ financial model.[40]. The Capex Funding Requirement is funded through two sources, Debt Component and Equity Component. Debt Component is calculated following the AER approach:

$$Debt\ Component = (Closing\ RAB - Opening\ RAB) * Leverage$$

143. Equity Component is the remaining value of Capex Funding Requirement that is not funded through Debt Component. This methodology ensures that the network operator maintains its leverage of 42% in its regulatory asset base while its capex funding requirements are met.

144. Retained Cash Flow for each year in the regulatory period is used as the first option to fund the equity component. This option is assumed to be costless. The remaining

37 See AER Electricity post-tax revenue models (transmission and distribution – April 2021 amendment.

38 The range for Aurora, Orion, Unison, Vector and Wellington.

39 https://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/divfund.htm

40 Discounted by 6 months using the vanilla WACC

amount is the unfunded component of the Equity Component. This is component is called Equity Required.

145. The Equity Required component is aggregated over the 5 year regulatory period after discounting. By aggregating the Equity Required across the 5 years, the cost of equity raising is reduced because it implies that the capex in one of the years of the regulatory period can be funded using the retained cash flow from the other years in the same regulatory period. (Implicitly this assumes a temporary deviation from the target gearing is occurring.)

146. Table 6-2 below illustrate the cash flow analysis for the 5 largest network operators for the years from 2020/21 to 2024/25. Explanation of the table is provided as follows:

- Dividend at Assumed Payout Ratio show the amount of dividend each operator pays at the 63% dividend payout ratio of its taxable income.
- Dividend Reinvested Available shows the maximum amount of dividend that is available for reinvestment (assumed to be 30% of dividend).
- Capex Funding Requirement shows the amount of capex forecasted by the network operator. Debt component is assumed to be 42% of the growth in RAB (based on NZCC leverage assumption). The remaining component is assumed to be funded through equity.
- Retained Cashflow Available for Reinvestment under Regular Payout Ratio shows the retained cashflow available to the network operator assuming the operator pays out dividend at the regular payout ratio of 63% of earning.
- Equity Required shows the amount of equity required to be funded through some of the equity raising approaches: dividend reduction, dividend reinvestment and equity offering.

Table 6-2: Cash flow analysis for equity raising cost aggregated over 2021-2025 ($thousands, real 2019/20)

	Aurora	Orion	Unison	Vector	Wellington
Dividend at Assumed Payout Ratio	57,532	143,566	72,605	373,779	75,734
Dividend Reinvested Available	17,260	43,070	21,781	112,134	22,720
Capex Funding Requirement	199,796	332,590	209,793	892,929	164,829
Debt Component	64,751	90,062	45,306	235,282	35,861
Equity Component	135,045	242,528	164,487	657,647	128,967
Retained Cashflow Available for Reinvestment under Assumed Payout Ratio	94,992	163,932	133,507	501,428	116,362
Equity Required	40,053	78,596	30,980	156,219	12,605

Value for Powerco not available due to lack of data on Powerco capex in the NZCC financial model.

6.1.3 Estimating equity raising costs

147. Table 6-3 below illustrates the equity raising cost calculation for the 5 largest network operators for the years from 2020/21 to 2024/25. Explanation of the table is provided as follows:

- Equity Component of Capex shows the portion of network operators' capex forecast that is funded through equity (based on 42% leverage assumption).
- Retained Cashflow Available for Reinvestment under Assumed Payout Ratio shows the retained cashflow available to the network operator assuming the operator payouts dividend at the ratio of 63% of its taxable income
- Equity Required shows the amount of equity required to be funded through some of the equity raising approaches: dividend reduction, dividend reinvestment and equity offering.
- The rows Dividend Reinvestment and Equity Offering shows the amount of equity required raised through each of the three channels.
- The next two rows show the cost of equity raising associated with each of the two channels.
- The last row shows the total equity raising cost.

Table 6-3: Equity raising cost aggregated over 2021-2025 ($thousands, real 2019/20)

	Aurora	Orion	Unison	Vector	Wellington
Equity Component of Capex	135,045	242,528	164,487	657,647	128,967
Retained Cashflow Available for Investment at Assumed Payout Ratio	94,992	163,932	133,507	501,428	116,362
Equity Required	40,053	78,596	30,980	156,219	12,605
Dividend Reinvestment	17,260	43,070	21,781	112,134	12,605
Equity Offering	22,794	35,526	9,199	44,085	-
Cost of Dividend Reinvestment	173	431	218	1,121	126
Cost of Equity Offering	456	711	184	882	-
Total Equity Raising Cost	628	1,141	402	2,003	126

Powerco not available due to lack of data on Powerco capex in the NZCC financial model.

NERA
ECONOMIC CONSULTING

Financeability considerations under the DPP

Electricity Networks Association

16 January 2023

Project Team

Will Taylor, PhD
Kate Eyre
Asahi Koizumi

NERA Economic Consulting
Level 11
15 Customs Street West
Auckland 1010
New Zealand
+64 9 328 9232
www.nera.com

Contents

1. Introduction and summary

1. The Electricity Networks Association (ENA) has commissioned NERA Economic Consulting (NERA) to review the desirability of introducing an explicit role for financeability or alternatives into the regulatory framework for regulated energy networks and considering the potential for future implementation.
2. The term "financeability" refers to a business's ability to raise sufficient capital to meet its requirements and deliver its operations and its programme of capital expenditure. A business is said to be "financeable" if it can raise sufficient capital to continue to operate, and "unfinanceable" if it may not. The ability to raise capital depends on the business's ability to earn sufficient revenue to cover its operating costs, its debt interest payments, and retain sufficient profit to attract equity investors. Businesses that are not financeable will ultimately face financial distress, which will disrupt services to their customers and effect their ability to invest. Ensuring Electricity Distribution Businesses (EDBs) are financeable is therefore in the long-term interest of consumers.
3. In most industries, market forces in the market for the goods and services it sells determine the financeability of a business. For 'natural monopolies', such as EDBs, where competition is impractical, economic regulators determine the revenues businesses may earn over a given price control period. Accordingly, the financeability of EDBs in practice is at least partly due to regulatory decision-making. The financeability of the regulator's view of an efficient EDB is entirely due to regulatory decision-making (at least given information available at the time the decision was made). If the regulator sets cost allowances in line with those of an efficient EDB, and a rate of return that is sufficient to provide the market rate of return required by debt and equity holders for the profile of recovered revenues, efficient EDBs will be financeable.
4. Financeability concerns in regulatory determinations stem largely from several considerations under the price control method that apply to both New Zealand and countries where some regulators have already adopted financeability testing such as the UK and Australia:
    a. **Uses benchmark costs of debt**: New Zealand Commerce Commission (NZCC) like the UK and Australia uses benchmark cost of debt instead of passing through actual debt costs. As a result, efficient EDBs whose profile of embedded debt does not precisely match the benchmark index may be non-financeable, even if they procured that debt on efficient and competitive terms at the time of issuance;
    b. **Inflation indexation of the RAB:** Like the UK and Australia, NZCC also indexes the regulated asset base (RAB) for inflation so that the allowable revenue set for EDBs returns a real rate of return. However, the indexation defers the recovery of investments and reduces short term cash-flows relative to if the RAB is not indexed for inflation, resulting in a higher risk of financeability issues. When RAB indexation is combined with nominal debt-issuance, it can be more prone to financeability problems because companies earn a real cost of debt in their revenue building blocks but face nominal debt repayments;
    c. **Adoption of incentive regulation**: NZCC operates under an incentive regulation rather than a cost pass-through regime. As a result, EDBs are exposed to risk around differences between the level of allowances and outturn costs, which can put the financeability of EDBs at risk;
5. The following specific features of the NZ regime could also potentially lead to financeability concerns:
    a. **Use of alternative X-factors:** In order to smooth any large price increases across default price-quality path (DPPs), the NZCC can choose to set an alternative rate of change for some distributors, which will backload cash recovery and risk distributors failing the financeability test in earlier periods of the DPP. While there are no distributors that face an alternative X-factor in the current DPP, this could become a serious consideration in future DPP

determinations as New Zealand works towards decarbonisation. Decarbonisation will lead to large capex and thus allowable revenue will be likely to significantly increase in the upcoming DPPs, resulting in NZCC considering applying an alternative rate of change for a number of distributors.

b. **10% intra-period cap on gross allowable revenue:** Currently for DPP3, NZCC sets a default 10% intra-period cap on the percentage increase of each distributor's gross allowable revenue (or maximum allowable revenue (MAR)). The limit works in a present value-neutral way, with any under-recovery of revenue deferred to subsequent years of the DPP (or until the next DPP) via the wash-up mechanism. [1] Since the 10% limit applies to a distributor's gross allowable revenue which includes pass-through and recoverable costs, when there is an increase in these costs during a period, EDBs cannot recover their entire costs, as much of their allowable revenue will be used to cover their pass-through and recoverable costs which back-loads the cash recovery and again puts pressure on the financeability of the distributor in earlier periods.

6. In addition, the following environmental factors have the potential to lead to financeability concerns for EDBs, given the way the regime in NZ functions:

   a. **High inflation**: because the RAB is indexed, high forecast inflation has the effect of backloading recovery.

   b. **Low interest rates**: lower interest rates flow through to a lower regulatory cost of equity which leaves less residual cash flow to service debt.

   c. **Increased capex needs:** the need to increase investment to support decarbonisation will have the effect of making the RAB "newer", which given the backloaded recovery profile of an indexed RAB, may result in financeability concerns.

7. We have demonstrated many of the preceding points in the body of this report using a stylised calculation of the financial ratios for a notional distributor over DPP3 (specifically, we have averaged all the inputs to the DPP3 financial model to create the notional distributor). The purpose of this is not to prove that a financeability problem currently exists for EDBs in New Zealand, rather it is to show that financeability concerns *could* exist given the regulatory framework and operating environment for EDBs. Financeability is thus something the NZCC should keep an eye on.

8. Our recommendations are therefore as follows:

   a. **The NZCC should implement financeability testing** as the benefits to consumers of implementing financeability testing outweigh the costs. In particular, the costs are trivial as the NZCC already has the information needed to calculate the core financial ratios used by Moody's and S&P (we have done so using the NZCC's financial models as part of preparing this report).

   b. **Testing should focus on the benchmark efficient firm** represented by the NZCC's financial models, as this ensures the NZCC's decisions are internally consistent and focuses the financeability conversation on the levers that the NZCC controls.

   c. **Financeability testing should occur during the periodic Input Methodologies (IM) reviews and the DPP resets**, as these are the points in time when the NZCC makes decisions that may impact financeability.

   d. **A financeability test should focus on quantitative metrics used by credit agencies**. The test could more generally replicate the rating methodology used by credit rating agencies,

[1] NZCC, Default price-quality paths for electricity distribution businesses from 1 April 2020, Final decision reasons paper. November 2019, para 6.23-6.24.

though this would require the NZCC to make assumptions regarding the qualitative factors that credit rating agencies take into account.

e. **Any remedies should map to the underlying problem.** In particular, regulatory errors should not be addressed by front loading recovery and vice versa. Recovery can be brought forward by un-indexing the RAB (as the NZCC had once for Transpower) or directly accelerating depreciation.

f. **The intra-period cap on MAR changes should be set consistent with forecast inflation and any alternative X factors.** If an internally consistent approach to these parameters is not taken, then the intra-period MAR cap will bind and trigger a wash-up, deferring recovery which could worsen financeability.

g. **The NZCC should consider changing the intra-period MAR cap to exclude pass-through and recoverable costs**. At present, the intra period MAR cap applies to total allowable revenue. Therefore, changes in recoverable costs during the period, such as transmission charges, can result in the cap being hit and recovery being deferred despite EDBs incurring the costs and thus experiencing a reduction in short term cash flows, which could worsen financeability.

9. This report is structured as follows:

   a. Section 2 sets out the conceptual basis for financeability and financeability testing, including why it is likely to be in consumers' interests;

   b. Section 3 provides an overview of practical international experiences of financeability assessments;

   c. Section 4 discusses the conceptual features of New Zealand's current regulatory regime that can lead to potential financeability issues and demonstrates this using a stylized model;

   d. Section 5 sets out the possible options for implementing financeability testing in New Zealand;

   e. Appendix A describes Moody's credit rating methodology;

   f. Appendix B describes S&P's credit rating methodology; and

   g. Appendix C describes our approach to constructing a stylised model of EDB financeability.

2. Introduction to financeability and financeability testing

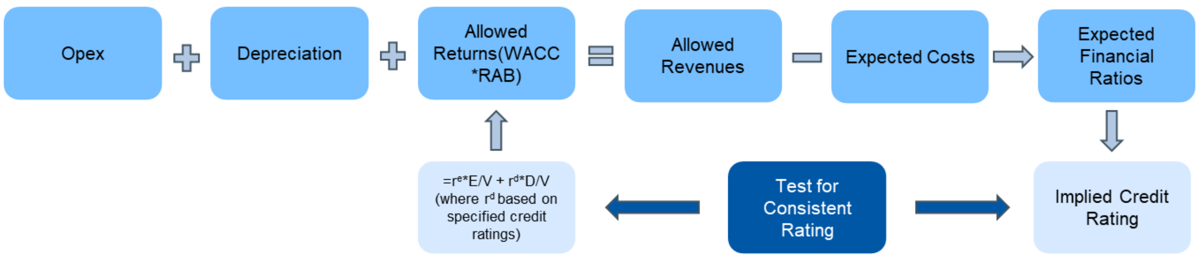
2.1. Financeability in a regulatory context

10. Financeability testing provides an opportunity for stakeholders to test the regulators' decision-making. It tests the internal consistency of regulatory decision making and provides an objective basis for assessing claims and evidence submitted by the stakeholders to price control decisions. It therefore provides an opportunity to improve the consistency and evidential basis of regulatory decision-making. As we discuss in section 2.2.1 below, ensuring EDBs are financeable benefits consumers as well as EDBs.

11. Assessing the underlying cost of equity is challenging from market data, which affords regulators discretion in setting the key parameters that underpin their estimate. Accordingly, financeability tests focus on the ability of regulated businesses to raise debt on the terms assumed by their regulators.

12. Figure 1 below presents an archetypal financeability test in a diagrammatic form. The test relies on the key building blocks of the price control as inputs (including opex, depreciation, and return on capital). The regulator may set operating costs using a range of different methods, including benchmarking and/or historical costs and depreciation of the installed asset base follows from the asset lives of historical capital expenditure (and with an indexed regulatory asset base (RAB), inflation). The allowed rate of return typically consists of an estimate of the weighted average of the regulator's estimates of the efficient cost of equity and debt capital. The regulator calculates financial ratios from those allowed revenues by deducting expected costs.

Figure 1: Financeability Test – Test for Consistency Between Allowed Return and the Expected Financial Ratios



Source: NERA illustration.

13. The relative importance of financial ratios and which ones regulators use vary, however, the most critical ratios typically involve Funds From Operation (FFO) (equal to revenue less opex, tax, and interest payments). Accordingly, capex and dividend payments tend to be less critical to the ultimate result. The two most prominent ratios used are:

    a. FFO interest coverage;

    b. FFO/Net debt, to interest coverage or net debt.

14. In setting allowances for debt costs, regulators implicitly or explicitly identify the credit-rating that they anticipate regulated entities will be able to achieve. Credit rating agencies, such as Moody's and S&P, rely on financial ratios to calculate credit ratings and publish thresholds for the level of each ratio consistent with each rating level. Investors use that guidance in setting the

interest rates that they require from borrowing firms.[2] If the projected financial ratios imply that a regulated business cannot raise debt finance on the terms (i.e., credit rating) assumed in the allowed rate of return, the regulator has not set overall revenues that allow the company to have a reasonable prospect of recovering its costs, and the regulatory determination is inconsistent.

15. For EDBs, this credit rating is the S&P rating of BBB+, which is equivalent to Baa1 under Moody's rating methodology.[3]

2.2. Should regulators care about financeability?

2.2.1. Financeability Testing is a Tool to Protect Consumers, Not EDBs

16. The previous section describes the need for a financeability testing from a regulatory framework point of view (i.e., ensuring internally consistent price controls), but the argument can also be made from a consumer benefit standpoint. Financeability testing offers at least four broad categories of benefits for consumers.

17. Firstly, financeability testing ensures that **consumers get access to the investment that they need**. Failing a well-calibrated financeability test means that an EDB would be unable to raise capital to finance new investments. This creates an incentive for EDBs to sweat assets and avoid new investments. If EDBs responded to that incentive, it would result in higher costs for consumers over the long term (e.g., due to excessive opex and reductions in the quality of service).

18. In some circumstances, even an unfinanceable EDB could be incentivised to invest in the network to, for instance, avoid penalties for failing to meet licence obligations. However, over the long term, EDBs will require new debt and/or equity injections to finance new investments. By definition, these capital injections will not be forthcoming in exchange for the returns on offer, if EDBs are not financeable.

19. Secondly, financeability testing **provides confidence in regulatory decision-making**. It is possible in principle for NZCC to set a maximum allowable revenue (MAR) that resulted in efficient EDBs being financeable without testing the financeability of their decision. However, without conducting financeability testing, it is not possible to be sure that a new DPP determination *ensures* that EDBs are financeable. Financeability testing offers a transparent method for cross-checking regulatory decisions and ensuring that the regulator is creating an investment climate that will deliver on consumers' needs.

20. Thirdly, by building confidence in the regulatory process, it **minimises financing costs for consumers**. In asset-intensive industries, the cost of capital accounts for a material proportion of the total price paid by consumers.[4] Providing a stable and transparent framework for assessing the financeability of networks provides investors with confidence and ultimately reduces, over the long-term, the returns investors require for investing in the sector.

21. Fourthly, financeability testing **minimises the costs of service over time**. In the absence of financeability testing, EDBs may go through periods of time in which they are not financeable as businesses. In these periods, they will be incentivised to eschew investment and wait for periods in which the regulator increases the cost of capital. Starving networks of the investment they need in fallow periods and investing intensively in periods when the business is financeable

[2] See Appendix A and B for detailed criteria (and the relevant financial ratios) applied by Moody's and S&P in rating firms.

[3] The Association of Corporate Treasurers, *Corporate credit ratings: a quick guide*, 2007.

[4] Using the stylised model we created using the DPP3 financial model with averaged EDB inputs to give a notional distributor, we calculate that the cost of capital accounts for on average 36% of the total revenue requirement between 2021 and 2025. A detailed description of the model we built can be found in Appendix C.

results in a boom-and-bust cycle which is likely to increase investment costs over time. This deferral could also have the effect of inequitably shifting costs to future consumers.

2.2.2. The Potential Benefits of Introducing Financeability Testing Materially Exceed the Cost of Doing So

22. A failed financeability tests stem from setting the allowed rate of return below the cost of capital given the risks and planned profile of recovery of capex. Much like the consequences of setting the cost of capital too low, the costs of failing to test for financeability are both potentially severe and asymmetric. The consequence of a reset process that over-rewards investment is additional capex, whilst the consequences of under-investment can be lost load, priced at $25,000/MWh,[5] causing higher prices for customers and imposing wider effects on the economy by having unreliable electricity.

23. The direct costs of financeability testing are low and largely administrative. The NZCC already produces detailed models of the costs and revenues of EDBs under the existing DPP processes. A financeability test would require the NZCC only to select a set of credit metrics for analysis, consult on those credit metrics with stakeholders and then calculate those credit metrics during the IM review and price path reset processes to cross-check its proposed allowances. As an example of its low cost, in the process of preparing this report, we have taken the DPP3 financial model and pulled the relevant information to calculate the core credit metrics of FFO/net debt and FFO interest cover. International precedent for financeability testing offers models that the NZCC could readily adopt (we discuss this precedent in section 3).

24. In addition to the theoretical merits of financeability testing, international regulatory practice suggests that it is likely to have benefits for consumers. Regulators (and legislators) internationally introduced financeability testing for the purpose of protecting long-term consumer interests. British regulators must have regard for the ability of licensed entities to finance their activities (the "financing duty"). British legislation requires regulators to have regard for the ability of licensed entities to finance their activities in order to protect consumers, not instead of it. The regulators of the energy and water sectors (Ofgem and Ofwat, respectively) have chosen how to interpret those duties, and both have concluded that explicit financeability testing is necessary to promote consumers' long-term interests.[6] Similarly, in the New South Wales water sector, the regulator (IPART) also decided that it was necessary to do so to protect consumers' interests, without a specific legal framework that suggests that it should.[7]

[5] NZCC, *Default price-quality paths for electricity distribution businesses from 1 April 2020: Final decision reasons paper*, November 2019, para 7.50.

[6] OFWAT, *Financeability and financing the asset base, Discussion paper,* March 2011, p4. Ofgem, *Regulating energy networks for the future, Working paper*, May 2010, p3

[7] IPART, *Financeability tests and their role in price regulation, Discussion paper,* September 2010, p.7.

3. Regulatory financeability tests in other jurisdictions

25. Internationally, and particularly in Great Britain (i.e., England, Scotland, and Wales) as well as for water in New South Wales, explicit testing of whether regulated businesses are financeable emerged for two main reasons:

    a. Regulatory decisions carry with them a risk of error. Regulators may inadvertently set allowed revenues for a regulated business at a level that does not allow an efficient business to finance its activities.

    b. Consumers have a clear interest in the continued provision of network services by efficient providers.

26. In response, regulators have considered that explicitly testing whether proposed allowances for network businesses enabled those businesses to finance their activities was in the interests of the consumers that they serve.

27. A regulated business may be unfinanceable for a range of reasons, including underperformance relative to its operating cost allowances. That underperformance may be due to the regulator misestimating the level of efficient operating costs or inefficiency by the unfinanceable firm. However, ensuring that a notionally efficient regulated business is financeable acts as the most basic cross-check on the consistency of the price control. Testing the financeability of a notionally efficient firm boils down to assessing whether debt and equity holders would be willing to make capital available to the business on the terms assumed by the regulator.

28. The following sections describe the financeability tests adopted by Ofgem, Ofwat, and IPART, as well as the remedies proposed for firms that fail the test.

3.1. Ofgem uses a basket of quantitative financial ratios

29. Ofgem is the energy regulator for Great Britain and their duty in terms of financeability is to “have regard to” the need to ensure that licensees can finance their activities.[8]

30. Ofgem focuses on the notional company for setting price control parameters to comply with its financeability duty.[9] While the financeability test should, in principle, draw on notional gearing (leverage) and efficient cost of debt, Ofgem also considers actual company debt positions to inform the notional structure and to increase monitoring of those companies more exposed to a material risk of financial distress. On the cost of debt, where a company’s actual cost of debt differs from the regulators’ allowance (e.g., where the regulator has allowed an industry-wide embedded debt cost rather than a company specific cost of debt), and that difference in the cost of debt is due to the time-profile of issuance, Ofgem may rely on actual debt costs in the test.

31. According to Ofgem, an “investment grade credit rating signals a strong likelihood that the company will be able to meet its liabilities”.[10] However, Ofgem does not provide a specific methodology with explicit ratio thresholds or factor weightings for assessing financeability. In its 2019 Decision on the methodology for the upcoming round of price controls, RIIO-2, Ofgem states it is “likely to use a Moody’s rating methodology simulator (as this methodology is the clearest to simulate) as a tool when reviewing network companies’ financeability assessments”.[11] As it is not required for the licensee to have a rating issued by Moody’s, and not all companies

[8] Section 3A of the Electricity Act 1989 and section 4AA of the Gas Act 198.

[9] Ofgem, *Decision: RIIO-2 Sector Specific Methodology – Finance*, 24 May 2019, p. 82.

[10] Ofgem, *Consultation: RIIO-2 Sector Specific Methodology Annex: Finance*, 14 March 2019, p. 55.

[11] Ofgem, *Decision: RIIO-2 Sector Specific Methodology – Finance*, 24 May 2019, p. 82.

have such a credit rating, Ofgem will also assess key financial ratios against other rating agencies' ratio thresholds and evidence submitted by network companies. For its consultation on the RIIO-2 sector methodology, Ofgem proposed to continue to use a basket of quantitative ratios to assess financeability, together with qualitative factors.[12]

32. In addition to Ofgem's duty to ensure that an efficient network company is financeable when setting price controls, regulated companies themselves have licence requirements that require them "to take all appropriate steps within their power to maintain an investment grade credit rating".[13]

33. Specifically, given an adequate allowed return on a notional company basis, in the event of any financeability concerns, Ofgem argues that companies can:[14]

    a. Adjust dividend policies to retain cash within the ring-fence during the control period;

    b. Inject equity to reduce gearing;

    c. Re-finance debt or any other financial commitment; and

    d. Propose alternative capitalisation rates and depreciation rates: under the RIIO framework introduced in 2013, Ofgem adopted a totex framework for analysing costs and allows companies to propose their own proportions and asset lives for "fast" and "slow" money.

34. Ofgem recognises that this final option of adjusting capitalisation or depreciation rates, introducing a trade-off between an increase in revenues in the short term and a lower RAB growth, is NPV neutral. Thus, this measure can be used to increase cashflow and some of the financial ratios. However, accelerating depreciation also has the potential to make some financial ratios worse, even in the short term, such as the Adjusted Cash Interest Coverage Ratio (AICR), which feeds into Moody's credit ratings and is equal to revenues less depreciation divided by interest payments.[15]

3.2. Ofwat uses a basket of quantitative financial ratios

35. Ofwat, the water regulator in England and Wales, has a similar "financing duty" to Ofgem's, which requires it to ensure that "relevant undertakers are able (in particular, by securing reasonable returns on their capital) to finance the proper carrying out of those functions".[16]

36. As Ofgem does, Ofwat bases its financeability assessment on the notional structure and expects companies to target a credit rating at least two notches above the minimum investment grade (i.e., to target BBB+/Baa1). In its guidance document for the upcoming PR24 review period, Ofwat confirms it will continue to use a suite of financial metrics as part of its assessment of financeability.[17,18] Ofwat assesses financeability on a basket of ratios used by credit agencies, placing the greatest weight on gearing, interest cover, and funds from operations to net debt ratios.[19]

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[12] A full list of financial metrics Ofwat uses is provided in the Appendix.

[13] Ofgem , *Consultation: RIIO-2 Sector Specific Methodology Annex: Finance*, 14 March 2019, p. 55.

[14] Ofgem, *Consultation: RIIO-2 Sector Specific Methodology Annex: Finance*, 14 March 2019 p. 57.

[15] Ofgem , *Decision: RIIO-2 Sector Specific Methodology – Finance*, 24 May 2019, p. 92.

[16] Water Industry Act 1991, 2 (2) (b).

[17] Ofwat, *Creating tomorrow together: consulting on our methodology for PR24 Appendix 10 – Aligning risk and return*, July 2022, p. 104,105.

[18] A full list of financial metrics Ofwat uses is provided in the Appendix.

[19] Ofwat, *Creating tomorrow together: consulting on our methodology for PR24 Appendix 10 – Aligning risk and return*, July 2022, p. 104.

37. Ofwat does not consider it necessary for companies to target a specific position for each financial ratio within the guidance range set out by the credit rating agencies since a credit rating is an in-the-round assessment and not reliant on a single specific financial metric.[20]

38. When there is a potential financeability problem, Ofwat notes that companies have two options to address financeability at the notional level. Companies can:[21]

    a. Reduce dividends when real regulatory capital value (RCV) growth exceeds 10 percent to maintain gearing close to the notional level of 60%; and

    b. Advance revenue from future customers using Pay-As-You-Go (PAYG) and RCV run-off. In other words, water companies in England and Wales are able to propose as part of their business plans what proportion of their expenditure should be expensed within the year (PAYG) and what proportion should be capitalised and depreciated (RCV run off).

39. For example, a number of companies addressed notional financeability in their PR19 business plans via PAYG and RCV run-off. Ofwat has considered these measures to be appropriate when they do not have a material impact on financial resilience over the long term, and there is sufficient evidence of customer support. In addition, Ofwat stated that it considers:[22]

> *[T]he use of PAYG or RCV run-off to address a financeability constraint to be preferable to increasing the cost of equity above the level expected by market participants for the period of the price control.*

3.3. IPART uses financial ratios to verify its regulatory decisions

40. IPART routinely relies on financeability assessments to verify its decision-making.

41. For its price determinations, IPART estimates the revenues that a regulated business requires to recover its efficient costs over the control period. To do so, it uses a "building block" approach to estimate these costs. However, IPART recognises that this approach does not ensure that a regulated company will be able to raise funds to finance its activities per se.[23] Thus, IPART conducts a financeability test to assess whether its pricing decisions are likely to have an effect over the control period on regulated businesses' financial sustainability and the ability to raise funds to fund their activities:[24]

> *The purpose of the financeability test is not to assess or assign a credit rating for the business. Rather, it is to check whether our pricing decisions are likely to give rise to a financeability concern and to identify the reasons for any concern.*

42. IPART's objective is for its pricing decision to be consistent with businesses maintaining a BBB target rating.[25] IPART performs its tests using three of the four financial ratios used by Moody's to assess regulated companies' credit ratings: Funds from operations (FFO), interest cover, gearing, and FFO divided by debt.[26] As explained in Appendix A, Moody's credit rating methodology involves assessing both qualitative factors and quantitative ratios. IPART's test

[20] Ofwat, *Creating tomorrow together: consulting on our methodology for PR24 Appendix 10 – Aligning risk and return*, July 2022, p. 28.

[21] Ofwat, *PR19 final determination, Aligning risk and return technical appendix*, December 2019, p. 94.

[22] Ofwat, *Technical appendix 3: Aligning risk and return*, January 2019, p. 25.

[23] IPART, *Financeability tests and their role in price regulation*, September 2010, p. 2.

[24] IPART, *Review of our financeability test*, November 2018, p. 10.

[25] IPART, Review of our financeability test, November 2018, p. 35.

[26] See Appendix C for the list of ratios used by IPART and their definition.

however uses only quantitative ratios, on the basis that a test based only on quantitative ratios is more transparent.[27]

43. It is not clear from IPART's published documents precisely what it meant by transparency in this context, but we assume that it intended to indicate that the process Moody's follows to assess qualitative factors cannot be replicated and therefore any financeability assessment taking qualitative ratios into account would depend on Moody's expert (and subjective) judgement.

44. For its 2018 financeability test, IPART tests the impact of its decision on both the notional company and the actual business. IPART explains that the purpose of the benchmark test was to ensure that the regulator's "pricing decisions allow an efficient business to raise finance and remain financeable during the regulatory period". The test based on the companies' actual cashflows instead "generates a warning that the actual business might face a financeability concern over the course of the regulatory period".[28] In other words, the failure of the benchmark test indicates that IPART has set an internally inconsistent price control whilst the failure of the test based on actual cashflows (alone) suggests that the company may not be behaving prudently from a financial perspective.

45. Once IPART calculates the financial ratios for both the benchmark and the actual tests if the firm does not meet the target ratios in all years of the regulatory period, IPART will:[29]

    a. rank the ratios, placing more weight on the Interest Coverage Ratio and FFO divided by debt ratios;

    b. assess the trends in the financial ratios over the regulatory period, and decide whether the business faces a potential financeability concern;

    c. if there is a financeability concern with respect to the benchmark test, IPART would reassess its pricing decisions and adjust its regulatory settings; and

    d. if there is a financeability concern with respect to the actual test, IPART could include any other idiosyncratic factors in its analysis, in order to tailor its response to solve the problem. For example, if the company has made imprudent or inefficient decisions, IPART would recommend injecting more equity, accepting a lower rate of return on equity, or both. On the contrary, if the financeability concern is related to a temporary cash flow problem, IPART would consider an NPV-neutral adjustment to its pricing, e.g., a temporary increase in prices followed by a reduction at a later time so that the two price changes offset each other in net present value terms.

46. IPART has conducted financeability tests of its own volition, without a specific statutory requirement. Doing so illustrates that IPART believes that financeability tests are core to its obligations to "protect and promote the interests of consumers, taxpayers, and citizens of New South Wales".[30] The avenues by which financeability testing may improve consumer welfare are manifold: for instance, financeability ensures that consumers avoid unnecessary disruption from financial distress in the short term, and could signal a reliable and consistent regulatory regime that lowers the cost of capital over the long term.

[27] IPART, *Review of our financeability test*, November 2018, p. 20.

[28] IPART), *Review of our financeability test*, November 2018, p. 16.

[29] IPART, *Review of our financeability test*, November 2018, p. 58.

[30] IPART , *Code of Ethics and Conduct*, May 2018, p.1.

4. Conceptual features of the New Zealand regulatory regime that could lead to the need for a financeability test

47. Financeability testing is most necessary where there is the highest risk that the price control allowances determined by the regulator does not automatically ensure that the firm is financeable. New Zealand shares many features with Australian or the UK regimes that have already adopted financeability tests. In this section we describe these features and illustrate the cashflow and credit metric impact of these different features using a stylised model based upon the DPP3 financial model and the "average" EDB.

48. We summarise our overall modelling approach in Section 4.1. In the rest of this section, we discuss the following features of the New Zealand regime and contextual factors which suggest there is the potential for financeability concerns to arise:

    a. Indexation of the RAB (Section 4.2) and how the associated backloading is exaggerated when:

        i. Forecast inflation is high

        ii. Capex needs are high relative to the existing RAB; and

        iii. EDBs issue nominal debt.

    b. The use of alternative X-factors to backload recovery (Section 4.3);

    c. The cap applied to the within (intra) period changes in the MAR (Section 4.4); and

    d. The impact of low interest rates (Section 4.5).

4.1. Summary of modelling approach

49. To demonstrate the impact of different price control parameters on financeability of an EDB, we have built a stylised Building Blocks Model (BBM) based on the DPP3 financial model. For the purposes of our illustrations, the model generates cost, revenue and financing parameters for a notional EDB, based on industry average values for existing Regulated Asset Base (RAB), lives of existing assets, forecast asset disposals, capital expenditure (capex) plans, and operating expenditure (opex) over a five-year period from 2021 to 2025. We incorporate price control parameters as defined by NZCC, such as allowed financing costs and notional gearing.

50. From this model, we are able to calculate the core credits metrics of FFO/Net debt[31] and FFO interest coverage.[32] These are two of the three metrics used in IPART's financeability test and the metrics that have the most weight placed on them by Moody's and S&P among quantitative rating factors. The final quantitative metric used by IPART is gearing, but this is not sensitive to the price control parameters we vary in the model, so we do not include it in our analysis. More detail on this model as well as the thresholds we used for different credit metrics is set out in Appendix C.

51. At a high level, we use the cut-off for each quantitative metric for Moody's credit rating Baa, which is broadly equivalent to the NZCC's assumed BBB+ S&P rating (specifically, Baa1 is equivalent to BBB+). Moody's thresholds for quantitative metrics do not distinguish between the different levels of Baa, rather a range for the whole Baa range (Baa1 – Baa3) is provided for each metric. To be conservative, in our analysis we have used the lower cut off for each metric at

[31] (Revenue – opex – tax – interest)/(RAB * notional gearing), where interest is (RAB * notional gearing * cost of debt).

[32] (Revenue – opex – tax)/interest

which point the rating for that metric switches to Ba. More detail on Moody's credit scoring methodology is provided in Appendix A.

52. Consistent with IPART, we adopt the standard that an EDB should be financeable under both metrics in each year of a notional DPP period (defined as 2021 to 2025 in our model, but this is simply illustrative).

53. In the remainder of this chapter, we demonstrate how different price control parameters would affect the measured financeability metrics over the course of the notional DPP period.

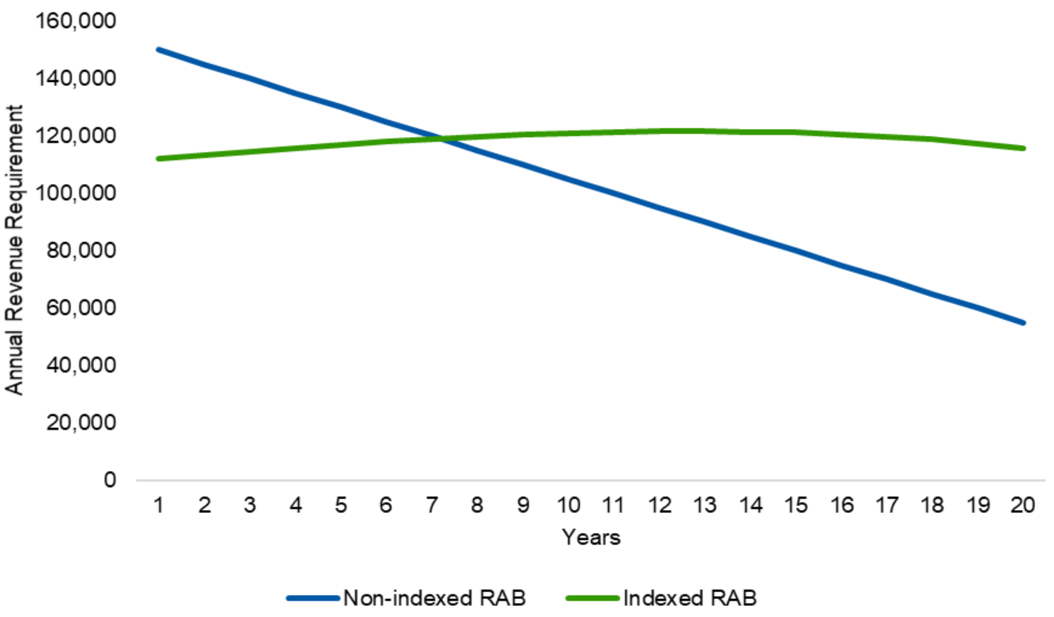
4.2. Indexation of the RAB

54. Much like in Australia and the UK, EDBs operate in a regime whereby the RAB is indexed for inflation. Such indexation defers the recovery of investments and reduces short term cash-flows relative to a non-indexed RAB, and is, therefore, more prone to failing a financeability test.

55. In New Zealand, NZCC uses a nominal weighted average cost of capital (WACC) and an indexed asset base. This means that inflation is compensated for by revaluing the asset base each year. To ensure that the regulatory regime allows regulated entities to earn back the Net Present Value (NPV) of their investments (and no more, all else equal), the indexation of the asset base is treated as income and deducted from the annual revenue requirement to prevent double counting of inflation adjustments. Effectively NZCC's approach results in a revenue/price-path that includes a real return on capital; with a revaluation of the RAB providing the compensation for inflation over the period.

56. The alternative approach would be to use a nominal rate of return and not index the asset base.[33] Relative to the approach adopted by the NZCC, this would result in front loading of recovery and a RAB that falls more quickly. This is demonstrated in Figure 2 which shows a stylised example of the different recovery profiles.

Figure 2: Revenue Path Example – Indexed vs Un-Indexed RAB ($m Nominal)



Source: NERA illustration. Example assumes a 5% WACC, 20 year asset life, straight line depreciation and forecast revaluations of 2% per year.

[33] Some suppliers have also proposed this in the past. See para 247., from NZCC, 2016, Input methodologies review and decisions: Topic paper 1: Form of control and RAB indexation for EDBs, GPBs, and Transpower.

57. The NZCC currently adopts an un-indexed approach to roll forward the RAB for Transpower. In the 2010 IM Review for Transpower the NZCC provides an explanation of why they have decided on un-indexing the RAB and the effect it will have on Transpower:[34]

> *"Transpower will apply an un-indexed approach to update the value of the RAB. This is important because an un-indexed approach results in relatively high initial cash flows on any investments that Transpower makes in future."*
>
> *"Transpower is planning to invest over $3 billion in upgrading and renewing the transmission network over the next five years, which will more than double the value of Transpower's RAB. […] The level of Transpower's investments will result in it having, relative to other lines businesses, high investment programme funding requirements;"*
>
> *"updating the RAB value using an un-indexed approach will, given the likely age structure of Transpower's asset base, be likely to lead to higher revenues for Transpower over the near term. This level of revenue will be likely to be better matched to Transpower's investment needs;"*

58. The AER has recognised this difference in the profile of recovery and the NPV equivalence of the two revenue profiles: [35]

> *Under an alternative approach where a nominal rate of return was used in combination with an un-indexed (historical cost) RAB, no adjustment to the depreciation calculation of total revenue would be required. This alternative approach produces a different time path of total revenue compared to our standard approach. In particular, overall revenues would be higher early in the asset's life (as a result of more depreciation being returned to the TNSP) and lower in the future—producing a steeper downward sloping profile of total revenue. Under both approaches, the total revenues being recovered are in present value neutral terms—that is, returning the initial cost of the RAB.*

59. While the choice between the two revenue profiles is theoretically neutral, the reprofiling does have cashflow implications, which can affect an EDB's ability to meet its interest payments, and thus can affect financeability. This matters for the present context because the indexation of RAB compensates parties for inflation through the RAB rather than current cash-flows. It follows that the financial ratios that EDBs are able to achieve under an indexed RAB approach are therefore worse in earlier years of an asset's life than they would be under an unindexed RAB approach.

60. Table 1 depicts how high forecast inflation needs to get for the hypothetical distributor in our model to fail the financeability test, defined as failing to achieve a Baa rating in a single year in a single metric. This table shows that when the RAB is indexed, our notional EDB (essentially an average company across all EDBs) fails the financeability test when the forecast inflation rate is higher than 1%. The same distributor is able to stay financeable under higher inflation rates (and only fails once the inflation rate is above 3%) if the RAB is not indexed, as demonstrated in Table 2.

[34] NZCC, *Input Methodologies (Transpower) Reasons Paper*. December 2010, para 4.3.12, and para 5.2.2 .

[35] AER, *AusNet Services transmission determination 2017–18 to 2021–22: Draft Decision, attachment 5 – Regulatory depreciation*, July 2016, p.22.

Table 1: Financeability metrics at different forecast inflation rates for a distributor that has an indexed RAB

Inflation rate	FFO interest coverage 2021	2022	2023	2024	2025	FFO/net debt 2021	2022	2023	2024	2025
0%	Aa	Aa	Aa	Aa	Aa	A	Baa	Baa	Baa	Baa
1%	A	A	A	A	A	Baa	Baa	Baa	Baa	Baa
2%	Baa	Baa	Baa	Baa	Baa	Baa	Ba	Ba	Ba	Ba
3%	Ba	Ba	Ba	Ba	Ba	Ba	Ba	Ba	Ba	Ba
4%	B	B	B	B	B	B	B	B	B	B

Source: NERA analysis

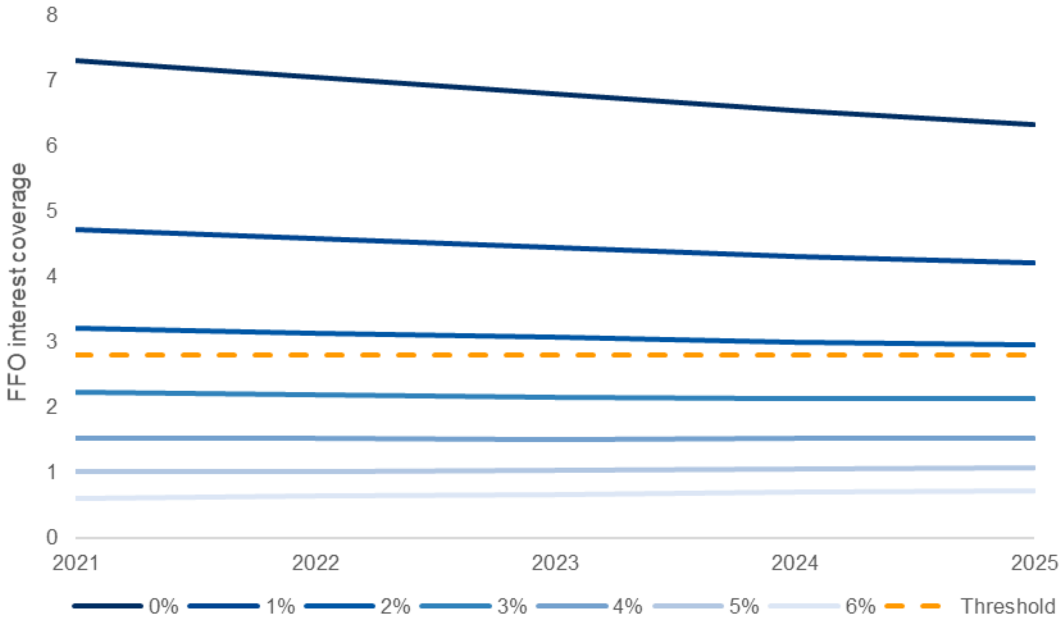
Table 2: Financeability metrics at different forecast inflation rates for a distributor that has an unindexed RAB

Inflation rate	FFO interest coverage 2021	2022	2023	2024	2025	FFO/net debt 2021	2022	2023	2024	2025
0%	Aa	Aa	Aa	Aa	Aa	A	Baa	Baa	Baa	Baa
1%	A	A	A	A	A	Baa	Baa	Baa	Baa	Baa
2%	A	A	Baa	Baa	A	Baa	Baa	Baa	Baa	Baa
3%	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa
4%	Ba	Ba	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa

Source: NERA analysis

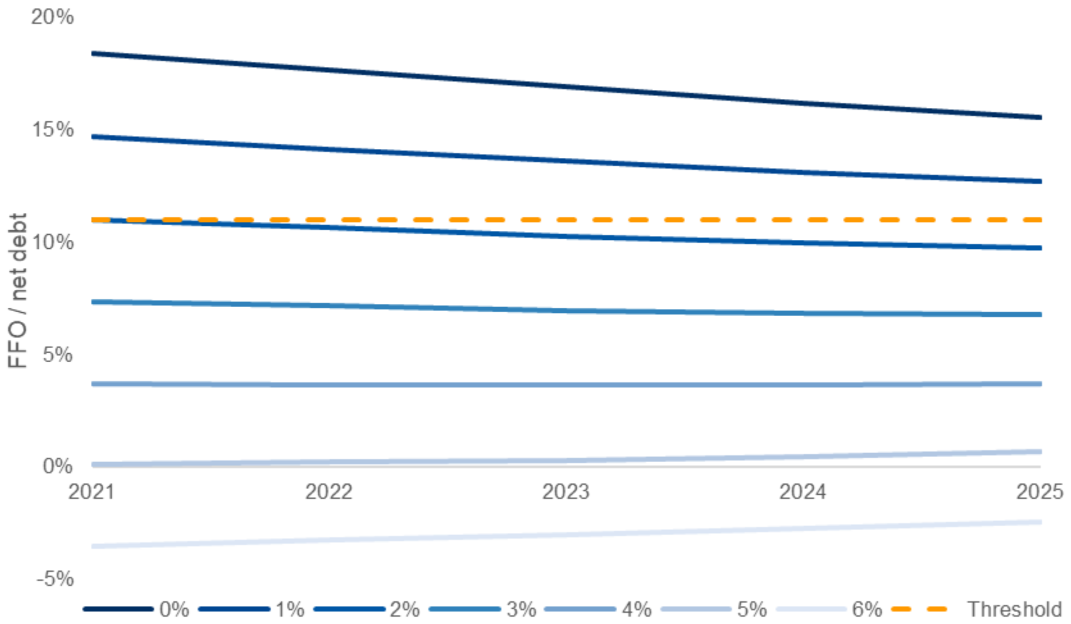
61. In Figure 3 and Figure 4 below, we show how the raw quantitative score of each metric varies by year under different inflation rate assumptions, compared to the Baa threshold.

Figure 3: FFO interest coverage at different forecast inflation rate with indexed RAB



Source: NERA analysis

Figure 4: FFO/net debt at different forecast inflation rates with indexed RAB



Source: NERA analysis

62. There are several factors that are likely to exacerbate the potential financeability issues caused by indexation:

a. **High inflation environment:** The current high inflation environment, if it feeds through to high *forecast* inflation, results in more backloading of the cash recovered due to the indexation. This is demonstrated by Table 1 and Table 2 above, which show that the hypothetical distributor's credit metrics deteriorate as forecast inflation increases (all other things being equal).

b. **Biased inflation forecasts:** Mismeasurement of inflation given RAB indexation can result in systematic under-recovery of the real WACC and exacerbate financeability concerns. Actual, rather than benchmark, financeability may also deteriorate where the regulatory regime indexes the RAB using inflation outturns but uses a measure of forecast inflation to set the rate of return, where inflation outturns are routinely below forecast.

c. **EDBs issue nominal (unindexed) debt**: By indexing the entire RAB, the NZCC approach effectively assumes that EDBs issue inflation indexed debt, whereas we understand that none of the largest 6 EDBs issue inflation indexed debt. While the NZCC has suggested in the past that this issue can be addressed by issuing inflation-linked debt/swaps instead of nominal debt,[36] we understand that the reason EBDs don't issue inflation indexed debt is that there is no liquid market in NZ.

d. **Increased capex needs:** The upcoming need for large amounts of capex to fund decarbonisation and renew aging assets[37] will exaggerate the issues caused by indexation and nominal debt costs, and results in significant financeability issues as the balance may tip towards most assets being in the under-recovery phase (i.e., left hand side of Figure 2 above). For this exact reason, as mentioned above, the input methodologies provide for an unindexed asset roll forward approach to Transpower's RAB. This treatment was concessionary and

[36] NZCC, *Input methodologies review decisions Topic paper 1: Form of control and RAB indexation for EDBs, GPBs and Transpower*, December 2016, para 244.2.

[37] ENA, *Part 4 Input Methodologies Review, Submission to the Commerce Commission.*, July 2022.

was intended to aid Transpower with financing its investment needs over the short to medium term. This has allowed Transpower's cash flows to be advanced compared to other sectors.[38]

63. We illustrate the impact of increased capex needs in two ways:

a. Changing the remaining life of existing assets at the start of the period (i.e., making existing assets at the start of our hypothetical reset "newer"); or

b. Flexing the forecast capex, such that the balance of new to old assets changes over the regulatory period.

64. The tables below show how the financial metrics respond differently to the change in the average remaining life of the RAB depending on whether the RAB is indexed or not. As new assets are commissioned to achieve decarbonization or new assets replace aged assets, the average remaining life of the RAB will improve. Table 3 and Table 4 show how when the RAB is indexed the hypothetical distributor will fail to pass the financeability test in all scenarios including the base case (average remaining asset life of 24 years) because as mentioned above when the RAB is indexed the distributor is compensated more as the assets mature. Therefore, if there is an increase in new assets being commissioned and the average remaining life of the RAB improves, this will result in there being more assets in the under-recovery phase and thus lead to lower allowable revenue for the distributor. On the other hand, if the RAB is not indexed, as the right half of Table 3 and Table 4 indicate, there will be no financeability issues.

Table 3: FFO/net debt and average RAB remaining life for hypothetical EDB

		Indexed RAB					Unindexed RAB				
		2021	2022	2023	2024	2025	2021	2022	2023	2024	2025
Remaining life	24	Baa	Ba	Ba	Ba	Ba	Baa	Baa	Baa	Baa	Baa
	25	Ba	Ba	Ba	Ba	Ba	Baa	Baa	Baa	Baa	Baa
	26	Ba	Ba	Ba	Ba	Ba	Baa	Baa	Baa	Baa	Baa
	27	Ba	Ba	Ba	Ba	Ba	Baa	Baa	Baa	Baa	Baa
	28	Ba	Ba	Ba	Ba	Ba	Baa	Baa	Baa	Baa	Baa
	29	Ba	Ba	Ba	Ba	Ba	Baa	Baa	Baa	Baa	Baa
	30	Ba	Ba	Ba	Ba	Ba	Baa	Baa	Baa	Baa	Baa

Source: NERA analysis

Table 4: FFO interest coverage and average RAB remaining life for hypothetical EDB

		Indexed RAB					Unindexed RAB				
		2021	2022	2023	2024	2025	2021	2022	2023	2024	2025
Remaining life	24	Baa	Baa	Baa	Baa	Baa	A	Baa	Baa	Baa	A
	25	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa
	26	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa
	27	Baa	Baa	Baa	Ba	Ba	Baa	Baa	Baa	Baa	Baa
	28	Baa	Baa	Baa	Ba	Ba	Baa	Baa	Baa	Baa	Baa
	29	Baa	Baa	Ba	Ba	Ba	Baa	Baa	Baa	Baa	Baa
	30	Baa	Ba	Ba	Ba	Ba	Baa	Baa	Baa	Baa	Baa

Source: NERA analysis

[38] NZCC, *Proposed amendments to input methodologies for Transpower*, March 2014, para 34.

65. While it is not reported in the tables above, results from our analysis indicate that if the RAB is not indexed, the hypothetical distributor will not fail the financeability test until the average remaining life of the RAB is 41 years. This is unrealistic given that the remaining life of a newly commissioned asset is 44 years which means that to have an average remaining life of the RAB of 41 years the EDB must have replaced their entire asset base in the last 5 years.

66. Another potential issue that could lead to financeability issues is when EDBs face a capex uplift due to expected/unexpected capital expenditures as mentioned in the above sections. Table 5 and Table 6 show how a benchmark entity's credit rating changes depending on how much the capex is increased by. Interestingly, for FFO/interest coverage credit ratings deteriorate as the amount capex is flexed by increases, while for FFO/net debt credit ratings improve as the amount capex is flexed by increases. In both FFO/interest coverage and FFO/net debt, later years of the DPP period are more susceptible to failing the financeability test compared to earlier years. This occurs as the RAB becomes progressively "newer" at the back end of the period when we flex capex, and therefore the backloading of recovery becomes more pronounced.

Table 5: FFO/interest coverage under different capex uplift scenarios and indexed RAB

Capex uplift	2021	2022	2023	2024	2025
105%	Baa	Baa	Baa	Baa	Baa
110%	Baa	Baa	Baa	Baa	Baa
115%	Baa	Baa	Baa	Baa	Baa
120%	Baa	Baa	Baa	Baa	Baa
125%	Baa	Baa	Baa	Baa	Baa
130%	Baa	Baa	Baa	Baa	Baa
135%	Baa	Baa	Baa	Baa	Baa
140%	Baa	Baa	Baa	Baa	Baa
145%	Baa	Baa	Baa	Baa	Ba
150%	Baa	Baa	Baa	Baa	Ba

Source: NERA analysis

Table 6: FFO/net debt under different capex uplift scenarios and indexed RAB

Capex Uplift	2021	2022	2023	2024	2025
105%	Baa	Ba	Ba	Ba	Ba
110%	Baa	Ba	Ba	Ba	Ba
115%	Baa	Ba	Ba	Ba	Ba
120%	Baa	Ba	Ba	Ba	Ba
125%	Baa	Ba	Ba	Ba	Ba
130%	Baa	Ba	Ba	Ba	Ba
135%	Baa	Ba	Ba	Ba	Ba
140%	Baa	Ba	Ba	Ba	Ba
145%	Baa	Ba	Ba	Ba	Ba
150%	Baa	Ba	Ba	Ba	Ba

Source: NERA analysis

4.3. Use of alternative (negative) X-factors

67. At each DPP determination, NZCC assesses whether alternative rates of change are necessary based on: (1) whether a distributor's increase in allowable revenue – including any incremental rolling incentive scheme (IRIS) incentives – would otherwise exceed +10% in real terms across DPPs; and (2) whether a decrease in a distributor's allowable revenue would cause financial hardship due to the change in cashflow profile between DPPs.[39] While the current DPP3 did not implement any alternative rates of change for any distributors, in a scenario with large increases in forecast capex associated with decarbonization, there will be a large increase in allowable revenue as a result which makes alternative X-factors more likely in the future to smooth the price increases. The use of alternative X-factors will help ease the transition to higher prices for consumers but will backload cash recovery for distributors (within a DPP period) and put pressure on their financeability in the earlier periods of a DPP.

68. Table and Table 8 below show how adopting an alternative X-factor can deteriorate an EDB's credit ratings in the earlier periods of a DPP. As the alternative X-factor becomes larger in absolute value terms, the lower the allowable revenue in earlier years, and thus the financeability metrics deteriorate in these years.

Table 7: FFO/net debt for each year under different X-factors with indexed RAB

	FFO / net debt				
X-factor	2021	2022	2023	2024	2025
0%	Baa	Ba	Ba	Ba	Ba
-1%	Ba	Ba	Ba	Ba	Ba
-2%	Ba	Ba	Ba	Ba	Ba
-3%	Ba	Ba	Ba	Ba	Baa
-4%	Ba	Ba	Ba	Baa	Baa
-5%	Ba	Ba	Ba	Baa	Baa
-6%	Ba	Ba	Ba	Baa	Baa
-7%	Ba	Ba	Ba	Baa	Baa
-8%	Ba	Ba	Ba	Baa	Baa
-9%	Ba	Ba	Ba	Baa	Baa
-10%	Ba	Ba	Ba	Ba	Baa

Source: NERA analysis

[39] NZCC, *Default Price-quality path for electricity distribution businesses from 1-April 2020 Final decision Reasons paper*, November 2019, para 6.10.

Table 8: FFO interest coverage for each year under different X-factors with indexed RAB

X-factor	FFO interest coverage 2021	2022	2023	2024	2025
0%	Baa	Baa	Baa	Baa	Baa
-1%	Baa	Baa	Baa	Baa	Baa
-2%	Baa	Baa	Baa	Baa	Baa
-3%	Baa	Baa	Baa	Baa	Baa
-4%	Ba	Baa	Baa	Baa	Baa
-5%	Ba	Baa	Baa	Baa	Baa
-6%	Ba	Baa	Baa	Baa	Baa
-7%	Ba	Ba	Baa	Baa	Baa
-8%	Ba	Ba	Baa	Baa	Baa
-9%	Ba	Ba	Baa	Baa	Baa
-10%	Ba	Ba	Baa	Baa	Baa

Source: NERA analysis

4.4. 10% intra period cap on gross allowable revenue

69. The revenue cap places a limit on the change in total revenue (including pass-through and recoverable costs) of 10% per year. If the EDB under-recovers (or over-recovers) the revenue allowance in a given year, this under-recovery is added (or subtracted in the case of an over-recovery) to the net allowable revenue two years following the under(over)-recovery. This under/over-recovery is carried forward using the regulatory WACC and thus is theoretically NPV-neutral.[40]

70. If a distributor reaches this threshold, this means that the distributor will under-recover in that year, triggering a wash-up that is recovered in the following two years, which has the effect of backloading recovery.[41] As we have already discussed, backloading recovery can worsen the cashflow position of the firm and thus worsen credit metrics.

71. As a starting point, we note that with a large negative X-factor or in an environment of high expected inflation, the 10% cap is much more likely to be triggered or may be triggered before even considering changes in pass-through or recoverable costs. It is thus important that the NZCC considers these factors jointly when setting the intra-period cap so that its own decision is internally consistent in this respect.

72. High expected inflation and/or negative X factors, combined with the 10% limit on changes in the MAR have the potential effect of further backloading recovery, which has the potential to create or exaggerate financeability issues. The current +10% limit on the annual increase in the distributor's gross "forecast revenue from prices" includes pass-through and recoverable costs.[42]

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[40] NZCC, *Electricity distribution services input methodologies determination 2012*, May 2020.

[41] If an EDB under-recovers (or over-recovers) the revenue allowance in a given year, this under-recovery is added (or subtracted in the case of an over-recovery) to the net allowable revenue two years following the under(over)-recovery. This is called the "wash-up" mechanism and while this system ensures the EDBs recover any under-recovered revenue allowances (leading to a positive wash-up balance), the time lag of the recovery (recovery made two years following the under-recovery) leads to a backloading of cash recovery.

[42] NZCC, *Default Price-quality path for electricity distribution businesses from 1-April 2020 Final decision Reasons paper*, November 2019, para 6.23, 6.24.

73. The IM determination lists the costs that EDBs can pass through or recover.[43] Costs that can be passed through are rates on system fixed assets paid or payable by an EDB to a local authority under the Local Government (Rating) Act 2002, and levies payable under the Commerce Act and the Electricity Industry Act 2010. Recoverable costs include IRIS incentive adjustments, Transpower and electricity line services charges, Transpower's new investment contract charges, distributed generation allowance, Fire and Emergency NZ levies, and avoided transmission charges.

74. While triggering this limit results in an NPV neutral reprofiling of cashflows, if there are high pass-through/recoverable costs in a given year, such as an increase in transmission charges, this will result in a deterioration of the cashflow in the year that the cost occurs, which raises the potential for a financeability issue in that year. It could be likely that there are such cost increases during periods (in particular, changes in transmission charges), which could cause particular issues in a high inflation environment if the intra-period cap is not set to account for this.

75. Thus, the intra-period cap should be set to account forecast inflation, the X-factor and any expected changes in pass-through or recoverable costs. In this regard it could be worth exploring whether the intra-period cap should apply to total revenue excluding pass-through and recoverable costs.

76. While not within the scope of this paper, changes to the opex IRIS could also be considered to result in the IRIS recoverable cost being smoothed across the period to avoid tripping the 10% intra-period threshold.

4.5. Correlation between the interest rate and credit metrics

77. Under the NZCC's current approach to calculating WACC, as the interest rate falls, the allowed cost of equity falls. All other things equal, this results in reduced profitability for the firm and, given debt has priority over equity, can reduce the residual cashflow available to pay debt holders and thus worsens EDBs credit metrics. Mechanically in the NZCC model, a lower risk-free rate has three impacts:

    a. The cost of equity falls (which worsens credit metrics);

    b. The cost of debt falls (which improves credit metrics); and

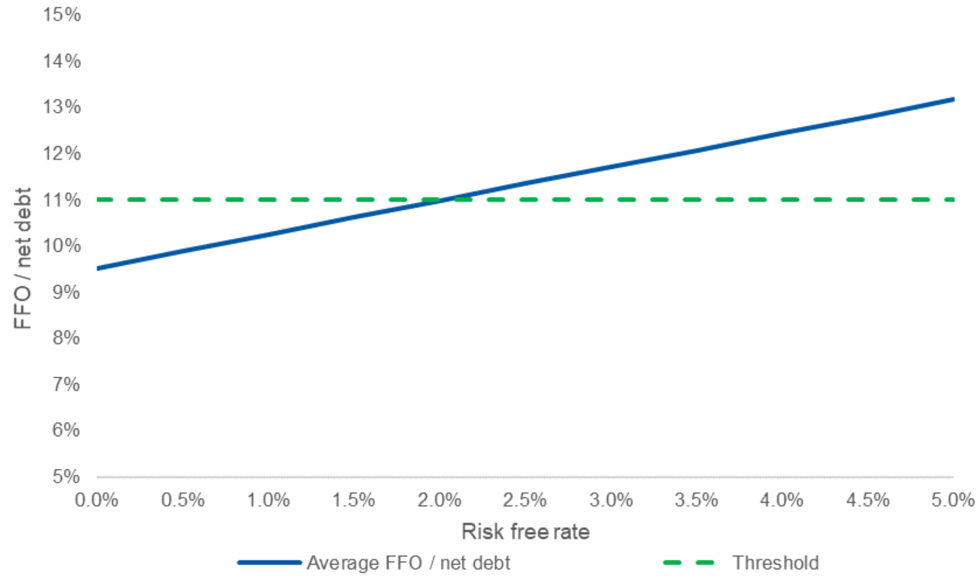
    c. The conversion of the BBAR to the MAR will give a lower total revenue stream if the BBAR is flat or falling over the period (which worsens credit metrics) and a higher revenue stream if BBAR is increasing over the period (which improves credit metrics).44

78. As we now show, which impact dominates depends on the credit metric in question. Figure 5 below shows the impact of a falling risk-free rate on the core ratio of FFO/net debt. For this metric, a lower risk-free rate worsens the credit metric because a falling interest rate worsens the FFO metric.

[43] NZCC, *Electricity distribution services input methodologies determination 2012*, May 2020, para. 3.1.2, para 3.1.3.

[44] Intuitively, if the BBAR is increasing over time, then the BBAR is weighted towards future periods. A lower discount rate would discount the later cashflows less, which happen to be larger. In this situation a higher smoothed cashflow profile is needed to give the same NPV as the BBAR.

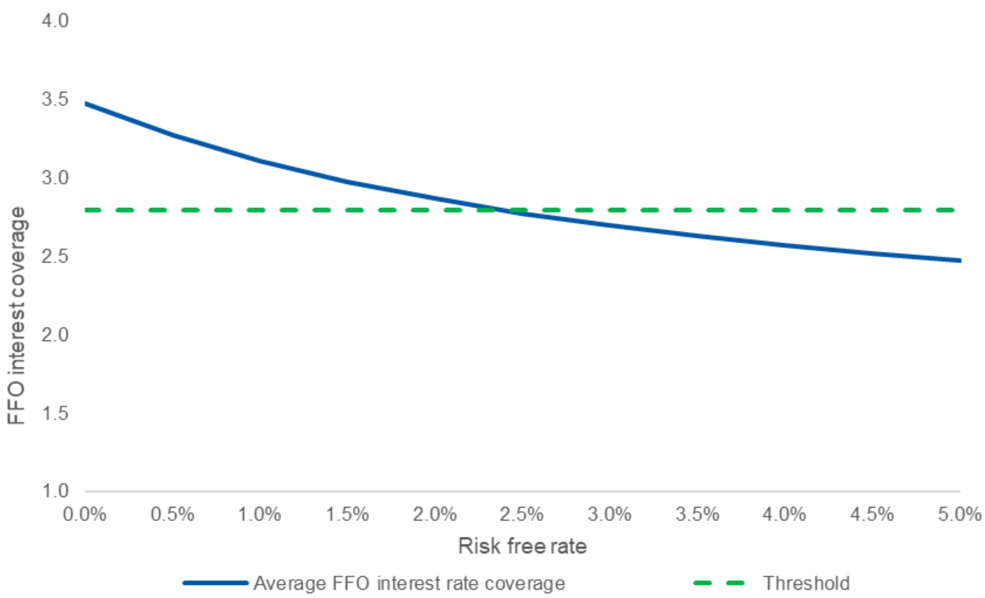
Figure 5: Average 5-year FFO/Net debt



Source: NERA analysis

79. Interestingly, when we examine the other core ratio of FFO interest coverage, the opposite occurs, as shown in Figure 6 below. This is because the numerator in the ratio is the notional interest expense, which declines as the interest rate declines. This is driven by the regulatory assumption that the EDB refinances the entirety of its debt portfolio at the beginning of the regulatory period and thus the same interest rate assumption that drives the cost of equity drives the cost of debt. If a trailing average approach was taken to the base rate component of the cost of debt, this link would be broken, and a falling interest rate used for the cost of equity would likely deteriorate this metric as well. This also means that if a financeability test was calculated using the actual forecast debt cost, a lower regulatory risk-free rate assumption would likely flow through to a deterioration in this credit metric, if firms adopt a refinancing strategy that differs from the "on the day" approach implicit in the NZCC's cost of debt calculation.

Figure 6: Average 5-year FFO Interest Coverage



Source: NERA analysis

5. Options and considerations for implementing financeability testing

80. Introducing financeability testing in New Zealand would require the NZCC to take a series of decisions about the design of any test. In designing a financeability test the NZCC would need to decide on at least four dimensions of any test in order to realise the benefits of financeability testing:

    a. Identity of the Target Firm;

    b. Methodology and Calculations;

    c. Frequency of testing; and

    d. Remedies.

81. We discuss each of these dimensions in turn.

5.1. Identity of the target firm

82. As a first step, financeability tests require a notional firm and a set of accounts in order to calculate financial ratios. In principle, the NZCC could run financeability tests based on the:

    a. *Benchmark Efficient Entity (BEE):* The starting point for incentive regulation is usually that decisions on costs and allowances should be made with reference to notional costs and financial structures. This approach would be in line with Ofgem's, Ofwat's, and IPART's approaches.

    b. *Actual Entity:* The risk of failure of actual entities could provide an argument for relying on actual costs to assess financeability.

    c. *Hybrid of actual and BEE (IPART approach):* Hybrid approaches are also possible: IPART used what it described as "actual" financeability as a cross-check on its work in previous price controls, applying the test to the BEE but using actual financing costs.

83. In our view, the primary purpose of a financeability test is to test the internal consistency of the regulatory price control, and therefore it makes sense to apply a financeability test to the BEE. Applied this way, testing does not need to require any information beyond what is already contained in the financial models used at each reset. Indeed, as part of this report, we have developed a spreadsheet that pulls information from the DPP3 financial model and calculates the core credit ratios of FFO/Net Debt and FFO interest coverage.

84. The actual or hybrid IPART approach requires more information, in particular about the actual forecast debt costs of the firm. While there are reasons that this may be a useful exercise, (for example, it can illustrate if firms are making imprudent decisions in a situation where the BEE passes but the actual entity fails), it moves the exercise beyond testing the levers the NZCC controls. If not assessed in conjunction with the benchmark test, it may mask issues with the regulatory price path. In particular, it can result in a situation where the actual entity passes but the BEE fails. This would indicate that the price path set is problematic, as it implies the actual firm has needed to find a way to compensate for a deficiency in the price control.

85. Therefore, our view is that the BEE should be the primary focus of any regulatory financeability test.

5.2. Methodology and calculations

86. We briefly described the approaches used by British regulators and IPART as well as the methodologies taken by credit-rating agencies in Section 3. The NZCC could adopt one of these

methodologies or approaches directly as part of the reset decision-making process. Alternatively, it could set out its own set of credit metrics drawn from the methodologies used by credit-rating agencies.

87. Replicating the methodologies used by Moody's and S&P would most directly address the question of whether the EDBs can actually raise debt on the terms the NZCC assumes. Therefore, in one sense this would be the preferred option. Weighing against this is:

    d. Both Moody's and S&P's methodologies have qualitative factors[45] that essentially relate to the regulatory regime, which can introduce circularity to the analysis. For example, the quantitative scores might suggest a fail but the qualitative factors pull the score up to a pass. This could result in the odd situation where the regulator sets an unfinanceable price control but considers it to be financeable because the credit rating agencies have historically viewed the regulatory regime favourably.

    e. Not all of the ratios used by S&P and Moody's methodologies can be calculated without making additional assumptions (for example around dividend payments).

88. Based on this, our suggestion is that any testing focus on metrics readily available from the NZCC's. This would be low cost and avoid any circularity/subjective with the qualitative assessment, which is essentially IPART's rationale for focusing on quantitative metrics and assessing financeability based on the two financial metrics that Moody's puts significant weight on (FFO interest coverage ratio and FFO/Net debt).

5.3. Frequency of testing

89. Financial market conditions change over time and the financeability of EDBs will also change, so there is a decision to be made as to the frequency at which financeability tests are conducted. In principle the NZCC could conduct financeability tests:

    f. **Annually**, for all networks throughout the price control, which would allow the NZCC to respond to financial conditions as they emerged;

    g. **At periodic resets**, which would give NZCC the opportunity to assess financeability for the forthcoming DPP determination for each network to ensure they were financeable on an *ex-ante* basis; and/or

    h. **During the IM Review process**, which would give NZCC the opportunity to assess the impact of its IM decisions on the financeability of EDBs.

90. As a generalisation, we think it makes sense for the NZCC to assess financeability when it is making decisions that have the potential to affect the financeability of EDBs. This suggests that the appropriate time to test financeability would be during the IM reviews and at the DPP resets.

91. In the recent Part 4 IM Review Decision Making Framework paper published by the NZCC, it appears to have acknowledged that financeability testing could be an input in a decision to set an alternative X factor: [46]

    > *We do not consider that introducing a new economic principle in the form of a financeability test would further help us in applying the Part 4 purpose. However, we may take financeability into account to the extent doing so is consistent with promoting the Part 4 purpose in a particular context. Further, in*

[45] Moody's relies on a mix of qualitative and quantitative factors with a fifty-fifty weighting. Moody's scores for qualitative factors are therefore directly part of the calculated credit score. Moody's qualitative factors are mostly external to the control of the firm being rated and flow from the risks imposed by the regulatory environment and revenue cap model. S&P relies on qualitative estimates of country risk, industry risk, and competitive position to set the initial range of expected credit ratings. Thus, by contrast to Moody's where the qualitative factors directly flow into the calculated score, S&P's qualitative factors sets a floor and ceiling on the credit rating determined by the quantitative factors.

[46] NZCC, *Part 4 IM Review Decision Making Framework Paper*, October 2022, para 4.33.5.

resetting a DPP, we may set an alternative rate of change for a particular supplier if, we consider it necessary or desirable to minimise any undue financial hardship to the supplier or to minimise price shock to consumers.

92. However, in our view it is equally important that financeability testing is conducted during the IM review, as the IM review will lock in decisions that affect the financeability of EDBs at the DPP reset, which limits the remedies available to the NZCC of a failed financeability test.

5.4. Remedies

93. Testing the financeability of EDBs will not increase the financeability of EDBs or the consistency of reset decisions per se. The financeability of EDBs will only improve if:

    a. following a failed test, the NZCC acts and adjusts the reset decision to ensure that EDBs are more financeable; or

    b. anticipating the potential for a failed test, the NZCC adjusts the reset decision.

94. In principle, remedies could consist of accelerating the profile of depreciation to ensure that distributors remain financeable or increasing the rate of return. In practice, accelerating depreciation has been the prominent response to failed financeability tests in the UK, though Ofgem and Ofwat have suggested other remedies, as we set out in Table 9 below.

Table 9: Ofgem and Ofwat's remedies in case of a failed test

Ofgem[47]	Ofwat[48]
▪ Adjust dividend policies to retain cash within the ring-fence during the control period ▪ Inject equity to reduce gearing ▪ Re-finance debt or any other financial commitment ▪ Propose alternative capitalisation rates and depreciation rates: under the RIIO framework introduced in 2013, Ofgem adopted a totex framework for analysing costs and allows companies to propose their own proportions and asset lives for “fast” and “slow” money	▪ Reduce dividends when real regulatory capital value (RCV) growth exceeds 10 per cent to maintain gearing close to the notional level of 60% ▪ Advance revenue from future customers using Pay-As-You-Go (PAYG) and RCV run-off. Thus, water companies in England and Wales are able to propose as part of their business plans what proportion of their expenditure should be expensed within year (PAYG) and what proportion should be capitalised and depreciated (RCV run off).

Source NERA analysis

95. Which remedy meets consumers’ needs will depend on the underlying cause of the financeability problem, i.e., whether the profile or the sufficiency of the rate of return is the primary driver of the lack of financeability. Understanding the source of the financeability issue is important, as if the problem is with the allowed rate of return being too low, accelerating depreciation to bring cash forward in some sense just kicks the can down the road.

96. In this regard, we note IPART’s approach appropriately recognises that the solution depends on the problem as shown in Table 10. In particular, if the benchmark test fails, IPART reassesses the

[47] Ofgem, *Consultation: RIIO-2 Sector Specific Methodology Annex: Finance*, 24 May 2019, p. 57.

[48] Ofwat, *PR19 final determination, Aligning risk and return technical appendix,* December 2019, p. 94.

regulatory pricing decision, whereas if the actual test fails, it liases with the business about the source of the issue.[49]

Table 10: IPART matches the remedy to the source of the financeability problem

Source of financeability concern	Remedy
Regulatory error	Correct the error by reassessing pricing decision
Imprudent or inefficient business decisions	Alert business owners to need to inject more equity/accept a lower return on equity.
Temporary cash flow problems	NPV-neutral adjustment to prices.

Source: IPART, Review of our financeability test, Final Report, 2018, p.63 Decisions 24-26.

97. Our view is therefore that an approach similar to IPART's, in the sense of focusing on quantitative measures and matching the remedy to the problem, would be most appropriate.

[49] IPART, *Review of our financeability test,* Final Report, 2018.

Appendix A. Moody's rating methodology for regulated electric and gas networks

A.1. Overview of Moody's Approach to assessing credit ratings

98. Moody's assesses credit rating for regulated electric and gas companies using a range of qualitative as well as quantitative factors (financial ratios), as set out in Table 11 below.

Table 11: Moody's assesses electric and gas credit rating based on qualitative and quantitative Factors

Broad Grid Factors	Factor Weighting	Sub-Factors	Sub-Factor Weighting
Regulatory Environment and Asset Ownership Model	40%		
		Stability and Predictability of Regulatory Regime	15%
		Asset Ownership Model	5%
		Cost and Investment Recovery (Ability and Timeliness)	15%
		Revenue Risk	5%
Scale and Complexity of Capital Program	10%		
		Scale and Complexity of Capital Program	10%
Financial Policy	10%		
		Financial Policy	10%
Leverage and Coverage	40%		
		AICR or FFO Interest Coverage	10%
		Net Debt / RAB or Net Debt / Fixed Assets	12.5%
		FFO / Net Debt	12.5%
		RCF / Net Debt	5%
Total	100%		100%

Source: NERA, Moody's (April 2022), Rating Methodology: Regulated Electric and Gas Networks, p. 4.

99. The qualitative factors include three key areas: Regulatory environment and asset ownership model (40%); scale and complexity of the capital programme (10%), as defined by the capex to RAB ratio; and financial policy (10%).

100. The quantitative factors (leverage and coverage) have a weighting of 40 per cent in the overall rating and are assessed based on Moody's calculation of four key financial ratios:

a. Adjusted Interest Cover Ratio (AICR) or Funds From Operations (FFO) interest coverage;

b. Net debt/Regulated Asset Base (RAB);

c. FFO/Net Debt; and

d. Retained Cash Flows (RCF)/Net Debt.

101. Table 12 shows how Moody's defines its quantitative metrics.

Table 12: Moody's definition of quantitative scores

Sub Factor	Definition
AICR	(Revenue - Opex - Tax - Depreciation) / Notional Interest
FFO Interest Coverage	(Revenue - Opex - Tax) / Notional Interest
Net Debt / RAB	(RAB x Notional Gearing) / RAB
FFO / Net Debt	(Revenue - Opex - Tax - Notional Interest) / (RAB x Notional Gearing)
RCF / Net Debt	(Revenue - Opex - Tax - Notional Interest - Net Dividends) / (RAB x Notional Gearing)

Source: NERA, Moody's (April 2022), Rating Methodology: Regulated Electric and Gas Networks, p. 14.

A.2. How Moody's assigns credit ratings for regulated electric and gas companies

102. As the first step of its rating assessment, Moody's assigns a rating score based on Moody's broad categories Aaa, Aa, A, Baa, Ba, B, or Caa to each of the sub-factors set out in Table 13.

103. The rating score for qualitative factors is based on Moody's criteria set out in the methodology document[50] and for financial ratios based on rating thresholds as shown in Table 13 below.

Table 13: Sub-factor rating thresholds for Moody's financial ratios

Sub Factor	Sub factor weight	Aaa	Aa	A	Baa	Ba	B	Caa
AICR or	10%	≥5.5x	3.5-5.5x	2-3.5x	1.4-2x	1.1-1.4x	0.9-1.1x	<0.9x
FFO Interest Coverage		≥7.5x	5.5-7.5x	4-5.5x	2.8-4x	1.8-2.8x	1.1-1.8x	<1.1x
Net Debt / RAB	12.5%	<30%	30-45%	45-60%	60-75%	75-90%	90-100%	≥100 %
FFO / Net Debt	12.5%	≥35%	26-35%	18-26%	11-18%	5-11%	0-5%	<0%
RCF / Net Debt	5%	≥30%	21-30%	14-21%	7-14%	1-7%	(4)-1%	<(4)%

Source: NERA, Moody's (April 2022), Rating Methodology: Regulated Electric and Gas Networks, p. 4-8.

104. In the second step, Moody's converts the rating score into a numerical score based on a scale as in Table 14 below.

Table 14: Conversion of rating scores into numerical scores for each sub-factor

Aaa	Aa	A	Baa	Ba	B	Caa
1	3	6	9	12	15	18

Source: NERA, Moody's (April 2022), Rating Methodology: Regulated Electric and Gas Networks, p. 20.

105. As a third step, the numeric score for each sub-factor (or each factor, when the factor has no sub-factors) is multiplied by the weight for that sub-factor (or factor), with the results then summed to produce an aggregate numeric score.

[50] Moody's, *Rating Methodology Regulated Electric and Gas Networks*, April 2022.

106. A further weighting is then applied by rating category as set out in the table below. Moody's weights lower scores more heavily than higher scores in the scorecard because a serious weakness in one area often cannot be completely offset by strength in another.

Table 15: Additional weight for the aggregate numeric score

Aaa	Aa	A	Baa	Ba	B	Caa
1	1	1	1.15	2	3	5

Source: NERA, Moody's (April 2022), Rating Methodology: Regulated Electric and Gas Networks, p. 20.

107. The actual weighting applied to each sub-factor is the product of that sub-factor's standard weighting and its over-weighting, divided by the sum of these products for all the sub-factors (an adjustment that brings the sum of all the sub-factor weightings back to 100%.)

108. The numerical score for each sub-factor is multiplied by the adjusted weight for that sub-factor, with the results then summed to produce an aggregate numeric score before notching factors (the preliminary outcome). Moody's then considers whether the preliminary outcome that results from the weighted factors should be notched upward or downward in order to arrive at an aggregate core after notching factors. The Uplift for Structural Considerations notching factor can result in a total of up to three upward notches from the preliminary outcome to arrive at the scorecard-indicated outcome.

109. The aggregate numeric score before and after the notching factor is mapped to an alphanumeric score. For example, an issuer with an aggregate numerical score before notching factors of 11.7 would have a Ba2 preliminary outcome, based on the ranges in the table below. If the combined notching factors totalled two upward notches, the aggregate numeric score after notching factors would be 9.7, which would map to a Baa3 scorecard-indicated outcome.

110. The scorecard-indicated outcome is then assessed against (i) Other Considerations (ii)Instrument Considerations, and (iii) Cross-Sector Methodologies, to reach the final assigned rating.

Table 16: Scorecard-indicated rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	x < 1.5
Aa1	1.5 ≤ x <2.5
Aa2	2.5 ≤ x < 3.5
Aa3	3.5 ≤ x < 4.5
A1	4.5 ≤ x < 5.5
A2	5.5 ≤ x < 6.5
A3	6.5 ≤ x < 7.5
Baa1	7.5 ≤ x < 8.5
Baa2	8.5 ≤ x < 9.5
Baa3	9.5 ≤ x < 10.5
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5

Source: NERA, Moody's (April 2022), Rating Methodology: Regulated Electric and Gas Networks, p. 21.

Appendix B. S&P's rating methodology for regulated electric and gas networks

B.1. Overview of S&P's approach to assessing credit ratings

111. To determine credit ratings, S&P assesses companies' risk along two key dimensions: (i) Business risk profile and (ii) Financial risk profile.

112. To assess companies' business risk profile, S&P considers three broad areas:

    a. Country risk: which considers a range of factors including economic, institutional and governance, legal and financial systems, that arise from doing business with or in a specific country.

    b. Industry risk: which considers a range of factors that affect the industry in which the rated company operates in, including industry growth trends, market structure & competition and industry cyclicality.

    c. Competitive position: which looks at the competitive position of the rated company, including competitive advantages; scale, scope & diversity; operating efficiency and profitability.

113. There are six possible scores from S&P's assessment of the Business risk profile based on the above factors: excellent, strong, satisfactory, fair, weak, and vulnerable.

114. To assess its financial risk profile, S&P considers a range of financial ratios as follows:

    a. "Core" ratios including:

   i. Funds from operations (FFO)/debt; and
   ii. Debt/EBITDA.
b. "Supplementary" coverage and payback ratios including:
   i. Funds from operations (FFO)/ cash interest;
   ii. EBITDA/interest;
   iii. Cash flow from operations (CFO)/debt;
   iv. Free operating cash flow (FOCF)/debt; and
   v. Discretionary cash flow (DCF)/debt.

115. S&P defines its quantitative ratios as described in Table 17.

Table 17: S&P's definition of financial ratios

Financial Ratios	Definition
FFO / Debt	(Revenue - Opex - Tax - Notional Interest) / (RAB x Notional Gearing)
Debt / EBITDA	(RAB x Notional Gearing) / (Revenue - Opex)
FFO / Cash Interest	(Revenue - Opex - Tax - Notional Interest) / Notional Interest
EBITDA / Cash Interest	(Revenue - Opex) / Notional Interest
CFO / debt	(Revenue - Opex - Tax) / (RAB x Notional Gearing)
FOCF / debt	(Revenue - Opex - Tax - Capex) / (RAB x Notional Gearing)
DCF / debt	(Revenue - Opex - Tax - Capex - Net Dividends) / (RAB x Notional Gearing)

Source: S&P (November 2013), S&P Corporate Methodology, p. 30.

116. We note the key difference between S&P's and Moody's approaches to calculating financial ratios is the treatment of accrued interest on index linked debt. Moody's takes a "cash-flow" apporach to interest costs which recognizes the cash benefit of index-linked debt by calculating FFO and other ratios after subtracting cash interest but not the accrued interest on index-linked debt. In contrast, S&P takes a "P&L" approach to interest and calculates FFO and other ratios taking into account the full interest expense, including cash interest and the accrued interest. As a result of different treatment of debt interest costs, companies with index-linked debt will exhibit weaker ratios (i.e., FFO/debt) from S&P compared to Moody's.

117. S&P publishes explicit guidance on the relevant thresholds for each ratio which translate into one of six possible scores for financial risk profile: minimal, modest, intermediate, significant, aggressive, and highly leveraged. We understand that energy networks operating in a regulated environment are assessed by S&P against its low-volatility cash-flow financial metrics, summarized in Table 18 below.

Table 18: S&P ratio thresholds for an industry exhibiting low volatility

	Core Ratios		**Supplementary Coverage Ratios**		**Supplementary Payback Ratios**		
	FFO/ Debt	Debt/ EBITDA	FFO/ Cash Interest	EBITDA/ Interest	CFO/ Debt	FOCF/ Debt	DCF/ Debt
	%	x	x	x	%	%	%
Minimal	>35	<2	>8	>13	>30	>20	>11
Modest	23-35	2-3	5-8	7-13	20-30	10-20	7-11
Intermediate	13-23	3-4	3-5	4-7	12-20	4-10	3-7
Significant	9-13	4-5	2-3	2.5-4	8-12	0-4	0-3
Aggressive	6-9	5-6	1.5-2	1.5-2.5	5-8	(10)-0	(20)-0
Highly Leveraged	<6	>6	<1.5	<1.5	<5	<(10)	<(20)

Source: NERA, S&P (November 2013), S&P Corporate Methodology, p. 35.

118. Unlike Moody's, S&P does not have a prescribed approach to combining the different financial ratios in a final score for the financial risk profile. In the case of regulated energy companies, we understand that S&P focuses primarily on the FFO/debt core ratio for determining a company's financial risk profile.

119. Based on its assessment of the Business risk profile and financial risk profile, S&P then combines the two risk factors to form a rating anchor according to the "anchor" matrix set out in Table 19 below.

Table 19: S&P determines anchor rating based on assessment of business and financial risk

	Financial risk profile					
Business Risk Profile	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
1 (excellent)	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
2 (strong)	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
3 (satisfactory)	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
4 (fair)	bbb/bbb-	bbb-	bb+	bb+/bb-	bb-	b
5 (weak)	bb+	bb+	bb	bb-	b+	b/b-
6 (vulnerable)	bb-	bb-	bb-/b+	b+	b	b-

Source: NERA, S&P (November 2013), S&P Corporate Methodology, p. 8.

Appendix C. Methodology for stylized model

C.1. Model construction

120. We have calculated the stylized financeability ratios reported in section 4 using a financial model based on the DPP3 financial model. This stylized model is a Building Blocks Model and calculates the financial ratios used in financeability analysis while varying certain price control inputs such as inflation assumptions, average asset lives, and the X-factor used in the BBM model. The inputs into this model, represent an 'averaged EDB'. We do this using the DPP3 financial model and data and calculating the averaged RAB, asset lives, opex and capex of all the EDBs.

121. To calculate cashflows we have used the outputs of the BBM regarding costs (opex, depreciation and tax) and the smoothed MAR regarding revenue. Note that the tax allowance value from the BBM model is used for 'tax payable' in calculating the FFO. This will likely understate the cash tax liability as this would be calculated on the final revenue rather than the pre-tax revenue.

C.2. Approach to credit metric thresholds

122. In section 4, we apply the financeability test adopted by IPART to our stylized model, and test whether the three financial metrics (FFO interest coverage, gearing (leverage), and FFO over net debt) are all above the Baa rating for a five-year period. In Section 4 we only reported the changes made in FFO interest coverage and FFO over net debt because gearing (leverage) is constant in the benchmark case.

123. We use IPART's financeability test because compared to the test conducted by Ofgem and Ofwat, IPART provides a clear description of the financial metrics and thresholds for whether or not a firm is financeable or not. It also is based solely on quantitative values rather than a mix of quantitative and qualitative (used by Moody's and S&P) which is simpler and is more objective. IPART uses three of the four quantitative financial metrics used in Moody's quantitative assessment section to derive the credit rating and test financeability, comprising the vast majority (88%) of the total quantitative assessment.[51] The metric which IPART does include which we do not (RCF/debt) requires dividend information which is not provided in the NZCC financial model that we base our stylized model off of. We have therefore excluded it from our analysis rather than rely on assumptions.

124. In its 2018 final report, IPART concluded that the passing threshold will be based on Moody's Ba threshold set for regulated water utilities.[52] In other words, to pass IPART's financeability test, firms must score at least the Ba value set by Moody's for regulated water utilities.[53] IPART set a target credit rating of Baa2 using Moody's rating method (equivalent to BBB of S&P) for all firms, but used the Ba threshold for each financial metric's target because "Moody's Ba benchmark ratios tend to be more consistent with the credit rating outcomes for Australian regulated water utilities (and Australian regulated energy and gas networks) and more applicable for our purpose (than the Baa range)".[54]

125. The NZCC uses S&P's BBB+ rating (equivalent to Baa1 of Moody's) to set the cost of debt. To be consistent with this, we use the lower end of the Baa range set by Moody's for regulated energy networks as our modelled threshold. Thus for the purpose of our exercise, we are imposing a more stringent threshold than IPART, but one that is internally consistent with

[51] Table 3 above.

[52] IPART, *Review of our financeability test, Final Report,* November 2018. P.53 Table 3.

[53] Moody's Investor Service, *Rating methodology – Regulated Water Utilities*, June 2018.

[54] IPART, *Review of our financeability test*, November 2018, p. 52,53.

NZCC's view of the cost of debt. Table 20 below shows the different target ratios adopted by IPART and Moody's, as well as the target ratios used in our financeability test.

Table 20: Nominal metrics used by IPART and credit rating agencies

	ICR	FFO over Debt
IPART (final decision using a Ba threshold)	>1.8x	>6%
Moody's (Baa) –Energy networks	2.8-4x	11-18%
Threshold used in NERA's analysis (based on Moody's Baa threshold)	>2.8x	>11%

Source: NERA analysis, IPART (November 2018), Review of our financeability test, p.53.

126. In practice, IPART's assessment of the notional company is based on a real interest rate and adjusted thresholds which capture how the relevant ratios change when inflation is excluded. By contrast, its assessment of actual businesses uses nominal definitions of interest, consistent with Moody's methodology and with how companies would actually finance their activities (index-linked debt is not commonly used). Our modelling approach relies on nominal interest.

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NERA Economic Consulting
Level 11
15 Customs Street West
Auckland 1010
New Zealand
www.nera.com