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Scale efficiencies in electricity distribution: options short of mandated amalgamation

Report for ERGANZ

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1. Introduction and Conclusions

1.1. Our task

1. In 2025, the New Zealand government commissioned Frontier Economics to review the performance of the New Zealand electricity market. One of the recommendations from this review was consolidating the 28 electricity distribution businesses (EDBs) into five. The Government responded in a Cabinet paper of July 2026, released alongside a discussion document. The discussion document did not adopt the recommendation, but retained the diagnosis that EDBs are too small to be efficient. The discussion document still seeks stronger incentives for consolidation or amalgamation where that delivers better outcomes, and the Minister is scoping intervention powers if collaboration is too slow.
2. The Electricity Retailers' and Generators' Association of New Zealand (ERGANZ) has asked us four questions for its submission on the discussion document:
   A. Does the evidence support the claim that EDBs are too small to be efficient? If efficiencies remain, how large are they and where?
   B. Does the changing role of EDBs in the energy transition change that answer?
   C. Can the remaining efficiencies be captured with policies less invasive than amalgamation, and if so how?
3. Fragmentation can create two kinds of inefficiency:
   A. **Network cost inefficiencies.** These are inefficiencies in the cost of producing the distribution service: the owner's fixed costs spread over too few connections, and any economies of scale in operating the network.
   B. **EDB/retailer interface inefficiencies.** These are the transaction costs that retailers, aggregators and flexibility providers bear in dealing with 28 EDBs that each set their own prices, processes and data formats.
4. These efficiencies have different underlying drivers (scale vs transaction/co-ordination costs) and therefore likely require different remedies.
5. For each kind of inefficiency we take the first two of ERGANZ's questions together, looking at what the New Zealand and international evidence says about the scope for efficiencies today and what the energy transition adds.
6. Having examined the evidence for each type of efficiency, we then ask whether exempt and non-exempt EDBs have the incentive to achieve these efficiencies, if they exist. The answer to this question informs the problem definition against which we assess options for achieving efficiencies (so that options are targeted at specific problems or market failures).
7. We then consider whether alternative structures to amalgamation would achieve these efficiencies at lower cost and then consider high level policy options that would address barriers to these structure being adopted. Our options development and assessment is deliberately high level and intended to supplement options MBIE is already considering (in particular for exempt EDBs).

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8. NERA peer-reviewed the Frontier report for the Ministry of Business, Innovation and Employment (MBIE) in 2025 and found Frontier's conclusion that EDBs are frequently too small to deliver economies of scale "plausible, albeit weakly evidenced"; in particular, it found no clear evidence that five is the optimal number of EDBs or of the total benefits of amalgamation. In this report, we assemble the evidence on scale that the peer review found Frontier had not provided.

1.2. Our findings and recommendations

9. Our findings for ERGANZ's questions are:
   A. On the existing scope for efficiencies:
      i. Network costs: **Once customer density is controlled for, the empirical evidence suggests that economies of scale in total cost at New Zealand EDB sizes are likely small**. The scale economy that remains is in operating costs, and sits mainly in the head-office functions. This is confined to the seven EDBs with fewer than 20,000 connections. On the illustrative assumption that half of overhead costs could be avoided through shared functions, the savings could comprise around $10 million a year (under one per cent of current sector distribution costs, measured by aggregate builing blocks costs). This is an illustrative example, not a forecast of what amalgamation would deliver: where distributors elsewhere have merged, the savings forecast for them have generally not been realised, and the one-off costs of integration have not been quantified.
      ii. EDB/retailer interface: **Without policy intervention a set of 28 independently determined EDB/retailer interfaces will likely to be a growing source of inefficiency**. This is not, however, an issue of size per-se, but one of complexity and difference between the 28 EDBs.
   B. The energy transition adds complexity to the retailer interface and additional functions with fixed costs and specialist skills, which strengthens the case for scale in those functions. However, these functions are data, software and contracts, and in other countries, these are often shared. **The transition therefore strengthens the case for shared provision and/or standardisation of processes**.
   C. Regarding alternatives to forced amalgamation:
      i. **A number of market structures/outcomes exist that would be less costly means of achieving efficiencies than forced amalgamation**:
         a. shared management companies and further contracting out, which capture the head-office efficiency;
         b. shared or national platforms for the new functions, which capture the platform efficiency and part of the interface efficiency; and
         c. standardised interface terms, processes and data, which capture the interface efficiency.
      ii. **EDBs are unlikely to capture the efficiencies on their own** because:
         a. exempt EDBs have a weak incentive to reduce any cost, because of how consumer ownership is organised and not because of network size;

b. non-exempt EDBs appear to have an adequate incentive to move existing functions to shared providers where it would reduce inefficiencies and not incur large upfront costs, but potentially a weaker one to share new functions rather than build them, because the regime *may* fund a capital own build more readily than a shared subscription; and

c. Regarding the EDB/retailer interface, EDBs pay the one-off cost of harmonising while retailers and consumers receive the benefit (externality problem), and no single EDB can make a standard, so none gains by moving first (collective action problem).

iii. **MBIE could therefore consider the following policy options as alternatives to amalgamation** (in addition to those it is already consulting on), which are directly targeted at the underlying barrier to the efficiencies being achieved:

a. stronger incentives for shared delivery of head-office functions and new platforms, including a review of whether the price-quality regime funds a capital own build more readily than a shared subscription;

b. Incentives for the merger of small EBDs, such a longer IRIS retention period; and

c. binding standards governing the interfaces between EDBs and retailers set by the Electricity Authority under ministerial direction, if necessary, with cost recovery for EDBs, including:

1. pricing structures (as opposed to pricing levels);
2. increased standardisation of core terms in default distribution agreements, for example to standardise planned outage and fault notification procedures;
3. standardised network visibility tools and procedures to value, procure, and dispatch flexibility resources for network needs; and
4. standardised load management protocols to govern the control of loads by both networks and retailers or aggregators.

1.3. Report structure

10. The structure of this report is as follows:

A. Section 2 sets out the background: MBIE's package, the framework that separates the two kinds of inefficiency, and the regulatory regime that shapes EDBs' incentives.

B. Section 3 reviews the evidence on network cost efficiencies and closes with a problem definition.

C. Section 4 does the same for the EDB/retailer interface.

D. Section 5 identifies the options, including mandated amalgamation, and assesses them against the status quo.

2. Background

11. In this section, we set out:

    A. the context for MBIE's review and the proposals it is consulting on (section 2.1);

    B. the framework we use to separate the two kinds of inefficiency (section 2.2); and

    C. the regulatory regime that shapes EDBs' incentives (section 2.3).

2.1. Context for current MBIE review and proposals being consulted on

12. In May 2025 Frontier Economics reported to the Government on the performance of the electricity market. One of its recommendations was to amalgamate the EDBs into five regional businesses, on the basis that the sector is too fragmented. The Government rejected forced amalgamation in its October 2025 Energy Package, and instead wrote to EDBs asking them to collaborate.[1]

13. The question had been asked before. The 2018 to 2019 Electricity Price Review, the last government-commissioned review of the sector before the Frontier review, considered requiring small EDBs to amalgamate in its 2018 options paper and did not carry the option into its final report. It recommended instead that the Electricity Authority require EDBs to offer retailers standard default terms for network access, and that the Commission be given power to recommend removing an EDB's exemption from price-quality regulation and to use comparative benchmarking. The first recommendation became the default distributor agreement of 2020; the others were not implemented and are options in the current discussion document.[2]

14. In July 2026 Cabinet agreed a package of measures in response and in August 2026 released a consultation document on this package of measures. The package has three strands:

    A. Voluntary collaboration and standardisation, including: standard connection processes and pricing; a coordination group to develop a DSO model; and better visibility of low-voltage networks.

    B. New tools for economic regulation under the Commerce Act, including: revenue thresholds, performance requirements, quality-only regulation, financial ring-fencing with limits on dividends from consumer-owned EDBs, rules for significant investments, regulatory periods of three to six years, and individual price paths.[3] MBIE also proposes to allow the use of comparative benchmarking to set default price-quality paths.[4]

    C. Governance reform for consumer-owned EDBs, including: statutory objectives, board capability, limits on investment outside the core business, and mandatory reviews of ownership.

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1 Office of the Minister for Energy, Improving the Performance of Electricity Distribution Businesses, Cabinet paper, 29 July 2026 ("Cabinet paper"), para 17.

2 Electricity Price Review, Final Report, May 2019, recommendations C4 and E4; Electricity Price Review, Options Paper, February 2019.

3 MBIE, Improving the Performance of Electricity Distribution Businesses: Discussion Document, August 2026 ("Discussion Document"), Responsive regulation under Part 4, Options 2A and 2C.

4 Discussion Document, Monitoring performance, Option 1A; Commerce Act 1986, s 53P(10).

15. We refer to these together as MBIE's package. Two features of MBIE's package are of particular relevance for this for this report:

    A. First, the Government has kept Frontier's diagnosis that NZ EDBs are "too small". In the Cabinet paper, it says small EDBs cannot achieve scale efficiencies, adopt technology, attract skilled staff or access capital, and it seeks stronger incentives for collaboration and amalgamation where these deliver better outcomes.[5]

    B. Second, the only measure aimed at the interface between EDBs and retailers (one of the two kinds of inefficiency we distinguish in section 2.2) is the voluntary standardisation programme. MBIE notes that retailers, who deal with 28 different pricing plans, would gain from standardisation, [6] but it proposes no measure to require it.

2.2. Framework: two kinds of inefficiency

16. Fragmentation can create two kinds of inefficiency in the context of EBDs:

    A. **Network cost inefficiencies:** inefficiencies in the cost of producing the distribution service; and

    B. **EDB/retailer interface inefficiencies:** Transaction and co-ordination costs at the interface between EBDs and retailers.

17. Network cost inefficiencies may be driven by fragmentation in two ways:

    A. Where the fixed costs of owning a network (e.g. overheads) are invariant to its size, more networks mean these costs are duplicated and spread over fewer customers.

    B. There may be economies of scale in operating the network itself.

18. However, the cost of owning a network is also driven by customer density – a network with few customers per kilometre of line costs more per customer to run than a dense one, whatever its size. Amalgamating networks does not change their density, so cost differences that come from density are not an inefficiency caused by fragmentation.

19. EDB/retailer interface inefficiencies relate to the transaction cost at the interface between EDBs and the retailers, aggregators and flexibility providers that deal with them. It is driven by how many EDBs there are and how much they differ, rather than the size of individual EDBs.

20. Our framework also distinguishes between the "poles and wires", and the functions layered on top of them. Network cost inefficiencies can arise in the wires or in the functions, while interface inefficiencies arise only in the functions.

21. While the poles and wires portion is a natural monopoly over a franchise area, the functions layered on top are not, as these functions are not tied to a franchise area. They can be performed by the network owner, bought from a contractor, or shared among several owners through a management company, a joint venture or a central service provider. If the function can be provided at efficient scale without common ownership of the wires, amalgamation is unnecessary.

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5 Cabinet paper, paras. 14 and 20.

6 Discussion Document, page 13.

22. Because network cost and EDB/retailer interface efficiencies have different drivers, they are likely to have different least cost remedies, so we analyse the two kinds of inefficiency separately, in sections 3 and 4.

2.3. Incentive framework for EDBs

23. All 28 EDBs are regulated under Part 4 of the Commerce Act 1986. All are subject to information disclosure (ID) regulation, under which they publish audited financial, asset and performance data each year. Of these, 15 are also subject to price-quality (PQ) regulation, which caps the revenue they may recover and sets minimum quality standards. The other 13 are exempt from price-quality regulation because they are consumer-owned.[7]

24. PQ regulation is applied through a default price-quality path (DPP) that the Commission resets for all non-exempt EDBs together, normally every five years.[8] Within a period, the incremental rolling incentive scheme (IRIS) governs what happens when actual spend departs from the forecast. If an EDB spends less (or more) than its allowance in a year, it retains (or must bear) a share of the difference for a fixed period (5 years) before the saving or extra cost is passed to consumers through an adjusted allowance at the next reset.

25. Two features matter for our analysis. First, allowances for operating costs are built from what the EDB has historically spent (adjusted for forecast scale growth, inflation and productivity). Cutting a cost that is already in the allowance is therefore rewarded through IRIS. A new recurring cost enters the allowance in only three ways:

    A. overspending the current allowance (and incurring an IRIS penalty) and having the expenditure form part of the base year used at the next reset;

    B. through a step change at a reset, capped in aggregate at five per cent of operating expenditure; or

    C. through the innovation and non-traditional solutions allowance (INTSA), capped at 0.8 per cent of revenue, of which a quarter is reserved for projects run jointly by more than one EDB.

26. A step change or an INTSA both require the EDB to present a case to the Commission.

27. Second, capital spending enters the allowance by a different route. An EDB forecasts its capital projects in its asset management plan, and the Commission adopts those forecasts at the reset, subject to a cap of 120 per cent of recent spend. A new capital project is therefore funded by being forecast;[9] a new operating cost is funded only by being argued for or incurring a penalty.

28. An EDB is exempt from PQ regulation if it is "consumer owned", which broadly means owned by an elected trust or co-operative that has fewer than 150,000 connections.[10] Because size is part of the definition, exempt status and small size are correlated by construction, and any comparison of exempt with non-exempt performance is therefore confounded. Information disclosure is therefore

[7] Commerce Act 1986, ss 54D and 54G.

[8] Commerce Commission, Default price-quality paths for electricity distribution businesses from 1 April 2025 – Final decision, , November 2024 ("DPP4 Decision"), para. 1.6; reopeners at paras. 1.12 to 1.14.

[9] Or allowed mid regulatory period through a reopener.

[10] Commerce Act 1986, s 54D.

the only regulatory instrument that applies to an exempt EDB: the Commission can publish its performance and compare it with others, but cannot cap its revenue.

29. Ownership form matters because it sets who receives the return. Of the 28 EDBs, 19 are wholly or partly owned by consumer or community trusts, and a further three by councils.[11] A consumer trust holds the shares on behalf of the connected consumers, who elect the trustees. Its income from the EDB is ultimately distributed to consumers.

30. Whether the trust presses the EDB for lower costs therefore depends on whether its consumers can understand and reward spending that controls costs. They see the discount or dividend directly, but cost control is harder to see. The remaining EDBs are privately owned or listed, and their owners receive any cost saving as profit within the limits price-quality regulation sets.

[11] MBIE, Further advice on encouraging EDB efficiency, Briefing REQ-0015251, 14 June 2025 ("MBIE Briefing June 2025"), footnote 1.

3. Scope for network cost efficiencies

31. In this section, we consider whether some EDBs are too small to run their networks at efficient cost.
    A. In section 3.1, we set out Frontier's claims and the evidence behind them;
    B. In section 3.2, we review the econometric evidence on scale and density and the outcomes of EDB mergers elsewhere;
    C. In section 3.3, we describe what New Zealand's own consolidation and outsourcing already captured;
    D. In sections 3.4 and 3.5, we assess the claims about capability, technology and capital, and the functions the energy transition adds; and
    E. In section 3.6, we consolidate all of the above into a problem definition: which network-cost efficiencies remain, and whether EDBs will capture them unprompted.

3.1. Frontier's claims about EDB size and the evidence behind them

32. Frontier's May 2025 review made one central claim about the size of EDBs: that the industry is too fragmented and that most EDBs operate well below minimum efficient scale. Frontier claims that this limits the ability of most EDBs to operate and invest efficiently and to innovate. Frontier makes three further claims about small EDBs:
    A. They cannot attract and retain the skilled staff needed to plan networks, manage corporate finance, engage with regulators and deliver complex investment programmes;
    B. They find it harder to raise capital for network investment; and
    C. Their small size may also lead to poorer governance and decision-making.[12]
33. Frontier's scale claim rests on a comparison with the Australian state of Victoria, which has a similar land area to New Zealand, a population about 30 per cent larger, but only five EDBs. Frontier observes that 26 New Zealand EDBs are smaller than the smallest Victorian EDBs.[13] However, Frontier does not estimate the scale at which unit costs stop falling, and instead concludes that most New Zealand EDBs are below minimum efficient scale from the size comparison alone.
34. Frontier's remaining claims have thinner support, and do not distinguish size from remoteness and ownership.
35. The skills claim rests on a theme that Frontier reports hearing from stakeholders: EDBs headquartered outside the main cities are too small and too remote to attract and retain experienced staff. This claim appears to derive from remoteness rather than network size.
36. The capital claim relies on two comparisons with limited applicability to small EDBs:

[12] Frontier Economics, Review of Electricity Market Performance: Final Report to Ministers and MBIE, 23 May 2025 ("Frontier Report"), pp. 118 to 120.

[13] Frontier Report, Table 10 and Figure 44, pp. 118to 119.

A. Council-owned water networks in Australia have been reluctant to borrow money, but this is a point about ownership structure rather than size.

B. Vector, the largest EDB, draws on listed equity and a large debt book, but this is a single large firm.

37. The governance claim rests on two examples of small EDBs investing outside electricity distribution, which again concerns ownership and oversight rather than scale.

38. Frontier offers no data on EDB costs, staffing or financing for any of these claims. The distinction between size, remoteness and ownership matters for any potential remedy. Amalgamation changes size but not remoteness, and ownership is addressed by a separate strand of MBIE's package.

39. Frontier's claims therefore fall into two groups:

A. We can assess the scale claim against existing evidence: econometric studies of scale and density in distribution, the outcomes of EDB mergers elsewhere, and what earlier consolidation and outsourcing in New Zealand has already captured. We set this out in sections 3.2 and 3.3.

B. The claims about skills, capital and governance rest on assertion, and there is little direct evidence to assess them with. We assess these claims qualitatively in Section 3.4, including whether contracting and shared services have substituted for scale in New Zealand.

3.2. Evidence on scale economies and merger outcomes

3.2.1. Econometric evidence on scale and density

40. Once customer density is controlled for, the econometric evidence finds small economies of scale in total cost. These are driven by operating cost rather than capital cost.

41. The most direct evidence is a 2024 study of the New Zealand EDBs by Stannard and Barry, using Commerce Commission disclosure data for 2013 to 2022.[14] When unit cost is regressed on size alone, larger EDBs have significantly lower unit costs. However, when customer density, measured as connections per kilometre of line, is added, the size effect becomes small and statistically insignificant, showing that density is much more important than size (regardless of how it is measured) in driving unit costs.

42. Two features of the study limit how broadly we can interpret the results. First, its cost measure is total cost, including operating and capital costs. Those capital costs are about 60 per cent of the total, and they reflect the network already built, so amalgamation would not change them. If economies of scale are found in operating costs, as the two New Zealand studies discussed next show, a total-cost regression would underestimate it. Second, the estimate is a sector-wide average. It does not identify the size below which unit costs start to rise.

43. Two New Zealand studies that estimated separate cost functions for operating cost and for total cost show this directly. Both studies examine the 1998 separation of lines businesses from retail and generation, and each finds economies of scale in operating cost and almost none in total

[14] Stannard, T. and Barry, P. (2024), Scale efficiency gains in utilities? The case of electricity distribution in New Zealand, New Zealand Economic Papers ("Stannard and Barry"), Table 1.

cost.[15] We use them only to show that the operating-cost economy of scale is material and that it does not appear in total cost.

44. Two Nordic studies (in Norway and in Sweden) are often cited as evidence that distributors have unexploited scale economies. Neither contradicts the New Zealand evidence, though for different reasons:

    A. The Norwegian study finds returns to scale of about 1.09, meaning a one per cent increase in both customers and line length raises cost by about 0.92 per cent.[16] Its further claim, that the smallest firms have the most to gain, relies on a sample in which the median firm has about 6,000 customers, far smaller than any New Zealand EDB.

    B. The Swedish study of 171 distributors reports a cost-minimising size of about 160,000 customers and a 35 per cent saving from consolidating to nine firms.[17] Its reported size effect is confounded by a density effect, and the raw averages in the same paper show unit cost flat above 10,000 to 20,000 customers. Applied to five mergers that took place in Sweden in 2018 and 2019, the authors' model predicts savings of between minus 0.4 and plus 1.0 per cent.

45. The North American evidence points the same way. Yatchew's study of Ontario municipal utilities finds minimum efficient scale at about 20,000 customers, with constant or decreasing returns above it.[18] Kwoka's study of United States distributors, which uses a density-controlled approach like Stannard and Barry's, finds mild scale economies, concentrated in lines operations rather than administration.[19]

46. Domah and Pollitt's study of England and Wales and Zhang, Parker and Kirkpatrick's study of developing-country reforms, which do separate the effects of structure, ownership and regulation, attribute most of the observed gains to the regulatory regime rather than to structure or ownership.[20] More generally, Michael Pollitt, in a 2025 report commissioned by the Commerce Commission, cautions that static estimates of scale economies, from whatever country, do not by themselves show that a given merger would lower cost. He adds that there is no single right

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15 Nillesen, P.H.L. and Pollitt, M.G. (2011), Ownership unbundling in electricity distribution: empirical evidence from New Zealand, Review of Industrial Organization 38(1), 61 to 93 ("Nillesen and Pollitt"), Table 3 (output elasticity of 0.80 in the operating-cost regression); Filippini, M. and Wetzel, H. (2014), The impact of ownership unbundling on cost efficiency: empirical evidence from the New Zealand electricity distribution sector, Energy Economics 45, 412 to 418 ("Filippini and Wetzel"), Table 5 (economies of scale for a median firm of 1.116 to 1.122 in variable cost and 0.981 to 1.035 in total cost) and Table 3 (density elasticity of about minus 0.27).

16 Mydland, Ø., Haugom, E. and Lien, G. (2018), Economies of scale in Norwegian electricity distribution: a quantile regression approach, Applied Economics 50(40), 4360 to 4372 ("Mydland et al."); Table 2 shows mean elasticities and returns to scale; Figure 1 shows returns to scale histogram; Table A6 shows quantile results.

17 Söderberg, M. and Vesterberg, M. (2025), Scale properties and efficient network structures in the Swedish electricity distribution market, Journal of Regulatory Economics 68, 17 to 37 ("Söderberg and Vesterberg")

18 Yatchew, A. (2000), Scale economies in electricity distribution: a semiparametric analysis, Journal of Applied Econometrics 15(2), 187 to 210 ("Yatchew").

19 Kwoka, J.E. (2005), Electric power distribution: economies of scale, mergers and restructuring, Applied Economics 37(20), 2373 to 2386 ("Kwoka").

20 Domah, P. and Pollitt, M.G. (2001). The restructuring and privatisation of electricity distribution and supply businesses in England and Wales: a social cost-benefit analysis. Fiscal Studies 22(1), 107–146; Zhang, Y.-F., Parker, D. and Kirkpatrick, C. (2008). Electricity sector reform in developing countries: an econometric assessment of the effects of privatization, competition and regulation. Journal of Regulatory Economics 33(2), 159–178.

answer to optimal scale, because the economies measured for a regulated company depend on which activities that company happens to keep in-house and which it buys in.[21]

47. From the econometric evidence we conclude that:

    A. Scale economies in the wires are largely exhausted at moderate scale;

    B. The economies that remain are in operating cost, not in the capital cost of the network; and

    C. The cross-firm differences in unit cost that motivate Frontier's concern are mostly differences in customer density, which amalgamating geographically separate networks does not change.

48. Seven of the 28 EDBs have fewer than 20,000 connections. They serve about 76,000 connections between them, three per cent of the national total, and their combined total cost (operating expenditure plus depreciation and a return on the asset base, the "asset operating cost" measure Stannard and Barry use) is roughly $130 million a year.[22] Their corporate overheads are $1 million to $3 million each.[23]

49. If an EDB of 20,000 connections were folded into a neighbour five to ten times larger and took on the larger firm's cost structure entirely, the empirical evidence implies that its unit operating cost would fall by somewhere between approximately 15 and 35 per cent, with no change in its capital cost.[24] In practice the saving would come from sharing functions rather than from the whole cost structure. For illustrative purposes, if achievable savings were equivalent to half of overhead costs this would imply savings of $0.5 million to $2 million a year for each firm, approximately $10 million across all EDBs with fewer than 20,000 connections. This comprises about 0.3 per cent of sector distribution cost.[25] These potential savings should be compared against integration costs that have not been well measured.

3.2.2. Outcomes of actual mergers and integration costs

50. In practice, mergers of EDBs have not delivered the savings forecast for them. The scale estimates rom the econometric literature compares firms of different sizes as they stand. They therefore say what a merged firm might cost if it took on the cost structure of firms its new size, not what happens when firms actually merge.

51. Kwoka and Pollitt's study of United States distribution mergers between 1994 and 2003, comparing merging with non-merging units, finds that mergers were not associated with improved cost performance.[26] In Ontario, where the government promoted amalgamation of local distributors and forecast savings of 10 to 30 per cent, Cronin and Motluk found few real gains. Distributors

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21 Pollitt, M.G. (2025), Benchmarking and optimal scale for electricity distribution boards in New Zealand, study for the Commerce Commission, 23 July 2025 ("Pollitt 2025").

22 Commerce Commission information disclosures, 2025. Asset operating cost is as defined by Stannard and Barry.

23 Commerce Commission information disclosures, 2025, Schedule 6b (business support category)

24 The 20 to 35 per cent range applies the Nillesen and Pollitt output elasticity of 0.801 and the Filippini and Wetzel variable-cost scale economy of 1.122 to a five- to ten-fold increase in size at constant density.

25 Sector distribution cost, measured as aggregate building blocks costs (operating expenditure plus depreciation and return on the asset base) is about $3.1 billion in 2025 on the Commerce Commission's 2025 information disclosures.

26 Kwoka, J. and Pollitt, M. (2010), Do mergers improve efficiency? Evidence from restructuring the US electric power sector, International Journal of Industrial Organization 28(6), 645 to 656 ("Kwoka and Pollitt").

with high costs before merging improved, while those with low costs saw average cost rise.[27] Clark and Samano find that Ontario's tax incentives for consolidation had no effect on either efficiency or the number of consolidations.[28] One of the best identified results on consolidation is in the structurally similar water business, Klien and Michaud's study of more than 400 water utilities in Central and Eastern Europe. They used a matched comparison of consolidated and non-consolidated utilities, finds no significant fall in unit cost after consolidation and one-off cost increases during it.[29] Becker-Blease, Goldberg and Kaen find that United States utilities that grew by acquisition underperformed those that did not.[30] Söderberg and Vesterberg, applying their Swedish cost model (section 3.2.1) to five mergers that took place in 2018 and 2019, predict savings of between minus 0.4 and plus 1.0 per cent.[31]

52. Despite this, sector reforms are often predicated on an assumption of savings from mergers. Ontario's 2012 Distribution Sector Review Panel recommended consolidating some 70 distributors into eight to twelve, on savings evidence consisting of individual utility examples, and acknowledged that the research on amalgamation efficiencies was not unanimous.[32] Queensland merged its two state-owned distributors in 2016 on a forecast of $680 million in savings over five years.[33] When Ofgem (UK) assessed the sale of gas distribution networks in 2003, the ex ante synergy estimates it recorded were 20 to 30 per cent of controllable operating cost.[34] We are aware of no ex post study that finds savings in that order.

53. Integration *costs* are typically acknowledged by regulators but almost never quantified. The Ontario Energy Board notes that distributors describe them as significant and as a barrier to consolidation, and allows a merged distributor to defer the reset of its revenue allowance for up to ten years so that it can recover them, [35] but does not itself estimate the costs. One documented figure is from Queensland: the merged distributors' IT programme, budgeted at $238 million in 2016, had an approved budget of $717 million by 2022 and was still incomplete. The Audit Office attributes the growth partly to the post-merger decision to align the two networks' systems and

27 Cronin, F.J. and Motluk, S.A. (2007). How effective are M&As in distribution? The Electricity Journal 20(3), 60–68.

28 Clark, R. and Samano, M. (2022). Incentivized mergers and cost efficiency: evidence from the electricity distribution industry. Journal of Industrial Economics 70(4), 791–837.

29 Klien, M. and Michaud, D. (2019). Water utility consolidation: are economies of scale realized? Utilities Policy 61, 100972.

30 Becker-Blease, J.R., Goldberg, L.G. and Kaen, F.R. (2008). Mergers and acquisitions as a response to the deregulation of the electric power industry: value creation or value destruction? Journal of Regulatory Economics 33(1), 21–53.

31 Söderberg and Vesterberg, Table 7.

32 Ontario Distribution Sector Review Panel (2012), Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First, p.28 & p.39.

33 Nick Wiggins, "Energy Queensland: Energex, Ergon merger unveiled at Townsville headquarters", ABC News, 2 June 2016, www.abc.net.au/news/2016-06-02/ergon-and-energex-will-become-energy-queensland/7471462

34 Ofgem (2003), National Grid Transco: potential sale of gas distribution networks, Regulatory impact assessment, 17 December 2003, p.2.

35 Ontario Energy Board (2016), Handbook to Electricity Distributor and Transmitter Consolidations, 19 January 2016 ("OEB Handbook"), pp. 8 to 9 and 11 to 12; OEB (2015), Report of the Board on Rate-Making Associated with Distributor Consolidation, EB-2014-0138, 26 March 2015.

partly to scope added for other reasons. Not all of it is integration cost, and the Audit Office does not say how much is.[36]

54. New Zealand's own 1990s mergers have no ex post study. The closest is Nillesen and Pollitt's study of the 1998 separation, which finds that part of the fall in unit cost after 1998 is attributable to the consolidation from 43 to 28 companies that accompanied it, and that scale economies were smaller by the 2000s than in the 1980s.

55. Norway's government looked at the same question and chose not to mandate mergers. Its 2014 expert group, reviewing a sector of about 150 distributors (mostly smaller than New Zealand's), concluded that many were probably too small but that there was no certain relationship between size and efficiency. [37]

56. We conclude the following from this evidence:

    A. Forecast savings from distributor mergers have typically not been realised, and the pattern is the same in the United States, Ontario, Sweden and European water.

    B. The one-off costs of consolidation are real enough that two regulators have built their merger policies around them, but their size is unknown. This suggests that shared arrangements may be cheaper to enter than mergers.

3.3. What New Zealand's earlier consolidation and outsourcing already captured

57. New Zealand has already been through a version of the consolidation Frontier proposes. In 1985 there were 61 electricity supply authorities.[38] The Energy Companies Act 1992 turned them into companies with a commercial objective,[39] and a wave of mergers followed. By the early 2000s there were 29 lines companies, and there are 28 today.[40]

58. Two further reforms changed what EDBs do. The Electricity Industry Reform Act 1998 required ownership separation of lines businesses from generation and retail.[41] Metering has also since moved out of the EDBs - since the rollout of smart meters, they have been largely owned and operated by retailers or specialist metering companies.[42] Over the same period many EDBs contracted out field services, either to independent contractors or to contracting subsidiaries that also compete for work on other networks. The typical EDB of today owns and plans the network and contracts out much of the work done on it.

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36 Queensland Audit Office (2023), Energy 2023, Report 5: 2023–24, chapter on Energy Queensland's digital programme.

37 Reiten, E., Sørgard, L. and Bjella, K. (2014), Et bedre organisert strømnett, report to the Norwegian Ministry of Petroleum and Energy.

38 MBIE, Chronology of New Zealand Electricity Reform, August 2015 ("MBIE Chronology") (93 supply authorities in 1945, 61 electricity supply authorities in 1985).

39 Energy Companies Act 1992, s 36.

40 Cabinet paper, para. 14.

41 Electricity Industry Reform Act 1998, s 17; MBIE Chronology, p.13.

42 Electricity Authority, EMI Metering snapshot, 31 August 2026; Commerce Commission, Visibility of Low Voltage Networks across Electricity Distribution Businesses: Summary report, disclosure year 2024, 12 February 2025 ("LV Visibility Report"), para. 18.

59. While these reforms were subjectively comprehensive, the evidence on their savings in network costs attributable to consolidation is thin. The best-studied change is the 1998 ownership separation. The two studies cited in section 3.2.1 also measure what the separation saved, and both find that it lowered costs. Nillesen and Pollitt, studying the 28 companies over 1995 to 2007, find a one-off fall in unit operating cost of about 19.5 per cent after controlling for output, connection density and quality. Filippini and Wetzel estimate a one-off improvement in cost efficiency of about 14 percentage points on total cost and 24 on variable cost.[43]

60. The authors attribute part of the fall in unit cost to the consolidation that accompanied separation, from 43 network companies in 1995 to 28 by 2007. Their study is the nearest thing to an ex post study of the 1990s mergers,[44] and MBIE's own advice to the Minister in 2025 records that there is no conclusive evidence of significant economies of scale in New Zealand distribution.[45]

61. Two things follow for the present debate:

    A. The easily accessible economies of scale have likely been taken already: the overheads of the smallest boards were reduced through merger, while retail, metering and field work were made more efficient by moving those activities into competitive markets.

    B. The activities that left the EDBs are the ones with the clearest scale economies, and they were captured without amalgamating the networks.

62. What remains inside a lines company is the network itself, its planning and asset management, and a corporate overhead. We set out in section 3.2 why scale economies in the network are limited once customer density is held constant. If economies remain, they are most likely in the functions that stay in-house: the owner's planning, asset-management, regulatory and corporate functions, and the platforms the energy transition is adding. We discuss each of these in turn in sections 3.4 and 3.5.

3.4. Capability, technology and capital access

63. In section 3.1 we set out three claims Frontier makes about small EDBs beyond scale economies in the network. The first is that they cannot attract and retain skilled staff. The second, stated loosely, is that their scale limits their ability to innovate. The Cabinet paper restates this as an inability to adopt technology to discipline costs. The third is that they find it harder to raise capital.[46] Frontier supports its claims with stakeholder comment, an analogy and one example.[47] We are not aware of any available empirical work or data that would help further substantiate these claims. We therefore ask whether each claim describes a gap that only a larger network owner could close, or one that the market has already found other ways to fill.

64. The first claim, about skilled staff, is the strongest of the three on its face. An EDB needs engineers to plan the network, asset managers to decide what to renew and when, people who can run a price-quality or customised price path process with the Commerce Commission, managers who can deliver a multi-year investment programme, and the finance, IT and procurement functions

43 Nillesen and Pollitt, Table 3 (19.5 per cent); Filippini and Wetzel, Tables 4.

44 Nillesen and Pollitt, pp. 82 to 83.

45 MBIE, Encouraging EDB Efficiency, Briefing REQ-0013881, 21 May 2025 ("MBIE Briefing May 2025"), para. 9.

46 Frontier Report, pp. 3 and 112; Cabinet paper, para. 14.

47 Frontier Report, section 8.4.2, pp. 119 to 120.

that sit behind them. A network with a few thousand connections cannot employ a full set of these people.

65. However, small networks often do not need to employ a full staff of specialists. It is already the case that contractors typically do the design, construction and maintenance. Some are independent and some are owned by other EDBs, and they work across several networks. Several small networks in Southland and Otago are run under a single management company, PowerNet, on behalf of separately owned companies, so that one planning and asset-management team serves all of them. Regulatory submissions and asset-management plans draw on the same small pool of consultants regardless of who the client is.

66. The remoteness problem Frontier's stakeholders describe is likely real, but it derives from remoteness rather than network size. For work that must be done locally, such as fault response and field maintenance, an amalgamated EDB headquartered in a city would face the same choice in any remote location: find people willing to live there, or pay people to travel there.

67. The second claim, about technology, is the least specific of the three. Frontier names no technology, so we assess the claim in the Cabinet paper's form: an inability to adopt technology to discipline costs. The largest EDBs have led on smart-grid and network-visibility investment. Whether that reflects a scale economy in the functions themselves, or the fact that until recently there was no shared platform for a smaller EDB to join, is a question we address later, in section 3.5.

68. There is however a scale effect here that cannot be addressed purely by contracting. A small EDB can license the same advanced distribution management or low-voltage monitoring platform as a large one, but cannot spread the fixed cost of specifying, integrating and operating it over many connections.

69. The third claim, about capital, conflates two things: access to capital and willingness to use it. A regulated network with a stable revenue allowance can access credit at any size. The smallest EDB in the country, Buller Electricity, carries $16 million of secured bank debt on ordinary commercial terms, with covenants that cap how much it may borrow relative to its assets.[48]

70. Frontier's capital claim is about ownership form rather than size. A consumer trust cannot issue equity, and the trust-owned EDBs have chosen to carry about half the debt of the investor-owned ones, with net debt of about 22 per cent of assets against 39 per cent, while paying dividends and discounts to their owners each year.[49] The Auditor-General's 2025 review of the trust- and council-owned EDBs makes the funding point directly: those forecasting large increases in capital expenditure will need to manage how they fund it, and additional funds from their owners are likely to be limited. Amalgamating two trust-owned EDBs changes none of this; MBIE's governance strand addresses it.

71. What limits the capital available to trust-owned EDBs is their owners' preference for low debt and steady distributions, not their size.[50] That leaves less capital available for the network, but it is an

[48] Buller Electricity Limited, Financial Report for the year ended 31 March 2026, note 10.

[49] Office of the Auditor-General (2017), Electricity distribution businesses: Managing the assets that distribute electricity ("Auditor-General 2017"), paras. 2.27 to 2.28. The 22 and 39 per cent figures are the Auditor-General's, not our calculation.

[50] Auditor-General 2017, paras..27 to 2.28; Office of the Auditor-General, Electricity distribution businesses: Observations from the 2023/24 audits, June 2025, para. 2.67.

ownership choice. MBIE's package addresses it from both sides: the proposed dividend limits and ring-fencing sit in the economic-regulation strand, and the governance strand goes to how consumer-owned boards make that choice.[51]

72. The one place where size does impact on capital availability is the cost of the regulatory process itself. Frontier notes, and we agree, that the cost and burden of a customised price path deters small EDBs from applying for one, which can leave a small network with an allowance that does not fund the investment it needs.[52] The cost of that process argues for a cheaper regulatory route for small networks, rather than for fewer networks. MBIE's proposals partly supply one: revenue thresholds and quality-only regulation would let the Commission set a lighter path for a small EDB without a full CPP, longer regulatory periods would reduce how often the question arises, and the proposed exempt route would let the Commission recommend any of these tools for a particular EDB rather than price-quality regulation alone.[53]

73. Across the three claims about the efficiency of small EDBs we see that contracting and shared management have substituted for scale in the delivery of network services in New Zealand. What they have not substituted for is the owner's own capacity to specify what it wants, buy it well and hold the supplier to account. That function is small in headcount but it is real, and its cost is largely fixed, so it weighs more heavily per connection on a small network. A small trust cannot pay for the experienced senior managers that the largest EDBs can. For a network of ten or twenty thousand connections this is a material economy of scale, and it is where the operating-cost scale economy identified in section 3.2 sits. But the test in section 2.2 is whether the function can be provided at efficient scale without common ownership of the wires. It can: several owners can buy one management team, as the Southland and Otago networks do through PowerNet.

3.5. The changing role of EDBs in the energy transition

74. The preceding sections assess the case for scale against the EDB's historical role. That role was to own, plan and maintain the poles and wires. The network was designed for one-way flow, demand was predictable, and the EDB's contact with the market ran through a small number of retailers and a periodic planning cycle. Most of the work was physical and local, and, as we show in section 3.3, much of it has already moved to contractors. The energy transition is adding a different kind of work. We ask whether it changes the answer.

75. The energy transition adds four functions to the EDB's role:

    A. Visibility of the low-voltage network: sensors, smart-meter data and analytics that tell the EDB what is happening on the streets and transformers that it has never monitored, so that it can safely and efficiently host solar, batteries and electric vehicle charging without over-building;

    B. Procuring and dispatching flexibility: contracting with customers or aggregators to shift or reduce load at particular places and times as an alternative to new capacity;

    C. Registration of distributed energy resources, so that the EDB and the system operator know what is connected, where, and with what capability; and

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51 Discussion Document, Responsive regulation under Part 4 (Option 2A) and Governance (Options 3A to 3D); Cabinet paper, paras. 39 and 41.

52 Frontier Report, p. 117.

53 Discussion Document, Responsive regulation under Part 4, Options 2A to 2C.

D. A data and cyber layer beneath all three: the systems that collect, store and secure the data, and the interfaces through which retailers, aggregators and the system operator exchange it.

76. Each of these requires a software platform and a team with skills that were not previously part of a lines business: data engineering, power-systems analysis of low-voltage networks, market and contract design, and cyber security. The hardware is a smaller part of the cost than it might appear: for low-voltage visibility the main source of data is the smart meter, which for all but two EDBs is owned by a retailer or a metering company rather than by the EDB (section 3.3), so the EDB's cost is buying the data and building the platform to use it.[54, 55]

77. The cost of these functions splits in two, with different implications for scale economies:

A. Sensors, meters and communications in the field scale with the number of transformers and connections, so they cost a small network no more per connection than a large one, apart from any volume discount a large buyer obtains, which a group of small EDBs can also obtain by buying jointly, as SmartCo, a metering company jointly owned by seven smaller EDBs, does for its owners.[56]

B. The platform, the data handling and the specialist team are unlikely to scale with the size of the network. A platform and a core team are needed at 10,000 connections as at 500,000. A larger network adds staff to handle more data and more cases, but the cost of building and operating the platform is unlikely to rise in proportion to connections. The platform cost is fixed in the same way as the head-office functions cost in section 3.4. The fixed part is material for a small EDB. Whether it is a case for amalgamation turns on whether the platforms and skills can be provided at scale without common ownership of the wires (see section 2.2).

78. Other countries already provide similar functions above the level of the individual network:

A. Great Britain runs smart-meter data through a single national data communications body and is building a central asset register for flexible resources;[57]

B. Australia's market operator holds a national register of distributed energy resources;[58]

C. Denmark and Norway route all metering and switching data through national data hubs. Norway's hub has had integration problems: it ran at about double its forecast operating cost in 2021 and a 2022 comparison put its annual cost above Denmark's and Finland's;[59]

D. The Netherlands' network companies procure congestion flexibility through one shared platform.[60]

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54 LV Visibility Report, para. 18.

55 The grouping of the four functions is ours.

56 SmartCo, "Our shareholders", smartco.co.nz/our-shareholders (accessed 1 October 2026).

57 Smart Data Communications Company (DCC), licensed under the Smart Meters Act 2008 and Energy Act 2008, operates the national smart-meter data and communications network for Great Britain; Ofgem, Flexibility Market Asset Registration (FMAR).

58 See AEMO, "About the DER Register", available at: https://www.aemo.com.au/energy-systems/electricity/der-register/about-the-der-register. Accessed 07 October 2026.

59 Menon Economics and A-2 Norge, Økonomisk analyse Elhub, Menon publication 51/2022, May 2022, chapter 1 and Figure 1-2.

60 GOPACS (Grid Operators Platform for Congestion Solutions), operated jointly by TenneT and the Dutch regional network operators since 2019.

79. New Zealand already provides some comparable market functions centrally: the registry of connection points, reconciliation and clearing are run once for the whole market by service providers to the Electricity Authority.[61] The functions with the largest fixed costs and the greatest need for consistency tend to be provided once and shared, whoever owns the wires.

80. The pattern in New Zealand for new functions so far is less clear-cut. The larger EDBs have generally led on flexibility trials and distribution system operation planning. On low-voltage visibility the picture is more mixed. The Commerce Commission's 2025 summary of EDB disclosures finds wide variation that does not track size, with some of the smallest EDBs among the more advanced and some mid-sized EDBs with no smart-meter data at all.[62] There are three candidate explanations:

    A. Scale may matter for these functions;

    B. Shared platforms may not yet exist, so only a large EDB could justify building its own; or

    C. The regulatory regime may play a part, which we consider in section 3.6.

81. The three are not exclusive, and which dominates determines the appropriate remedy.

82. The evidence on what shared provision saves, and on how far EDBs of different sizes have progressed in taking on the new functions, is thin. Part of the reason is that each shared platform is a one-off. A country builds its data hub or register once, and there is no counterfactual in which the same country built it 28 times. The Asset Dynamics work for MBIE identified low-voltage visibility and a coordinated approach to distribution system operation as priorities across the sector, which implies uneven progress,[63] and the Commission's February 2025 summary of low-voltage visibility disclosures is the one systematic comparison across all EDBs. It classifies EDBs by the sophistication of their data collection and modelling and does not find that size determines the result. Nor have we found an ex post costing of a shared platform against EDB-by-EDB provision, in New Zealand or elsewhere.

83. We therefore assume that providing these functions once and sharing them costs less than 28 separate builds. The assumption rests on their fixed-cost structure and the international pattern, not on a direct costing. How much less, and how far that gap already explains the difference in progress between large and small EDBs, is unknown.

84. Our conclusion regarding the impact of the transition has two limbs:

    A. The transition adds fixed costs and specialist skills, which weighs against very small network owners standing alone.

    B. But the functions it adds are the most separable ones the EDB has. They are data, contracts and software, and the international pattern is to provide them once and share them.

85. The transition therefore strengthens the case for scale in these functions (from a network cost perspective) and weakens the case that scale must come through ownership of the wires.

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61 Electricity Industry Participation Code 2010, Part 11 (registry), Part 15 (reconciliation) and Part 14 (clearing and settlement); the Electricity Authority contracts market operation service providers for each function.

62 LV Visibility Report, paras. 16 to 38. Flexibility trials: FlexForum, Progress with delivering the Flexibility Plan, August 2023 and August 2025.

63 Asset Dynamics, Electricity Distribution Business Efficiency – Recommendations for Standardisation and Collaboration – Independent Advice and Recommendations, April 2026, as summarised in Discussion Document, p.6.

3.6. Problem definition: will EDBs capture the remaining network-cost efficiencies on their own?

3.6.1. Scope of remaining efficiencies

86. In sections 3 and 4 we end by asking the same question: if the efficiencies identified exist, will EDBs capture them without intervention? The answer is the problem definition we address in section 5. Our analysis arrived at a shorter list of network-cost efficiencies than Frontier's diagnosis implies. In the wires themselves, we find that scale economies are largely exhausted at moderate scale and that much of the apparent size effect is customer density, which amalgamation does not change. Furthermore, the 1990s reforms appear to have taken the most readily available economies once already: the consolidation of 60 boards into 29 removed the very small boards where unit costs are highest, and the unbundling of retail, metering and field services moved into national markets the activities that have since consolidated to national scale. The likely remaining efficiencies fall under two categories:

    A. The owner's own planning, asset-management, regulatory and corporate capability, which is a material fixed cost for the smallest EDBs.

    B. The platforms and specialist teams that the energy transition adds, which likely have a large fixed component.

87. Both these efficiencies can be characterised as "functions" that sit on top of the underlying poles and wires. Each can therefore likely be provided at efficient scale by contracting or shared provision, and New Zealand has working examples of each.

88. The separability of these functions changes the incentive question. If the remaining efficiencies required amalgamation, the question would be whether the regime rewards a merger. For non-exempt EDBs, that means whether the savings retained under IRIS are large enough and last long enough to justify the one-off costs of consolidation, and for exempt EDBs, whether the owner has any reason to pursue savings at all. But most of the remaining efficiencies do not require amalgamation. A management contract, a joint platform or a shared-services arrangement is a smaller and more reversible commitment than a merger, with lower one-off costs. For non-exempt EDBs, the question is therefore whether incentives exist that justify entering arrangements of this kind.

3.6.2. Incentive for non-exempt EDBs

89. For the 15 non-exempt EDBs, the incentive to reduce cost comes from the price-quality path and from IRIS. Under IRIS, an EDB that spends less than its allowance keeps the difference for a fixed period before it passes to consumers, and bears part of any overspend for the same period.[64] How well this works depends on whether the cost being saved is already in the EDB's allowance.

90. For functions the EDB already performs, such as corporate finance or asset management, the cost is in the base year. Moving the function to a shared provider lowers spend below the allowance, the EDB retains the difference, and the incentive works as intended. The incentive is weaker where the move carries one-off costs that fall in the current period while the savings arrive later and the

[64] See section 2.3 for the description of IRIS and the DPP4 incentive rates.

business case only stacks up if more than five years of savings can be retained. The incentive is weaker again for a merger, where those up front costs are largest.

91. For the new functions described in section 3.5 the position is less clear. An EDB that has not yet built a low-voltage monitoring or flexibility platform has no such cost in its base. The Commission has equalised the IRIS incentive rates for operating and capital expenditure so that the choice between an own build and a shared subscription is not distorted by the retention mechanism itself. DPP4 also includes an innovation allowance with a share ring-fenced for collaborative projects.[65]

92. What may still differ is the route by which each option gets into the allowance. An own build that can be categorised as capex is funded by being forecast in the asset management plan. A shared subscription is a new operating cost that must be argued for as a step change or through the innovation allowance, otherwise an IRIS penalty will be incurred. Minimising IRIS penalties might lead EDBs towards more shared functions as this would reduce the overspend where they are unable to get step changes. DPP4 does include a step change for purchasing low-voltage network data, so the Commission has already recognised one cost of this kind across all regulated EDBs.[66] On its face, incurring capex may therefore be procedurally easier than getting a step changed approved where the expenditure is prospective and has not yet been incurred, though how this plays out in practice is currently subject to uncertainty and the Commission has demonstrated a willingness to approve transition related step changes.

93. On the existing functions, then, it would appear that non-exempt EDBs have an adequate incentive to outsource them to shared providers, provided the upfront costs of transitioning to these arrangements are not high. Whether they have an equal incentive to adopt shared provision for new functions depends on the funding routes described above, which may result in a procedural bias towards capex, depending on the Commission's willingness to approve step changes. Adoption so far fits that split between existing and new functions:

    A. Contracted field services and shared contractors, which replace costs already in the base, appear to be widespread.

    B. Shared platforms for the new functions, which would avoid costs not yet in the base, remain at the trial or design stage or are not yet widely adopted.

94. Two explanations fit this pattern, and neither depends on the size of the EDBs. One is that the regime may fund a capital own build more readily than a shared subscription. The other is that until recently there was no shared platform to subscribe to, so the only way to get these functions was to build them, which only a large EDB could justify. Both explanations are also consistent with the larger EDBs having led on these functions, as we note in sections 3.4 and 3.5.

3.6.3. Incentives for exempt EDBs

95. For the 13 exempt EDBs there is no price-quality path and no IRIS. The only pressure to reduce cost comes from the owner. A consumer trust receives the EDB's profits and returns them to consumers as dividends or line-charge discounts. In principle, every dollar saved reaches the people who pay the line charges, and the owners have the same interest in low cost as the shareholders of a private company.

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65 DPP4 Decision, decision O3.7 (step changes) and decision U1 and paras. 3.13 to 3.15 (INTSA).

66 DPP4 Decision, decision O3.3 (step change for low-voltage network data).

96. In practice the pressure is weaker, for three reasons that go to how the ownership is organised rather than to who the owners are:

    A. The ownership is spread over every connected consumer, so no owner has a stake large enough to justify learning how the business could run more cheaply and pressing for it. By contrast a shareholder with a large block, or a board answerable to one, does;

    B. The trustees are elected by those consumers, and what consumers can see and vote on is the size of the discount and the level of the line charge, not whether the EDB's costs are as low as they could be. Distinguishing short-sighted cost-cutting from long-run cost control is hard even for an informed owner; and

    C. Beyond trustee elections, there is no market for control, meaning no way for an outsider to buy the business and run it better: the shares cannot be sold, so there is no share price, no analyst coverage and no takeover threat to reveal an efficiency the trust has not pursued.

97. Information disclosure is the only external check, and the Commission cannot use it to set prices for these EDBs.[67] The pattern in section 3.4, of low borrowing and high distributions, is consistent with owners who prefer a known payout now to a cost-saving programme with upfront effort. That pattern alone does not establish inefficiency. It also fits owners who lack the means to press for savings. The theory of consumer ownership predicts weak pressure to control cost. Ownership by customers removes the incentive to overcharge them, which is why the exemption exists, but does little to make owners press for lower cost.[68]

98. The direct evidence on whether exempt EDBs are less productive than non-exempt ones is limited. The Commerce Commission commissioned a study of EDB productivity in 2024 that covers both groups.[69] It finds total factor productivity falling by about 1.3 per cent a year over 2008 to 2023, with little difference between exempt and non-exempt EDBs and most of the fall before 2014. On operating expenditure alone, productivity fell faster for exempt EDBs, by about 2.1 per cent a year against 1.2 per cent for the regulated group. Stannard and Barry's work on distribution productivity found no clear relationship between size and efficiency once density is controlled for.[70] Any comparison between the two groups is confounded, because the exempt EDBs are also the smallest and among the most rural. A gap in measured productivity may therefore reflect density rather than regulatory status or ownership. We treat this evidence as inconclusive on its own and rely on the incentive analysis above.

99. Two further pieces of evidence point the same way. Three of the six EDBs Frontier cites for rising equipment-related outages are exempt and have no revenue cap. That sits awkwardly with Frontier's explanation that constrained price paths are the cause. The international literature that separates the effects of regulation from those of ownership generally finds regulation the stronger

67 Commerce Act 1986, ss 54G and 54H and Part 4 subpart 4; Discussion Document, Responsive regulation under Part 4, Option 2B.

68 Hansmann, H. (1996). The Ownership of Enterprise. Harvard University Press.

69 CEPA, EDB Productivity Study: A report prepared for the Commerce Commission, June 2024, as read in MBIE Briefing June 2025, p.12.

70 Stannard and Barry; MBIE Briefing May 2025.

driver of cost performance, though the same literature shows that such estimates are sensitive to specification.[71]

3.6.4. Summarised network cost problem definition

100. The network-cost problem definition we carry into section 5 is therefore as follows:

A. The remaining efficiencies lie in the head-office functions, and in the platforms the energy transition adds.

B. They can be captured by shared provision or contracting without amalgamation.

C. Non-exempt EDBs have an adequate incentive to move existing functions to shared providers, though a weaker one where the move carries large one-off costs and small ongoing benefits. Their incentive to share new functions rather than build them may be weaker, because the regime may fund a capital own build more readily than a shared subscription.

D. Exempt EDBs have a weak incentive in either case, and the reason is ownership and regulatory status, not network size. Mandated amalgamation would therefore address that incentive gap only incidentally, by folding exempt networks into larger regulated entities.

[71] Frontier Report, Figure 68; Saal and Parker (2001), Journal of Regulatory Economics 20(1); Estache and Rossi (2005), Economics Letters 86(2); Söderberg (2011), Contemporary Economic Policy 29(2).

4. Scope for EDB/retailer interface efficiencies

101. Each of the 28 EDBs sets its own prices, processes and data formats.[72] A retailer that sells nationwide deals with most or all of them, and maintains a version of each for every one it deals with. Aggregators and flexibility providers carry the same cost, so we describe all three as "retailers."

102. This cost has two parts. One grows with the number of EDBs a retailer deals with. The other comes from handling any variation at all: the billing engine that must cope with more than one tariff structure, the complexity of internal processes for handling non-standard cases, and the staff who know more than one system. Reducing 28 EDBs to five would cut the first part by about 80 per cent and leave the second; a common interface would remove nearly all of both. The interface is one of the functions layered on top of the wires, as we explain in section 2.2. The remedy that matches the problem is therefore standardisation. The questions are how far it should go and who should set it.

4.1. Nature and evidence of interface costs

103. A retailer selling nationwide has to work with every EDB's own prices, processes and systems. Each EDB[73] means a separate set of pricing structures and billing rules, a separate connection procedure, a separate planned outage and fault procedure, and a separate procedure for control of flexible load. Embedded networks may add further interfaces/bespoke arrangemetns. Retailers need staff trained on all of them, and each hand-off brings errors and delays that consumers also pay for. The cost rises with the number of EDBs and with how different their arrangements are. It does not depend on how large any one of them is.[74] However, it may mean that some retailers forgo operating nationwide if it is not worth incurring the cost of dealing with smaller EBDs, or that variations in EDB tariff structure will not be reflected in retail offerings.

104. We have not found a published estimate of this cost for New Zealand, though MBIE and the Authority recognise that it exists. MBIE says, in the discussion document, that retailers dealing with 28 different pricing plans would benefit from standardisation.[75] The Electricity Authority has worked on the problem for more than a decade:

    A. Its distribution pricing principles and limited pricing reform in respect of connection pricing;

    B. The default distributor agreement that sets a baseline contract between each EDB and each retailer, although significant variation remains; and

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72 The differences are documented in the Electricity Authority's distribution pricing scorecards and in the material behind its 2025 connection decisions: Electricity Authority, Network connections project (stage one): decision paper, 18 July 2025, and Distribution connection pricing Code amendment: decision paper, July 2025.

73 Note that embedded networks may add further intefaces/bespoke arrangemetns.

74 The description is of the retailer's own activities; Electricity Authority (2018), Default Distributor Agreement research report ("DDA Research Report"), records retailers' accounts of these costs.

75 Discussion Document, pp. 12-13.

C. The registry and switching rules in the Electricity Industry Participation Code (the Code).[76]

105. The Authority's work has narrowed the differences but not removed them. Pricing structures still differ. Connection processes are still set EDB by EDB. The first of the Asset Dynamics priorities the Minister adopted in 2026 is to standardise connection processes and pricing. The work is therefore unfinished.[77]

106. The default distributor agreement is also the closest New Zealand has come to measuring the interface cost. Before imposing it in 2020 the Authority surveyed retailers. Every retailer surveyed expected its costs to fall under a standard agreement. About half said there were networks they would not trade on, mostly because of pricing and metering arrangements. The agreement was imposed under the Code after a cost-benefit analysis[78] and survived a legal challenge to the Authority's power to impose it.[79] We understand from ERGANZ that considerable scope remains under the DDA to alter non-core terms and wide variation remains in planned outage and fault procedures and procedures for control of flexible load on each network.

107. Great Britain rebuilt its interface, and it is the one case in which the cost of harmonising an interface has been quantified. In 2022 Ofgem's Switching Programme replaced the separate data flows between each supplier and each network and metering party with one central switching service. Ofgem's business case set out what the old arrangements cost, in slow and failed switches, reconciliation work and duplicated systems. It estimated the benefit of centralising at between £185 million and £1,077 million over 18 years, against a programme cost of £426 million. Great Britain has 14 distribution networks and several dozen suppliers. New Zealand has fewer retailers and twice as many distributors, so each retailer here carries more interfaces per customer than a British supplier did. The interface cost is therefore real, and it depends on how many EDBs there are and how much they differ.

4.2. What the energy transition adds to the interface

108. In section 3.5 we describe the new functions the transition gives EDBs and the platforms behind them. Each of those functions has an interface with retailers too. To connect a customer's solar panels or battery, whoever applies on the customer's behalf (today usually the installer, in future possibly the retailer or aggregator) submits data to the EDB in the EDB's format through the EDB's process, and no EDB yet has a standard process for registering controllable load such as a home charger. To sell flexibility, an aggregator responds to the EDB's product definition, procurement process and settlement rules.[80] To manage a customer's export, a retailer or aggregator reads whatever low-voltage data is available, from the EDB's own sensors or from the smart meters that

[76] Electricity Authority, Distribution Pricing Principles (2019) and subsequent distribution pricing reform work; Default Distributor Agreement, Electricity Industry Participation Code 2010, Part 12A; registry and switching, Code Parts 11 and 15.

[77] Asset Dynamics, Electricity Distribution Business Efficiency: Recommendations for Standardisation and Collaboration, report to MBIE, 9 April 2026 ("Asset Dynamics Report"), as summarised in Discussion Document, Part One.

[78] Electricity Authority (2020), Code amendment and decision paper (in force 20 July 2020);

[79] Vector Ltd v Electricity Authority [2017] NZHC 1774; [2018] NZCA 543; [2019] NZCA 49. The High Court rejected Vector's challenge. The Court of Appeal allowed the appeal only on the point that the Authority cannot mandate quality standards in the Commerce Act sense, leaving its power to set default terms intact.

[80] We understand that the ENA is currently consulting on a common load management protocol, see https://www.ena.org.nz/assets/Common-LMP/EDB-Common-LMP-V1.0.pdf.

metering providers hold, in whatever form each EDB publishes it. If each EDB designs these on its own, each function becomes a new 28-way interface, and the cost in section 4.1 repeats for every function as it arrives.

109. Not everything at the interface has to be common. The elements a retailer or aggregator handles the same way for every EDB are the obvious candidates: data formats and exchange mechanisms, registration and connection processes, the definition and settlement of flexibility products, and the terms on which network data is published.

110. The elements that reflect each network's own conditions, such as prices, the places and times at which an EDB wants flexibility, and a network's technical limits, can differ without adding much to a retailer's cost so long as the structure of that information is standardised. For example, a common tariff structure, in terms of the components, but with differing levels across the components, would be less costly for retailers than a series of completely different tariff structures.

111. In each of the five overseas cases of shared provision a transition function described in section 3.5, a regulator, a market operator or a body the network operators set up fixed the common elements once. The distributors then built or bought to that standard.[81] None of the five reached a standard by amalgamating networks. Two began as the network operators' own initiatives: the Dutch congestion platform and the British flexibility products. Both developed under a regulator that expected a common outcome and could have required one. None reached a standard through independent distributors converging without that pressure. The transition raises the value of a common standard, because the number of interfaces is about to multiply.

4.3. Who bears the cost of harmonisation and who benefits

112. To harmonise, each EDB must change its own tariff structure, processes and systems to match a common standard. Two features of this process matter:

    A. Who bears the cost and who benefits; and

    B. Standardisation requires coordination and collective action.

113. Regarding the costs and benefits, the EDBs pay most of the one-off cost: rebuilding prices, rewriting connection processes, changing billing and data systems, and consulting on price changes for existing customers. Others receive most of the benefit. Retailers stop maintaining 28 variants, and consumers should see lower retail costs and fewer errors.[82] Even if every EDB harmonised at once, each would be paying for a gain that mostly went to someone else. This is an externality: the party that bears the cost does not receive the benefit.

114. Regulation makes the mismatch between costs and benefits worse. If a non-exempt EDB's allowance was set before it harmonised, the cost of harmonising is not in the allowance. Under IRIS, the EDB carries that overspend for the retention period. It has no saving to set against it, because the saving goes to retailers and consumers rather than to the EDB. Unless the EDB can get the cost recognised through a step change or the innovation allowance, harmonising is an

[81] See the footnotes to section 3.5 for the five platforms: the GB Data Communications Company and central switching service (Ofgem licence), the AEMO DER Register (National Electricity Rules), Energinet's DataHub (Danish Electricity Supply Act), Elhub (NVE regulation, owned by Statnett), and GOPACS (Dutch grid operators, under ACM oversight).

[82] DDA Research Report.

unrewarded overspend.[83] An exempt EDB has no IRIS, but faces the same mismatch. The saving accrues to retailers, and nothing requires them to share it with the EDB.

115. Turning to co-ordination and collective action, an EDB that harmonises on its own gains almost nothing for anyone, because each retailer still has 27 other interfaces. The benefit arrives only when most EDBs move together, and no EDB can make the others move. This is a collective-action problem.

116. In principle an EDB and a retailer could negotiate to share the gain. Each retailer would then have to strike that bargain with each of 28 EDBs, which is a further collective-action problem. Neither group has a financial reason to move first, and both have a reason to wait for someone else to set the standard.

117. These problems are independent, as the externality would exist even with a coordinator and the coordination/collective action problem would exist even if EDBs kept the benefit. These problems are also independent of who owns the EDB and how it is regulated.

118. However, standardisation is not costless, which a standard-setter must weigh against any transaction cost related benefits. Tariff structures and connection charges differ partly because networks differ: a rural network with long lines and low density has a different cost structure from an urban one, and an EDB's prices are the main way those costs signalled to the people who cause them. A standard that set price levels or the allocation of cost between consumer groups would blunt those signals and shift cost between regions. EDBs have objected on exactly this ground to the Authority's recent connection rules, arguing that the compliance cost was understated.[84] Weighed against this however is that a lack of standardisation may mean retailers don't pass signals on to retail customers, as the transaction costs of doing so are too high.

119. The distinction that matters is between having a common interface and maintaining flexibility around tariffs. The elements we identify as common in section 4.2 can likely be standardised without large impacts on the level and structure of most EDBs charges, though lost pricing flexibility for EDBs is a cost that would need to be considered when determining how standardised price structures are.

4.4. Problem definition: will EDBs harmonise the interface on their own?

120. The interface problem definition has three parts. The inefficiency is the cost that retailers, aggregators and flexibility providers pay to deal with 28 different sets of prices, processes and data, the fact that the transaction costs of reflecting these difference in retail offers may mean it doesn't happen and the larger cost they will pay as each new transition function is built 28 ways. Amalgamation to five would likely reduce but not remove these costs if standardisaiton occurred within the new entities. But some cost would remain since five non-standard interfaces would still impose transaction costs. One standard across 28 EDBs would remove nearly all of it.

[83] See section 2.3; DPP4 Decision, decisions U1 and O3.7.

[84] Aurora Energy, submission to the Electricity Authority on the Network connections project (stage one) consultation, 2025, stating that the CEPA cost-benefit analysis "significantly understated the additional ongoing transaction costs" to distributors.

121. The transaction/co-ordination cost efficiency goes uncaptured for two reasons:

    A. EDBs pay the one-off cost of harmonising and others receive the benefit; and

    B. No single EDB can make a standard, so none gains by moving first.

122. A decade of voluntary coordination has narrowed the differences without removing them, but the transition is about to add more, which raises the risk that voluntary standardisation will not achieve the efficient level of standardisation.

5. Options for capturing the remaining efficiencies

123. In this section we consider the policy options available to help the issues we have identified, namely that EDBs may not have adequate financial incentive to engage in shared provision of the functions that sit on top of the wires (section 3.6), and that EDBs may not have adequate incentive or ability to standardise their interfaces with retailers.

124. This section is structured first as a discussion of what market structures we believe are consistent with an efficient market for electricity distribution, followed by a discussion of specific policies that could be used to create those desirable market structures.

5.1. Desired market structures/outcomes

125. Our review tells us that while a market including small EDBs can pose real challenges to efficiency, these challenges sit in identifiable parts of the business, and can be resolved with three specific outcomes:

A. Amalgamation of the smallest EDBs, or shared provision of their head-office functions, so that those functions are provided at an efficient scale

B. Amalgamation of small EDBs and/or shared provision of energy transition services (e.g. low voltage monitoring) so that those functions can be executed at an economically efficient scale

C. Standardisation of the EDB-retailer interface across existing dimensions (e.g. tariff structure) and across emerging dimensions, such as the pricing and provision of demand flexibility.

5.2. Options targeting our identified problems and market structures/outcomes

126. To accomplish these goals, we consider several options that might satisfy these goals. We do this in Table 1 below by setting out the potential efficiencies, market structures that would capture them, barriers to those structures and policy options that would address those barriers.

127. MBIE's own proposals complement these options. Its exempt-EDB route and its governance reforms address the exempt incentive gap, directly and indirectly and lighter regulatory tools could lower the cost of the regime for small EDBs without reducing the number of networks. We have not assessed these measures in detail, since our purpose is to identify targeted options that MBIE could consider alongside them.

128. We have not assessed these options in detail as our purpose was to generate additional targeted options that MBIE could consider alongside these reforms, short of forced amalgamation. At a high-level however, options related to reforming the incentives for exempt EDBs appear worth further exploration.

Table 1: Potential efficiencies, structures that would capture them, reasons they may not be exploited and potential options

Efficiency	Industry structure/outcome that would achieve efficiencies	Problems impeding these structures	Options to directly address problem
Head-office functions	• Amalgamation of smaller EDBs • Shared management companies • Contracting out further functions	• Weak incentive to implement cost savings that incur upfront costs in return for savings that cover multiple regulatory periods • The weak incentive exempt EDBs have to reduce cost at all	• Forced amalgamation • Regulatory changes to encourage voluntary amalgamation. • Stronger incentives for shared delivery.
The platforms and teams the transition adds	• Shared or national platforms for new functions. • Amalgamation	• The possibility that the regime funds a capital own build of a new function more readily than a shared subscription. • Limited incentive to minimise costs of new functions where they are included in allowances	• Mandatory development of centralised platforms. • Stronger incentives for shared delivery. • Review of whether procedural bias favouring capex for new services exists.
Transaction/coordination costs between retailers and EDBs	• Standardised interface terms, processes and data. • Amalgamation	• The externality at the interface, where EDBs pay to harmonise and retailers and consumers gain. • Collective action.	• Voluntary standardisation. • Incentivised standardisation. • Compulsory standardisation.

5.3. Assessment of the options

129. We assess each option against the status quo: 28 EDBs, the current price-quality regime for 15 of them, information disclosure only for the other 13, and voluntary collaboration on standards. Mandated amalgamation into five is one of the options, assessed on the same footing as the others rather than as the benchmark. Amalgamation would address the exempt incentive gap only as a by-product, by folding exempt networks into regulated ones. We can reach the same result directly.

130. We use four criteria:

A. Which of the outcomes in section 5.1 it takes us towards;

B. Whether it works in the short run;

C. Its short-run cost; and

D. Its long-run cost against the counterfactual, including any effect on competition and innovation.

Table 2: Assessment of options against the status quo

OptionPolicy	Outcome served	Works in the short run?	Short-run cost	Long-run cost vs counterfactual
Forced amalgamation	Head-office functions; interface (partial)	Slow	Highest	High: direct costs and lost comparators
Regulatory changes to encourage voluntary amalgamation	Head-office functions	Slow	High	Low
Stronger incentives for shared delivery	Head-office functions; platforms	Yes	Low	Low
Mandatory use of centralised platforms	Platforms; interface in part	Once built	Medium	Low; lock-in risk
Review of procedural bias favouring capex	Platforms, non-exempt EDBs	From next reset	Low	Low
Voluntary standardisation	Interface	Little progress thus far	Low	High: interface cost persists
Incentivised standardization	Interface	If effective	Low to Medium, borne by EDBs	Low if effective, high otherwise
Compulsory standardisation	Interface	Yes	Medium, borne by EDBs	Low; some lost pricing flexibility

131. This table suggests the following for each of the three efficiencies:

A. For **head-office functions**, three policies work towards this outcome:

i. Stronger incentives for shared delivery work quickly at low cost.

ii. Voluntary and incentivized agglomeration can produce the same outcome, but at an uncertain and potentially high cost. Forced amalgamation costs even more. and

iii. both amalgamation options create a lasting cost in lost comparators.

B. For the **transition platforms:** the two proposed policies (in addition to stronger incentives) are substitutes. A review of the capex bias removes a reason an EDB might build rather than share, but delivers nothing by itself. A mandated central platform delivers the outcome once built, at medium cost and with some risk of lock-in.

C. For the **interface co-ordination/transaction costs**, the choice is between a voluntary policy that is cheap now but does not resolve the problem that is likely to become more costly over time, and a mandatory one that is costly now and cheap afterwards. Incentivised standardization sits between the other two options in both cost and benefit.

132. Taking the table as a whole, each of the three outcomes can be reached by a policy that costs less than forced amalgamation, and forced amalgamation is the only policy with a high long-run cost on every outcome it serves.

133. Two rows need further explanation:

A. **Voluntary amalgamation with a regulatory incentive**: A longer IRIS retention for post-merger savings would make mergers more attractive, and the Ontario and Ofgem schemes show that such an incentive can be designed. But it reaches the same outcome as stronger incentives for shared delivery, potentially more slowly and at higher one-off integration cost. If this was introduced it could be targeted at small EBDs where there are more likely to be efficiencies.

B. **Forced amalgamation**:

i. It reaches the head-office outcome at the highest one-off cost of any policy and over the longest period. It reaches the interface outcome only in part, because five different interfaces still impose most of the cost. On every column it is matched or beaten by a policy that does not require it.

ii. The mention of lost comparators as a cost of forced amalgamation warrants elaboration. Because MBIE is proposing to let the Commission benchmark EDBs against each other, the fewer firms there are, the less statistically reliable this becomes. With five EDBs, each would have four comparators. Ofgem deducted £32 million (2001/02 prices) from allowed revenue for each distribution merger, for the loss of a comparator.[85] Pollitt values the comparators created when Britain split gas distribution into eight networks at an extra three per cent a year of cost reduction.[86] NERA's peer review of Frontier raised the same concern.[87] Pollitt's suggestion of 10 to 15 EDBs rests on this argument, not on scale economies.[88] Any consideration of forced amalgamation and introducing benchmarking must therefore recognise that the two policies can work against each other.

134. Set against the table, MBIE's package covers the general measures and voluntary standardisation. It has nothing on the capex bias and nothing binding on the interface.

135. Two changes would fill those gaps:

A. Pair MBIE's measure for exempt EDBs with the review of any potential procedural capex bias. Bringing exempt EDBs under price-quality regulation gives them the incentive non-exempt EDBs already have to shed existing cost, but also exposes them to any bias the regime has towards building new functions rather than sharing them; and

B. Add a binding interface standard under the Code or the distribution system operator framework, with cost recovery for EDBs.

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85 Ofgem, letter to distribution licensees on electricity distribution mergers, 6 October 2005, p. 1, restating the May 2002 policy statement.

86 Pollitt 2025, section on the value of comparators, p.23.

87 NERA (2025), Peer review of Frontier Economics' final report, for MBIE ("NERA Peer Review"), section on EDB amalgamation, p.4.

88 Pollitt 2025, concluding section, p.24.

136. If the Minister's scoped powers extend to compelling consolidation, they are aimed at the wrong problem. A backstop that lets the Minister require the Authority to set and enforce an interface standard, should voluntary collaboration not deliver one, would directly address the co-ordiantion problems we have set.

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