NZ Party Energy Platforms 2026

How each platform would affect emissions, security and household power bills

Anthill Ltd · September 2026

Executive Summary

New Zealand votes on 7 November 2026. Cost of living, climate change, and de-industrialisation concerns are all vying for attention, and energy has become a key election issue. Seven parties have published energy platforms that differ sharply in method: state-owned firming, an LNG import terminal, gentailer separation, repeal of the Zero Carbon Act, a sovereign wealth approach to Māori and community ownership, and a cross-party renewables accord.

This report was generated using the Anthill Energy Intelligence platform as a non-partisan gauge of assessing policy impacts. It models each platform against a common baseline built from live market data, and reports six outcomes at 2027, 2032, 2037 and 2047. A diverse-portfolio benchmark is included for comparison; its generation build is a modelling construct, its carbon path comes from a Climate Change Commission benchmark. Method, sources and judgement calls are in the Methodology sections.

The platforms differ more in emissions and security of supply than in household bills. At 2032 the average annual residential bills range from roughly $3,000 (Greens) to $3,300 (NZ First), a spread of about 10%. Seven of the eight sit within about $160 of each other. Over the same horizon electricity-sector carbon intensity differs about fourfold between platforms, however all are low-carbon from an international perspective.

Despite being at opposite ends of modelled customer bills, The Greens and NZ first do share a policy that was not included in the modelling - separating the gentailers. No party and no published study puts a household saving on separation, and the direction of the effect is contested, so this paper does not invent one. It measures the size of the problem instead. Removing every dollar of the published market-power rent estimates from wholesale prices would save an average household $120 to $250 a year. That is less than the gap between the platforms we modelled, and separation on its own would capture only part of it.

That is not an argument that electricity policy does not matter to household bills. It is an argument that the lever which moves household bills most may not be the one the campaign is most focussed on. Before a household uses a single kilowatt hour, the fixed daily charge on its lines bill runs from around $100 a year on the cheapest networks to over $1,300 on the most expensive. That $1,200 gap is around four times the modelled difference between the cheapest and dearest platform. Modelling the proposed lines reforms was outside the scope of this report, but a 20% cut to the lines component would save approximately the entire spread between platforms.

> **KEY FINDINGS**
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> At 2032 average residential bills range from roughly $3,000 (Greens) to $3,300 (NZ First), a spread of about 10%. Seven of the eight platforms sit within about $160 of each other.
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> Electricity-sector carbon intensity differs about fourfold between platforms over the same horizon, far more than the bill spread.
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> Removing every dollar of published market-power rent from wholesale prices would save an average household $120 to $250 a year, less than the modelled gap between platforms.
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> The fixed daily lines charge alone runs from around $100 a year on the cheapest networks to over $1,300 on the most expensive, about four times the modelled difference between platforms.

How the platforms were characterised

Each scenario represents sustained implementation of one party's published platform from 2027, with no coalition negotiation and no change of government. That is deliberately unrealistic. It is the only way to see what a platform does in isolation, and every result should be read as a direction rather than a forecast.

Positions were extracted from party websites and contemporaneous reporting in September 2026 using Claude Sonnet. Where a platform is silent on a parameter the model needs, it receives the same common assumption as every other silent platform, and it departs from that only where the party has a stated policy. The model parameters are the six columns of Table 1. Clean dry-year cover is the assumed proportion of the dry-year energy gap met by zero-emissions resources. Geothermal was excluded from this category due to its non-zero operating emissions.

The core model excludes structural-reform policies: gentailer separation, distribution amalgamation, and cheaper capital for distributed build-out. Each is sized separately in its own section.

Table 1. Assumed scenario modelling parameters by platform. Carbon price and dry year cover values given from 2027 to 2047

Platform	Renewable additions (GWh/yr)	Coal exit	Min gas share	LNG online	Carbon price ($/t)	Clean dry-year cover (%)
National	1,100	No dated exit	4.5%	2028	55 / 70 / 80 / 90	25 / 30 / 36 / 50
ACT	900	No dated exit	4.5%	2028	45 / 50 / 55 / 60	25 / 28 / 32 / 42
Labour	1,200	No dated exit	3.0%	N/A	55 / 70 / 80 / 90	25 / 33 / 42 / 62

Platform	Renewable additions (GWh/yr)	Coal exit	Min gas share	LNG online	Carbon price ($/t)	Clean dry-year cover (%)
Green	1,400	2035	0%	N/A	55 / 70 / 80 / 90	25 / 38 / 55 / 85
NZ First	850	No dated exit	7.5%	2028*	55 / 70 / 80 / 90	25 / 27 / 30 / 36
Te Pāti Māori	1,150	No dated exit	1.5%	N/A	55 / 70 / 80 / 90	25 / 34 / 45 / 68
Opportunity	2,270; capped at 2,000	No dated exit	1.2%	N/A	55 / 70 / 80 / 90	25 / 32 / 40 / 58
Diverse-portfolio benchmark	1,300	2030	2.0%	N/A	60 / 80 / 95 / 110	25 / 35 / 47 / 72

The starting point

New Zealand generated 44,571 GWh in the twelve months to June 2026 at 93.0% renewable, with hydro at 58.0% of generation, geothermal 22.2%, wind 8.9%, solar 2.6%, gas 5.2% and coal 1.7%. Electricity-sector operational carbon intensity over that period was 44.4 gCO_2e/kWh.

The all-in residential rate at August 2026 was 42.15 c/kWh nationally, of which around 40% is lines charges. Average residential consumption is about 7,200 kWh a year, giving a measured average bill of $3,035. Between August 2023 and August 2026 the all-in residential rate rose 8.64 c/kWh, and 57% of that rise came from lines charges rather than energy.

Spot price has only a longer-term impact on household bills. In 2025 the all-in residential rate rose 10.8% while average spot fell 24%. In 2026 to date it is 8.3% higher again while spot is down 53%. How much of a wholesale price change reaches a household was measured rather than assumed, and the answer depends on whether the change lasts. The fraction of a transient wholesale price change passed to the bills is only around 0.39. A change sustained over three to five years reaches it at about 0.80. Platform bills are therefore compared at the long-run rate, and dry-year shocks at the short-run one. Lines charges do not respond to spot at all. The regressions are in Methodology: wholesale-to-retail pass-through.

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> The all-in residential rate at August 2026 was 42.15 c/kWh, giving a measured average bill of $3,035. Between August 2023 and August 2026 the rate rose 8.64 c/kWh, 57% of it from lines charges.
>
> A transient wholesale price change reaches the bill at about 0.39; a change sustained three to five years reaches it at about 0.80.

Renewable share

All eight scenarios raise renewable share, because the pipeline and the underlying economics already point that way regardless of who governs. They differ in how far and how fast. By 2047 the range runs from 92.5% under NZ First to 100% under the Greens.

Renewable share is the least discriminating of the six metrics. New Zealand starts at 93.0%, as this has been the grid average over the last 12 months. The remaining thermal generation is small in energy terms but it carries almost all the emissions, and it is what currently covers a dry year.

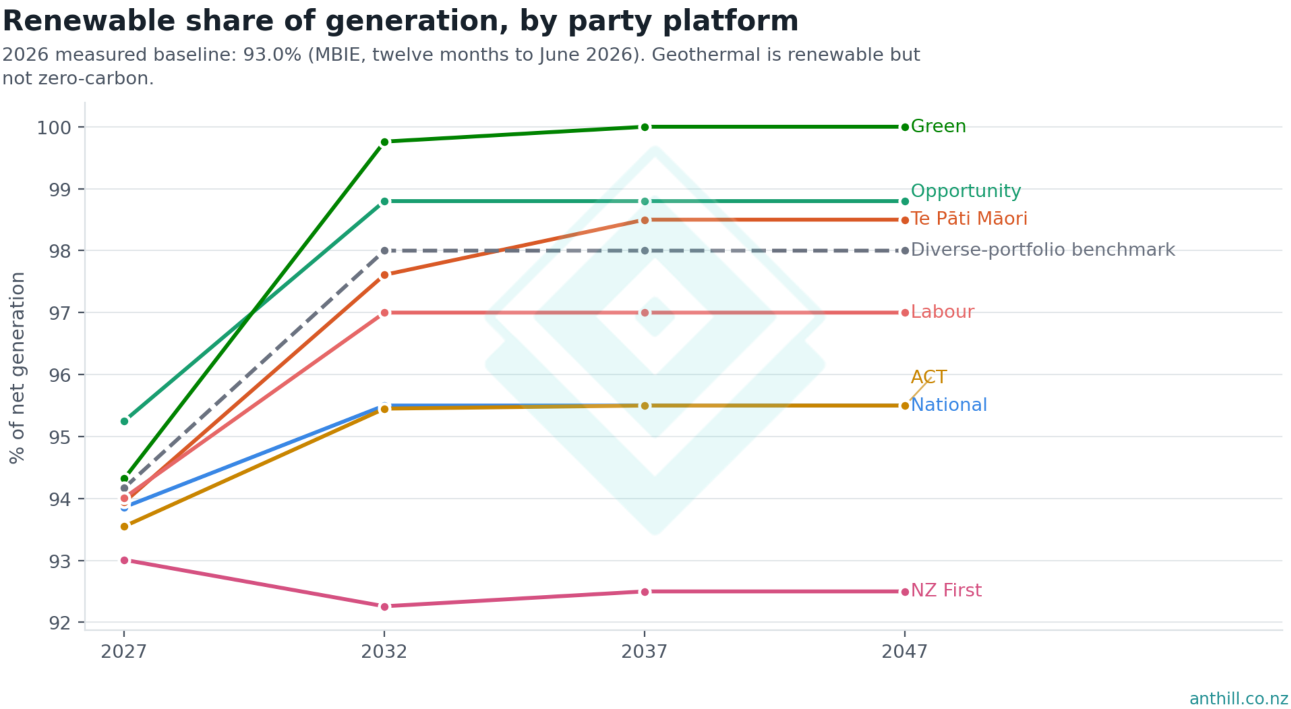

Figure 1. Renewable share of generation by platform. The 2026 baseline of 93.0% is measured.

Carbon intensity

Carbon intensity separates the platforms more sharply. By 2047 the range is 11.9 gCO2e/kWh under the Greens to 48.0 under NZ First, a fourfold difference against a renewable-share difference of seven and a half percentage points.

NZ First is the only platform that stays above 45 gCO2e/kWh through 2047. It keeps coal and the highest gas floor, and it requires firming to be fossil-fuelled. Its $1b offshore survey does not change the picture inside this horizon: a survey commissioned in 2027 does not produce gas before the late 2030s at the earliest, so it affects the 2047 column and not the 2032 one. Withdrawal from the Paris Agreement does not by itself change the domestic Emissions Trading Scheme, so NZ First is modelled with the same carbon price as other platforms without an ETS policy.

National and ACT land together at about 34 gCO2e/kWh from 2032. They share the LNG terminal and the same thermal assumptions, and ACT's lower carbon price barely changes dispatch, because NZUs already trade well below the auction floor ACT would remove.

No scenario reaches zero, because geothermal is renewable but not carbon free. Geothermal is about a fifth of national generation, which puts a floor of about 11 gCO2e/kWh under the grid as a whole. As geothermal expands, the floor rises with it.

Electricity-sector carbon intensity, by party platform

2026 baseline: 44.4 gCO_2e/kWh, twelve months to June 2026. The floor is geothermal, about 11 g/kWh at current output. No platform reaches zero.

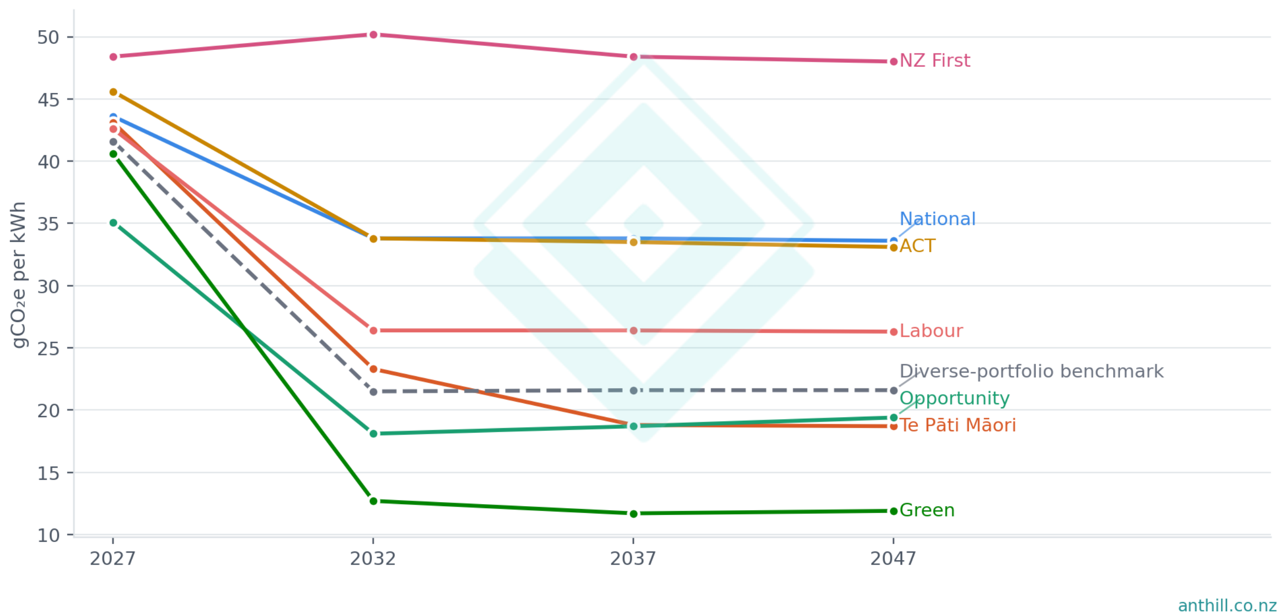

Figure 2. Electricity-sector carbon intensity. The geothermal floor is about 11 gCO2e/kWh.

Household bills

At 2032 the eight platforms land between $3,005 and $3,292 a year, a spread of $287 on the central assumptions. At 2047 the spread is $360. Bills rise over time under every platform, mainly because lines charges rise on their own trajectory in all of them; at 2032 only the Greens are below today's bill. No platform proposes changing how network costs are allocated to consumers, and Opportunity's consolidation of the lines companies is not modelled as a saving, for the reason given in Scenario parameters.

The Greens and Opportunity are cheapest at 2032, $46 apart, because they build the most low-price generation. Seven platforms sit within about $160 of each other. NZ First is dearest, $125 above National, because it has the smallest renewable build and the highest gas floor, leaving more thermal generation in the system. NZ First’s stance on the LNG terminal is uncertain or conditional; it has been modelled with the terminal, since it has not opposed it. Without LNG its 2032 bill would be $66 higher and the spread $353.

The ranking is stable. Across every sensitivity run listed in the Methodology the spread stays between $255 and $290, individual bills move by up to $125, and the order of the platforms does not change.

The size of the spread is less certain than the ranking, for two reasons. The spread is proportional to pass-through, so it runs from $140 to $358 across the rates tested. It also moves with the gas price, which sets the marginal cost of thermal generation: a 30% scaling either way puts it between $183 and $390. Both ranges are derived in the Methodology.

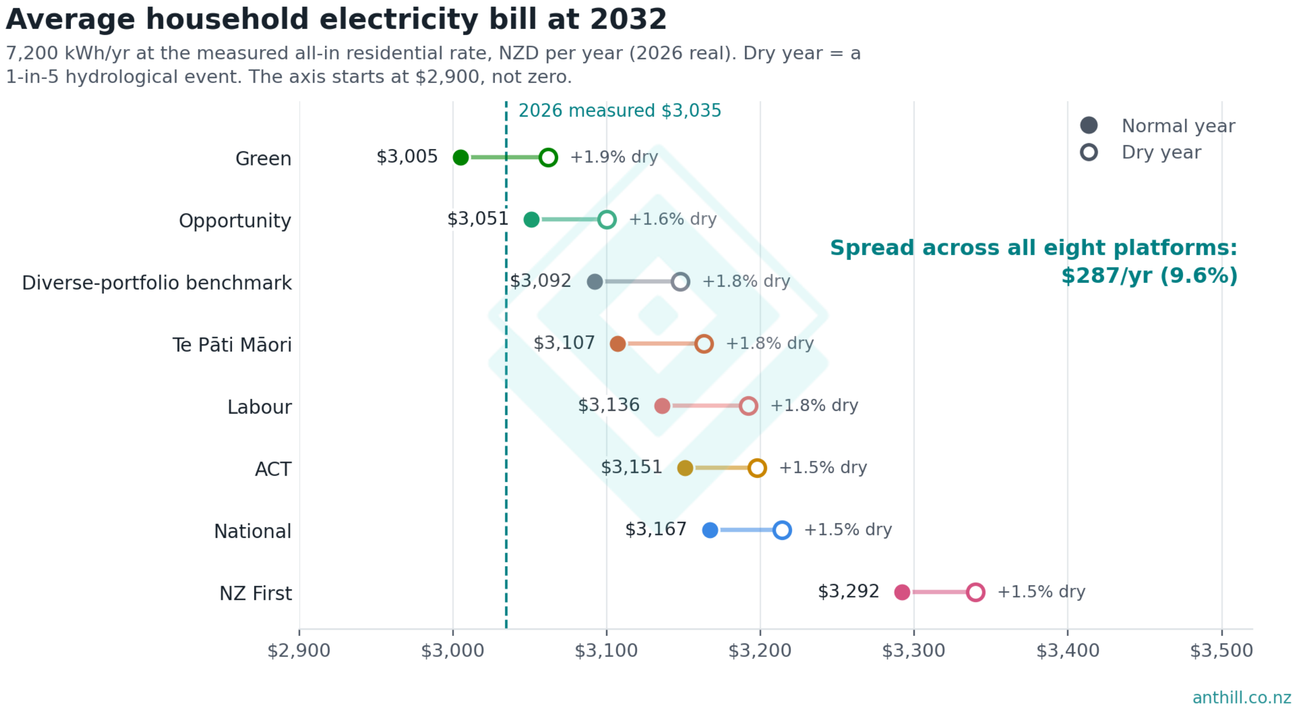

Figure 3. Average household bill at 2032, normal and dry year, against the measured 2026 baseline.

The dry-year question

The dry-year gap was derived rather than assumed. A one-in-five dry year is about 970 GWh below the 2005 to 2025 mean, and a one-in-ten about 1,410 GWh.

Annual totals understate the operational problem, because a dry year bites in winter when demand peaks. In 2024 annual hydro ran 717 GWh below the mean, yet thermal generation rose 1,209 GWh. The firming a system needs is set by the winter shortfall, which is larger than the annual one.

The household consequence is much smaller than the wholesale consequence. In the two dry years on record spot rose 59% and 63%, while the all-in bill rose 1.0% and 4.1%. About half of the 2024 rise was lines charges. The energy part of the bill rose no faster in 2024 than in 2023, which was not a dry year. Retail hedging and the fixed share of the bill absorb most of a dry year.

This paper anchors the dry-year effect on the 2024 rise in the energy component, and treats it as an upper bound. Scaled by the cost of each platform's marginal backstop, that gives dry-year bill increases of 1.5% to 1.9% at 2032, rising to 4.2% for the Greens at 2037. The Green peak arises because the legally binding 2035 fossil exit lands before Kiwipower's firming programme is complete. In this scenario, a 2037 dry year would require demand destruction as part of the marginal dry-year resource. By 2047, once that firming is built, the Greens' bill increases are back among the lowest.

The more important point is about incidence. Dry-year risk in New Zealand is real and expensive, but it falls on spot-exposed industrial consumers and unhedged retailers, not on the average hedged residential customer. Measuring dry-year risk as a household bill increase understates the problem and points it at the wrong people.

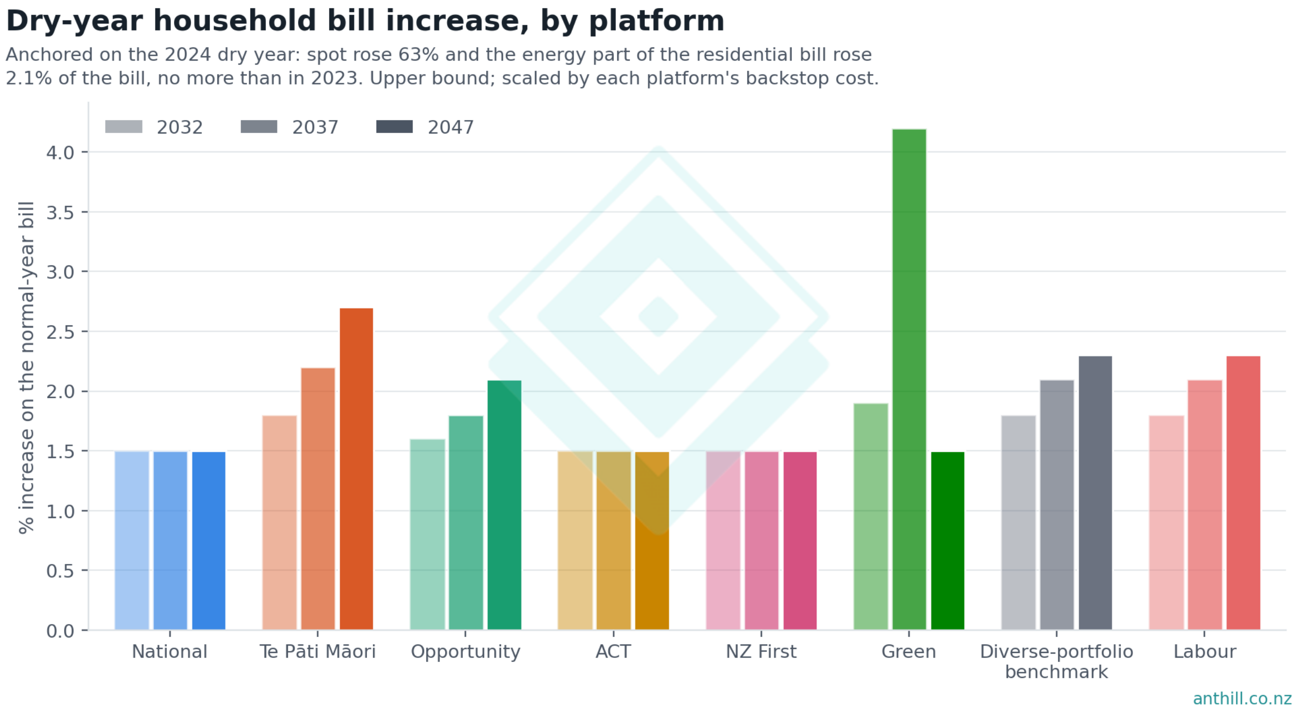

Figure 4. Dry-year bill increase by platform, at 2032, 2037 and 2047.

Build rates and deliverability

Between 2020 and 2025 New Zealand added about 806 GWh a year of new renewable generation, roughly 320 MW a year. Every platform in this comparison implies a higher rate than that, and the most ambitious imply several times it.

Opportunity's 30 GW by 2050 target is the clearest case. Current grid-connected renewable nameplate is 8,511 MW, so the target requires 21,489 MW of additions over 24 years, or 895 MW a year. That is 2.8 times the rate achieved between 2020 and 2025, sustained for a quarter of a century. The model gives Opportunity the build rate its own target implies, and then applies the deliverability ceiling. On that basis Opportunity reaches about 92% of its target by 2050.

The constraint is visible in the pipeline. Of 24,698 MW in Transpower's connection pipeline, only 4,794 MW (19%) holds granted consent and 14,442 MW has not yet reached application. Consenting, grid connection and supply chain, not policy ambition, decide how much renewable generation actually gets built.

Reforming transmission and distribution

Lines charges are the largest single component of a household bill after energy, and they are largely outside the campaign focus. Holding the lines charge trajectory at 1.0% a year instead of 2.0% lowers every platform's 2032 bill by about $78. Freezing it in real terms lowers it by $152. Running at the 3.5% a year actually observed between 2021 and 2026 raises it by $125. In every one of those runs the spread between platforms is unchanged, because the lines charge trajectory is common to all of them.

Put against the platform differences directly: at 2032 the lines component is about 18.93 c/kWh, or $1,363 of a bill of roughly $3,000 to $3,360. A 20% cut is worth $273, almost the entire modelled spread between platforms.

At the time of writing, only Opportunity, Act, and National are campaigning on reducing lines charges - Opportunity through distributor consolidation, National through mandated collaboration, and Act through increasing competition. The main results in this report give them no credit for it, as the nuances involved in modelling these proposals are outside the scope of this report.

The key to unlocking more efficient distribution may include consolidation, but care must be taken. The expensive networks are often the sparse ones, high-density networks sit at the cheap end. Consolidation without associated efficiency gains would simply move costs from the main centres to the sparse networks, leaving the average untouched.

However, the NZ electricity distribution sector does show signs of structural inefficiency driven by fragmentation. Each of the sector's lines companies runs full corporate, compliance, regulatory and analytics functions, producing a non-network overhead share of around 60% of total opex. That compares to roughly 35% in our Australian comparators who have undergone significant consolidation; however Australia does not pay lower per-customer lines charges. Opex has grown at roughly 2.6% per year in real terms since the Commerce Commission’s Default Price Path (DPP) began in 2013, against near-flat real costs in the pre-DPP period. If consolidation into five or eight regional entities could bring the non-network share down from 60% to 35%, that would imply savings of roughly $250-300 million per year across the sector at current opex levels, before any field-workforce rationalisation. That saving would flow directly to line charge reductions for consumers, who currently pay network charges that have risen faster than inflation for over a decade.

There is a second feature of network pricing that bears directly on every party's solar and efficiency policy. Across the residential network tariffs, an average of 53% of the residential lines bill is a fixed daily charge, and on 15 of them it is more than 60% (the highest approximately 91%). A fixed charge does not fall when a household generates its own power or uses less of it. National, Labour and the Greens have all costed solar packages, and on the most fixed-charge-heavy networks those packages cannot reach roughly nine tenths of the lines component of the bill. None of the parties campaigning on distribution charges (Opportunity, Act, National) propose changing the fixed/variable split itself; each addresses the overall charge level, not its structure.

Splitting the gentailers

Separating generation from retail is committed policy for two parties. NZ First proposes full structural separation and has named it the first item in any coalition negotiation. The Greens would first test level-playing-field rules on the gentailers and hold separation as the backstop if those fail. Labour has said separation is not off the table without committing to it. National, ACT and Opportunity oppose it. Neither committed party publishes an estimate of what separation would do to bills or emissions.

No published study was found that quantifies a household saving from vertical separation in New Zealand. The 2019 Electricity Price Review declined to recommend it and asked instead that gentailers be made to behave as if separated. The 2025 Frontier Economics review for MBIE did not recommend it either. The Electricity Authority has since amended the Code to impose non-discrimination obligations requiring the four gentailers to offer hedges to all buyers on the terms they give their own retail arms. Separation would be judged against that baseline, not against the market of 2019.

Because the sign of the effect on prices is contested, this paper does not model separation as a saving. An integrated firm hedges its retail book against its own generation, and separation removes that internal hedge, which raises retail risk costs. Separation may also widen access to hedges and firming for independent retailers and generators, which would lower retail costs. Neither effect has been measured in New Zealand. What can be measured is the size of the problem separation is aimed at, and that is what this section reports.

Concentration is high on every measure. Over the twelve months to August 2026 the four large gentailers produced 90.4% of metered generation, or 93.0% counting Manawa, which Contact acquired in 2025. The Herfindahl-Hirschman Index on generation output is about 2,400, or 2,500 with Manawa inside Contact, around the level competition authorities treat as highly concentrated. The campaign figure of about 95% is a retail or firming measure, not generation output.

Retail tells a more specific story. The four gentailer groups, counting their brands and subsidiaries from the date each was acquired, served 86% of connections in 2008. That fell steadily to 72% by 2021 as independent retailers grew. It has since risen back to 85% at March 2026, and most of the reversal came through acquisition rather than lost competition on price: Trustpower's retail business passed to Mercury in 2022 and Flick to Meridian in 2025. Forty-six retailers remain active.

What customers pay does not show a consistent gentailer premium. The Electricity Authority's retail margin disclosures put big-four retail revenue at $299 a MWh in 2025 against $313 for the smaller retailers that disclose, $278 against $288 in 2024, and $264 against $220 in 2023. The gentailers were cheaper in two of four years and dearer in one. Their retail margins look far thinner, $6.50 a MWh against $46 in 2025, but that is because they book wholesale electricity to their retail arms at an internal transfer price, $156 a MWh against $140 for the independents. The margin sits in the generation arm. That is the mechanism independent retailers object to, and it is what the non-discrimination rules target, but it does not appear as a higher price to the gentailers' own customers.

The one effect of separation whose direction is known concerns pass-through. A study of 340 New Zealand retail plans between 2018 and 2023 (Gibbard, Grubb and Wesselbaum, Energy Economics, 2025) found that vertically integrated retailers pass through significantly less of the wholesale generation cost than independent retailers. Both pass through lines costs alike. For an integrated firm the wholesale price is an opportunity cost; for an independent it is a cash cost. Separation would turn the first into the second. The likely consequence is that household bills track wholesale prices more closely, down when prices fall and up in dry years, which would widen every difference between the platforms reported here.

The largest thing separation could plausibly reach on price is the premium in wholesale prices over a competitive benchmark. Two econometric studies have estimated it for New Zealand. Wolak, for the Commerce Commission in 2009, put market-power rents at 18% of wholesale revenue over 2001 to 2007; Treasury later described that estimate as not credible, and its benchmark has been contested in the academic literature. Poletti, in Energy Economics in 2021, put them at 36% to 39% over 2010 to 2016. Both are disputed and both are dated, and neither covers the market since 2016.

Applied to today's market as a ceiling, those shares imply $0.9b to $1.9b a year of rent. The combined annual profit of about $1b that the Greens and NZ First cite is of the same order, but profit is not rent: it includes the normal return on the capital invested in generation. If every dollar of the estimated rent were removed permanently from the wholesale price, an average household would save $120 to $250 a year at the long-run pass-through of 0.80, or $150 to $310 if the whole saving reached retail prices.

Two things keep separation itself well inside that ceiling. First, vertical separation does not reduce the concentration of generation: the same four firms would own about 90% of output the day after. Market power in the wholesale market is addressed by the number and size of generators, not by who owns the retailers. Second, the Code changes already in force target the channel separation is best placed to fix. What separation adds beyond them is an empirical question that has not been answered.

The emissions channel is smaller still in this model. If separation speeds investment by independent generators, the effect runs through the renewable build rate. Raising the Green and NZ First build rates by 10% to 25% lowers 2032 carbon intensity by 0.8 to 1.5 gCO_2e/kWh, under 0.08 Mt CO_2e a year. By 2037 it has almost no effect, because each platform's thermal policy, not its build rate, then sets what thermal generation remains. A larger effect would require separation to change decisions about retaining thermal plant, which this model does not represent.

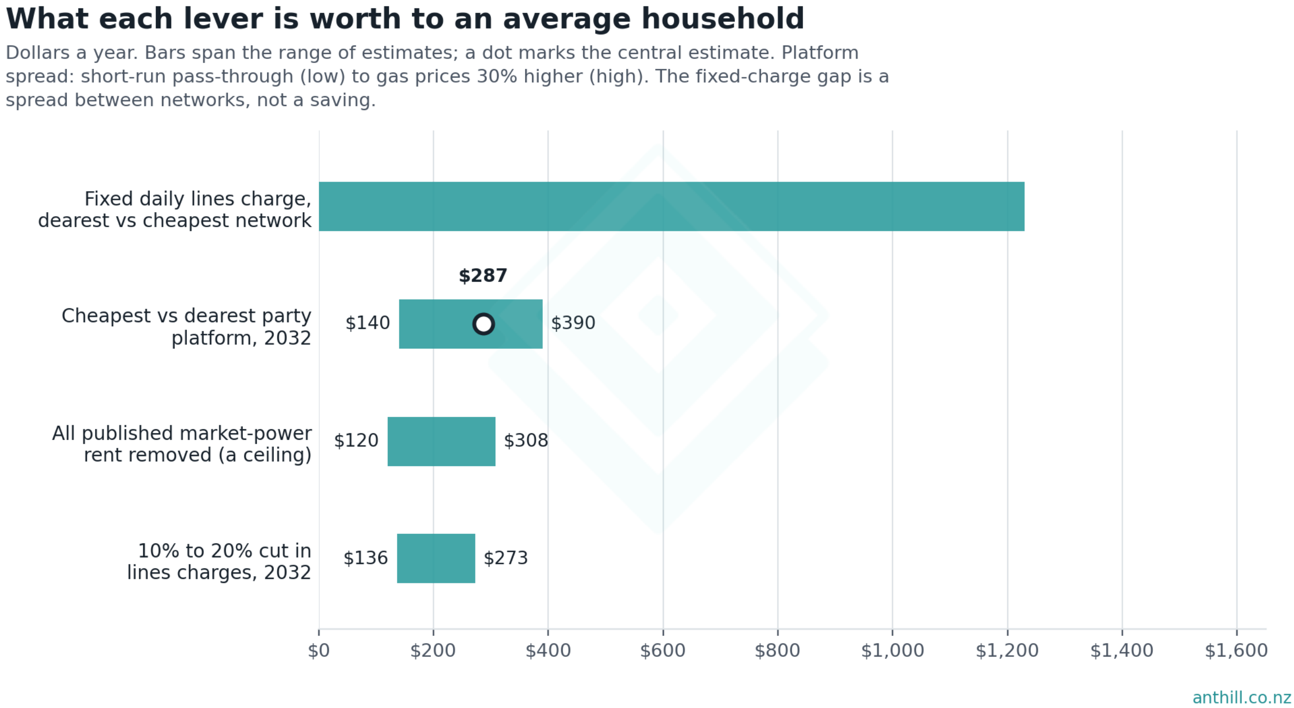

Figure 5. What each lever is worth to an average household, dollars a year. Bars span the range of estimates. The market-power bar is a ceiling on market-power reform, not an estimate of separation. The fixed-charge gap is a spread between networks, not a saving.

Reconciling the parties' savings claims

The parties publish household savings of $300 to $3,200 a year. This analysis puts roughly $290 a year between the cheapest platform and the dearest. Those figures do not measure the same thing, with one exception.

Almost every party figure is a return on a household capital investment: install solar, buy an electric car, put in a heat pump. The Greens quote up to $1,000 a year for a fully electric home with solar including the cost of paying the system off, and up to $350 for a renter with plug-in solar. Labour quotes $300 to $400 for the same plug-in case. Opportunity's $3,200 is explicitly for going electric at home across solar, a car and a heat pump, which is a whole-of-energy figure spanning petrol and gas as well as electricity.

Those returns are possible under any party platform. What differs between platforms is the subsidy and the finance offered, not the underlying economics of the investment. That is why this analysis reports the costed household programmes separately from the bill rather than netting them off it. Spread across all 1.92 million households, the household-facing programmes are worth $223 a year under the Greens, $45 under Opportunity, $21 under Labour and about $1 under National. The Green figure excludes its $429 million of solar loans, which are lent rather than spent, and the National figure excludes the loan volume its $7 million of Crown equity seeds. System spending is reported apart: Kiwipower's firming budget of about $245 million a year and Te Pāti Māori's $1 billion Energy Sovereignty Fund, about $250 million a year of equity and co-investment, are not household programmes. Concentrated on the households they reach, the programmes are worth several times these figures, which is the range the parties quote.

The household bill reported throughout this paper is the cost of electricity to a household that invests in nothing, at the same consumption under every platform. It does not include the return to households that take up subsidised or Crown-financed solar, batteries or heat pumps. For those households the return is likely to far exceed the $290 gap between platforms, in the range the parties quote. Averaged across all households it is small. The Greens' $429 million of solar loans would reach around 1% of households, worth under $20 a year averaged over every household (illustrative estimate, not a modelled result).

A large uptake of distributed generation does suppress wholesale market prices when it is generating, as has been seen with Australia. This effect has not been modelled for cross-party comparison because there is no New Zealand estimate of how far cheaper finance raises uptake beyond what households would install anyway. Homeowners can already borrow for solar through bank green lending, so Crown finance matters most to renters and households without a mortgage. Leaving it out understates the platforms with the largest household programmes for the households that take them up, but it would likely have a minor impact on the average bill.

Two programmes can be valued by what they do to consumption. Warmer Kiwi Homes heat pumps cut recipients' winter electricity use by 16% in Motu's evaluation, worth roughly $220 a year to a treated home. The Greens' $970 million expansion would reach roughly 190,000 homes over four years on an assumed $5,000 a home, about $22 a year averaged over every household; Opportunity's $80 million a year about $7. ACT's carbon refund is a cash transfer rather than a bill change. At base auction volumes and ACT's carbon price it would be roughly $100 a household in 2027, falling to about $40 by 2030 as auction volumes decline under the scheme's settings. These three figures are estimates built on the stated assumptions.

One party claim is directly comparable and it is Opportunity's $500 to $2,700, described as resting on cheaper electricity bills and household electrification together. Opportunity's 2032 bill is $241 below the dearest platform and $46 above the cheapest, so the unit-price part of the claim is below the bottom of its stated range. The rest is electrification, which is the larger part. Opportunity's own paper puts that unit-price portion at $600, measured from a retail price of about 34 c/kWh, citing an average household spend of $2,343 a year. That corresponds to the 2024 level: MBIE's series has the national all-in residential rate at 33.6 c/kWh in February 2024. The measured rate at the August 2026 survey is 42.15 c/kWh and average consumption is about 7,200 kWh, giving roughly $3,035. The saving is therefore quoted against a price that has since moved. Read from today's level, reaching 25 c/kWh would be worth more than $600, but would require a 41% reduction rather than the 25% fall in generation costs the assumption rests on.

National's published figure points the same way from the opposite direction. Its energy announcement claims a 2% annual reduction in wholesale prices would add more than $3 billion to GDP within a decade. On a wholesale price near $100/MWh that reduction is 0.2 c/kWh, and at the long-run pass-through it is worth about $12 a year to a household. The GDP benefit accrues to spot-exposed industrial users rather than to households.

Scenario parameters

The values below are the judgement calls. Each is traceable to a published policy position or to a common assumption applied to every platform that is silent on it. The numbers themselves are not measurements, and a reader who disagrees with one should expect the results to move. They are listed in full so that disagreement is possible.

- Demand growth 1.5% a year compound, identical across platforms, so the comparison isolates supply-side policy.
- Lines-charge growth 2.0% a year real, against 3.5% observed over 2021 to 2026.
- Thermal displacement efficiency 0.70.
- Marginal build mix 50% wind, 35% solar, 15% geothermal.
- Deliverability ceiling 2,000 GWh a year of new renewable energy, 2.5 times the 2020 to 2025 achieved rate.
- Wholesale price floor $55/MWh at zero thermal generation.
- Gas $14/GJ in 2026 rising to $18/GJ once LNG import parity applies.
- Carbon $45/t in 2026.
- LNG: the terminal is assumed to proceed from 2028 unless a party opposes it. Labour, the Greens, Te Pāti Māori and Opportunity oppose it; National, ACT and NZ First do not.
- Carbon price: a common NZU path of $55, $70, $80 and $90 a tonne at 2027, 2032, 2037 and 2047 for every platform without a stated ETS policy that moves the price. Only ACT has one. Paris withdrawal does not amend the ETS, and Labour's ETS review states no direction.
- Coal: no platform is given a dated coal exit unless it has one. Coal is displaced first as new renewable energy exceeds demand growth. The Greens' 2035 fossil exit is applied.
- The notes below give the reasons behind the values in Table 1 that are not mechanical. Labour and Te Pāti Māori take the common assumption on every parameter. National: Huntly is retained as reserve, and the 2028 LNG date is the party's own.
- ACT: the gas floor matches National's, since both rely on the same terminal. Carbon sits below the common path, reflecting removal of the auction floor and a cap benchmarked to trading partners.
- Green: clean cover reaches 85%, reflecting Kiwipower's firming mandate.
- NZ First: the gas floor reflects fossil-fuelled firming. It is modelled with LNG, because its stance on the terminal is conditional rather than opposed. The no-LNG case is reported as a sensitivity.
- The Opportunity Party: the build rate is the one its 30 GW target implies, capped by our imposed deliverability ceiling. Huntly is retained as emergency backup.
- Lines-charge growth is held identical across all eight platforms. The distribution reforms proposed by Opportunity, Act, and National could plausibly yield efficiencies, so the household bill results understate those platforms if the reforms

do deliver savings. See the Reforming transmission and distribution section for details.
- Gentailer separation is not a scenario parameter for any platform. NZ First and the Greens commit to it and no platform is credited or charged for it, for the reasons set out in the Splitting the gentailers section. Its possible size is reported separately as a ceiling.
- Diverse-portfolio benchmark: the carbon path runs toward the auction floor path.

Limitations

This is a comparative scenario model, not an energy system optimisation. It has no transmission constraints, no dispatch, no locational pricing and no inter-temporal storage optimisation. Rank order between platforms is more reliable than any absolute level, and the ranking is more reliable than the size of the spread.

The wholesale price projection is the weakest output and should be read as indicative - observed quarterly prices since 2011 have often differed from the equation's output by more than 30%, particularly in dry years. The gas price is the input most likely to move it. The paths used here are judgements benchmarked on the GIC's 2026 study. They could move materially in either direction depending on the outcome of the conflict in the Middle East, which bears on the price New Zealand would pay for imported LNG and on the value of domestic gas. A 30% move either way changes the 2032 spread to between $183 and $390 without changing the ranking.

Pass-through of wholesale prices to household bills is measured at two horizons, and the platform comparison uses the long-run rate. If the short-run rate applied instead, every difference between platforms would roughly halve.

The $55/MWh floor on the wholesale price is the assumption most likely to be wrong in a known direction. Opportunity cites a long-run marginal cost of $80 to $100/MWh for new wind and solar, and a price that sits below the cost of the capacity the system needs cannot persist. The floor is retained because the merit order sets price in the short run, and storage arbitrage can clear below long-run cost for extended periods. But the high-renewable platforms are the ones most exposed to it, so their prices here should be read as a lower bound.

Every scenario assumes uninterrupted implementation of one platform for twenty years. New Zealand has had MMP coalition governments since 1996 and no platform has ever been implemented in that form. Coalition negotiation would move all of these results, in most cases toward each other.

Beyond 2032 the results are set mainly by each platform's thermal policy, its gas floor and coal treatment, rather than by its build rate, because in most platforms new renewables have by then displaced all the thermal generation policy allows them to. Those floors are judgements, listed in Scenario parameters.

Demand growth is held common across scenarios. In reality the household electrification and efficiency programmes differ, and a party with a larger programme would drive somewhat different demand alongside somewhat lower household energy costs. The Warmer Kiwi Homes effect is estimated separately rather than fed back into demand.

Gas is modelled as a quantity of energy, not as a flexibility resource. The GIC study notes that Methanex's departure removes up to 95 TJ/day of contractual flexibility, leaving Ahuroa gas storage at up to 65 TJ/day as the primary balancing mechanism, and that the loss drives sharper seasonal price swings and tighter dry-year constraints. None of that is represented here, and it would bear on the dry-year results for every platform that retains gas.

Market structure is held fixed. No platform's policy changes the number or size of generators in the model, so the effect of gentailer separation, or of any other change to competition, is reported as a bound rather than modelled.

Party positions are as published in September 2026 and may move before 7 November.

Methodology: data and baseline

Every measured input was read from Anthill's data platform, which utilises public data from MBIE, the Electricity Authority, Transpower, the Commerce Commission and the distribution businesses, along with weather/climate, transport, and other energy-adjacent sources. Queries were run on 18 September 2026. Each constant in the model carries a tag marking it as measured, derived, benchmarked or assumed.

Generation, fuel mix and renewable share: MBIE Energy Quarterly, electricity generation by fuel, for the four quarters to June 2026 (the latest published). Net generation 44,571 GWh at 93.0% renewable.

All shares quoted are shares of generation, not of installed capacity. The two differ materially: hydro is about 47% of installed capacity and 58.0% of generation. Solar figures are MBIE's and include distributed generation, which is the majority of New Zealand's solar output; metered grid-scale solar alone is about a third of MBIE's figure.

Emissions: MBIE's quarterly electricity-sector greenhouse gas series, CO_2-equivalent basis. The series carries a total row alongside the individual fuels, so fuels are never summed with it. Twelve-month carbon intensity is MBIE's published total over the four quarters to June 2026, 1,981 kt, divided by net generation: 44.4 gCO_2e/kWh. Emission factors are each fuel's emissions divided by its generation over the eight quarters to June 2026: gas 0.500 t/MWh, coal 0.660 t/MWh, geothermal 0.051 t/MWh. These are operational emissions; lifecycle emissions for all generators are higher but are outside the scope of this report.

Geothermal emissions are about 51 gCO_2e per kWh of geothermal generation, about 500 kt CO_2e a year at current output. That sets a floor of roughly 11 gCO_2e/kWh across total generation. Future geothermal may capture and store its operational emissions, lowering this floor.

Wholesale prices: Electricity Authority half-hourly final energy prices at all nodes, time-weighted. The rolling ten-year window 2016 to 2026 averages $115.5/MWh;

calendar 2024 averaged $197.4, 2025 $150.0 and 2026 to date $70.6.

Retail prices: MBIE's quarterly survey of residential electricity prices, national series. The survey carries five rows per location; ranked by value they are all-in, energy, lines, distribution and transmission, and all-in equals energy plus lines. At the August 2026 survey the all-in residential rate was 42.15 c/kWh, being 25.33 c/kWh of energy and 16.81 c/kWh of lines charges.

Average residential consumption: MBIE residential electricity sales divided by residential connections over the latest four quarters, 7,201 kWh, rounded to 7,200 kWh, giving a measured baseline bill of $3,035.

Capacity factors: Electricity Authority metered generation for the twelve months to September 2026, for units with a full year of output and at least 20 MW of capacity, summing all meter points for each station. Utility solar 17.4%, geothermal 76.7%, hydro 54.0%. The metered wind fleet averages 37.1%, dragged down by 2004-era turbines at Te Apiti and Te Rere Hau running at 24% and 14%; new wind is assumed at 40%.

Capital cost benchmarks from actual New Zealand projects:

- Wind $2.30m/MW — Harapaki $448m for 176 MW, Turitea $464m for 222 MW.
- Solar $1.65m/MW DC — Lauriston $104m for 63 MW.
- Batteries $1.50m/MW — Ruakākā $186m for 100 MW, Glenbrook Ohurua 2 $235m for 200 MW.
- Geothermal at $5.0m/MW and pumped hydro at $8.0m/MW are judgements. No New Zealand project cost was available for either.
- Generation pipeline and consent status: Transpower connection pipeline, September 2026 snapshot.
- Historical build rate: growth in wind, solar and geothermal generation between 2020 and 2025, about 806 GWh a year, converted to capacity at the capacity factors above.

Methodology: wholesale-to-retail pass-through

The spread between platforms is proportional to how much of a wholesale price change reaches the retail bill, so this parameter was tested more heavily than any other.

Short-run rate: ordinary least squares of the national retail energy component on trailing twelve-month average spot, quarterly, 2012 to 2026, 59 observations: energy = 14.92 + 0.390 x spot (both c/kWh), R-squared 0.38. Twelve-month spot is dominated by dry-year spikes, which retailers hedge and smooth, so this measures the response to transient shocks.

Long-run rate: the same series against spot averaged over longer windows gives 0.65 (24 months), 0.79 (36 months) and 0.88 (60 months) over 2012 to 2026, with R-squared rising to 0.91. Changes over non-overlapping three- and five-year spans since 2004 give 0.83 and 0.79. Adding a linear time trend lowers the long-window estimates to 0.17 to 0.47, but spot itself trended upward over the period, so the trend absorbs part of the spot effect and those figures are a lower bound. The model uses 0.80.

Published estimates agree on the pattern. Short-run pass-through by incumbent retailers is about 40% in Victoria (Burns and Mountain, 2021) and 43% to 47% in Texas. Long-run estimates are complete or more: 0.88 to 1.42 in the United Kingdom (Ofgem, 2011), 1.04 in Norway and 1.39 in Sweden. For New Zealand, Gibbard, Grubb and Wesselbaum (Energy Economics, 2025) find that vertically integrated retailers pass through less generation cost than independent retailers, which is one reason New Zealand's long-run rate can sit below 1.

Use in the model: platform bills apply the long-run 0.80 to the difference between each platform's modelled wholesale price and the model's own 2026 price of $88.4/MWh. Dry-year effects use the observed short-run response. The market-power ceiling in Splitting the gentailers is reported at 0.80 and at 1.0.

Data note: 1999 to 2003 carry many half-hourly prices at exactly $100,000/MWh, a legacy placeholder rather than a price. They are excluded from the long-window tests; no other input in this paper draws on those years.

Methodology: the scenario model

The model runs each platform forward from the measured baseline to 2027, 2032, 2037 and 2047. It is deliberately simple, so that every result can be traced to a named input.

Demand grows 1.5% a year from the 2026 baseline in every scenario. That compounds to about 43% by 2050, slightly below the Climate Change Commission's expectation of about 50%, so the comparison is mildly conservative on the scale of the build task facing every platform.

Each platform adds renewable energy at its build rate, capped at the deliverability ceiling. New energy first meets demand growth. Any surplus displaces thermal generation at an efficiency of 0.70, the remainder being assumed lost to spill and curtailment. Coal is displaced first and leaves entirely at a platform's coal exit date where it has one; gas is displaced next, down to the platform's gas floor.

Emissions are gas, coal and geothermal generation multiplied by their emission factors. Geothermal grows with 15% of new builds.

The model estimates normal-year wholesale prices using two equations:

$$C = G \times 3.6 \div 0.48 + E \times 0.5004$$

$$P = 55 + (C - 55) \times s \div 0.15$$

Where C is the modelled gas-generation cost in $/MWh, G is the assumed gas price in $/GJ, E is the carbon price in $/tonne, s is the annual gas-plus-coal generation share expressed as a fraction, and P is the modelled wholesale price in $/MWh.

The factor 3.6 converts MWh to GJ. Coal contributes to the thermal-generation share, but the pricing calculation uses gas-generation costs.

The 48% efficiency represents a combined-cycle gas turbine. The emissions factor of 0.5004 tCO_2e/MWh is derived from recorded gas-generation emissions divided by gas-generated electricity over the eight quarters to June 2026. Gas and carbon price paths are scenario assumptions described below.

The $55/MWh zero-thermal price was chosen as a modelling judgement. It is consistent with current mean marginal price for hydro, and hydro is by far the dominant non-thermal marginal generator, however this value reflects today's system with thermal generation still available, not a system without it.

The 0.15 value is a conservative estimate of thermal's impact on price based on wet-year data. During dry years, the response is generally steeper.

Household-bill differences and rankings are conditional on the relationship between price and thermal share. With other assumptions unchanged, a higher zero-thermal price narrows the party-bill spread, by about $87 in both 2032 and 2047. A steeper response widens the spread.

Gas price paths are judgements benchmarked on published studies. Every case starts at $14/GJ in 2026. It rises to $18/GJ with LNG import parity, to $26/GJ without LNG as domestic supply depletes, and to $20/GJ under NZ First's exploration case, whose survey is assumed to yield no production before about 2037. The GIC 2026 Gas Supply and Demand Study (PwC, March 2026) has indigenous production at 1983 levels, Māui and Methanex closing in 2027, and supply approaching zero beyond 2035 in the central case. Its Scenario 2 assumes LNG from 2028 and states that LNG caps the local price. Transpower SOSA 2026 assumes 18 PJ of winter LNG from 2029. These paths could move significantly in either direction depending on the outcome of the conflict in the Middle East. A 30% sensitivity is reported.

Carbon price: New Zealand Units traded between $33 and $53 on the secondary market in 2026, while the auction price floor was $71 (rising to $82 by 2029) and the Cost Containment Reserve trigger $193 to $235. Every 2025 auction and the March and June 2026 auctions failed to clear, so the floor is not currently setting the market price. The 2026 carbon price is taken at $45, the midpoint of that range, and the common path assumes a gradual recovery toward, not onto, the floor path.

Retail bills are anchored on the measured 2026 level. Each platform's retail energy component is the measured 25.33 c/kWh plus 0.80 times the change in modelled wholesale price from the model's own 2026 price of $88.4/MWh. The model's own 2026 price is used as the reference rather than the observed trailing twelve-month spot, because the twelve months to August 2026 were unusually wet ($64/MWh), and anchoring on them would raise every bill for hydrological rather than policy reasons. The choice moves bill levels, not the spread between platforms.

Lines charges grow at 2.0% a year real in every platform from the measured 16.81 c/kWh. The bill is consumption times energy plus lines. Costed household programmes are reported separately and not netted off the bill; system spending is reported apart from household programmes.

These alter the spread between platforms, but the ranking is unchanged in every run.

- Lines-charge growth 0% to 3.5% a year.
- Thermal displacement efficiency 0.5 to 0.9.
- Demand growth 1.0% to 2.2% a year.
- Pass-through 0.20 to 1.00.
- Every gas path scaled by 0.7 and 1.3 from 2032.
- NZ First without LNG.
- Unserved-demand cost at $400/MWh.
- Post-thermal price floor at $85/MWh.
- Thermal price impact at 0.1, 0.15, 0.2.

Methodology: dry years

The dry-year gap is derived from MBIE annual hydro generation over 2005 to 2025: mean 24,309 GWh, minimum 22,126 GWh (2008). The one-in-five deficit is the mean less the 20th percentile, about 970 GWh; the one-in-ten deficit is the mean less the 10th percentile, about 1,410 GWh. Annual totals understate the winter shortfall: in 2024 annual hydro was 717 GWh below the mean while thermal generation rose 1,209 GWh.

The observed household response is taken from the two dry years on record, comparing annual means of the national residential rate with the year before. The all-in bill rose 1.0% in 2021 on a 59% rise in average spot, and 4.1% in 2024 on a 63% rise. The 2024 figure includes a rise in lines charges from 11.89 to 12.72 c/kWh unrelated to hydrology. The energy component rose 0.69 c/kWh in 2024, 2.1% of the 2023 bill, and 0.67 c/kWh in 2023, which was not a dry year.

The model anchors on the 2.1% energy-component rise, an upper bound on the hydrological effect since it is not distinguishable from trend. Scenario dry-year increases scale it by the cost of each platform's marginal dry-year backstop relative to a thermal-backed system at $150/MWh: LNG $190/MWh, domestic gas $210, coal $150, clean firming $110 and unserved demand $800, blended by how much of the dry-year gap the platform covers with clean firming. These costs are judgements; at $400/MWh for unserved demand the Green 2037 peak falls from 4.2% to 2.5%.

Fuel and electricity are kept distinct. 18 PJ of LNG is 5,000 GWh of fuel and about 2,400 GWh of electricity at 48% combined-cycle efficiency.

Methodology: network charges

Network charges: the 28 distributors' published residential pricing schedules effective 1 April 2026. The fixed daily charge is quoted directly, times 365 and grossed up by 15% for GST, and needs no further assumption. Total annual cost is reported only as indicative, because 15 of the 28 distributors price residential supply across more than two time bands and a total therefore depends on an assumed load profile. The paper names no single cheapest or dearest network on that basis.

The national level and the spread come from different sources deliberately. MBIE's survey gives the national residential lines component at 16.81 c/kWh, about $1,210 a year, which reflects where people live. An unweighted mean across network tariffs is higher, because the cheap networks are the populous ones.

Lines-charge levers are valued at 2032 on the model's lines trajectory: 18.93 c/kWh on 7,200 kWh.

Methodology: gentailer separation

Generation concentration: Electricity Authority metered generation, twelve months to August 2026, summed by owner of record at the time of generation from the platform's generator ownership register. Big-four output share 90.4% of 41,367 GWh metered; 93.0% counting Manawa, which Contact acquired in 2025 and which the register still lists separately. Herfindahl-Hirschman Index on output shares 2,389, or 2,500 with Manawa inside Contact. Metered generation excludes embedded generation, which is why it is below MBIE's national total.

Retail concentration: Electricity Authority retail market share by connection (ICP), March of each year to March 2026, the latest month published. Brands and subsidiaries are assigned to their parent by participant code from the date of acquisition, not by the current trading name, because the source relabels an acquired brand under its current owner for its whole history. Mercury includes GLOBUG and Bosco Connect, and Trustpower's retail business from May 2022. Meridian includes Powershop, and Flick from 13 May 2025. Genesis includes Energy Online. Contact includes Simply Energy, attributed on its participant code.

Retail prices and margins: Electricity Authority retail gross margin disclosures, 2022 to 2025, for retailers with more than 1% market share. The four gentailers are volume-weighted. The smaller retailers are anonymised in the source and not all report volume, so they are a simple average of five retailers. Revenue per MWh includes network charges, and differences in customer mix and region between the groups are not controlled for, so the comparison shows the absence of a consistent premium rather than measuring one.

Market-power ceiling: published estimates of wholesale market-power rent as a share of generator revenue, 18% (Wolak 2009, Commerce Commission, 2001 to mid-2007) and 37%, the midpoint of 36% to 39% (Poletti 2021, Energy Economics, 2010 to 2016). Both are contested. Applied to the ten-year average spot price of $115.5/MWh they imply a price reduction of $21 or $43/MWh. Household value is that reduction times the long-run pass-through of 0.80, or times 1.0 as a ceiling, times 7,200 kWh. Wholesale revenue is approximated as MBIE net generation times the time-weighted average price.

Pass-through and integration: Gibbard, Grubb and Wesselbaum (Energy Economics, 2025), monthly panel of 340 New Zealand retail plans, January 2018 to May 2023.

Emissions sensitivity: the model re-run with the Green and NZ First build rates raised by 10% and 25%, all else unchanged.

Policy context: Electricity Price Review final report (2019); Frontier Economics review of electricity market performance for MBIE and the government response (2025); Electricity Authority level-playing-field measures and non-discrimination obligations (2025 to 2026); party statements on separation as listed below. No published modelling of household bill or emissions effects of vertical separation in New Zealand was found.

Methodology: household programmes and transfers

Household-facing programmes are costed Crown spending a year divided by 1.92 million households.

Green about $428m — Warmer Kiwi Homes, public-housing solar, community energy, Māori housing. The $429m of zero-interest solar loans over four years is excluded as lending rather than spending, for consistency with National's loan volume.

Opportunity about $86m — Warmer Kiwi Homes expansion about $80m, electrification-loan administration about $6m, from its policy paper.

Labour $40m — SolarSaver.

National about $2m — a one-off $7m equity contribution over the term.

System spending is reported apart: Kiwipower about $245m a year, and the Energy Sovereignty Fund about $250m a year.

Warmer Kiwi Homes value: Motu's Warmer Kiwis Study found heat pumps cut recipients' winter electricity use by 16%. Winter is assumed to carry 45% of annual household use and the average cost per treated home is assumed at $5,000; both are estimates. On those assumptions a treated home saves about 520 kWh, roughly $220 a year.

ACT carbon refund: base auction volume of 5.2 million units in 2026, falling to 1.7 million in 2030 under the scheme's unit settings, times ACT's scenario carbon price, divided by households. Intermediate years are interpolated. ACT's own figure of about $195 million is the revenue forgone at a single auction.

Methodology: party positions and sources

Party positions were taken from party websites and contemporaneous reporting, compiled 17 and 18 September 2026 using Claude Sonnet.

National: national.org.nz energy announcement (1 October 2025) and solar policy; MBIE LNG procurement material; reporting of the LNG contract timetable (NZ Herald, Bloomberg, June 2026).

ACT: act.org.nz climate and carbon-refund statements; RNZ and NZ Herald election coverage of the Zero Carbon Act repeal.

Labour: labour.org.nz policy; RNZ and 1News coverage of SolarSaver (8 July 2026).

Green: greens.org.nz Power for All of Us and energy policy; NZ Herald and RNZ coverage of Kiwipower; Infometrics review of Green costings.

NZ First: interest.co.nz, 1News and BusinessDesk coverage of the subsurface survey and gentailer separation; BusinessDesk and The Post on Shane Jones's uncertain or conditional position on the LNG terminal; Newsroom (4 September 2026) on NZ First and Green separation positions.

Te Pāti Māori: NZ Herald and Stuff coverage of the Energy Sovereignty Fund; maoriparty.org.nz.

The Opportunity Party: opportunity.org.nz Abundant Energy platform and policy paper, including its table of claims, assumptions and justifications and its itemised use of dividend revenue.

Carbon market: International Carbon Action Partnership (NZ ETS settings); Climate Change Commission price control advice; market reports of 2026 NZU prices and auction results.

Research context: GIC Gas Supply and Demand Study 2026; Transpower Security of Supply Assessment 2026; MBIE Energy Quarterly; Motu Warmer Kiwis Study.

Read the abridged version

A seven-page abridged version of this report, covering the same model and figures at a fraction of the length, is available at anthill.co.nz/research/nz-party-energy-platforms-2026-abridged.