Retail Price Consistency Assessment Report

Contact Energy

3 September 2026

Executive Summary

1 This report sets out Contact Energy's first Retail Price Consistency Assessment (RPCA). It compares estimated retail revenues with the expected costs of supplying existing and new electricity customers, using the methodology and cost components described in the Electricity Authority's RPCA guidance.

2 At a nationwide level, the RPCA shows a narrow positive margin for existing customers of $11.12/MWh, equivalent to approximately 3% of revenue. The assessment shows a materially higher margin for new customers of $44.63/MWh.

3 The narrow positive margin for existing customers reflects current wholesale and retail market conditions. Over time, Contact expects this margin to improve as ASX electricity futures prices decline and as higher in-market revenues from new customer plans progressively flow through the customer base as customers move off legacy plans.

4 At a network reporting region level, the assessment identifies several regions with negative or narrow positive margins for existing customers. These results are generally explained by high regional input costs, or rapid increases in network charges.

5 Retail revenue is estimated using a bottom-up methodology, utilising actual customer data by network reporting region.

6 Non-electricity costs are calculated in the following way:

6.1 Retail costs (including shared and common costs) are calculated at a national level using Contact's actual financial data, and allocated to each region based on MWh consumed.

6.2 Metering and network costs are based upon actual billed prices per region, aggregated up to a national value based on a weighted average of MWh consumed per region.

6.3 Levies are based on actual national levy costs, divided by total MWh, and applied equally to each region.

7 Electricity costs are estimated based on:

7.1 Long-term hedges with a quarterly shape (62.2% of total load)

7.2 ASX-linked baseload hedges with a monthly shape (17.8% of total load)

7.3 Standardised superpeak hedges with a monthly shape (20% of total load)

7.4 A margin to cover the costs of unhedged load.

8 Electricity costs were modelled for the Otahuhu and Benmore nodes, and Contact's standard location factors were applied to determine prices at the network reporting region level.

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Disclaimer

9 This Retail Price Consistency Assessment (RPCA) Report has been prepared solely for the purposes of complying with the requirements of clause 13.236W of the Electricity Industry Participation Code and is consistent with the Electricity Authority's RPCA guidance. The RPCA is a regulatory assessment and is not intended to represent, and should not be interpreted as representing, Contact Energy's actual financial performance, profitability, segment results, or statutory accounts.

10 The methodologies, assumptions, allocations, forecasts and classifications applied in preparing this RPCA differ from those used for Contact Energy's financial reporting. In particular, the RPCA requires the use of forecast volumes, hypothetical electricity costs, static revenue assumptions, static network, metering and retail costs and cost allocation methodologies that are not used for statutory or management accounting purposes. The RPCA also contains forward-looking assumptions and estimates which are inherently subject to uncertainty and may differ from actual outcomes.

11 Accordingly, the results presented in this RPCA have been compiled on a different basis from Contact Energy's financial statements and other reported financial information. As a result, the information contained in this report should not be compared or reconciled to Contact Energy's statutory accounts, management accounts, or other publicly reported financial metrics. The methodologies, assumptions and judgements applied in preparing this RPCA may also differ from those adopted by other participants and, accordingly, the results presented in this report may not be directly comparable to RPCA results published by other participants.

12 No representation is made that the margins or costs reported in this RPCA correspond to, or can be used to derive, Contact Energy's retail profitability or the profitability of any business unit.

13 This RPCA Report may not be relied upon in connection with any purchase, disposal or valuation of Contact Energy securities. Any person considering an investment in Contact Energy should seek their own independent professional advice and refer to Contact Energy's statutory financial statements, market disclosures and other information released on the NZX and ASX.

Confidentiality

14 This report, and the associated files contain material confidential and commercially sensitive information. We have redacted this information from the public version of this report.

15 In the confidential version, confidential and commercially sensitive information is surrounded in square brackets and highlighted in red.

16 All information provided in the attached .csv files is confidential except where they are reported as non-confidential in this report. These files include detailed information of Contact's expected load profile and input costs. We consider that releasing this information would materially harm competition in the market.

RPCA Margins

Nation-wide margin

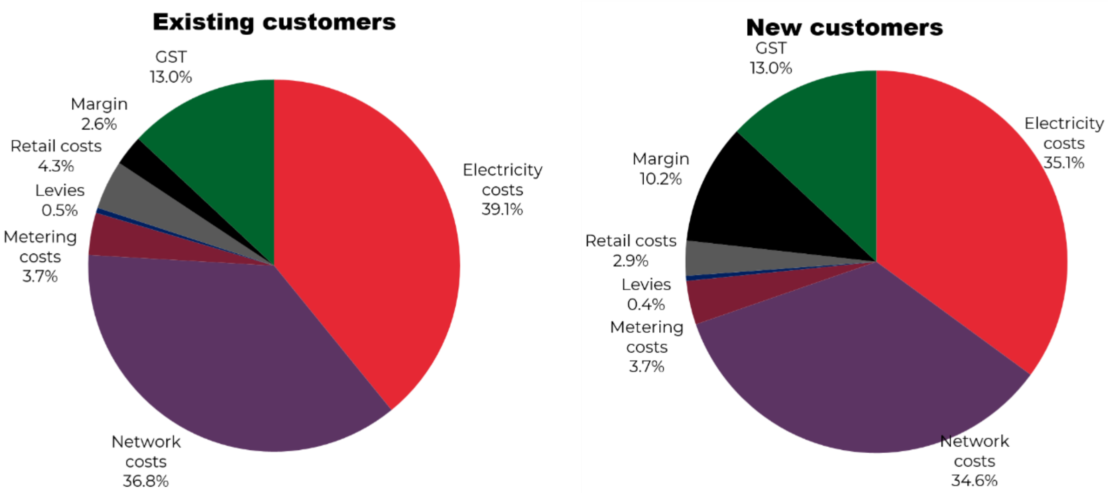
17 The nation-wide margin is:

17.1 $11.12/MWh for existing customers

17.2 $44.63/MWh for new customers.

18 Figure 1 below shows the proportional cost make-up for each of these segments

Figure 1: cost breakdown of RPCA results



19 We consider that the nationwide result for existing customers is 'narrow positive'. It represents a return of approximately 3% of revenue. We have chosen to report any margin less than 5% as narrow positive.

20 This result reflects current wholesale and retail market conditions. Over time we expect the margin for existing customers to improve because:

20.1 As ASX electricity futures prices continue to decline this will reduce the electricity cost.

20.2 As shown below, our average new customer revenues are higher than the average for our existing customers. We expect this to flow through over time as more customers move off legacy plans.

20.3 **[Redacted – commercially sensitive]**

21 For this RPCA there is a larger margin for new customers than for existing customers. This is because it measures incremental costs and incremental revenues. It therefore does not take into account fixed retail costs that do not change for an incremental customer, and it applies nearer term wholesale electricity prices, which have reduced in price recently.

22 We expect the reported margin for new customers to be highly volatile over time because of its higher reliance on near-term wholesale prices, which can fluctuate based on current year hydrology.

Network reporting region margins

23 The network reporting regions with negative and narrow positive margins for our existing customers are presented in table 1 below, including our explanation for these margins.

24 We consider that this table is commercially confidential. We consider it would harm efficient competition in the market if our competitors were able to see the regions where we are under pressure to increase prices to show an above 'narrow positive' margin in the RPCA.[1] However, we note that in most cases the negative or narrow positive margins can be explained because:

24.1 the region has particularly high input costs (electricity costs, network costs, retail costs, or metering), and/or

24.2 there has been rapid increases in network charges, which haven't yet been fully passed through into retail charges.

25 Due to a data mapping issue we were unable to estimate volumes or revenues for the Nelson and Frankton Network Reporting Regions. We have therefore excluded them from this first RPCA. We have corrected this data issue and will be able to report on these regions in future RPCAs.

Table 1: Regions with negative and narrow positive margins

Region	Margin / MWh	Explanation

[Table redacted – commercially sensitive]

26 For new customers there are only two regions that fall below our 'narrow positive' threshold, as set out in table 2 below.

[1] We note that because hedges are substitutable between regions via FTRs, then the only action we are able to take to change results at the NRR level is to change retail prices.

Table 2: Regions with negative and narrow positive margins

Region	Margin / MWh	Explanation

[Table redacted – commercially sensitive]

Retail Price Component

Nation-wide retail price

27 The nationwide retail price for existing customers is $365.41/MWh, and for new customers is $381.20/MWh.

28 We calculated retail price using a bottom-up method, that started with estimated revenue per network reporting region, and aggregated up to a national level based on a weighted average of forecast MWh volumes.

Calculation of retail price components

29 We began by calculating the average daily fixed and variable charge per ICP per region. This figure covers both residential and SME customers. This was averaged over late April to mid-July. Averaging over several months helps minimise the day-to-day variability in time-of-use variable tariffs (e.g. the variable tariff for customers on the Good Weekends plan with free periods on weekends is quite different on a Monday compared with a Sunday). This time period also means we captured tariffs following our most recent price changes. We did this separately for both existing customers and new customers. New customers were identified as those on our in-market offers.

30 The average fixed and variable rates was then multiplied by the expected demand per ICP per region. This ensures that we take account of the different demand patterns of different regions.

31 Expected demand per region is estimated by taking the following steps:

31.1 Start with Contact's opening connections broken down by network reporting region as at the 30th of June, using electricity registry information.

31.2 Estimate the total level of new customers Contact will acquire each month and the total level of customers we will lose. This is based on historical trends and the known activity we intend to execute throughout the year.

31.3 We then took Contact's gains and losses over the previous 12 months broken down by network reporting region and applied these proportions to the total level of monthly gains and losses. This provides a monthly view of gains and losses split out by network reporting region.

32 The revenue figure assumes no future price changes to either the new or existing customers. consistent with the RPCA guidance paragraph 5.8.

Non-electricity cost components

Retail costs

33 Retail costs are $17.92/MWh for existing customers and $12.90/MWh for new customers. Of this direct retail costs for existing customers is $10.43/MWh, and for new customers is $12.90/MWh.

34 Direct retail costs comprise of audit fees, bad debt, brand marketing, cash incentives, consultants, credit checks, office equipment, product marketing, sponsorships, staff costs, travel, and wellbeing support.

35 These costs were divided by our total connection numbers, including gas, broadband, and mobile, and then multiplied by our total electricity ICPs to get the total direct retail costs for electricity customers. They are then allocated to each region based on the number of ICPs in the region, and then divided by the MWh estimated for that region. This means that regions with a lower MWh consumption show as having a higher per MWh retail cost.

36 All fixed retail costs were fully allocated to existing customers. This is because Contact's fixed costs do not change as we take on a new customer. Fixed costs primarily relates to back-office retail team costs ($23.25/ICP). Other fixed costs are covered in the section below describing shared and common costs.

37 We have broken variable costs into four parts:

37.1 Cost to serve – this comprises our customer experience team, and the variable part of back-office support (billing, etc). This is allocated proportionately to new and existing customers **[Redacted – commercially sensitive]**

37.2 Energy wellbeing – This comprises our 'good' initiative which includes a number of activities to support vulnerable customers, including financial credits, and support to community organisations. We consider that this supports Contact Energy's social license across all aspects of our business. We have therefore allocated **[Redacted – commercially sensitive]** of this to retail, consistent with the revenue share of retail. This is fully allocated to existing customers, as we do not anticipate changing this value with changing volumes **[Redacted – commercially sensitive]**

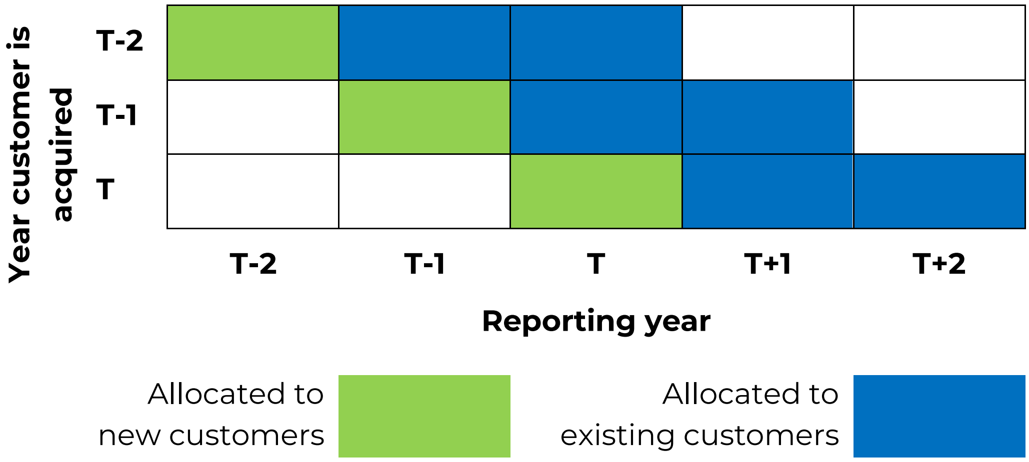
37.3 Cost to retain – this comprises a proportional allocation of brand marketing, cash incentives paid to existing customers, and prior year's cost to acquire, as described below. This is fully allocated to existing customers **[Redacted – commercially sensitive]**

37.4 Costs to acquire – this comprises a proportional share of brand marketing, product marketing, our internal sales team, and cash incentives paid to new customers. This is fully allocated to new customers **[Redacted – commercially sensitive]**

38 We have amortised acquisition costs over three years, as a proxy for how long we expect to retain a customer (consistent with paragraph 5.13 of the RPCA Guidance). Our forecast churn rate in this modelling is 1.4% /mth, which indicates an average customer term of 5 years, 10 months. However, new acquisitions tend to churn more quickly than the more stable parts of our base, so we have chosen a lower estimate of average new customer term.

39 Figure 2 below shows how these costs have been allocated between existing and new customers.

Figure 2: allocation of acquisition costs to existing and new customers



Retail shared and common costs

40 Retail shared and common costs are $7.49 for existing customers, and $0 for new customers.

41 We have defined shared and common costs as those costs in common with other parts of our business. Table 3 below lists each of the shared and common functions and how these have been allocated. These are all fixed costs, so none are allocated to new customers which only face incremental costs as described above.

Table 3: Allocation of Shared and Common Costs

Cost	% allocated to retail	Rationale
Insurance	5%	Retail related insurance costs are allocated based on revenue and asset value
Technology	27%	License fees, SAP support are allocated based on headcount of staff in retail that use each licensed software Security costs are based on Headcount or 100% to Retail if the software is only used by Retail Retail share of the platform costs and allocated on headcount
Corporate Affairs	7%	Retail related corporate affairs costs. This included legal / regulatory support to the retail business unit. Costs are allocated based on the FTEs required to support the Retail business
People Experience, Finance and staff rewards	8%	Retail staff awards are allocated on a headcount basis, and FTEs from Finance and People Experience who provide support to the Retail business

Metering costs

42 Metering costs are $15.46/MWh for existing customers and $16.24 for new customers.

43 These were calculated at a regional level by taking the charges we are forecasting for the 12 months from 1 July 2026 to 30 June 2027. We then divided by the forecast MWh per region and aggregated up to a national level as a weighted average.

44 New and existing customers have slightly different metering costs due to the different forecast consumption of new and existing customers.

Network costs

45 Network costs are $154.59/MWh for existing customers and $151.85/MWh for new customers.

46 These were calculated at a regional level by taking the charges we actually incurred in the last 12 months, and price changing them so that they reflected the current metering costs. We then divided by the forecast MWh per region and aggregated up to a national level as a weighted average.

47 New and existing customers have slightly different network costs due to the different forecast consumption of new and existing customers.

Levies

48 Levy costs are $1.90/MWh. This is the same for both new and existing customers.

49 Levy costs are based on the current levy rate as at 1 July 2026, divided by the MWh forecast. This is then equally applied to each region.

Expected electricity cost component

Nation-wide electricity cost

50 Electricity costs for existing customers is $164.41/MWh, and for new customers is $153.67/MWh. This is estimated at the ICP level, and therefore takes account of expected lines losses to the premise.

51 We have estimated electricity costs at the Otahuhu and Benmore nodes. These have then been applied to each region using the location factors described below.

52 To determine the national average we calculated a weighted average from each region based on our expected MWh volume per region over the forecast year.

Calculation of load profile

53 We have used our standard residential shape factors, multiplied by our expected MWh demand as explained in the retail price section above.

54 Our residential shape factors are consistently applied across the business, including for internal budgets and forecasting functions. The numbers are based on the average of the last two years of actual demand at a regional level. They are calculated at a plan level, and are calculated separately for the North Island and South Island. We then broke this down to a regional level using the expected customer numbers per region.

55 We have used the same load profile for both existing and new customers.

Methodology for 'as if' hedging

Methodology for existing customers

56 We have built up our notional hedge book for existing customers based on three types of hedges:

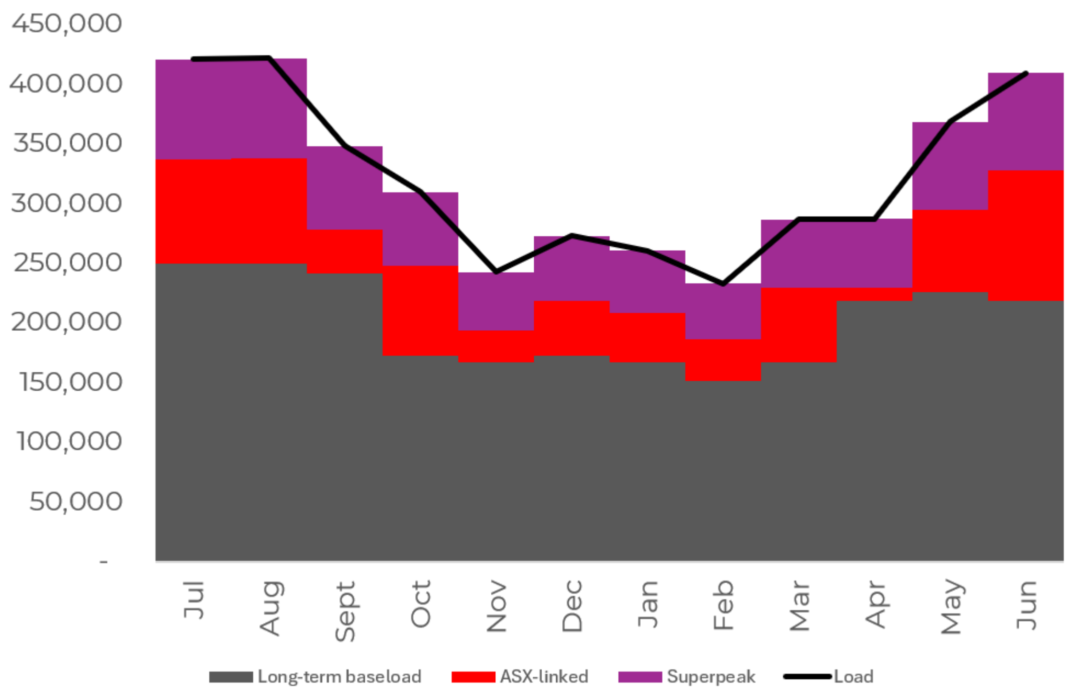
56.1 Long-term hedges with a quarterly shape

56.2 ASX-linked baseload hedges with a monthly shape

56.3 Standardised superpeak hedges with a monthly shape.

57 Figure 3 below shows this hedge book compared to our expected load profile.

Figure 3: 'As if' hedges compared to expected load profile



58 This mix of hedge types has allowed us to use observed market prices (ASX-linked and Superpeak) and reduces our reliance on thinly traded products, while still being reflective of the long-term nature of retail sales (Long-term baseload).

How we determined how much of each hedge to include

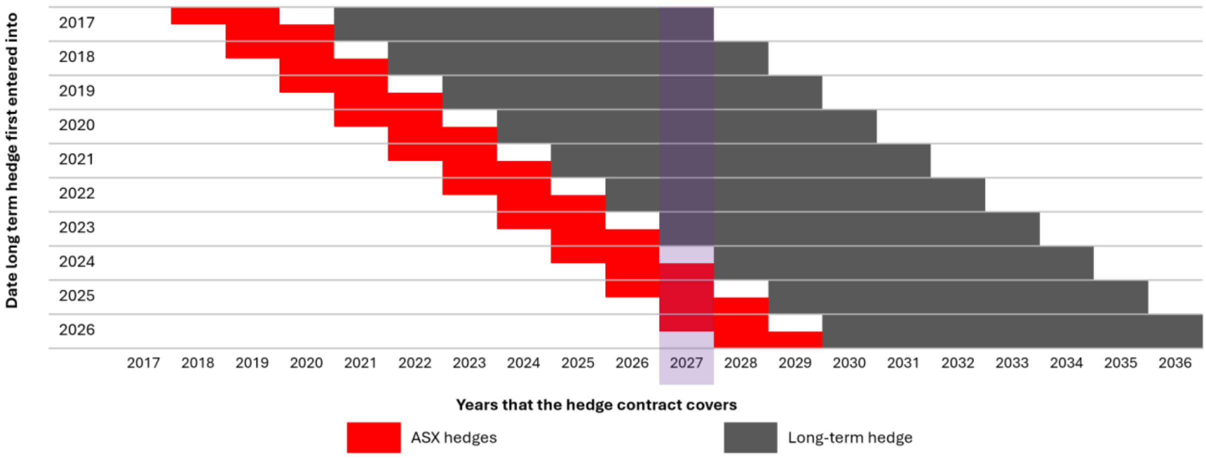
59 Our first principle was to purchase hedge volumes equal to expected load.

60 We then allocated 20% of total MWh demand to super-peak hedges. This ratio was chosen to balance between a lower electricity cost and the best 'fit' to Contact's daily load shape. The less superpeak hedges the lower the energy cost, but having less MWh met by superpeak hedges increases the average spot cost per MWh. We conservatively chose 20% of the portfolio met by superpeak. This meant that the 'as if' portfolio is never short during the superpeak period, when prices are most likely to be volatile.

61 For the baseload component, we estimated 10 hedges, each starting one year apart. This is shown in figure 4 below. Each of the horizontal lines consists of 1/10th of the baseload component. The first two years are based on ASX, with years 3-10 based on long-term prices. This is consistent with how Contact prices long-term hedges and ensures the 'as if' book faces a mixture of nearer term ASX pricing, and the stability of long-term prices.

62 This results in 17.8% of total hedges being ASX-linked, and 62.2% as a long-term hedge.

Figure 4: Illustration of the build up of baseload hedges



63 We consider that this is consistent with the actions of a large independent retailer who has operated in the market for 30 years. We consider that this appropriately balances the following factors:

63.1 improving customer retention by avoiding price shocks;

63.2 reducing input cost volatility for the retailer so it can better manage cashflows;

63.3 ensuring the 'as if' portfolio retains some flexibility to deal with volume risk; and

63.4 ensures the 'as if' portfolio retains some nearer-term hedges to remain responsive to changes in the market.

64 This ratio also enables a mixture of quarterly long-term contracts and monthly ASX-linked contracts to better meet our monthly load forecasts. As can be seen in figure 3 above, load in some months of quarters 2 and 3 are vastly different to the quarterly average. Any less monthly ASX-linked hedge and the 'as if' portfolio would have insufficient monthly shape.

Long term hedge – shape and price

65 The long-term hedge has a quarterly shape. We consider that this is consistent with longer-term hedges Contact has entered into and is consistent with what an independent retailer of Contact's size would likely demand. It balances between a simple year-round baseload contract, which does not reflect retail demand, and more fine-grained shape, which may be too difficult to confidently predict 10-years out.

66 The pricing of the long-term component is based on a series of hedges entered into on 1 June for years t-10 to t-3. For this RPCA this is years 2017 to 2023. This is illustrated in figure 4 above. The contracts then cover the period between 3 and 10 years after the date of signing.

67 Pricing for each of these contracts is based on prices that were available in the market at the time of purchasing. We estimated this market price by using Contact Energy's price path for year's available, supplemented with Energy Link price forecasts for older data.

67.1 For the years 2022 and 2023, Contact's long term price path was used. This is the same price path we use in our business cases for new investments, and forms the basis of long-term contracts we have entered into.

67.2 For the years 2017-2021, the Energy link's base case price path forecast for that year was used.

68 In both cases we applied the nominal FY 2027 forecasted prices at a quarterly level. The average price for this component was $112.29 at Otahuhu, and $107.41 at Benmore.

Baseload ASX-linked hedge – shape and price

69 The baseload ASX-linked hedge has a monthly shape. The shape is based on the residual after subtracting the long-term and superpeak hedge volumes from total demand load each month. This allows the 'as if' portfolio to reflect seasonal mass market shape. It is therefore reflective of what a large retailer would likely demand.

70 Price for this type of hedge was calculated by taking the following steps

70.1 For each quarter of the forecast period, we calculated the average ASX price over the period for which data was available for the forecast year, stopping 6 months ahead to avoid near term hydrology driven volatility. This is calculated as if we filled the book for each quarter by purchasing an equal volume each day.

70.2 We then applied a shaping factor to turn the quarterly price into a monthly price. This shaping factor is based on Contact's view of monthly shape

71 The average price for this component was $188.15 at Otahuhu, and $154.44 at Benmore.

72 Because this is directly based on ASX, and is of a shape and term that Contact has and will continue to enter into with other parties we consider that this meets the requirements of the RPCA.

Superpeak hedge – shape and price

73 The superpeak hedge meets 20% of load each month. It uses actual monthly auction data over which the period the standardised superpeak auctions have been in operation – January 2025 – June 2026. We intend to extend this out in future RCPA calculations as the period of available data increases. Ultimately, we intend to calculate this hedge in the same way as the ASX-linked hedge.

74 The average price for this component was $262.42 at Otahuhu, and $216.09 at Benmore.

Methodology for new customers

75 The detail of this calculation is confidential, as it could be used to back-solve our current long-term price path.

[Redacted – commercially sensitive]

76 The average price for new customers is $143.80 at Otahuhu, and $130.24 at Benmore.

Pricing of un-hedged load

77 We have added a cost of $3.00/MWh to our Otahuhu and Benmore electricity cost to cover un-hedged load. This is the same for existing and new customers.

78 We determined this value by applying the 'as if' hedge portfolio to actual load from 2025 and 2024, and stress testing against scenarios where the

portfolio was 5% over hedged and a scenario where it was 5% under hedged. Across these two scenarios we found an average spot exposure of $3.26 for 2025, and $3.03 for 2024. $3.00 was used as the closest round number to these figures.

79 The $3.00/MWh acts as a cash-flow buffer, actual spot exposure will be greater or less in any given month. To test this we looked at the monthly cash-flow impact of the residual spot exposure applying spot costs from 2025 and 2024. This is shown in figures 6 and 7 below. It shows the total spot exposure cost in each month, and the cash flow impact after taking account of the $3.00/MWh cost for unhedged load.

Figure 6: Spot exposure and price of unhedged load (2025)

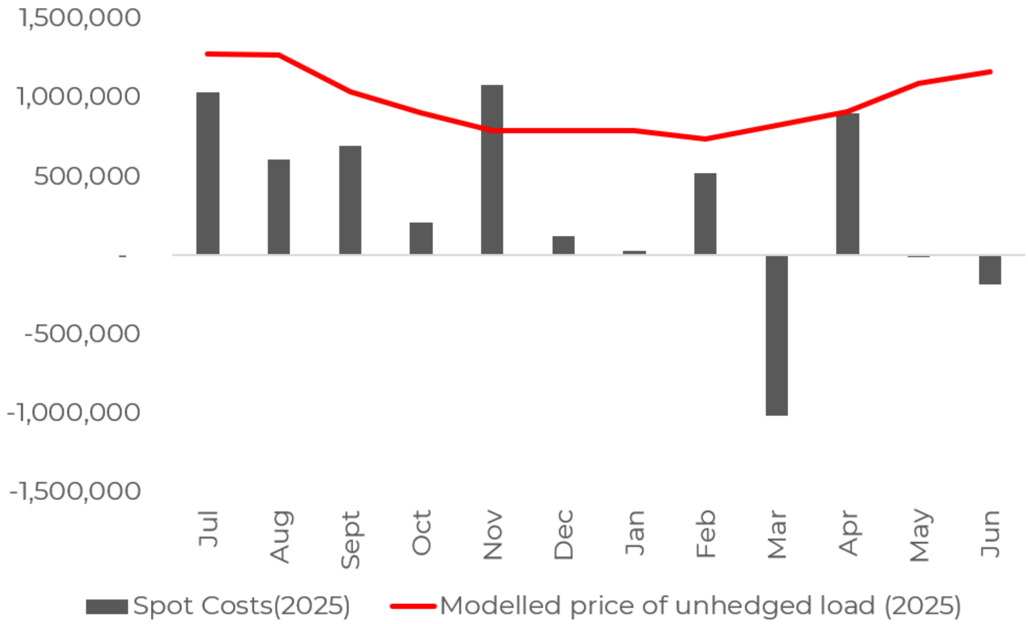
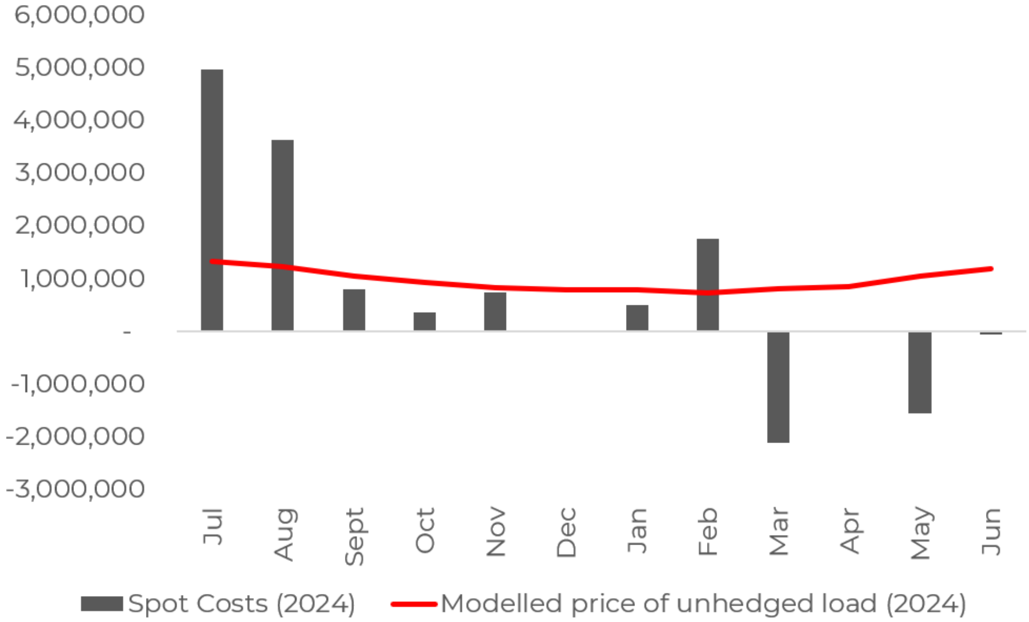


Figure 7: Spot exposure and price of unhedged load (2024)



80 These figures show that for the relatively benign 2025 year there is a healthy positive cashflow in all but one month. In the more challenging conditions in 2024 residual spot exposure exceeds the modelled unhedged load cost in July, August, and February but over the year is more than sufficient to meet total spot costs. Total cumulative cashflow impact in 2024 peaks at just over $6m. The cost of holding a debt facility to cover the shortfall is trivial.

Location adjustment

81 We have applied Contact's standard location factors. These factors are determined using **[Redacted – commercially sensitive]** for future periods. The factors are approved by the Commodity Risk Management Committee (CRMC) prior to being published for use in the Trading databases.