Company Name: Alpine Energy Limited

For Year Ended: 31 March 2025

Schedule 14 Mandatory Explanatory Notes

1. This schedule requires EDBs to provide explanatory notes to information provided in accordance with clauses 2.3.1, 2.4.21, 2.4.22, and subclauses 2.5.1(1)(f), and 2.5.2(1)(e).

2. This schedule is mandatory — EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. Information provided in boxes 1 to 11 of this schedule is part of the audited disclosure information, and so is subject to the assurance requirements specified in section 2.8.

3. Schedule 15 (Voluntary Explanatory Notes to Schedules) provides for EDBs to give additional explanation of disclosed information should they elect to do so.

Return on Investment (Schedule 2)

4. In the box below, comment on the return on investment as disclosed in Schedule 2. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 1: Explanatory comment on return on investment

The 2025 ROI-comparable to a post-tax WACC (reflecting all revenue earned) is 2.92%, a decrease from 5.96% in the prior year. This is 3.26% lower than the mid-point estimate of post-tax WACC for 2025. The resultant year-end ROI comparable to a post-tax WACC is 1.84%.

Compared to 2024, 2025 has a lower CPI (2.53%) which results in smaller revaluations ($7.9 million) and a smaller increase in the closing RAB and ROI.

There were no reclassified items in FY25.

Regulatory Profit (Schedule 3)

5. In the box below, comment on regulatory profit for the disclosure year as disclosed in Schedule 3. This comment must include-

   5.1 a description of material items included in other regulated income (other than gains / (losses) on asset disposals), as disclosed in 3(i) of Schedule 3; and

   5.2 information on reclassified items in accordance with subclause 2.7.1(2).

Box 2: Explanatory comment on regulatory profit

Regulatory profit for the year to 31 March 2025 is $11.4 million. This is $9.2 million lower than the previous year.

The reasons for this are:

- an increase in operating expenditure ($2.6 million);
- an increase in depreciation (1.7 million);
- a decrease in revaluations ($3.9 million);
- and lower revenue than allowed by the price-path

Our lines charge revenue was $65.1 million, (FY24: 65.7 million) which was less than the actual allowable revenue for FY25 ($75.2 million). In June 2024 we reduced our distribution prices for consumers by reducing our forecast revenue by $4 million from our 1 April forecast of $69.5 million revenue, to $65.4 million. This price reduction was made to ensure consumers did not continue to be overcharged because of the historic error in our disclosed depreciation and regulatory asset base values.

Our other regulated income in FY25 comprises sales of scrap metal and is less than $10,000.

Merger and acquisition expenses (3(iv) of Schedule 3)

6. If the EDB incurred merger and acquisition expenditure during the disclosure year, provide the following information in the box below-

   6.1 information on reclassified items in accordance with subclause 2.7.1(2)

   6.2 any other commentary on the benefits of the merger and acquisition expenditure to the EDB.

Box 3: Explanatory comment on merger and acquisition expenditure

We did not merge with nor acquire another regulated business, and no items were reclassified.

Value of the Regulatory Asset Base (Schedule 4)

7. In the box below, comment on the value of the regulatory asset base (rolled forward) in Schedule 4. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 4: Explanatory comment on the value of the regulatory asset based (rolled forward)

Our RAB value increased from $313 million to $338 million driven by:

- assets commissioned increasing to $29 million (2024: $21 million); and
- $7.9 million in revaluation adjustments (2024: 11.8 million).

Depreciation was 4.4% of the opening RAB, in line with the prior four years.

The revaluation rate decreased to 2.53% in the current disclosure year, which is less than prior year (2024) of 4.02%.

The works under construction (WIP) slightly decreased in the current year, from $11.2 million to $10.9 million. This is due to a greater number of assets commissioned during the year.

Non-network asset depreciation increased from $1.8 million in FY24 to $3.3 million. This is the result of reconciling non-network assets to the accounting asset register,a review of remaining useful asset lives, and the inclusion of non-network assets previously held by NETcon (now amalgamated into the regulated business).

Items reclassified

$1.2 million of assets have been reclassified from land and buildings into multiple plant and equipment assets..

Regulatory tax allowance: disclosure of permanent differences (5a(i) of Schedule 5a)

8. In the box below, provide descriptions and workings of the material items recorded in the following asterisked categories of 5a(i) of Schedule 5a-

   8.1 Income not included in regulatory profit / (loss) before tax but taxable;

   8.2 Expenditure or loss in regulatory profit / (loss) before tax but not deductible;

   8.3 Income included in regulatory profit / (loss) before tax but not taxable;

   8.4 Expenditure or loss deductible but not in regulatory profit / (loss) before tax.

Box 5: Regulatory tax allowance: permanent differences

The income not included in regulatory profit / (loss) before tax but taxable during this disclosure year is shown below:

	$
Interest on tax traders swap	7,133

The expenditures included in the regulatory profit / (loss) before tax but not during this disclosure year are shown below:

	$
Non-deductible Entertainment	61,281
Non-deductible GST on entertainment	6,603
Non-deductible donations	11,575
Non-deductible consultancy expenditure	7,082
Non-deductible legal fees	12,949
Total	**99,490**

The income included in regulatory profit / (loss) before tax but not taxable during this disclosure year is shown below:

	$
Non-taxable capital gain on land disposal	240,000

We had no expenditure or loss deductible but not in regulatory profit / (loss) before tax.

Regulatory tax allowance: disclosure of temporary differences (5a(vi) of Schedule 5a)

9. In the box below, provide descriptions and workings of material items recorded in the asterisked category 'Tax effect of other temporary differences' in 5a(vi) of Schedule 5a.

Box 6: Tax effect of other temporary differences (current disclosure year)

As a result of amalgamation, Field Services expenses are now recognised in the tax calculation and have impacted accrued ACC and annual leave provision.

The opening balance of the temporary differences was $955,619.

After amalgamation, the closing balance of Alpine Energy and Field Services is $1,981,612. This comprises the following items:

	$
Accrued ACC	33,826
Annual Leave Provision	1,481,748
Long Service Leave Provision	466,038

The tax effect on the net movement of $1,025,994 is $287,278.

Cost allocation (Schedule 5d)

10. In the box below, comment on cost allocation as disclosed in Schedule 5d. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 7: Cost allocation

In the current disclosure year (similar to prior years) business support costs are the only costs that require allocation and the only costs that are not 100% directly attributable to the electricity distribution services.

The total business support costs incurred related to electricity distribution services were $13.8 million which is $433,000 (3%) lower than the prior year. Directly attributable business support costs were $3.1 million which is $2.7 million higher than prior year's amount of $417,000. This is a result of costs associated with resolving the historic price path error ($1.7 million), and the allocation of centralised costs (e.g. cyber security, computer licences and support) to directly attributable activities.

The total not directly attributable business support costs are $11.6 million which is $3 million (or -20%) lower than the prior year. This is the result of reviewing our primary cost drivers in line with IDs and appropriately allocating costs following our amalgamation with NETcon.

As in prior years, we used revenue as the proxy allocator for business support costs. Revenue from regulated versus non-regulated activities is deemed to be an accurate representation of the cost allocation as it closely reflects the activities' output (and therefore the costs associated with it). From this year, as a result of amalgamation, this revenue includes Field Services' (formerly NETcon) regulatory and non-regulatory activities.

While some costs have been reallocated between expenditure categories (detailed above), no items have been reclassified as directly or non-directly attributable costs.

Asset allocation (Schedule 5e)

11. In the box below, comment on asset allocation as disclosed in Schedule 5e. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 8: Commentary on asset allocation

In the current disclosure year (similar to prior years) non-network assets are the only assets that required allocation and also the only asset category which is not 100% directly attributable to the electricity distribution services.

Directly attributable non-network assets, amount to $2 million, and relate to plant and equipment like drones which are solely used for network purposes. Total not directly attributable non-network assets, amounting to $16.6 million, include vehicles, land, buildings and computers and software which are used by all departments. These therefore require allocation. The total non-network assets attributable to regulated service are $18.6 million.

We allocated the value of all non-directly attributable non-network assets (land and building, computers and software, motor vehicles) using expenditure incurred as allocated to the various cost centres as the proxy.

Field Services vehicles, classified as non-directly attributable non-network assets and added to the RAB in FY25, are allocated using the same proxy.

No items have been reclassified as directly or non-directly attributable assets.

Capital Expenditure for the Disclosure Year (Schedule 6a)

12. In the box below, comment on expenditure on assets for the disclosure year, as disclosed in Schedule 6a. This comment must include-

    12.1 a description of the materiality threshold applied to identify material projects and programmes described in Schedule 6a;

    12.2 information on reclassified items in accordance with subclause 2.7.1(2).

Box 9: Explanation of capital expenditure for the disclosure year

Schedule 6a discloses our capex as follows:

- $30.1 million on network assets (2024: $27.8 million)
- $1.8 million on non-network assets (2024: $1.4 million)
- $2.9 million of capital contributions (2024: $3.8 million)
- $29.1 million total capital expenditure (2024: $25.4 million)

The majority of capex ($17.9 million) was asset replacement and renewals (2024: $18.4 million). Material projects delivered were the overhead line renewal and replacement projects at Coopers Creek ($1.1 million) and Arundel ($1.1million), and the fourth stage of the Timaru City overhead line renewal and replacement ($570,000).

System growth expenditure increased to $5.9 million (2024: $2.1million), driven by $4 million investment in the Washdyke Switching Station to increase capacity for industrial customers.

Asset relocation expenditure totalled $1.2 million (2024: $330,000), including $1.1 million undergrounding lines between Pages Road and Centennial Park, Timaru.

The materiality of capex projects is based on the impact of the project on network reliability, resilience, and capacity, and consumer outcomes, rather than a specific monetary threshold. Where applicable, we refer to a programme of work that delivers a material outcome for the network or customers, as opposed to a discrete project.

No items have been reclassified during this disclosure year.

Operational Expenditure for the Disclosure Year (Schedule 6b)

13. In the box below, comment on operational expenditure for the disclosure year, as disclosed in Schedule 6b. This comment must include-

    13.1 Commentary on assets replaced or renewed with asset replacement and renewal operational expenditure, as reported in 6b(i) of Schedule 6b;

    13.2 Information on reclassified items in accordance with subclause 2.7.1(2);

    13.3 Commentary on any material atypical expenditure included in operational expenditure disclosed in Schedule 6b, including the value of the expenditure the purpose of the expenditure, and the operational expenditure categories the expenditure relates to.

Box 10: Explanation of operational expenditure for the disclosure year
Schedule 6b discloses our opex as follows: • $7.7 million of network opex (2024: $6.6 million) • $25.3 million of non-network opex (2024: $23.8 million) This year business support costs include $1.8 million of material atypical expenditure relating to the cost for resolving the historic price path error. This year we completed a review of expenditure classifications for non-network opex to confirm alignment with ID definitions and accurately reflect cost following the amalgamation with NETcon. Centralised costs (e.g. cyber security, computer licences and support) that were previously classified as business support, have now been allocated between business support and system operations and network support using paid hours as a proxy. $3 million was reallocated to system operations and network support. Other non-material reclassifications occurred between non-network expenditure categories. As a result, the weighting of our non-network opex has changed from previous years: • $11.5 million of system operations and network support expenditure, 45% of non-network expenditure (2024: $9.5 million, 40% of non-network expenditure) • $13.8 million of business support costs, 55% of the non-network expenditure (2024: $14.3 million, 60% of non-network expenditure)

Variance between forecast and actual expenditure (Schedule 7)

14. In the box below, comment on the variance in actual to forecast expenditure for the disclosure year, as reported in Schedule 7. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 11: Explanatory comment on variance in actual to forecast expenditure
We have deemed any variance greater than +/-10% and greater than $1 million as a material variance. The forecast amounts were taken from the Asset Management Plan (AMP) published at the start of the disclosure year. There were no re-classified items.

Capital expenditure
Total actual capital expenditure of 2025 is 18% lower than the forecast. This is driven by lower than anticipated expenditure on consumer connection, system growth, reliability safety and environment, and non-network assets.

Consumer connection
The actual capital expenditure on consumer connection was 55%, or $4.0 million, lower than forecast. This was due to a significant reduction in consumer activity compared to prior years, and the timing of a major distributed generation project (reforecast to be delivered in FY26).

System growth
The actual capital expenditure on system growth was 33% or $2.9 million lower than forecast. With the significant reduction in consumer activity in FY25, some forecast growth projects have been deferred.

Total reliability safety and environment
The actual capital expenditure on other reliability safety and environment was 44%, or $1.5 million, lower than forecast due to the deferral of projects.

Operational expenditure

Total actual operational expenditure of 2025 is 18% ($7 million) lower than forecast. The primary driver of the variance is 33% ($6.9 million) decrease in business support expenditure resulting from the deferral of projects to future years. As disclosed in Box 10, some costs have also been reclassified as system operations and network support costs to better align with the cost drivers.

No material items have been reclassified during this disclosure year affecting the variance report .

Information relating to revenues and quantities for the disclosure year

15. In the box below provide-
    - 15.1 a comparison of the target revenue disclosed before the start of the disclosure year, in accordance with clause 2.4.1 and subclause 2.4.3(3) to total billed line charge revenue for the disclosure year, as disclosed in Schedule 8; and
    - 15.2 explanatory comment on reasons for any material differences between target revenue and total billed line charge revenue.

Box 12: Explanatory comment relating to revenue for the disclosure year
Our actual revenue of $65.1 million was $4.3 million lower (-0.06%) than the target revenue disclosed in our 2025 Pricing Methodology, and $10 million lower than actual allowable revenue under the price-path.

This variance was driven by our decision to reduce distribution prices from 1 June 2024 to the effect of a forecast $4 million revenue reduction for FY25. This decision was made to recognise and mitigate the fact that our 1 April 2024 distribution prices were set incorrectly because of a historical error in our depreciation calculations impacting the value of our regulatory asset base, which is a direct input to our allowable revenue under the default price-quality path regime.

Network Reliability for the Disclosure Year (Schedule 10)

16. In the box below, comment on network reliability for the disclosure year, as disclosed in Schedule 10.

Box 13: Commentary on network reliability for the disclosure year

Overall outage duration improved on the prior year, while interruptions were more frequent. Class C interruption duration on Alpine Energy's network has been reduced, reflecting quicker fault response and switching, and the weather has had less impact than last year.

Class C interruption frequency remained within the quality limit, and the interruption durations for both Class B and Class C were below DPP quality caps but above the target.

As we move to new quality limits for DPP4, we will continue to prioritise asset condition and defect remediation on distribution assets and refine outage planning to minimise planned outage time.

Worst performing feeder

Disclosing worst-performing feeders is a new ID requirement starting from disclosure year 2025. They are ranked separately by unplanned feeder SAIDI, unplanned feeder SAIFI, and the customer impact ratio. A worst-performing feeder sits at or above the 90th percentile for the disclosure year. For Alpine, this resulted in 14 distribution feeders between 1kV and 30kV being identified.

Insurance cover

17. In the box below, provide details of any insurance cover for the assets used to provide electricity distribution services, including-

    17.1 The EDB's approaches and practices in regard to the insurance of assets used to provide electricity distribution services, including the level of insurance;

    17.2 In respect of any self-insurance, the level of reserves, details of how reserves are managed and invested, and details of any reinsurance.

Box 14: Explanation of insurance cover

We take our insurance cover for our vehicles and buildings (including substations) and have public liability insurance. We do not have insurance coverage for our network (for example poles and lines) as the premiums are prohibitive.

Amendments to previously disclosed information

18. In the box below, provide information about amendments to previously disclosed information disclosed in accordance with clause 2.12.1 in the last 7 years, including:

    18.1 a description of each error; and

    18.2 for each error, reference to the web address where the disclosure made in accordance with clause 2.12.1 is publicly disclosed.

Box 15: Disclosure of amendment to previously disclosed information

There were no amendments to previously disclosed information during this disclosure year.

Company Name:	Alpine Energy Limited
For Year Ended:	31 March 2025

Schedule 15 Voluntary Explanatory Notes

1. This schedule enables EDBs to provide, should they wish to-

    1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.6.6;

    1.2 information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.

2. Information in this schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Treatment of payments made under Alpine Energy's enforceable undertakings

Alpine Energy's enforceable undertakings to the Commerce Commission, dated 28 March 2025, required a number of payments to address the historic overcharge of consumers from 2015 to 2024. The intent of the undertakings was to return the overcharge to consumers without the need to reopen the existing price-quality paths. Alpine has agreed to these payments outside of the revenue cap and information disclosure mechanisms. There has been no impact of these payments on the 2025 Annual Compliance Statement/Information Disclosures as no payments were made within the regulatory year. In addition, credits to current consumers are excluded from both the Default Price-Quality Path (DPP) and Information Disclosures (ID) except if less than $16.9m is credited. Any such difference along with credits to former customers and any unspent amounts of the community fund will only impact the price path (DPP) and lines charge revenue (IDs) in future regulatory periods in line with the enforceable undertakings.

Schedule 4 – RAB values (rolled forward)
In 2023 Alpine Energy identified errors in depreciation calculations supporting schedule 4 – RAB values, which resulted in annual revenues being set higher than they should have been over 2015 to 2024. In response to this, we corrected the error and restated our 2014-2022 Information Disclosures in 2023. In accordance with our undertakings to the Commerce Commission, we are preparing and implementing an improvement plan designed to mitigate the risk of a similar error occurring in the future. The priority action for this plan was reviewing computational models and inputs used to generate Schedule 4. This was completed as part of the preparation of the 2025 Information Disclosures. As part of this review, we identified and corrected some other non-material errors. These corrections have resulted in a one-off increase to depreciation and weighted average remaining asset life of non-network assets. These increases do not materially impact the RAB value for 2025 or historic periods.

Schedule 5b - Related Parties Transactions & Related Parties Disclosure Document
Field Services is Alpine Energy's internal function responsible for constructing and maintaining the electricity distribution network. These services were previously provided by the subsidiary NETCon Limited, along with other third parties. Following the amalgamation of NETcon into Alpine Energy in the 2024 financial year, we have evaluated whether Field Services should be treated as a related party for ID purposes.

We have determined that Field Services does not fall within the related parties' Information Disclosure (ID) requirements and therefore we are not required to include transactions relating to Field Services in our related party disclosures. The rationale for this is that:

- Alpine Energy's supplies to external customers (unregulated) do not exceed the unregulated supplies to the regulated service.
- These unregulated services do not have a management, sales, and support structure that is theoretically capable of being separated from the regulated supplier.

As a result, the Field Services function is considered part of the regulated supplier (Alpine Energy).

Field Services operates on a cost-recovery basis, except when providing services to external customers (unregulated services). Costs and assets associated with the delivery of these unregulated services are addressed through the ID cost allocation regime, identifying the non-directly attributable portion of operating costs and assets. These are disclosed in schedules 5d, 5e, 5f and 5g, and the supporting disclosures in schedule 14.

Schedule 10 – Reliability
There are inherent limitations in the ability of Alpine Energy to collect and record the network reliability information required to be disclosed in Schedule 10(i) to 10(iv), 10.2 and 10a (Commission only). Consequently, there is no independent evidence available to support the accuracy of recorded faults and control over the accuracy of installation control point ('ICP') data

included in the SAIDI and SAIFI calculations is limited throughout the year. This limitation will be removed once we move to an ADMS system, which is planned to be implemented in the next three to five years.

We treat successive interruptions in the following way:

a. Relates directly to that initial interruption. These would usually be reported as a separate outage, if however, the original outage was classed as unknown it is updated as if the following fault can be confirmed to have caused the original.
b. Occurs as part of the process of restoring the supply of electricity lines services following that initial interruption. In this situation, the outage would be recorded as part of the original fault, and the cause would be the same for both, but where ICPs go off more than once they would be reported as such to keep the SAIFI correct.