Company Name:	Alpine Energy Limited
For Year Ended:	31 March 2024

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 2024 ROI-comparable to a post-tax WACC (reflecting all revenue earned) is 5.96%, a decrease from 7.92% in the prior year. This is 0.09% lower than the mid-point estimate of post-tax WACC for 2024. The resultant year-end ROI comparable to a post-tax WACC is 5.02%.

Compared to 2023, 2024 has a lower CPI number (4.02%) which results in smaller revaluations ($11.8 million) and a smaller increase in the closing RAB and ROI.

The net recoverable cost allowed under the incremental rolling incentive scheme disclosed in Schedule 2(v) represents the value disclosed in the Annual Compliance Statement for the assessment period ended 31 March 2024[1], prepared pursuant to the Electricity Distribution Services Default Price Quality Path Determination 2020 (consolidated May 2020).

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).

[1] https://www.alpineenergy.co.nz/corporate/disclosures/information-disclosures

Box 2: Explanatory comment on regulatory profit
- Sale of cross arms and steel ($10,688) - Sale of scrap transformers ($15,988) - Nexans Rebate (in relation to cable purchases – ($12,876))

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 $293.3 million to $313.1 million during the disclosure year because of $21 million in assets commissioned and $11.8 million in revaluation adjustments in the current disclosure year. The revaluation rate increased by 4.02% in the current disclosure year, smaller than 6.65% in 2023 because of a small increase in inflation rates (CPI). $10.8 million of assets commissioned were acquired from our related party, AEL Field Services (formerly NETcon). In completing the RAB, we identified $89k of assets were incorrectly classified and have corrected this in the current year. $72k was reclassified from “Zone substations” to “Distribution switchgear” and $17k was reclassified from “Distribution substations and transformers” to “Distribution and LV cables”.

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	1,817

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

	$
Non-Deductible Entertainment	79,874
Non-deductible GST on entertainment	4,410
Total	**84,284**

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

	$
Non-taxable interest income	3,814

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)

The opening balance of the temporary differences was $862,000.

The closing balance is $956,000 and comprises the following items:

	$
Accrued ACC	12,767
Annual Leave Provision	706,853
General provision for sponsorship	12,083
Long Service Leave Provision	112,858
Payroll accrual	111,058

The tax effect on the net movement of $93,000 is $29,000.

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 required allocation and also the only costs that are not 100% directly attributable to the electricity distribution services.

Directly attributable business support costs are $417,000, similar to the prior year's amount of $402,000. Not directly attributable business support costs are $13.9 million which is $3.7 million higher than the prior year's amount of $10.2 million. Most subcategories of business support costs increased in the current disclosure year. The most significant ones are Cybersecurity (+367% or +$267,132), Project Management Office (+100% or +$738,125), Digital Services (+43% or +$1.3 million), and ELT (+24% or +$925,174). The total business support costs incurred not related to electricity distribution services are $704,000, which is $154,000 higher than the prior year.

Like the prior year, 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).

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, amounting to $1.5 million, are in relation to plant and equipment and include items like drones which are used 100% for network purposes. Total not directly attributable non-network assets, amounting to $18.3 million, include land and buildings and computers and software which are used by all departments, and $2.9 million of non-electricity distribution services like metering and fibre departments. These therefore require allocation. The total non-network assets attributable to regulated service are $16.9 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.

Land and building

As a result of the amalgamation of NETcon and AEL, a total of 7% of AEL's building was allocated to AEL Field Services for the year. The move was made on 18 December 2023 before the office closed for the Christmas shutdown on 21 December 2023. A pro rata rate was calculated for the three months that Field Services occupied Alpine House, this equates to 1.61%.

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
Capital expenditure for this disclosure year was $29 million ($25 million when capital contributions are deducted) compared to $24 million ($21 million when capital contributions are deducted) during 2023. The materiality of our CAPEX projects is based on the impact of the project on the network, resource availability, etc., and not a monetary materiality threshold. Where applicable, we refer to a programme of work that is material as opposed to a specific project. We had three specific projects in asset relocations which we disclosed separately due to the different natures of these projects. 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
Operational expenditure for this disclosure year was $30 million, compared to $22 million during 2023. The total operating expenditure on asset replacement and renewal was $321,000 in the current disclosure year. The OPEX for asset replacement and renewal is mainly in relation to temporary maintenance on poles identified during outages or other work. No items have been reclassified and no material atypical expenditure occurred during this disclosure year.

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% as a material variance and have provided commentary on those below. 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 for either opex or capex other than correctly accounting for software-as-a-service as opex.

Capital expenditure
Total actual capital expenditure of 2024 is 15% lower than the forecast. This is driven by expenditure on system growth and non-network assets.

System growth
The actual capital expenditure on system growth was 53% or $2.5 million lower than forecast. This is due to the timing of the construction of the Washdyke 11kV switching station build. $2.4 million of this expenditure has been deferred to 2025.

Asset relocations
The actual capital expenditure on asset relocations was 17% or $69,362 lower than forecast. The target expenditure was $400,000 but actual expenditure was $331,000.

Two projects were budgeted for in FY24: Overhead to Underground Conversions and B1508 Transformer Replacement. Overhead to Underground Conversions is a portfolio expenditure budgeted at $250,000. There were no projects or customer requests for Overhead to Underground conversion during the disclosure year which meant there was no expenditure related to this. B1508 Transformer Replacement was budgeted at $150,000. However, the actual cost increased by $60,000 to allow for crane, traffic management, and the building of a concrete box around the asset to protect the building to meet standards. There was a further increase in spending of $28,000 due to an additional pole change that was awarded to a contractor who had to travel from Christchurch.

Further expenditure of $93,000 arose relating to design costs for FY25 projects that were not budgeted in AMP 2023.

Quality of supply
The actual capital expenditure on quality of supply was 100% or $150,000 lower than forecast. $150,000 was allocated to "Voltage Regulator for Load And Voltage Control". However, no new project or defect arose for voltage regulators or capacitor banks, so no money was spent.

Non-network assets
The actual capital expenditure on non-network assets was 71% or $3.4 million lower than forecast. There are 2 parts to the variance:

1) The budget was based on some assumptions on what would be required at the time of completing the 2023 AMP. Some projects were reprioritised and did not proceed in this disclosure year. Our approach to this year's budget forecast has been revised to ensure these are aligned with our Target Architecture roadmap with clear projects to commence in the next financial year.

2) Forecast capex for digital spend in 2024 has been reallocated to opex driving the 71% variance. This is due to a change in the application of accounting rules for Software as a Service (SaaS). There is a corresponding increase in non-network opex - business support above forecast (discussed in Box 7 Cost Allocation).

Operational expenditure
Total actual operational expenditure of 2024 is 10% higher than forecast. This is driven by increased expenditure for non-network opex.

Service interruptions and emergencies
The actual capital expenditure on service interruptions and emergencies was 10% or $202,155 higher than forecast. $146,000 was assigned to the faults budget for Transpower outages and deployment of AMG (Alpine Mobile Generator) to Tekapo for Transpower Outage. An increase in the Fault Supervisor and Faults allowances during this period would also not have been accounted for within the budget set at the beginning of the year.

Vegetation management
The actual vegetation management expenditure was 23% lower than forecast. This is due to reduced resource availability across field services and external contractors meaning we did not deliver our annual inspection programme.

Non-network opex
Non-network opex is 15% higher than forecast. The biggest driver for the increase is business support, with the reallocation of SaaS digital expenditure from capex to opex.

Business support
The actual business support expenditure was 30% higher than forecast. Capex forecast for digital services has been reallocated to non-network opex to align with the correct treatment of SaaS.
There were also significant increased costs in relation to the amalgamation with NETcon which were not forecasted.

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 $65.7 million was $2.6 million higher (4%) than the target revenue disclosed in our 2024 Pricing Methodology.

$1.1 million of the difference is a result of the commissioning of Woolworks, which was not considered when drawing up the budget figure. The balance of the difference is mainly due to the drought conditions experienced in South Canterbury, resulting in higher-than-average irrigation volumes. Budgeting is done on an expectation of average irrigation volumes.

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
The total normalised SAIFI increased from 1.20 to 1.45 and the total normalised SAIDI increased from 194.2 to 287.8.

This change was primarily driven by an increase in Class C interruptions during the disclosure year. The Alpine Energy network was significantly impacted by three major events, the most severe of which was the windstorm on 1 October 2023. The resulting outages were distributed across the Alpine Energy network, with the majority occurring in the lower regions, from Rangitata to Glenavy, and fewer incidents further inland. The primary cause of these outages was high winds, particularly in cases where no other contributing factor was identified. Additional outages were attributed to wind-blown vegetation, fallen trees, broken crossarms, downed wires, poles on a lean, and broken poles. Some of these issues were secondary effects, such as wind-blown trees within falling distance striking power lines, resulting in broken lines and poles.

It is important to note that the normalisation methodology used is as per the Input Methodologies and is inconsistent with the methodology employed in the Default Price-Quality Path disclosure.

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 2024

Schedule 14a **Mandatory Explanatory Notes on Forecast Information**

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

   This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

2. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

The nominal dollars capital expenditure forecast for 31 March 2024 represents the forecast actual capital expenditure for the year ending 31 March 2024. The constant price for 31 March 2024 represents the forecast values as per the prior year AMP.

To derive the capital expenditure in nominal dollar terms, the constant price forecasts (using 2025 real dollars) were inflated by 2.4% for 2026, 2.1% for 2027, and 2.0% for the other years, based on forecasts by ANZ and the Reserve Bank of New Zealand (RBNZ). To derive the ten-year forecast, 2.4% for 2026, 2.1% for 2027, and 2.0% for the other years, as conservative inflationary rates. Therefore, the difference between nominal and constant expenditure forecasts is an inflationary impact of 2.4 in 2026, 2.1% in 2027, and 2.0% in other years.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

3. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

The nominal dollars operational expenditure forecast for 31 March 2024 represents the forecast actual operational expenditure for the year ending 31 March 2024. The constant price for 31 March 2024 represents the forecast values as per the prior year AMP.

To derive the operational expenditure in nominal dollar terms, the constant price forecasts (using 2025 real dollars) were inflated by 2.4% for 2026, 2.1% for 2027, and 2.0% for the other years, based on forecasts by ANZ and the Reserve Bank of New Zealand (RBNZ). To derive the 10-year forecast, 2.4% for 2026, 2.1% for 2027 and 2.0% for the other years, as conservative inflationary rates. Therefore, the difference between nominal and constant expenditure forecasts is an inflationary impact of 2.4% for 2026, 2.1% for 2027, and 2.0% in other years.

Company Name:	Alpine Energy Limited
For Year Ended:	31 March 2024

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

Schedule 10

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). 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.