COMMERCE COMMISSION
NEW ZEALAND

EDB Information Disclosure Requirements
Information Templates
for
Schedules 1–10

Company Name	Alpine Energy Limited
Disclosure Date	31 August 2022
Disclosure Year (year ended)	31 March 2022

Templates for Schedules 1–10 excluding 5f–5g
Template Version 4.1. Prepared 21 December 2017

Table of Contents

Disclosure Template Instructions

These templates have been prepared for use by EDBs when making disclosures under clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, and 2.5.2 of the Electricity Distribution Information Disclosure Determination 2012.

Company Name and Dates

To prepare the templates for disclosure, the supplier's company name should be entered in cell C8, the date of the last day of the current (disclosure) year should be entered in cell C12, and the date on which the information is disclosed should be entered in cell C10 of the CoverSheet worksheet.
The cell C12 entry (current year) is used to calculate disclosure years in the column headings that show above some of the tables and in labels adjacent to some entry cells. It is also used to calculate the ‘For year ended’ date in the template title blocks (the title blocks are the light green shaded areas at the top of each template).
The cell C8 entry (company name) is used in the template title blocks.
Dates should be entered in day/month/year order (Example -"1 April 2013").

Data Entry Cells and Calculated Cells

Data entered into this workbook may be entered only into the data entry cells. Data entry cells are the bordered, unshaded areas (white cells) in each template. Under no circumstances should data be entered into the workbook outside a data entry cell.
In some cases, where the information for disclosure is able to be ascertained from disclosures elsewhere in the workbook, such information is disclosed in a calculated cell.

Validation Settings on Data Entry Cells

To maintain a consistency of format and to help guard against errors in data entry, some data entry cells test keyboard entries for validity and accept only a limited range of values. For example, entries may be limited to a list of category names, to values between 0% and 100%, or either a numeric entry or the text entry “N/A”. Where this occurs, a validation message will appear when data is being entered. These checks are applied to keyboard entries only and not, for example, to entries made using Excel’s copy and paste facility.

Conditional Formatting Settings on Data Entry Cells

Schedule 2 cells G79 and I79:L79 will change colour if the total cashflows do not equal the corresponding values in table 2(ii).
Schedule 4 cells P99:P105 and P107 will change colour if the RAB values do not equal the corresponding values in table 4(ii).
Schedule 9b columns AA to AE (2013 to 2017) contain conditional formatting. The data entry cells for future years are hidden (are changed from white to yellow).
Schedule 9b cells AG10 to AG60 will change colour if the total assets at year end for each asset class does not equal the corresponding values in column I in Schedule 9a.
Schedule 9c cell G30 will change colour if G30 (overhead circuit length by terrain) does not equal G18 (overhead circuit length by operating voltage).

Inserting Additional Rows and Columns

The templates for schedules 4, 5b, 5c, 5d, 5e, 6a, 8, 9d, and 9e may require additional rows to be inserted in tables marked 'include additional rows if needed' or similar. Column A schedule references should not be entered in additional rows, and should be deleted from additional rows that are created by copying and pasting rows that have schedule references.
Additional rows in schedules 5c, 6a, and 9e must not be inserted directly above the first row or below the last row of a table. This is to ensure that entries made in the new row are included in the totals.
Schedules 5d and 5e may require new cost or asset category rows to be inserted in allocation change tables 5d(iii) and 5e(ii). Accordingly, cell protection has been removed from rows 77 and 78 of the respective templates to allow blocks of rows to be copied. The four steps to add new cost category rows to table 5d(iii) are: Select Excel rows 69:77, copy, select Excel row 78, insert copied cells. Similarly, for table 5e(ii): Select Excel rows 70:78, copy, select Excel row 79, then insert copied cells.
The template for schedule 8 may require additional columns to be inserted between column P and U. To avoid interfering with the title block entries, these should be inserted to the left of column S. If inserting additional columns, the formulas for standard consumers total, non-standard consumers totals and total for all consumers will need to be copied into the cells of the added columns. The formulas can be found in the equivalent cells of the existing columns.

Disclosures by Sub-Network

If the supplier has sub-networks, schedules 8, 9a, 9b, 9c, 9e, and 10 must be completed for the network and for each sub-network. A copy of the schedule worksheet(s) must be made for each sub-network and named accordingly.

Schedule References

The references labelled 'sch ref' in the leftmost column of each template are consistent with the row references in the Electricity Distribution ID Determination 2012 (as issued on 21 December 2017). They provide a common reference between the rows in the determination and the template.

Description of Calculation References

Calculation cell formulas contain links to other cells within the same template or elsewhere in the workbook. Key cell references are described in a column to the right of each template. These descriptions are provided to assist data entry. Cell references refer to the row of the template and not the schedule reference.

Worksheet Completion Sequence

Calculation cells may show an incorrect value until precedent cell entries have been completed. Data entry may be assisted by completing the schedules in the following order:

1. Coversheet
2. Schedules 5a–5e
3. Schedules 6a–6b
4. Schedule 8
5. Schedule 3
6. Schedule 4
7. Schedule 2
8. Schedule 7
9. Schedules 9a–9e
10. Schedule 10

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 1: ANALYTICAL RATIOS

This schedule calculates expenditure, revenue and service ratios from the information disclosed. The disclosed ratios may vary for reasons that are company specific and, as a result, must be interpreted with care. The Commerce Commission will publish a summary and analysis of information disclosed in accordance with the ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of the determination.

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

1(i): Expenditure metrics

	Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
Operational expenditure	28,800	669	165,370	5,143	37,076
Network	8,976	208	51,540	1,603	11,555
Non-network	19,824	460	113,830	3,540	25,521
Expenditure on assets	31,194	724	179,114	5,570	40,157
Network	29,366	682	168,618	5,244	37,804
Non-network	1,828	42	10,497	326	2,353

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	68,091	1,581
Standard consumer line charge revenue	84,297	1,440
Non-standard consumer line charge revenue	22,972	390,736

1(iii): Service intensity measures

Demand density	31	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	179	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	8	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	23,217	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	22,245	42.28%
Pass-through and recoverable costs excluding financial incentives and wash-ups	14,039	26.68%
Total depreciation	10,860	20.64%
Total revaluations	14,495	27.55%
Regulatory tax allowance	2,168	4.12%
Regulatory profit/(loss) including financial incentives and wash-ups	17,797	33.83%
Total regulatory income	52,614	

1(v): Reliability

Interruption rate	26.12	*Interruptions per 100 circuit km*

Company Name **Alpine Energy Limited**
For Year Ended **31 March 2022**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).

EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
8		31 Mar 20	31 Mar 21	31 Mar 22
9	**ROI – comparable to a post tax WACC**	%	%	%
10	Reflecting all revenue earned	11.66%	5.64%	8.40%
11	Excluding revenue earned from financial incentives	11.54%	5.59%	7.98%
12	Excluding revenue earned from financial incentives and wash-ups	8.82%	5.59%	8.03%
13				
14	**Mid-point estimate of post tax WACC**	4.27%	3.72%	3.52%
15	25th percentile estimate	3.59%	3.04%	2.84%
16	75th percentile estimate	4.95%	4.40%	4.20%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	12.08%	5.97%	8.70%
21	Excluding revenue earned from financial incentives	11.96%	5.92%	8.28%
22	Excluding revenue earned from financial incentives and wash-ups	9.25%	5.92%	8.33%
23				
24	**WACC rate used to set regulatory price path**	7.19%	4.57%	4.57%
25				
26	**Mid-point estimate of vanilla WACC**	4.69%	4.05%	3.82%
27	25th percentile estimate	4.01%	3.37%	3.14%
28	75th percentile estimate	5.37%	4.73%	4.50%
29				

30	**2(ii): Information Supporting the ROI**			($000)	
31					
32		Total opening RAB value	210,581		
33	*plus*	Opening deferred tax	(12,167)		
34	**Opening RIV**			198,414	
35					
36	**Line charge revenue**			52,594	
37					
38		Expenses cash outflow	36,285		
39	*add*	Assets commissioned	18,509		
40	*less*	Asset disposals	50		
41	*add*	Tax payments	629		
42	*less*	Other regulated income	20		
43	**Mid-year net cash outflows**			55,353	
44					
45	**Term credit spread differential allowance**			–	
46					
47		Total closing RAB value	238,090		
48	*less*	Adjustment resulting from asset allocation	5,415		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(13,706)		
51	**Closing RIV**			218,970	
52					
53	**ROI – comparable to a vanilla WACC**				8.70%
54					
55		Leverage (%)			42%
56		Cost of debt assumption (%)			2.55%
57		Corporate tax rate (%)			28%
58					
59	**ROI – comparable to a post tax WACC**				8.40%
60					

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).

EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

2(iii): Information Supporting the Monthly ROI

Opening RIV	N/A

	Line charge revenue	Expenses cash outflow	Assets commissioned	Asset disposals	Other regulated income	Monthly net cash outflows
April	–	–	–	–	–	–
May	–	–	–	–	–	–
June	–	–	–	–	–	–
July	–	–	–	–	–	–
August	–	–	–	–	–	–
September	–	–	–	–	–	–
October	–	–	–	–	–	–
November	–	–	–	–	–	–
December	–	–	–	–	–	–
January	–	–	–	–	–	–
February	–	–	–	–	–	–
March	–	–	–	–	–	–
Total	–	–	–	–	–	–

Tax payments	N/A
Term credit spread differential allowance	N/A
Closing RIV	N/A
Monthly ROI – comparable to a vanilla WACC	N/A
Monthly ROI – comparable to a post tax WACC	N/A

2(iv): Year-End ROI Rates for Comparison Purposes

Year-end ROI – comparable to a vanilla WACC	8.08%
Year-end ROI – comparable to a post tax WACC	7.78%

** these year-end ROI values are comparable to the ROI reported in pre 2012 disclosures by EDBs and do not represent the Commission's current view on ROI.*

2(v): Financial Incentives and Wash-Ups

Net recoverable costs allowed under incremental rolling incentive scheme	898	
Purchased assets – avoided transmission charge	–	
Energy efficiency and demand incentive allowance	–	
Quality incentive adjustment	251	
Other financial incentives	–	
Financial incentives		1,149
Impact of financial incentives on ROI		0.42%
Input methodology claw-back	–	
CPP application recoverable costs	–	
Catastrophic event allowance	–	
Capex wash-up adjustment	(130)	
Transmission asset wash-up adjustment	–	
2013–15 NPV wash-up allowance	–	
Reconsideration event allowance	–	
Other wash-ups	–	
Wash-up costs		(130)
Impact of wash-up costs on ROI		–0.05%

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref				
7		**3(i): Regulatory Profit**		**($000)**
8		**Income**		
9		Line charge revenue		52,594
10	*plus*	Gains / (losses) on asset disposals		20
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		–
12				
13		**Total regulatory income**		52,614
14		**Expenses**		
15	*less*	Operational expenditure		22,245
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		14,039
18				
19		**Operating surplus / (deficit)**		16,329
20				
21	*less*	Total depreciation		10,860
22				
23	*plus*	Total revaluations		14,495
24				
25		**Regulatory profit / (loss) before tax**		19,964
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		2,168
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		17,797
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	115	
36		Commerce Act levies	106	
37		Industry levies	163	
38		CPP specified pass through costs	–	
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	12,308	
41		Transpower new investment contract charges	1,337	
42		System operator services	10	
43		Distributed generation allowance	–	
44		Extended reserves allowance	–	
45		Other recoverable costs excluding financial incentives and wash-ups	–	
46		**Pass-through and recoverable costs excluding financial incentives and wash-ups**		14,039
47				

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref				
48	**3(iii): Incremental Rolling Incentive Scheme**		**($000)**	
49			**CY-1**	**CY**
50			**31 Mar 21**	**31 Mar 22**
51	Allowed controllable opex		–	–
52	Actual controllable opex		–	–
53				
54	Incremental change in year			–
55				
56			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
57	CY-5	31 Mar 17	–	–
58	CY-4	31 Mar 18	–	–
59	CY-3	31 Mar 19	–	–
60	CY-2	31 Mar 20	–	–
61	CY-1	31 Mar 21	–	–
62	**Net incremental rolling incentive scheme**			–
63				
64	**Net recoverable costs allowed under incremental rolling incentive scheme**			–
65	**3(iv): Merger and Acquisition Expenditure**			
70				**($000)**
66	Merger and acquisition expenditure			–
67				
68	*Provide commentary on the benefits of merger and acquisition expenditure to the electricity distribution business, including required disclosures in accordance with section 2.7, in Schedule 14 (Mandatory Explanatory Notes)*			
69	**3(v): Other Disclosures**			
70				**($000)**
71	Self-insurance allowance			–

Company Name	Alpine Energy Limited
For Year Ended	31 March 2022

SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.
EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref				RAB	RAB	RAB	RAB	RAB
7	**4(i): Regulatory Asset Base Value (Rolled Forward)**							
8			for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
9				($000)	($000)	($000)	($000)	($000)
10		**Total opening RAB value**		178,990	199,621	201,495	205,600	210,581
11								
12	*less*	**Total depreciation**		12,244	12,793	13,167	12,731	10,860
13								
14	*plus*	**Total revaluations**		1,969	2,962	5,104	3,127	14,495
15								
16	*plus*	**Assets commissioned**		30,906	17,962	11,810	14,585	18,509
17								
18	*less*	**Asset disposals**		–	–	65	–	50
19								
20	*plus*	**Lost and found assets adjustment**		–	–	424	–	–
21								
22	*plus*	**Adjustment resulting from asset allocation**		–	(6,257)	(0)	(0)	5,415
23								
24		**Total closing RAB value**		199,621	201,495	205,600	210,581	238,090
25								

sch ref			Unallocated RAB *		RAB	
26	**4(ii): Unallocated Regulatory Asset Base**					
28			($000)	($000)	($000)	($000)
29		**Total opening RAB value**		222,676		210,581
30	*less*					
31		**Total depreciation**		10,987		10,860
32	*plus*					
33		**Total revaluations**		15,333		14,495
34	*plus*					
35		Assets commissioned (other than below)	9,192		9,148	
36		Assets acquired from a regulated supplier				
37		Assets acquired from a related party	9,360		9,360	
38		**Assets commissioned**		18,553		18,509
39	*less*					
40		Asset disposals (other than below)	50		50	
41		Asset disposals to a regulated supplier	–		–	
42		Asset disposals to a related party	–		–	
43		**Asset disposals**		50		50
44						
45	*plus*	**Lost and found assets adjustment**		–		–
46						
47	*plus*	**Adjustment resulting from asset allocation**				5,415
48						
49		**Total closing RAB value**		245,525		238,090
50						

** The 'unallocated RAB' is the total value of those assets used wholly or partially to provide electricity distribution services without any allowance being made for the allocation of costs to services provided by the supplier that are not electricity distribution services. The RAB value represents the value of these assets after applying this cost allocation. Neither value includes works under construction.*

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.

EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref						
51						
52		**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**				
53						
54		CPI_4				1,142
55		CPI_4^{-4}				1,068
56		Revaluation rate (%)				6.93%
57						
58			**Unallocated RAB ***		**RAB**	
59			**($000)**	**($000)**	**($000)**	**($000)**
60		Total opening RAB value	222,676		210,581	
61	*less*	Opening value of fully depreciated, disposed and lost assets	1,377		1,377	
62						
63		Total opening RAB value subject to revaluation	221,299		209,204	
64		**Total revaluations**		15,333		14,495
65						
66		**4(iv): Roll Forward of Works Under Construction**				
67			**Unallocated works under construction**		**Allocated works under construction**	
68		**Works under construction—preceding disclosure year**		3,062		3,182
69	*plus*	Capital expenditure	20,641		20,614	
70	*less*	Assets commissioned	18,553		18,509	
71	*plus*	Adjustment resulting from asset allocation			–	
72		**Works under construction - current disclosure year**		5,150		5,288
73						
74		Highest rate of capitalised finance applied				–
75						

Company Name: **Alpine Energy Limited**
For Year Ended: **31 March 2022**

SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.
EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

76 4(v): Regulatory Depreciation

sch ref		Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
79	Depreciation - standard	9,616		9,616	
80	Depreciation - no standard life assets	1,372		1,244	
81	Depreciation - modified life assets	–		–	
82	Depreciation - alternative depreciation in accordance with CPP	–		–	
83	**Total depreciation**		10,987		10,860

85 4(vi): Disclosure of Changes to Depreciation Profiles

($000 unless otherwise specified)

sch ref	Asset or assets with changes to depreciation*	Reason for non-standard depreciation (text entry)	Depreciation charge for the period (RAB)	Closing RAB value under 'non-standard' depreciation	Closing RAB value under 'standard' depreciation
87	N/a	N/a	N/a	N/a	N/a
88					
89					
90					
91					
92					
93					
94					

95 ** include additional rows if needed*

96 4(vii): Disclosure by Asset Category

($000 unless otherwise specified)

sch ref			Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
99		**Total opening RAB value**	13,127	5,178	52,817	36,875	50,972	16,257	15,445	9,236	10,674	210,581
100	*less*	Total depreciation	484	175	1,177	3,933	1,685	1,436	442	284	1,244	10,860
101	*plus*	Total revaluations	909	359	3,657	2,539	3,532	1,126	1,056	582	735	14,495
102	*plus*	Assets commissioned	0	8	3,422	4,648	5,362	1,051	2,177	425	1,414	18,509
103	*less*	Asset disposals	0	0	4	0	0	0	0	46	0	50
104	*plus*	Lost and found assets adjustment	0	0	0	0	0	0	0	0	0	–
105	*plus*	Adjustment resulting from asset allocation	0	0	0	0	0	0	0	0	5,415	5,415
106	*plus*	Asset category transfers	0	0	0	0	0	0	0	0	0	–
107		**Total closing RAB value**	13,552	5,370	58,715	40,130	58,182	16,998	18,236	9,913	16,994	238,090
109		**Asset Life**										
110		Weighted average remaining asset life	32.6	39.1	34.6	35.9	39.0	27.8	34.6	29.4	24.0	(years)
111		Weighted average expected total asset life	51.0	45.0	43.1	53.3	55.5	45.0	41.2	36.4	25.8	(years)

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section

sch ref

7	**5a(i): Regulatory Tax Allowance**			**($000)**	
8	**Regulatory profit / (loss) before tax**			19,964	
9					
10	*plus*	Income not included in regulatory profit / (loss) before tax but taxable	–		*
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible	29		*
12		Amortisation of initial differences in asset values	2,844		
13		Amortisation of revaluations	1,498		
14				4,371	
15					
16	*less*	Total revaluations	14,495		
17		Income included in regulatory profit / (loss) before tax but not taxable	–		*
18		Discretionary discounts and customer rebates	–		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax	–		*
20		Notional deductible interest	2,098		
21				16,594	
22					
23	**Regulatory taxable income**			7,741	
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income		7,741	
27					
28		Corporate tax rate (%)	28%		
29	**Regulatory tax allowance**			2,168	
30					
31	*	Workings to be provided in Schedule 14			
32	**5a(ii): Disclosure of Permanent Differences**				
33		In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i).			
34	**5a(iii): Amortisation of Initial Difference in Asset Values**			**($000)**	
35					
36		Opening unamortised initial differences in asset values	35,830		
37	*less*	Amortisation of initial differences in asset values	2,844		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	–		
40		Closing unamortised initial differences in asset values		32,986	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		12.6	
43					

pwc

Company Name	Alpine Energy Limited
For Year Ended	31 March 2022

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section

sch ref

44	**5a(iv): Amortisation of Revaluations**			($000)
45				
46		Opening sum of RAB values without revaluations	181,541	
47				
48		Adjusted depreciation	9,362	
49		Total depreciation	10,860	
50		Amortisation of revaluations		1,498
51				
52	**5a(v): Reconciliation of Tax Losses**			($000)
53				
54		**Opening tax losses**	–	
55	*plus*	Current period tax losses	–	
56	*less*	Utilised tax losses	–	
57		**Closing tax losses**		–
58	**5a(vi): Calculation of Deferred Tax Balance**			($000)
59				
60		**Opening deferred tax**	(12,167)	
61				
62	*plus*	Tax effect of adjusted depreciation	2,621	
63				
64	*less*	Tax effect of tax depreciation	3,387	
65				
66	*plus*	Tax effect of other temporary differences*	112	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	796	
69				
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year	–	
71				
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year	255	
73				
74	*plus*	Deferred tax cost allocation adjustment	166	
75				
76		**Closing deferred tax**		(13,706)
77				
78	**5a(vii): Disclosure of Temporary Differences**			
79		*In Schedule 14, Box 6, provide descriptions and workings of items recorded in the asterisked category in Schedule 5a(vi) (Tax effect of other temporary differences).*		
80				
81	**5a(viii): Regulatory Tax Asset Base Roll-Forward**			
82				($000)
83		**Opening sum of regulatory tax asset values**	115,791	
84	*less*	Tax depreciation	12,097	
85	*plus*	Regulatory tax asset value of assets commissioned	19,593	
86	*less*	Regulatory tax asset value of asset disposals	959	
87	*plus*	Lost and found assets adjustment	–	
88	*plus*	Adjustment resulting from asset allocation	6,009	
89	*plus*	Other adjustments to the RAB tax value	8,469	
90		**Closing sum of regulatory tax asset values**		136,806

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

This schedule provides information on the valuation of related party transactions, in accordance with clause 2.3.6 of the ID determination.
This information is part of audited disclosure information (as defined in clause 1.4 of the ID determination), and so is subject to the assurance report required by clause 2.8.

sch ref		($000)	($000)
7	**5b(i): Summary—Related Party Transactions**		
8	**Total regulatory income**		–
9			
10	**Market value of asset disposals**		–
11			
12	Service interruptions and emergencies	1,869	
13	Vegetation management	354	
14	Routine and corrective maintenance and inspection	2,773	
15	Asset replacement and renewal (opex)	92	
16	**Network opex**		5,088
17	Business support	–	
18	System operations and network support	888	
19	**Operational expenditure**		5,976
20	Consumer connection	1,596	
21	System growth	376	
22	Asset replacement and renewal (capex)	8,616	
23	Asset relocations	84	
24	Quality of supply	–	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	148	
27	**Expenditure on non-network assets**		18
28	**Expenditure on assets**		10,838
29	Cost of financing		–
30	Value of capital contributions		–
31	Value of vested assets		–
32	**Capital Expenditure**		10,838
33	**Total expenditure**		16,814
34			
35	**Other related party transactions**		117

36 5b(iii): Total Opex and Capex Related Party Transactions

	Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
37			
38	NETcon - Capex	Consumer connection	1,596
39	NETcon - Capex	Asset replacement and renewal (capex)	8,616
40	NETcon - Capex	System growth	376
41	NETcon - Capex	Asset relocations	84
42	NETcon - Capex	Other reliability, safety and environment	148
43	NETcon - Capex	Expenditure on non-network assets	18
44	NETcon - Opex	Service interruptions and emergencies	1,869
45	NETcon - Opex	Vegetation management	354
46	NETcon - Opex	Routine and corrective maintenance and inspection	2,773
47	NETcon - Opex	Asset replacement and renewal (opex)	92
48	NETcon - Opex	System operations and network support	888
53	**Total value of related party transactions**		16,814
54	** include additional rows if needed*		
55			

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

This schedule is only to be completed if, as at the date of the most recently published financial statements, the weighted average original tenor of the debt portfolio (both qualifying debt and non-qualifying debt) is greater than five years.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7

8 ### 5c(i): Qualifying Debt (may be Commission only)

9

sch ref	Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
11	N/a								
12									
13									
14									
15									
16	* include additional rows if needed						–	–	–

17

18 ### 5c(ii): Attribution of Term Credit Spread Differential

sch ref			
19			
20	**Gross term credit spread differential**		–
21			
22	Total book value of interest bearing debt	–	
23	Leverage	42%	
24	Average opening and closing RAB values	–	
25	**Attribution Rate (%)**		–
26			
27	**Term credit spread differential allowance**		–

Company Name: **Alpine Energy Limited**
For Year Ended: **31 March 2022**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

This schedule provides information on the allocation of operational costs. EDBs must provide explanatory comment on their cost allocation in Schedule 14 (Mandatory Explanatory Notes), including on the impact of any reclassifications.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7 5d(i): Operating Cost Allocations

sch ref		Arm's length deduction	Value allocated ($000s) Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
8						
9						
10	**Service interruptions and emergencies**					
11	Directly attributable		2,084			
12	Not directly attributable	–	–	–	–	–
13	**Total attributable to regulated service**		2,084			
14	**Vegetation management**					
15	Directly attributable		831			
16	Not directly attributable	–	–	–	–	–
17	**Total attributable to regulated service**		831			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		3,843			
20	Not directly attributable	–	–	–	–	–
21	**Total attributable to regulated service**		3,843			
22	**Asset replacement and renewal**					
23	Directly attributable		175			
24	Not directly attributable	–	–	–	–	–
25	**Total attributable to regulated service**		175			
26	**System operations and network support**					
27	Directly attributable		7,563			
28	Not directly attributable	–	–	–	–	–
29	**Total attributable to regulated service**		7,563			
30	**Business support**					
31	Directly attributable		402			
32	Not directly attributable	–	7,348	1,038	8,385	–
33	**Total attributable to regulated service**		7,750			
34						
35	**Operating costs directly attributable**		14,898			
36	**Operating costs not directly attributable**	–	7,348	1,038	8,385	–
37	**Operational expenditure**		22,245			
38						

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

This schedule provides information on the allocation of operational costs. EDBs must provide explanatory comment on their cost allocation in Schedule 14 (Mandatory Explanatory Notes), including on the impact of any reclassifications.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref		
39	**5d(ii): Other Cost Allocations**	
40	**Pass through and recoverable costs**	**($000)**
41	**Pass through costs**	
42	Directly attributable	384
43	Not directly attributable	–
44	**Total attributable to regulated service**	384
45	**Recoverable costs**	
46	Directly attributable	13,655
47	Not directly attributable	–
48	**Total attributable to regulated service**	13,655
49		

sch ref				($000)	
50	**5d(iii): Changes in Cost Allocations* †**				
51				**($000)**	
52	**Change in cost allocation 1**			**CY-1**	**Current Year (CY)**
53	Cost category	Business Support Costs	Original allocation	8,594	8,184
54	Original allocator or line items	Timesheets	New allocation	7,716	7,348
55	New allocator or line items	Revenue	Difference	878	836
56					
57	Rationale for change	Revenue from regulated versus non-regulated activities is deemed to be a more accurate representation of the cost allocation than timesheet allocations as it reflects the output of the activities (and therefore the costs associated with it) more accurately.			
58					
59					
60				**($000)**	
61	**Change in cost allocation 2**			**CY-1**	**Current Year (CY)**
62	Cost category	N/a	Original allocation		
63	Original allocator or line items		New allocation		
64	New allocator or line items		Difference	–	–
65					
66	Rationale for change	N/a			
67					
68					
69				**($000)**	
70	**Change in cost allocation 3**			**CY-1**	**Current Year (CY)**
71	Cost category	N/a	Original allocation		
72	Original allocator or line items		New allocation		
73	New allocator or line items		Difference	–	–
74					
75	Rationale for change	N/a			
76					
77					

78 ** a change in cost allocation must be completed for each cost allocator change that has occurred in the disclosure year. A movement in an allocator metric is not a change in allocator or component.*
79 *† include additional rows if needed*

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

This schedule requires information on the allocation of asset values. This information supports the calculation of the RAB value in Schedule 4.
EDBs must provide explanatory comment on their cost allocation in Schedule 14 (Mandatory Explanatory Notes), including on the impact of any changes in asset allocations. This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

5e(i): Regulated Service Asset Values

sch ref		Value allocated ($000s) Electricity distribution services
10	**Subtransmission lines**	
11	Directly attributable	13,552
12	Not directly attributable	-
13	**Total attributable to regulated service**	13,552
14	**Subtransmission cables**	
15	Directly attributable	5,370
16	Not directly attributable	-
17	**Total attributable to regulated service**	5,370
18	**Zone substations**	
19	Directly attributable	58,715
20	Not directly attributable	-
21	**Total attributable to regulated service**	58,715
22	**Distribution and LV lines**	
23	Directly attributable	40,130
24	Not directly attributable	-
25	**Total attributable to regulated service**	40,130
26	**Distribution and LV cables**	
27	Directly attributable	58,182
28	Not directly attributable	-
29	**Total attributable to regulated service**	58,182
30	**Distribution substations and transformers**	
31	Directly attributable	16,998
32	Not directly attributable	-
33	**Total attributable to regulated service**	16,998
34	**Distribution switchgear**	
35	Directly attributable	18,236
36	Not directly attributable	-
37	**Total attributable to regulated service**	18,236
38	**Other network assets**	
39	Directly attributable	9,913
40	Not directly attributable	-
41	**Total attributable to regulated service**	9,913
42	**Non-network assets**	
43	Directly attributable	283
44	Not directly attributable	16,711
45	**Total attributable to regulated service**	16,994
46		
47	**Regulated service asset value directly attributable**	221,379
48	**Regulated service asset value not directly attributable**	16,711
49	**Total closing RAB value**	238,090

5e(ii): Changes in Asset Allocations* †

sch ref				($000) CY-1	Current Year (CY)
53	**Change in asset value allocation 1**				
54	Asset category	Land and Buildings	Original allocation	5,638	5,781
55	Original allocator or line items	Headcount	New allocation	10,717	10,989
56	New allocator or line items	Expenditure	Difference	(5,079)	(5,208)
58	Rationale for change	The expenditure ratio between allocated and unallocated spending is a more accurate reflection of the use of the spending than the headcount ratio. The headcount ratio was previously determined based on the Alpine House being occupied by Alpine Energy Limited and NETcon and Infratec employees. However, Alpine house was occupied only by Alpine Energy Limited employees in the current disclosure year and headcount is therefore no longer an accurate proxy			

sch ref				($000) CY-1	Current Year (CY)
62	**Change in asset value allocation 2**				
63	Asset category	Computers and Software	Original allocation	5,117	5,636
64	Original allocator or line items	Fully allocated	New allocation	5,071	5,585
65	New allocator or line items	Expenditure	Difference	46	51
67	Rationale for change	The expenditure ratio between allocated and unallocated spending is a more accurate reflection of the use of the spending than full allocation.			

sch ref				($000) CY-1	Current Year (CY)
71	**Change in asset value allocation 3**				
72	Asset category	Motor Vehicles	Original allocation	155	141
73	Original allocator or line items	Fully allocated	New allocation	150	137
74	New allocator or line items	Expenditure	Difference	5	5
76	Rationale for change	The expenditure ratio between allocated and unallocated spending is a more accurate reflection of the use of the spending than full allocation.			

79 ** a change in asset allocation must be completed for each allocator or component change that has occurred in the disclosure year. A movement in an allocator metric is not a change in allocator or compon*
80 *† include additional rows if needed*

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 6a: REPORT ON CAPITAL EXPENDITURE FOR THE DISCLOSURE YEAR

This schedule requires a breakdown of capital expenditure on assets incurred in the disclosure year, including any assets in respect of which capital contributions are received, but excluding assets that are vested assets. Information on expenditure on assets must be provided on an accounting accruals basis and must exclude finance costs.
EDBs must provide explanatory comment on their expenditure on assets in Schedule 14 (Explanatory Notes to Templates).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		5,198
9		System growth		3,296
10		Asset replacement and renewal		13,201
11		Asset relocations		140
12		Reliability, safety and environment:		
13		Quality of supply	–	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	848	
16		**Total reliability, safety and environment**		848
17		**Expenditure on network assets**		22,682
18		Expenditure on non-network assets		1,412
19				
20		**Expenditure on assets**		24,094
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		3,480
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		20,614
26		**6a(ii): Subcomponents of Expenditure on Assets (where known)**		**($000)**
27		Energy efficiency and demand side management, reduction of energy losses		–
28		Overhead to underground conversion		326
29		Research and development		–
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Commercial	1,936	
33		HV alterations	299	
34		Irrigation	486	
		LV alterations	60	
35		Residential	1,410	
36		Subdivision	1,007	
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		5,198
39				
40	*less*	Capital contributions funding consumer connection expenditure	3,219	
41		**Consumer connection less capital contributions**		1,979

42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement and**
43			**System Growth**	**Renewal**
44			**($000)**	**($000)**
45		Subtransmission	198	376
46		Zone substations	901	329
47		Distribution and LV lines	–	6,165
48		Distribution and LV cables	1,724	1,900
49		Distribution substations and transformers	1	680
50		Distribution switchgear	467	3,136
51		Other network assets	5	615
52		**System growth and asset replacement and renewal expenditure**	3,296	13,201
53	*less*	Capital contributions funding system growth and asset replacement and renewal	–	214
54		**System growth and asset replacement and renewal less capital contributions**	3,296	12,987
55				

56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		FLE Relocate D/Box 1219 Fairlie	8	
59		Forth Street 11 kV OHUG	52	
		James Street, Timaru Relocate L23	15	
		Lilybank Rd, Tek #25486 move for MDC	1	
		Morris Rd Morven	31	
60		TIM Branscombe Street new connection x 4	4	
61		TIM Dawson Street OHUG	28	
62		TIM Mahoneys Hill Pole relocate	0	
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	–	
65		**Asset relocations expenditure**		140
66	*less*	Capital contributions funding asset relocations	47	
67		**Asset relocations less capital contributions**		92

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 6a: REPORT ON CAPITAL EXPENDITURE FOR THE DISCLOSURE YEAR

This schedule requires a breakdown of capital expenditure on assets incurred in the disclosure year, including any assets in respect of which capital contributions are received, but excluding assets that are vested assets. Information on expenditure on assets must be provided on an accounting accruals basis and must exclude finance costs.
EDBs must provide explanatory comment on their expenditure on assets in Schedule 14 (Explanatory Notes to Templates).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref				
68				
69		**6a(vi): Quality of Supply**		
70		*Project or programme**	**($000)**	**($000)**
71		N/a	–	
72			–	
73			–	
74			–	
75			–	
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply	–	
78		**Quality of supply expenditure**		–
79	*less*	Capital contributions funding quality of supply	–	
80		**Quality of supply less capital contributions**		–
81		**6a(vii): Legislative and Regulatory**		
82		*Project or programme**	**($000)**	**($000)**
83		N/a	–	
84			–	
85			–	
86			–	
87			–	
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory	–	
90		**Legislative and regulatory expenditure**		–
91	*less*	Capital contributions funding legislative and regulatory	–	
92		**Legislative and regulatory less capital contributions**		–
93		**6a(viii): Other Reliability, Safety and Environment**		
94		*Project or programme**	**($000)**	**($000)**
95		Automation	71	
96		Communications	196	
97		Reclosers	581	
98				
99				
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment	–	
102		**Other reliability, safety and environment expenditure**		848
103	*less*	Capital contributions funding other reliability, safety and environment	–	
104		**Other reliability, safety and environment less capital contributions**		848
105				
106		**6a(ix): Non-Network Assets**		
107		**Routine expenditure**		
108		*Project or programme**	**($000)**	**($000)**
109		Plant and Equipment	37	
110		Software and IT	915	
111		Land and buildings	172	
112				
113				
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure	–	
116		**Routine expenditure**		1,124
117		**Atypical expenditure**		
118		*Project or programme**	**($000)**	**($000)**
119		Land and Buildings	72	
120		Software and IT	216	
121				
122				
123				
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure	–	
126		**Atypical expenditure**		288
127				
128		**Expenditure on non-network assets**		1,412

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 6b: REPORT ON OPERATIONAL EXPENDITURE FOR THE DISCLOSURE YEAR

This schedule requires a breakdown of operational expenditure incurred in the disclosure year.
EDBs must provide explanatory comment on their operational expenditure in Schedule 14 (Explanatory notes to templates). This includes explanatory comment on any atypical operational expenditure and assets replaced or renewed as part of asset replacement and renewal operational expenditure, and additional information on insurance.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	2,084	
9	Vegetation management	831	
10	Routine and corrective maintenance and inspection	3,843	
11	Asset replacement and renewal	175	
12	**Network opex**		6,933
13	System operations and network support	7,563	
14	Business support	7,750	
15	**Non-network opex**		15,312
16			
17	**Operational expenditure**		22,245
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		–
20	Direct billing*		–
21	Research and development		–
22	Insurance		297
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

This schedule compares actual revenue and expenditure to the previous forecasts that were made for the disclosure year. Accordingly, this schedule requires the forecast revenue and expenditure information from previous disclosures to be inserted.
EDBs must provide explanatory comment on the variance between actual and target revenue and forecast expenditure in Schedule 14 (Mandatory Explanatory Notes). This information is part of the audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8. For the purpose of this audit, target revenue and forecast expenditures only need to be verified back to previous disclosures

sch ref

sch ref		Target ($000) [1]	Actual ($000)	% variance
7	**7(i): Revenue**			
8	Line charge revenue	54,104	52,594	(3%)
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	2,400	5,198	117%
11	System growth	2,921	3,296	13%
12	Asset replacement and renewal	10,297	13,201	28%
13	Asset relocations	500	140	(72%)
14	Reliability, safety and environment:			
15	Quality of supply	–	–	–
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	1,210	848	(30%)
18	**Total reliability, safety and environment**	1,210	848	(30%)
19	**Expenditure on network assets**	17,328	22,682	31%
20	Expenditure on non-network assets	1,837	1,412	(23%)
21	Expenditure on assets	19,165	24,094	26%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	2,045	2,084	2%
24	Vegetation management	820	831	1%
25	Routine and corrective maintenance and inspection	3,330	3,843	15%
26	Asset replacement and renewal	290	175	(40%)
27	**Network opex**	6,485	6,933	7%
28	System operations and network support	4,886	7,563	55%
29	Business support	9,038	7,750	(14%)
30	**Non-network opex**	13,924	15,312	10%
31	**Operational expenditure**	20,409	22,245	9%
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses	–	–	–
34	Overhead to underground conversion	500	326	(35%)
35	Research and development	–	–	–
36				
37	**7(v): Subcomponents of Operational Expenditure (where known)**			
38	Energy efficiency and demand side management, reduction of energy losses	–	–	–
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	250	297	19%
42				

43 *1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of this determination*

44 *2 From the CY+1 nominal dollar expenditure forecasts disclosed in accordance with clause 2.6.6 for the forecast period starting at the beginning of the disclosure year (the second to last disclosure of Schedules 11a and 11b)*

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

sch ref

8(i): Billed Quantities by Price Component

					Billed quantities by price component							
				Price component	Distribution Fixed	Distribution Variable Day	Distribution Variable Night	Distribution Demand	Transmission Fixed	Transmission Variable Day	Transmission Variable Night	Transmission Demand
Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Number of ICP's	MWh	MWh	MW	Number of ICP's	MWh	MWh	MW
LOWHCA	Low Charge	Standard	2,097	13,307	2,097	9,652	3,655	–	–	9,652	3,655	–
LOWLCA	Low Charge	Standard	10,683	63,164	10,683	45,817	17,347	–	–	45,817	17,347	–
LOWUHCA	Low Uncontrolled	Standard	16	99	16	72	27	–	–	72	27	–
LOWULCA	Low Uncontrolled	Standard	41	240	41	174	66	–	–	174	66	–
015HCA	015	Standard	5,825	56,213	5,825	40,775	15,438	–	–	40,775	15,438	–
015LCA	015	Standard	11,410	99,746	11,410	72,352	27,394	–	–	72,352	27,394	–
015UHCA	015 Uncontrolled	Standard	35	510	35	370	140	–	35	370	140	–
015ULCA	015 Uncontrolled	Standard	39	344	39	250	95	–	39	250	95	–
360HCA	360	Standard	519	10,297	519	7,469	2,828	–	–	7,469	2,828	–
360LCA	360	Standard	733	20,884	733	15,149	5,736	–	–	15,149	5,736	–
360UHCA	360 Uncontrolled	Standard	14	634	14	460	174	–	14	460	174	–
360ULCA	360 Uncontrolled	Standard	15	363	15	263	100	–	15	263	100	–
ASSHCA	Assessed	Standard	1,283	105,313	1,283	76,186	29,128	109	–	76,186	29,128	109
ASSLCA	Assessed	Standard	402	37,080	402	26,948	10,131	37	–	26,948	10,131	37
TOU400HCA	TOU 400V	Standard	37	22,251	37	15,594	6,657	8	–	15,594	6,657	8
TOU400LCA	TOU 400V	Standard	100	100,324	100	68,762	31,562	22	–	68,762	31,562	22
TOU11HCA	TOU 11kV	Standard	4	23,950	4	17,184	6,766	7	–	17,184	6,766	7
TOU11LCA	TOU 11kV	Standard	4	13,569	4	9,370	4,198	4	–	9,370	4,198	4
Individual Direct Billed	IND	Non-standard	12	204,114	12	137,408	66,705	–	–	137,408	66,705	–
Add extra rows for additional consumer groups or price category codes as necessary												
		Standard consumer totals	33,257	568,288	33,257	406,848	161,440	187	103	406,848	161,440	187
		Non-standard consumer totals	12	204,114	12	137,408	66,705	–	–	137,408	66,705	–
		Total for all consumers	33,269	772,401	33,269	544,256	228,145	187	103	544,256	228,145	187

Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)

Add extra columns for additional billed quantities by price component as necessary

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

8(ii): Line Charge Revenues ($000) by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)
LOWHCA	Low Charge	Standard	$1,392	–	$1,134	$258
LOWLCA	Low Charge	Standard	$6,297	–	$5,071	$1,226
LOWUHCA	Low Uncontrolled	Standard	$13	–	$9	$4
LOWULCA	Low Uncontrolled	Standard	$29	–	$19	$10
015HCA	015	Standard	$5,440	–	$4,349	$1,091
015LCA	015	Standard	$9,660	–	$7,724	$1,935
015UHCA	015 Uncontrolled	Standard	$47	–	$30	$17
015ULCA	015 Uncontrolled	Standard	$41	–	$26	$15
360HCA	360	Standard	$1,559	–	$1,359	$200
360LCA	360	Standard	$2,050	–	$1,644	$405
360UHCA	360 Uncontrolled	Standard	$60	–	$44	$15
360ULCA	360 Uncontrolled	Standard	$43	–	$33	$10
ASSHCA	Assessed	Standard	$10,947	–	$7,830	$3,117
ASSLCA	Assessed	Standard	$3,054	–	$1,878	$1,176
TOU400HCA	TOU 400V	Standard	$1,456	–	$978	$478
TOU400LCA	TOU 400V	Standard	$3,932	–	$2,862	$1,070
TOU11HCA	TOU 11kV	Standard	$1,122	–	$728	$394
TOU11LCA	TOU 11kV	Standard	$764	–	$427	$338
Individual Direct Billed	IND	Non-standard	$4,689	–	$3,453	$1,236
Add extra rows for additional consumer groups or price category codes as necessary						
		Standard consumer totals	$47,905	–	$36,146	$11,759
		Non-standard consumer totals	$4,689	–	$3,453	$1,236
		Total for all consumers	$52,594	–	$39,599	$12,995

Line charge revenues ($000) by price component

Price component	Distribution fixed	Distribution variable day	Distribution variable night	Distribution demand	Transmission Fixed	Transmission Variable day	Transmission Variable night	Transmission demand
Rate (eg, $ per day, $ per kWh, etc.)	$/annum	$/MWh	$/MWh	$/(MWh*annum)	$/annum	$/MWh	$/MWh	$/(MWh*annum)
LOWHCA	$103	$792	$238	–	–	$222	$36	–
LOWLCA	$539	$3,500	$1,032	–	–	$1,054	$172	–
LOWUHCA	$1	$6	$2	–	–	$3	$1	–
LOWULCA	$2	$13	$4	–	–	$8	$2	–
015HCA	$2,942	$1,211	$196	–	–	$938	$153	–
015LCA	$5,228	$2,149	$348	–	–	$1,664	$271	–
015UHCA	$17	$11	$2	–	$7	$9	$1	–
015ULCA	$18	$7	$1	–	$8	$6	$1	–
360HCA	$1,101	$222	$36	–	–	$172	$28	–
360LCA	$1,122	$450	$73	–	–	$348	$57	–
360UHCA	$29	$14	$2	–	$3	$11	$2	–
360ULCA	$24	$8	$1	–	$3	$6	$1	–
ASSHCA	$887	$2,263	$370	$4,310	–	$1,752	$288	$1,077
ASSLCA	$188	$800	$129	$761	–	$620	$100	$455
TOU400HCA	$18	$176	$32	$752	–	$97	$17	$364
TOU400LCA	$38	$963	$189	$1,672	–	$316	$63	$691
TOU11HCA	$2	$335	$57	$334	–	$175	$30	$189
TOU11LCA	$2	$128	$25	$272	–	$99	$19	$219
Individual Direct Billed	$3,453	–	–	–	$1,236	–	–	–
Standard consumer totals	$12,259	$13,049	$2,737	$8,101	$22	$7,500	$1,243	$2,994
Non-standard consumer totals	$3,453	–	–	–	$1,236	–	–	–
Total for all consumers	$15,712	$13,049	$2,737	$8,101	$1,257	$7,500	$1,243	$2,994

Add extra columns for additional line charge revenues by price component as necessary

Check: OK

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	12

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	

SCHEDULE 9a: ASSET REGISTER

This schedule requires a summary of the quantity of assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	25,049	25,192	143	3
10	All	Overhead Line	Wood poles	No.	19,813	19,393	(420)	3
11	All	Overhead Line	Other pole types	No.	244	233	(11)	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	250	250	–	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	34	34	–	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	23	23	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	2	2	–	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	2	2	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	6	6	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	119	114	(5)	4
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	7	7	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	25	22	(3)	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	168	163	(5)	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	8	8	–	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	27	27	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,903	2,887	(16)	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	7	7	–	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	296	298	2	2
39	HV	Distribution Cable	Distribution UG PILC	km	143	136	(7)	2
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	62	69	7	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	N/A
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	6,892	7,076	184	2
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	36	44	8	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	444	462	18	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,991	5,017	26	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,063	1,098	35	4
48	HV	Distribution Transformer	Voltage regulators	No.	68	68	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	N/A
50	LV	LV Line	LV OH Conductor	km	354	353	(1)	3
51	LV	LV Cable	LV UG Cable	km	360	367	7	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	N/A
53	LV	Connections	OH/UG consumer service connections	No.	33,805	34,096	291	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	449	458	9	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	352	355	3	3
56	All	Capacitor Banks	Capacitors including controls	No	9	9	–	4
57	All	Load Control	Centralised plant	Lot	6	6	–	4
58	All	Load Control	Relays	No	–	–	–	N/A
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	Alpine Energy Limited
For Year Ended	31 March 2022
Network / Sub-network Name	

SCHEDULE 9b: ASSET AGE PROFILE

This schedule requires a summary of the age profile (based on year of installation) of the assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

8 Disclosure Year (year ended): 31 March 2022

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006
10	All	Overhead Line	Concrete poles / steel structure	No.		205	3,396	5,546	3,805	2,432	1,574	140	228	252	445	454	824	307
11	All	Overhead Line	Wood poles	No.		7	2,809	1,842	2,244	1,873	1,981	176	208	460	517	412	574	362
12	All	Overhead Line	Other pole types	No.			42	53	36	22	16	7			3	2		
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km			4	36	44	11	55	5		8	14	–	–	1
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km														
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km							1						21	
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km														
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km														
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km														
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km														
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km														
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km														
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km														
23	HV	Subtransmission Cable	Subtransmission submarine cable	km														
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.			3	1	2	5	1					2	1	
25	HV	Zone substation Buildings	Zone substations 110kV+	No.														
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.														
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.														
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.														
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			1	11	15	12	11							
30	HV	Zone substation switchgear	33kV RMU	No.														
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.														
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.			1			4	3						2	
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.			8			25	15						26	5
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.														
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.					4		2					2		2
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	6		841	484	343	239	151	2	27	34	76	63	135	35
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km														
38	HV	Distribution Line	SWER conductor	km					7									
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km			1	1	4	7	8	1	5	14	11	6	11	19
40	HV	Distribution Cable	Distribution UG PILC	km				8	41	53	30	2	1			1		
41	HV	Distribution Cable	Distribution Submarine Cable	km														
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.							4	2	2				5	2
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.														
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2	1	402	490	417	338	326	27	63	82	163	125	181	133
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.				1		1	2						1	
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.				6	52	30	32	2	12	11	9	11	14	13
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	4	26	387	658	564	405	505	64	129	133	145	142	77	136
48	HV	Distribution Transformer	Ground Mounted Transformer	No.		1	11	46	146	107	36	6	19	38	46	24	52	50
49	HV	Distribution Transformer	Voltage regulators	No.										2	2			
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.														
51	LV	LV Line	LV OH Conductor	km	1		57	120	102	40	18	1	1	1	1	1		1
52	LV	LV Cable	LV UG Cable	km				13	72	88	66	3	4	4	4	7	7	9
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km														
54	LV	Connections	OH/UG consumer service connections	No.								26,364	250	280	326	340	447	458
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.					2	7				12		22	17	10
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot						1								
57	All	Capacitor Banks	Capacitors including controls	No														
58	All	Load Control	Centralised plant	Lot					1						1		1	
59	All	Load Control	Relays	No														
60	All	Civils	Cable Tunnels	km														

sch ref	Asset class	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year	No. with default dates	Data accuracy (1–4)
10	Concrete poles / steel structure	313	310	339	325	141	381	481	378	313	370	231	285	317	487	431	376				106	25,192		3
11	Wood poles	521	712	639	355	234	386	346	487	280	241	150	127	162	208	195	255				630	19,393		3
12	Other pole types		3	1	3	2	3	6	1												33	233		3
13	Subtransmission OH up to 66kV conductor				1	–	–	21	31	–	12	–	–	4	3	–						250		3
14	Subtransmission OH 110kV+ conductor																					–		N/A
15	Subtransmission UG up to 66kV (XLPE)										2	3	1			3	3					34		4
16	Subtransmission UG up to 66kV (Oil pressurised)																					–		N/A
17	Subtransmission UG up to 66kV (Gas pressurised)																					–		N/A
18	Subtransmission UG up to 66kV (PILC)																					–		N/A
19	Subtransmission UG 110kV+ (XLPE)																					–		N/A
20	Subtransmission UG 110kV+ (Oil pressurised)																					–		N/A
21	Subtransmission UG 110kV+ (Gas Pressurised)																					–		N/A
22	Subtransmission UG 110kV+ (PILC)																					–		N/A
23	Subtransmission submarine cable																					–		N/A
24	Zone substations up to 66kV					4	1					1	1		1							23		4
25	Zone substations 110kV+				1								1									2		4
26	50/66/110kV CB (Indoor)																					–		N/A
27	50/66/110kV CB (Outdoor)				1								1									2		4
28	33kV Switch (Ground Mounted)						6															6		4
29	33kV Switch (Pole Mounted)		1	1	1	3	6	11	8	7	2	12		7	3	2						114		4
30	33kV RMU																					–		N/A
31	22/33kV CB (Indoor)						6			1												7		4
32	22/33kV CB (Outdoor)				1		2	1	2		2	2		2								22		4
33	3.3/6.6/11/22kV CB (ground mounted)	9		8	5		20	15	18	2	1		6									163		4
34	3.3/6.6/11/22kV CB (pole mounted)		4							2				1	1							8		4
35	Zone Substation Transformers		2	1	2	3		1	1				2		2	1	2					27		4
36	Distribution OH Open Wire Conductor	51	53	59	36	16	29	39	38	29	27	12	9	10	14	25	4					2,887		3
37	Distribution OH Aerial Cable Conductor																					–		N/A
38	SWER conductor																					7		4
39	Distribution UG XLPE or PVC	14	19	13	11	12	18	15	8	16	12	17	24	9	6	14	2					298		2
40	Distribution UG PILC																					136		2
41	Distribution Submarine Cable																					–		N/A
42	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	1	3	1	7	2	3		9	5	3	2	6	4	2	6						69		4
43	3.3/6.6/11/22kV CB (Indoor)																					–		N/A
44	3.3/6.6/11/22kV Switches and fuses (pole mounted)	166	261	279	212	179	281	273	277	350	232	598	343	228	261	195	188				3	7,076		2
45	3.3/6.6/11/22kV Switch (ground mounted) - except RMU					1				1	2	6	8	6	7	5	3					44		4
46	3.3/6.6/11/22kV RMU	12	14	10	16	7	7	6	11	27	31	23	38	8	16	23	21					462		4
47	Pole Mounted Transformer	150	110	226	90	75	106	76	163	128	92	72	115	58	56	68	57					5,017		4
48	Ground Mounted Transformer	41	62	58	9	10	28	19	33	48	47	39	34	31	13	26	18					1,098		4
49	Voltage regulators	4	10	21	2	5		4	6		4		2	4	2							68		4
50	Ground Mounted Substation Housing																					–		N/A
51	LV OH Conductor		1	1	1	1		1		1		1	1	1								353		3
52	LV UG Cable	8	6	7	8	5	3	3	3	3	8	4	7	7	4	7	7					367		3
53	LV OH/UG Streetlight circuit																					–		N/A
54	OH/UG consumer service connections	408	452	442	362	258	314	328	395	353	359	342	311	302	346	334	325					34,096		4
55	Protection relays (electromechanical, solid state and numeric)	1	9	4	14	134	36	54	35	7	45	24	7	4	4						10	458		3
56	SCADA and communications equipment operating as a single sys		1	1		44	20	15	8	25	30	28	17	12	19	32	50				52	355		3
57	Capacitors including controls		1	1	4		2									1						9		4
58	Centralised plant												2		1							6		4
59	Relays																					–		N/A
60	Cable Tunnels																					–		N/A

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

This schedule requires a summary of the key characteristics of the overhead line and underground cable network. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref				
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	–	–	–
12	50kV & 66kV	–	–	–
13	33kV	250	34	285
14	SWER (all SWER voltages)	–	7	7
15	22kV (other than SWER)	145	15	160
16	6.6kV to 11kV (inclusive—other than SWER)	2,741	419	3,161
17	Low voltage (< 1kV)	352	361	713
18	**Total circuit length (for supply)**	3,489	837	4,326
19				
20	Dedicated street lighting circuit length (km)	–	–	–
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			36
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	304	9%	
25	Rural	3,089	89%	
26	Remote only	–	–	
27	Rugged only	96	3%	
28	Remote and rugged	–	–	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	3,489	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,748	40%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	734	21%	

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

This schedule requires information concerning embedded networks owned by an EDB that are embedded in another EDB's network or in another embedded network.

sch ref

sch ref	Location *	Number of ICPs served	Line charge revenue ($000)
8			
9	N/a		
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			

26 ** Extend embedded distribution networks table as necessary to disclose each embedded network owned by the EDB which is embedded in another EDB's network or in another embedded network*

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

This schedule requires a summary of the key measures of network utilisation for the disclosure year (number of new connections including distributed generation, peak demand and electricity volumes conveyed).

sch ref

sch ref			
8	**9e(i): Consumer Connections**		
9	*Number of ICPs connected in year by consumer type*		
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11	Low Charge	25	
12	Low Uncontrolled	0	
	15	272	
	015 Uncontrolled	0	
	360	16	
	360 Uncontrolled	0	
	Assessed	10	
13	TOU 400V	1	
14	TOU 11kV	0	
15	IND	0	
16	** include additional rows if needed*		
17	**Connections total**	324	
18			
19	**Distributed generation**		
20	Number of connections made in year	56	**connections**
21	Capacity of distributed generation installed in year	0.35	**MVA**

sch ref				
22	**9e(ii): System Demand**			
23				
24				
25		**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
26		GXP demand	128	
27	*plus*	Distributed generation output at HV and above	7	
28		**Maximum coincident system demand**	135	
29	*less*	Net transfers to (from) other EDBs at HV and above	–	
30		**Demand on system for supply to consumers' connection points**	135	
31		**Electricity volumes carried**	**Energy (GWh)**	
32		Electricity supplied from GXPs	784	
33	*less*	Electricity exports to GXPs	23	
34	*plus*	Electricity supplied from distributed generation	39	
35	*less*	Net electricity supplied to (from) other EDBs	–	
36		**Electricity entering system for supply to consumers' connection points**	801	
37	*less*	Total energy delivered to ICPs	772	
38		**Electricity losses (loss ratio)**	29	3.6%
39				
40		**Load factor**	0.68	

sch ref		
41	**9e(iii): Transformer Capacity**	
42		**(MVA)**
43	Distribution transformer capacity (EDB owned)	600
44	Distribution transformer capacity (Non-EDB owned, estimated)	20
45	**Total distribution transformer capacity**	620
46		
47	**Zone substation transformer capacity**	368

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)	2	
11	Class B (planned interruptions on the network)	597	
12	Class C (unplanned interruptions on the network)	525	
13	Class D (unplanned interruptions by Transpower)	4	
14	Class E (unplanned interruptions of EDB owned generation)	–	
15	Class F (unplanned interruptions of generation owned by others)	–	
16	Class G (unplanned interruptions caused by another disclosing entity)	–	
17	Class H (planned interruptions caused by another disclosing entity)	–	
18	Class I (interruptions caused by parties not included above)	2	
19	**Total**	1,130	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	276	249
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	0.00	0.3
26	Class B (planned interruptions on the network)	0.24	85.4
27	Class C (unplanned interruptions on the network)	0.86	211.7
28	Class D (unplanned interruptions by Transpower)	0.03	1.4
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	0.00	1.1
34	**Total**	1.14	299.8
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	1.10	232.5
38			

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

39 **10(ii): Class C Interruptions and Duration by Cause**

		SAIFI	SAIDI
41	**Cause**		
42	Lightning	0.00	0.1
43	Vegetation	0.04	4.3
44	Adverse weather	0.24	129.3
45	Adverse environment	–	–
46	Third party interference	0.16	18.4
47	Wildlife	0.13	9.2
48	Human error	0.00	0.0
49	Defective equipment	0.21	38.7
50	Cause unknown	0.08	11.8

52 **10(iii): Class B Interruptions and Duration by Main Equipment Involved**

		SAIFI	SAIDI
54	**Main equipment involved**		
55	Subtransmission lines	–	–
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	0.22	75.3
69	Distribution cables (excluding LV)	0.03	10.0
60	Distribution other (excluding LV)	–	–

61 **10(iv): Class C Interruptions and Duration by Main Equipment Involved**

		SAIFI	SAIDI
63	**Main equipment involved**		
64	Subtransmission lines	0.00	0.4
65	Subtransmission cables	–	–
66	Subtransmission other	–	–
67	Distribution lines (excluding LV)	0.85	209.7
68	Distribution cables (excluding LV)	0.01	1.6
69	Distribution other (excluding LV)	0.00	0.0

70 **10(v): Fault Rate**

		Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
71	**Main equipment involved**			
72	Subtransmission lines	1	250	0.40
73	Subtransmission cables	–	34	–
74	Subtransmission other	–		
75	Distribution lines (excluding LV)	1,053	2,887	36.48
76	Distribution cables (excluding LV)	81	442	18.33
77	Distribution other (excluding LV)	4		
78	**Total**	1,139		

EDB Information Disclosure Requirements
Information Templates
for
Schedules 5f & 5g

Company Name	Alpine Energy Limited
Disclosure Date	31 August 2022
Disclosure Year (year ended)	31 March 2022

Templates for Schedules 5f & 5g
Template Version 4.1. Prepared 24 March 2015

Table of Contents

Disclosure Template Instructions

These templates have been prepared for use by EDBs when making disclosures under subclause 2.3.2 of the Electricity Distribution Information Disclosure Determination 2012.

Instructions for completing schedules 5f & 5g

When completing schedules 5f & 5g, EDBs are only required to report on cost or asset values that are not directly attributable. If EDBs do not have any cost or asset values that are not directly attributable, they should indicate this on the first "Insert cost description" input box.
EDBs are required to submit schedules 5f & 5g to the Commission even if they do not have any cost or asset values that are not directly attributable.

Company Name and Dates

To prepare the templates for disclosure, the supplier's company name should be entered in cell C8, the date of the last day of the current (disclosure) year should be entered in cell C12, and the date on which the information is disclosed should be entered in cell C10 of the CoverSheet worksheet.
The cell C12 entry (current year) is used to calculate the ‘For year ended’ date in the template title blocks (the title blocks are the light green shaded areas at the top of each template).
The cell C8 entry (company name) is used in the template title blocks.
Dates should be entered in day/month/year order (Example -"1 April 2013").

Data Entry Cells and Calculated Cells

Data entered into this workbook may be entered only into the data entry cells. Data entry cells are the bordered, unshaded areas (white cells) in each template. Under no circumstances should data be entered into the workbook outside a data entry cell.
In some cases, where the information for disclosure is able to be ascertained from disclosures elsewhere in the workbook, such information is disclosed in a calculated cell.

Validation Settings on Data Entry Cells

To maintain a consistency of format and to help guard against errors in data entry, some data entry cells test keyboard entries for validity and accept only a limited range of values. For example, entries may be limited to a list of category names, to values between 0% and 100%, or either a numeric entry or the text entry “N/A”. Where this occurs, a validation message will appear when data is being entered. These checks are applied to keyboard entries only and not, for example, to entries made using Excel’s copy and paste facility.

Inserting Additional Rows

The templates for schedules 5f and 5g may require additional rows to be inserted in tables.
Additional rows must not be inserted directly above the first row or below the last row of a table. This is to ensure that entries made in the new row are included in the totals. Column A schedule references should not be entered in additional rows.

Schedule References

The references labelled 'sch ref' in the leftmost column of each template are consistent with the row references in the Electricity Distribution ID Determination 2012 (as issued on 24 March 2015). They provide a common reference between the rows in the determination and the template.

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5d (Cost allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7

8 Have costs been allocated in aggregate using ACAM in accordance with clause 2.1.1(3) of the IM Determination? | No

9

sch ref	Line Item*	Allocation methodology type	Cost allocator	Allocator type	Allocator Metric (%)		Value allocated ($000)				OVABAA allocation increase ($000)
					Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	
12	**Service interruptions and emergencies**										
13	N/a									-	
14										-	
15										-	
16										-	
17	**Not directly attributable**						-	-	-	-	-
18	**Vegetation management**										
19	N/a									-	
20										-	
21										-	
22										-	
23	**Not directly attributable**						-	-	-	-	-
24	**Routine and corrective maintenance and inspection**										
25	N/a									-	
26										-	
27										-	
28										-	
29	**Not directly attributable**						-	-	-	-	-
30	**Asset replacement and renewal**										
31	N/a									-	
32										-	
33										-	
34										-	
35	**Not directly attributable**						-	-	-	-	-
36											

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2022**

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5d (Cost allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref											
37	**System operations and network support**										
38	N/a									-	
39										-	
40										-	
41										-	
42	**Not directly attributable**						-	-	-	-	-
43	**Business support**										
44	Business support	ABAA	Revenue	Proxy	87.63%	12.37%	-	7,348	1,038	8,385	
45										-	
46										-	
47										-	
48	**Not directly attributable**						-	7,348	1,038	8,385	-
49											
50	**Operating costs not directly attributable**						-	7,348	1,038	8,385	-
51											
52	**Pass through and recoverable costs**										
53	**Pass through costs**										
54	N/a									-	
55										-	
56										-	
57										-	
58	**Not directly attributable**						-	-	-	-	-
59	**Recoverable costs**										
60	N/a									-	
61										-	
62										-	
63										-	
64	**Not directly attributable**						-	-	-	-	-
65	** include additional rows if needed*										

Company Name **Alpine Energy Limited**
For Year Ended **31 March 2022**

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5e (Report on Asset Allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7
8 Have assets been allocated in aggregate using ACAM in accordance with clause 2.1.1(3) of the IM Determination? No
9

sch ref	Line Item*	Allocation methodology type	Allocator	Allocator type	Allocator Metric (%)		Value allocated ($000)				OVABAA allocation increase ($000)
10					Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	
12	**Subtransmission lines**										
13	N/a									-	
14										-	
15										-	
16										-	
17	**Not directly attributable**						-	-	-	-	-
18	**Subtransmission cables**										
19	N/a									-	
20										-	
21										-	
22										-	
23	**Not directly attributable**						-	-	-	-	-
24	**Zone substations**										
25	N/a									-	
26										-	
27										-	
28										-	
29	**Not directly attributable**						-	-	-	-	-
30	**Distribution and LV lines**										
31	N/a									-	
32										-	
33										-	
34										-	
35	**Not directly attributable**						-	-	-	-	-

Company Name **Alpine Energy Limited**
For Year Ended **31 March 2022**

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5e (Report on Asset Allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref												
36	**Distribution and LV cables**											
37		N/a									-	
38											-	
39											-	
40											-	
41	**Not directly attributable**							-	-	-	-	-
42												
43	**Distribution substations and transformers**											
44		N/a									-	
45											-	
46											-	
47											-	
48	**Not directly attributable**							-	-	-	-	-
49												
50	**Distribution switchgear**											
51		N/a									-	
52											-	
53											-	
54											-	
55	**Not directly attributable**							-	-	-	-	-
56	**Other network assets**											
57		N/a									-	
58											-	
59											-	
60											-	
61	**Not directly attributable**							-	-	-	-	-
62	**Non-network assets**											
63		Land and Buildings	ABAA	Expenditure	Proxy	91.53%	8.47%	-	10,989	1,017	12,006	
64		Computers and Software	ABAA	Expenditure	Proxy	99.10%	0.90%	-	5,585	51	5,636	
65		Motor Vehicles	ABAA	Expenditure	Proxy	96.79%	3.21%	-	137	5	141	
66											-	
67	**Not directly attributable**							-	16,711	1,073	17,783	-
68												
69	**Regulated service asset value not directly attributable**							-	16,711	1,073	17,783	-
70	** include additional rows if needed*											

Company Name	Alpine Energy Limited
For Year Ended	31 March 2022

Schedule 14 Mandatory Explanatory Notes

(Guidance Note: This Microsoft Word version of Schedules 14, 14a and 15 is from the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 9 December 2021. Clause references in this template are to that determination)

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 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 2022 ROI-comparable to a post-tax WACC (reflecting all revenue earned) is 8.40%, an increase from 5.64% in the prior year. The resultant year-end ROI comparable to a post-tax WACC is 7.78%.

The main reason for the increase is the increase in the closing regulatory asset base (RAB) value, from $211 million to $238 million, which was in part due to a significant increase in CPI for the current disclosure year leading to a $14 million valuation adjustment.

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 2022[1], prepared pursuant the Electricity Distribution Services Default Price Quality Path Determination 2020 (consolidated May 2020). This value does not represent the disclosures in Schedule 3(iii): Incremental Rolling Incentive Scheme.

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

[1] https://www.alpineenergy.co.nz/__data/assets/pdf_file/0015/18222/Alpine-Energy-Limited-DPP-Annual-Compliance-Statement-2022-Signed.pdf

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

Box 2: Explanatory comment on regulatory profit
There were no items included in other regulated income (other than gains / (losses) on asset disposals) in the current disclosure year and no items were reclassified.

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

6. If the EDB incurred merger and acquisitions 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 $211 million to $238 million during the disclosure year as a result of increased assets commissioned ($19 million in 2022 compared to $15 million in 2021) and higher revaluation adjustments ($14 million in 2022 compared to $3 million in 2021) in the current disclosure year.

The revaluation rate increased significantly in the current disclosure year (6.93% in 2022 compared to 1.52% in 2021) because of increased inflation rates (CPI).

We also changed the allocator for non-network assets (refer to Box 8 for full details) which resulted in an upward adjustment from asset allocation of $5 million.

<u>Opening unallocated RAB (Schedule 4(ii))</u>
In completing the current year RAB, we identified that the opening balance of the unallocated RAB as disclosed in Schedule 4(ii) was understated by $6 million. This represents the value of Land and Buildings which were not allocated to the electricity distribution business, as presented in Schedule 5g in published disclosures for the disclosure year ended 31 March 2021[2]. The assets commissioned disclosed in Schedule 4(ii) was incorrect in the year when Alpine House was brought into the unallocated RAB (disclosure year ended 31 March 2018) and as a result have been rolled forward incorrectly ever since. This has no impact on the closing RAB value, or any other metrics disclosed in the information disclosures. The error in the opening balance only represents 3% of the total unallocated RAB and assessed by management as having minimal impact on the users of the disclosure information and as such, immaterial. This has therefore been corrected through an adjustment to the opening balance in the current disclosure year and no restatement of the prior year published schedules were deemed necessary. The opening balance will therefore not match the closing balance as disclosed for the disclosure year ended 31 March 2021.

No items have been reclassified during the current disclosure year.

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.

[2] https://www.alpineenergy.co.nz/__data/assets/pdf_file/0021/17715/Alpine-Energy-Limited-Information-Disclosure-Schedules.pdf

Box 5: Regulatory tax allowance: permanent differences

We did not have any income which were not included in regulatory profit / (loss) before tax but taxable during this disclosure year.

The expenditure included in the regulatory profit / (loss) before tax but not deductible in the current year are shown below:

	Full amount per tax statement $	Allocated Amount (based on Business Support allocation %) $
Imputation Credits on Dividends Received	400	350
Non-Deductible Consulting	14,075	12,334
Non-Deductible Entertainment	13,652	11,963
Non-Deductible Legal Expenditure	3,275	2,870
Non-deductible GST on entertainment	2,184	1,914
Total		**29,431**

We did not have any income included in regulatory profit / (loss) before tax but not taxable or 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 tax effect of other temporary differences is shown below:

	Movement (2022 closing balance - 2022 opening balance per tax statement) $	Allocated Amount (based on Business Support allocation %) $
Accrued ACC	2,815	
Annual Leave Provision	72,811	
Insurance Accrual Not Derived	381,313	
Long Service Leave Provision	1,744	
Total	455,195	398,888
Tax impact @ 28%		**111,689**

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 which are not 100% directly attributable to the electricity distribution services.

Directly attributable business support costs are $402K and not directly attributable business support costs are $7 million. The total business support costs incurred which are not in relation to electricity distribution services are $1 million.

We changed the proxy allocator for business support costs from timesheets to revenue in the current disclosure year. Revenue from regulated versus non-regulated activities is deemed to be a more accurate representation of the cost allocation than timesheet allocations as it reflects the output of the activities (and therefore the costs associated with it) more closely. The change resulted in a decrease of $836K in the business support costs allocated to the electricity distribution services (the prior year would have been $878K less if revenue were used as the allocator).

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 $283K, are in relation to plant and equipment and includes items like drones which are used 100% for network purposes. The not directly attributable non-network assets include land and buildings, vehicles and computers and software, which is used by all departments, including non-electricity distribution services like metering and fibre departments. These therefore require allocation. The total non-network assets allocated to electricity distribution services are $17 million.

We also changed the proxy allocators non-network assets not directly attributable. The reasons and results of these changes are summarised below:

Land and building

The proxy allocator for land and buildings was headcount in the prior years. The reasoning was that the new Alpine House building were to be used by Alpine, NETcon and Infratec employees. However, in the current disclosure year, the Alpine House was occupied only by Alpine Energy employees. Using headcount would therefore no longer be an accurate proxy and we changed to the use of expenditure on land and buildings as the proxy allocator, based on cost centre allocation. This is in line with the methodology applied in our annual budget process. The change resulted in an increase in the allocation of land and buildings to the electricity distribution services (RAB) of $5 million (if this allocator were used in the prior year, the non-network assets in the RAB would have increased by $5 million).

Computers and software and motor vehicles

In prior periods these were allocated 100% to the electricity distribution services. However, there are costs incurred in relation to non-electricity distribution services and we therefore changed the treatment in the current year to allocate the value of these assets based on the expenditure incurred as allocated to the various cost centres. This will more accurately reflect the value that should be attributable to the electricity distribution services. The change resulted in a decrease in the allocation of to the electricity distribution services (RAB) of $56K (if this allocator were used in the prior year, the non-network assets in the RAB would have decreased by $51K).

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 $24 million ($21 million when capital contributions are deducted) compared to $20 million ($16 million when capital contributions are deducted) during 2021.

We do not apply a materiality threshold to identify material CAPEX projects and programmes. All our CAPEX spend is given a project number within our accounting system, Technology One, against which forecast expenditure and actual expenditure is set. The materiality of our CAPEX projects is based on impact of the project on the network, resource availability, etc. not a monetary threshold.

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, a 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 $22 million, compared to $20 million during 2021.

The total operating expenditure on asset replacement and renewal was $175K 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 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 published at the start of the disclosure year. There were no re-classified items for either OPEX or CAPEX.

Capital expenditure

Consumer connections

The actual capital expenditure on consumer connections was 117% higher than the forecast.

During the current disclosure year we received two applications for large scale new connections which were not included in our forecasts (one for a new shopping mall and one for an electrification of processing plant).

System growth & Asset replacement and renewal

System growth and asset replacement and renewal have been reviewed together as many of the material projects have elements of both categories included in the project. When viewed in conjunction, the actual capital expenditure exceeded the forecast by $3.3 million (or 25%).

$1 million of the overspend was in relation to the Grasmere circuit 16 project, which doubled in size (two cables were installed during the project, instead of the one that was included in the forecast). A further $371K was unplanned capital expenditure on overhead lines after a severe weather event in September 2021. Increased costs due to supply chain issues worldwide also resulted in a number of smaller projects being over budget.

Asset relocation

The actual capital expenditure on asset relocation was 72% lower than the forecast. Per definition is expenditure where third parties have requested that we relocate assets. The budget reflected the best estimate at the time, but fewer asset relocations were requested during this disclosure year than what was anticipated.

Other reliability, safety, and the environment

The actual capital expenditure on other reliability, safety and the environment were 30% lower than the forecast. The forecast included $100K for a SCADA master station module upgrade which were not completed and a number of smaller communication projects which were not completed due to resource constraints.

Non-network assets

The actual capital expenditure on non-network assets was 23% lower than forecast. The main reason for the underspend is that a number of information technology upgrades were not completed in the current disclosure year, including an upgrade to our billing system. These projects have been delayed until the roll-out of our new company strategy and specifically the automation of our core business processes.

Operational expenditure

Routine and corrective maintenance and inspection

The actual operational expenditure on routine and corrective maintenance and inspection was 15% higher than the forecast. We experienced two major events during the year, a windstorm in September 2021 and again in December 2021, which resulted in additional expenditure to ensure network safety and reliability during and after the events.

Asset replacement and renewal
The actual asset replacement and renewal expenditure was 40% lower than the forecast. At the time the budget is prepared, a best estimate of this expenditure is made, but the actuals are dependent on the volumes of work performed by the contractors when identifying issues with assets during planned or emergency work.

Non-network opex
The business support and system operations and network support are 10% higher than the forecast amount. It should be noted that the actual split between business support and system operations and network support is also different from the forecast amounts. We reviewed our regulatory classifications in Technology One during this disclosure year to ensure the classification into business support and system operation and network support is more accurate (i.e., ensuring all corporate cost centres are in business support and all cost centres in relation to asset planning, asset management etc. are included in system operations and network support). The main driver for the increased non-network OPEX is an increase in permanent employees and increased expenditure on IT and software, including licence fees.

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 at $53 million was $1.5 million lower (3%) than the target revenue disclosed. Our revenue is impacted by variability in consumption and due to high rainfall during summer months (December 2021 – February 2022), we experienced lower than expected consumption from irrigation. This had a negative impact on our overall revenue for this disclosure year.

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 decreased from 1.23 to 1.10 and the total normalised SAIDI increased from 196.23 to 232.5. We experienced two major events during this disclosure year in relation to weather, which caused the higher SAIDI values.

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 its vehicles and buildings (including substations) and have public liability insurance. We do not have insurance cover for our network (for example poles and lines) as the premiums are prohibitive and we do not self-insure.

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. Please refer to Box 4 and Schedule 15 for information on prior period errors which were identified in Schedule 4 and Schedule 5a respectively and corrected in the current disclosure year. These were assessed by management to not be material and the previously disclosed information disclosures were therefore not restated.

Company Name	Alpine Energy Limited
For Year Ended	31 March 2022

Schedule 14a Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 9 December 2021)

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

2. 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)

3. 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

To derive the capital expenditure in nominal dollar terms, the constant price forecasts were inflated by 4.5% for 2023, 2.5% for 2024, and 2.0% for the other years, based on New Zealand Treasury forecasts. To derive the 10-year forecast, 4.5% was used for 2023, 2.5% for 2024, 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 4.5% in 2023, 2.5% in 2024, and 2.0% in the other years.

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

4. 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

To derive the capital expenditure in nominal dollar terms, the constant price forecasts were inflated by 4.5% for 2023, 2.5% for 2024, and 2.0% for the other years, based on New Zealand Treasury forecasts. To derive the 10-year forecast, 4.5% was used for 2023, 2.5% for 2024, 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 4.5% in 2023, 2.5% in 2024, and 2.0% in the other years.

Company Name	Alpine Energy Limited
For Year Ended	31 March 2022

Schedule 15 Voluntary Explanatory Notes

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 9 December 2021.)

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 and 2.5.2;

   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 5a – prior period errors

In reviewing the current year disclosure schedules, additional work was performed to improve the reliability of the information disclosed in Schedule 5a – Regulatory Tax Allowance. As a result, it was identified that there were errors in the prior year disclosures as outline below:

Schedule 5a(iv): Amortisation of Revaluations

The opening sum of RAB values without revaluations for the prior year was $168 million and the adjusted depreciation $11.4 million. If the same principles we used to determine the current year values were applied to the prior year, the opening sum of RAB values without revaluations is $179 million and the adjusted depreciation is $11.1 million. The overall impact of this error is an increase of $316K in amortisation of revaluations and $88K increase in the regulatory tax allowance.

Schedule 5a(viii): Regulatory Tax Base Roll-Forward

In the current year, we performed a detailed reconciliation of the tax RAB to ensure that the tax RAB aligns with the RAB and the financial tax fixed asset register (taking into account regulatory tax requirements). The reconciliation identified that the prior year regulatory tax base roll-forward contained several errors, specifically in relation to non-network assets in the RAB. The impact of these errors is outlined in the table below:

Line impacted	2021 published values $'000	2021 recalculated values $'000	Difference $'000
Opening sum of regulatory tax asset values	115,340	122,068	6,728
Tax depreciation	14,445	14,048	(397)
Regulatory tax asset value of assets commissioned	14,896	15,996	1,100
Closing sum of regulatory tax asset values	115,791	124,016	8,225

The overall impact of these errors is however immaterial, overstating the closing deferred tax liability by $23K. Due to the immaterial impact on the deferred tax, management deemed it appropriate to correct the closing balance in the current year information disclosures. The difference above is included in the $8.5 million "Other adjustments to the RAB tax value" as disclosed in Schedule 5a(viii) for the current disclosure year.

The overall impact of these errors on the prior year ROI - comparable to a vanilla WACC is negative 0.05% (i.e., the ROI comparable to a vanilla WACC, if these were correctly disclosed, would have been 5.92% and not 5.97% as previously disclosed). Management have assessed these errors as overall immaterial to the users of the information disclosures and have therefore not made any corrections to previously published information disclosures.

Schedule 5a(iii) – Adjustments resulting from asset allocation

The adjustment resulting from asset allocation disclosed in Schedule 5a(iii) is as a result of the change in allocators used for non-network asset allocation, as explained in Box 8 of Schedule 14.

Schedule 10

Network reliability is compliant with quality requirements under the Default Price-Quality Path, however 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 two 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 supply of electricity lines services following that initial interruption. - In this situation the outage would be recorded as part of the original fault, the cause would be the same for both, but where ICP's go off more than once they would be reported as such to keep the SAIFI correct.

Exemption related to Schedule 10 - Network reliability and note on director certification

On 17 May 2021, the Commission Commerce released a document:
To: All suppliers of electricity distribution services as regulated under Part 4 of the Commerce Act 1986: titled, Information Disclosure exemption: Disclosure and auditing of reliability information within Schedule 10.

The Commission granted all EDBs an exemption for the 2021 and 2022 disclosure years, subject to the condition at paragraph 7 of the letter, from:

- the requirement that the assurance report required to be procured by clause 2.8.1(1) of the ID determination in respect of the information in Schedule 10 of the ID determination must take into account any issues arising out of the EDB's recording of SAIDI, SAIFI and number of interruptions due to successive interruptions.

The Directors of Alpine Energy Limited note that they have not been provided a comparable exemption from:

- the requirement that the certificate required by clause 2.9.2 of the ID determination in respect of clause 2.5.1(1)(f), the information in Schedule 10 of the ID determination, must take into account any issues arising out of the EDB's recording of SAIDI, SAIFI and number of interruptions due to successive interruptions.

The Directors of Alpine Energy Limited certify that:

Alpine Energy Limited has continued to treat successive interruptions in the same way for the 2022 disclosure year as they were for the 2019 disclosure year.

Schedule 18 – Certification for Disclosures

Clause 2.9.2

We, Warren McNabb and Linda Robertson, being directors of Alpine Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge–

a) the information prepared for the purposes of clauses 2.3.1, 2.3.2, 2.4.21, 2.4.22, 2.5.1, 2.5.2; and 2.7.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination;

b) the historical information used in the preparation of Schedules 8, 9a, 9b, 9c, 9d, 9e, and 14 has been properly extracted from Alpine Energy Limited's accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained; and

c) in respect of information concerning assets, costs and revenues valued or disclosed in accordance with clause 2.3.6 of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012, we are satisfied that-
   i. the costs and values of assets or goods or services acquired from a related party comply, in all material respects, with clauses 2.3.6(1) and 2.3.6(3) of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and 2.2.11(5)(a)-2.2.11(5)(b) of the Electricity Distribution Services Input Methodologies Determination 2012; and
   ii. the value of assets or goods or services sold or supplied to a related party comply, in all material respects, with clause 2.3.6(2) of the Electricity Distribution Information Disclosure Determination 2012.

Warren McNabb	Linda Robertson
Director	Director
31 August 2022	31 August 2022

The directors of Alpine Energy note the amendment to the Information Disclosure exemption. Disclosure and auditing reliability information within Schedule 10, issued by the Commerce Commission on 17 May 2021 that has removed the auditor report requirements relating to the treatment of successive interruptions for reporting SAIDI, SAIFI, and interruptions, because of potential inconsistencies in treatment of approaches across the industry.

Directors note that they do not appear to have been provided a similar exemption relating to treatment of successive interruptions regarding their certification. The information has been prepared on a basis consistent with the previous year's disclosure and Alpine network has recorded successive interruptions, originating from the same cause, as single interruptions.

Independent Assurance Report

To The Directors Of Alpine Energy Limited and To The Commerce Commission on the Disclosure Information for the Disclosure Year Ended 31 March 2022 as required by The Electricity Distribution Information Disclosure Determination 2021 (Consolidated 9 December 2021)

Alpine Energy Limited (the company) is required to disclose certain information under the Electricity Distribution Information Disclosure Determination 2012 (consolidated 9 December 2021) (the Determination) and to procure an assurance report by an independent auditor in terms of section 2.8.1 of the Determination.

The Auditor-General is the auditor of the company.

The Auditor-General has appointed me, Nathan Wylie, using the staff and resources of PricewaterhouseCoopers, to undertake a reasonable assurance engagement, on his behalf, on whether the information prepared by the company for the disclosure year ended 31 March 2022 (the Disclosure Information) complies, in all material respects, with the Determination.

The Disclosure Information that falls within the scope of the assurance engagement are:

- Schedules 1 to 4, 5a to 5g, 6a and 6b, 7, 10 and 14 (limited to the explanatory notes in boxes 1 to 11) of the Determination.
- Clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 20 May 2020) (the IM Determination), in respect of the basis for valuation of related party transactions (the Related Party Transaction Information).

This assurance report should be read in conjunction with the Commerce Commission's Information Disclosure exemption, issued to all electricity distribution businesses on 17 May 2021 under clause 2.11.1 of the Determination. The Commerce Commission granted an exemption from the requirement that the assurance report, in respect of the information in Schedule 10 of the Determination, must take into account any issues arising out of the company's recording of SAIDI, SAIFI, and number of interruptions due to successive interruptions.

Qualified Opinion

In our opinion, except for the possible effect of the matter described in the Basis for qualified opinion section of our report, in all material respects:

- as far as appears from an examination, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the company;
- as far as appears from an examination, the information used in the preparation of the Disclosure Information has been properly extracted from the company's accounting and other records, sourced from the company's financial and non-financial systems;
- the Disclosure Information complies with the Determination; and
- the basis for valuation of related party transactions complies with the Determination and the IM Determination.

Basis for qualified opinion

As described in Box 1 of Schedule 15, there are inherent limitations in the ability of the company to collect and record the network reliability information required to be disclosed in Schedules 10(i) to 10(iv). Consequently there is no independent evidence available to support the completeness and accuracy of recorded faults, and control over the completeness and accuracy of installation control point ('ICP') data included in the SAIDI and SAIFI calculations was limited throughout the year.

There are no practical audit procedures that we could adopt to independently confirm that all the faults and ICP data were properly recorded for the purposes of inclusion in the amounts relating to quality measures set out in Schedules 10(i) to 10(iv). Because of the potential effect of these limitations, we are unable to obtain sufficient appropriate audit evidence to confirm the completeness and accuracy of the data that forms the basis of the compilation of Schedules 10(i) to 10(iv).

We conducted our engagement in accordance with the Standard on Assurance Engagements (SAE) 3100 (Revised) *Assurance Engagements on Compliance*, issued by the New Zealand Auditing and Assurance Standards Board. An engagement conducted in accordance with SAE 3100 (Revised) requires that we comply with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised) *Assurance Engagements Other Than Audits or Reviews of Historical Financial Information*.

We have obtained sufficient recorded evidence and all the information and explanations we have required to provide a basis for our qualified opinion.

Key Assurance Matters

Key assurance matters are those matters that, in our professional judgement, required significant attention when carrying out the assurance engagement during the current disclosure year. These matters were addressed in the context of our compliance engagement, and in forming our opinion. We do not provide a separate opinion on these matters.

Key Assurance Matter	How our procedures addressed the key assurance matter
Regulatory Asset Base The Regulatory Asset Base (RAB), as set out in Schedule 4, reflects the value of the company's electricity distribution assets. These are valued using an indexed historic cost methodology prescribed by the Determination. It is a measure which is used widely and is key to measuring the company's return on investment and therefore important when monitoring financial performance or setting electricity distribution prices. The RAB inputs, as set out in the IM Determination, are similar to those used in the measurement of fixed assets in the financial statements, however, there are a number of different requirements and complexities which require careful consideration. Due to the importance of the RAB within the regulatory regime, the incentives to overstate the RAB value, and complexities within the regulations, we have considered it to be a key area of focus.	We obtained an understanding of the compliance requirements relevant to the RAB as set out in the Determination and the IM Determination. We have performed the following procedures: **Assets Commissioned** ● We reconciled the assets commissioned, as per the regulatory fixed asset register, to the asset additions disclosed in the audited annual financial statements and investigated any material reconciling items. ● We considered the nature of the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the Determination, which are required to be removed from the RAB. ● We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification. **Depreciation** ● We compared the standard asset lives by asset category to those set out in the IM Determination. ● For assets with no standard asset lives we assessed the reasonableness of the lives used by reference to the accounting depreciation rates used in preparing the financial statements. ● We verified the spreadsheet formula utilised to calculate regulatory depreciation expense is in line with IM clause 2.2.5.

Key Assurance Matter	How our procedures addressed the key assurance matter
	Revaluation ● We recalculated the revaluation rate set out in the IM Determination using the relevant Consumer Price Index indices taken from the Statistics New Zealand website. ● We tested the mathematical accuracy of the revaluation calculation performed by management.
Cost and Asset Allocation The Determination relates to information concerning the supply of electricity distribution services. In addition to the regulated supply of electricity, the company also supplies customers with other unregulated services such as metering services. As set out in schedules 5d, 5e, 5f and 5g, costs and asset values that relate to electricity distribution services regulated under the Determination should comprise: ● All of the costs directly attributable to the regulated goods or services; and ● An allocated portion of the costs that are not directly attributable. The IM Determination set out rules and processes for allocating costs and assets which are not directly attributable to either regulated or unregulated services. A number of screening tests apply which must be considered when deciding on the appropriate allocation method. The company has applied the Accounting-Based Allocation Approach Methodology (ABAA) utilising proxy cost and asset allocators to allocate the asset values and operating costs that are not directly attributable where causal relationships could not be identified. Given the judgement involved in the application of the cost and asset allocation methodologies we consider it a key assurance matter.	We obtained an understanding of the company's cost and asset allocation processes and the methodologies applied. Our procedures over cost and asset allocation included: ● Reconciling the regulated and unregulated financial information to the audited financial information. **Classification as directly/not directly attributable** ● Considering the appropriateness of the costs allocated as directly attributable, based on the nature and our understanding of the business to determine the reasonableness of the directly attributable classification. ● Testing a sample of transactions to ensure their classification as either directly attributable or not directly attributable costs are appropriate and in line with the Determination. ● Inspecting the fixed asset register to identify any asset classes which based on their nature and our understanding of the business could be considered assets directly attributable to a specific business unit. ● Testing a sample of assets commissioned to ensure their classification as either directly attributable or not directly attributable are appropriate and in line with the Determination by inspecting the related invoice. **Appropriateness of the allocators used for not directly attributable costs and assets** ● Considering the appropriateness of the cost and asset proxy allocators used in applying the ABAA to not directly attributable costs including understanding the rationale for the change in proxy allocators in the current year, inspecting supporting documentation and recalculating proxy allocators. ● Understanding why causal relationships could not be identified in allocating costs or assets and ensuring appropriate disclosure has been included outlining these in Schedule 14. ● Recalculating the split between not directly attributable costs and asset values allocated to electricity distribution services and non-electricity distribution services.

Key Assurance Matter	How our procedures addressed the key assurance matter
Related party transactions Disclosures over related party transactions including related party relationships, procurement policies/processes, application of these policies/processes and examples of market testing of transaction terms as required under the Determination and the IM Determination are set out in Appendix A. The Determination and the IM Determination require the company to value its transactions with related parties, disclosed in Schedule 5b, in accordance with the principles-based approach to the arm's length valuation rule. This rule states that the value of goods or services acquired from a related party cannot be greater than if it had been acquired under the terms of an arm's length transaction with an unrelated party, nor may it exceed the actual cost to the related party. A sale or supply to a related party cannot be valued at an amount less than if it had been sold or supplied under the terms of an arm's-length transaction with an unrelated party. Arm's-length valuation, as defined in the IM Determination, is the value at which a transaction, with the same terms and conditions, would be entered into between a willing seller and a willing buyer who are unrelated and who are acting independently of each other and pursuing their own best interests. The company is required to use an objective and independent measure to demonstrate compliance with the arm's-length principle. In the absence of an active market for similar transactions, assigning an objective arm's length value to a related party transaction is difficult and requires significant judgement. Management appointed a management expert to assist with benchmarking certain classes of expenditure to demonstrate compliance with the arm's-length principle. We have identified related party transactions at arm's-length as a key	We have obtained an understanding of the compliance requirements relevant to related party transactions as set out in the Determination and the IM Determination. We have ensured Schedule 5(b) and Appendix A includes all required disclosures including current procurement policies, descriptions of how they are applied in practice, representative example transactions and when and how market testing was last performed. We have performed the following procedures over Schedule 5(b) and Appendix A. **Completeness and accuracy of related party relationships and transactions** We have tested the completeness and accuracy of the related party relationships and transactions by: ● Agreeing the disclosures within Schedule 5(b) to audited financial information for the year ended 31 March 2022 and to the accounting records, investigating any differences and determining whether any such differences are justified; ● Applying our understanding of the business structure against the related party definition in IM Determination clause 1.1.4(2)(b) to assess management's identification of any "unregulated parts" of the entity. **Practical application of procurement policies** ● Testing a sample of operating expenditure and capital expenditure transactions disclosed in Schedule 5(b) by inspecting supporting documentation to determine compliance with the disclosed procurement policy and practices. **Arm's length valuation rule** We obtained the company's assessment of the available independent and objective measures used in supporting the arm's length valuation principle and performed the following procedures: ● Obtained an understanding of the procedures performed by the management expert and assessed the management expert's qualifications, experience and independence. ● Obtained the report from the management's expert and for a sample: – Evaluated the accuracy of the quoted amounts used by the management's expert to perform the benchmarking by agreeing it to the related party quote. – Evaluated the accuracy of the benchmark amount by agreeing the value in the report to the underlying management's expert's workbooks.

Key Assurance Matter	How our procedures addressed the key assurance matter
audit matter due to the judgement involved.	• Evaluated management's assessment of the management's expert's output. • Assessed whether the related party transaction values fell within an acceptable range. Qualitative factors were considered in determining the appropriate acceptable range. For expenditure classes not included in the management expert's report, we have: • Re-performed the calculations and agreed key inputs and assumptions to supporting documentation; and • Where benchmarking or other market information was used as independent and objective measures, we assessed whether the related party transaction values fell within an acceptable range. Qualitative factors were considered in determining the appropriate acceptable range.

Directors' responsibilities
The directors of the company are responsible in accordance with the Determination for:

- the preparation of the Disclosure Information; and
- the Related Party Transaction Information.

The directors of the company are also responsible for the identification of risks that may threaten compliance with the schedules and clauses identified above and controls which will mitigate those risks and monitor ongoing compliance.

Auditor's responsibilities
Our responsibilities in terms of clauses 2.8.1(1)(b)(vi) and (vii), 2.8.1(1)(c) and 2.8.1(1)(d) are to express an opinion on whether, in all material respects:

- as far as appears from an examination, the information used in the preparation of the audited Disclosure Information has been properly extracted from the company's accounting and other records, sourced from its financial and non-financial systems;
- as far as appears from an examination, proper records to enable the complete and accurate compilation of the audited Disclosure Information required by the Determination have been kept by the company and, if not, the records not so kept;
- the company complied with the Determination in preparing the audited Disclosure Information; and
- the company's basis for valuation of related party transactions in the disclosure year has complied with clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the IM Determination.

To meet these responsibilities, we planned and performed procedures in accordance with SAE 3100 (Revised), to obtain reasonable assurance about whether the company has complied, in all material respects, with the Disclosure Information (which includes the Related Party Transaction Information) required to be audited by the Determination.

An assurance engagement to report on the company's compliance with the Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the requirements. The procedures selected depend on our judgement, including the identification and assessment of the risks of material non-compliance with the requirements.

Inherent limitations

Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error or non-compliance with the Determination may occur and not be detected.

A reasonable assurance engagement throughout the disclosure year does not provide assurance on whether compliance with the Determination will continue in the future.

Restricted use

This report has been prepared for use by the directors of the company and the Commerce Commission in accordance with clause 2.8.1(1)(a) of the Determination and is provided solely for the purpose of establishing whether the compliance requirements have been met. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the company and the Commerce Commission, or for any other purpose than that for which it was prepared.

Independence and quality control

We complied with the Auditor-General's:

- independence and other ethical requirements, which incorporate the independence and ethical requirements of Professional and Ethical Standard 1 issued by the New Zealand Auditing and Assurance Standards Board; and
- quality control requirements, which incorporate the quality control requirements of Professional and Ethical Standard 3 (Amended) issued by the New Zealand Auditing and Assurance Standards Board.

The Auditor-General, and his employees, and PricewaterhouseCoopers and its partners and employees may deal with the company on normal terms within the ordinary course of trading activities of the company. Other than any dealings on normal terms within the ordinary course of trading activities of the company, this engagement, the Independent Appraiser's Report, regulatory advisory services, the assurance engagement on the Default Price-Quality Path and the annual audit of the company's financial statements and performance information, we have no relationship with, or interests in, the company.

Nathan Wylie
PricewaterhouseCoopers
On behalf of the Auditor-General
Christchurch, New Zealand
31 August 2022