COMMERCE COMMISSION
NEW ZEALAND

Electricity Distribution Information Disclosure Determination 2012
Consolidated determination as of 18 May 2023

Schedules 1–10
excluding 5f–5g

Company Name	EA Networks
Disclosure Date	16 August 2023
Disclosure Year (year ended)	31 March 2023

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Disclosure Template Instructions

This document forms Schedules 1–10 to the Electricity Distribution Information Disclosure Determination 2012 (Consolidated detemination as of 18 May 2023)

The Schedules take the form of templates 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 schedule 4, 5b, 5c, 5d, 5e, 6a, 8, 9d, and 9e templates 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 the schedule 5c, 6a, and 9e templates 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.

The schedule 5d and 5e templates 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.

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

Changes Since Previous Version
Refer to the Targeted Information Disclosure Review - Electricity Distribution Businesses Final reasons paper - Tranche 1, for the details of changes made. A summary is provided in Chapter 2.

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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 this ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of this determination.

This information is part of audited disclosure information (as defined in section 1.4 of this 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	27,378	752	99,206	4,870	25,829
Network	7,035	193	25,493	1,252	6,637
Non-network	20,343	559	73,713	3,619	19,191
Expenditure on assets	25,177	692	91,231	4,479	23,752
Network	24,509	673	88,810	4,360	23,122
Non-network	668	18	2,421	119	630

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	74,172	2,038
Standard consumer line charge revenue	74,172	2,038
Non-standard consumer line charge revenue	–	–

1(iii): Service intensity measures

Demand density	49	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	178	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	6	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	27,475	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	15,449	36.89%
Pass-through and recoverable costs excluding financial incentives and wash-ups	8,375	20.00%
Total depreciation	11,591	27.67%
Total revaluations	21,377	51.04%
Regulatory tax allowance	573	1.37%
Regulatory profit/(loss) including financial incentives and wash-ups	27,273	65.11%
Total regulatory income	41,884	

1(v): Reliability

Interruption rate	18.41	*Interruptions per 100 circuit km*

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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 this 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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref				
7	**2(i): Return on Investment**	**CY-2**	**CY-1**	**Current Year CY**
8		**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
9	**ROI – comparable to a post tax WACC**	**%**	**%**	**%**
10	Reflecting all revenue earned	4.40%	9.45%	8.40%
11	Excluding revenue earned from financial incentives	4.36%	9.77%	8.76%
12	Excluding revenue earned from financial incentives and wash-ups	4.36%	9.64%	8.64%
13				
14	**Mid-point estimate of post tax WACC**	3.72%	3.52%	4.88%
15	25th percentile estimate	3.04%	2.84%	4.20%
16	75th percentile estimate	4.40%	4.20%	5.56%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	4.73%	9.75%	8.91%
21	Excluding revenue earned from financial incentives	4.69%	10.07%	9.28%
22	Excluding revenue earned from financial incentives and wash-ups	4.69%	9.94%	9.15%
23				
24	**WACC rate used to set regulatory price path**	4.57%	4.57%	4.57%
25				
26	**Mid-point estimate of vanilla WACC**	4.05%	3.82%	5.39%
27	25th percentile estimate	3.37%	3.14%	4.71%
28	75th percentile estimate	4.73%	4.50%	6.07%
29				
30	**2(ii): Information Supporting the ROI**		**($000)**	
31				
32	Total opening RAB value	321,934		
33	*plus* Opening deferred tax	(16,414)		
34	**Opening RIV**		305,520	
35				
36	**Line charge revenue**		41,854	
37				
38	Expenses cash outflow	23,824		
39	*add* Assets commissioned	12,049		
40	*less* Asset disposals	522		
41	*add* Tax payments	(387)		
42	*less* Other regulated income	30		
43	**Mid-year net cash outflows**		34,934	
44				
45	**Term credit spread differential allowance**		–	
46				
47	Total closing RAB value	343,290		
48	*less* Adjustment resulting from asset allocation	43		
49	*less* Lost and found assets adjustment	–		
50	*plus* Closing deferred tax	(17,375)		
51	**Closing RIV**		325,872	
52				
53	**ROI – comparable to a vanilla WACC**			8.91%
54				
55	Leverage (%)			42%
56	Cost of debt assumption (%)			4.38%
57	Corporate tax rate (%)			28%
58				
59	**ROI – comparable to a post tax WACC**			8.40%
60				

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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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 this 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	9.07%
Year-end ROI – comparable to a post tax WACC	8.55%

** 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	(1,462)	
Purchased assets – avoided transmission charge		
Energy efficiency and demand incentive allowance		
Quality incentive adjustment	(39)	
Other financial incentives		
Financial incentives		(1,501)
Impact of financial incentives on ROI		–0.36%
Input methodology claw-back		
CPP application recoverable costs		
Catastrophic event allowance		
Capex wash-up adjustment	517	
Transmission asset wash-up adjustment		
2013–15 NPV wash-up allowance		
Reconsideration event allowance		
Other wash-ups		
Wash-up costs		517
Impact of wash-up costs on ROI		0.13%

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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 this 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	41,854
10	*plus*	Gains / (losses) on asset disposals	(361)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	391
12			
13		**Total regulatory income**	41,884
14		**Expenses**	
15	*less*	Operational expenditure	15,449
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	8,375
18			
19		**Operating surplus / (deficit)**	18,060
20			
21	*less*	Total depreciation	11,591
22			
23	*plus*	Total revaluations	21,377
24			
25		**Regulatory profit / (loss) before tax**	27,846
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	573
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	27,273
32			

sch ref			
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34	**Pass through costs**		
35	Rates	235	
36	Commerce Act levies	142	
37	Industry levies	96	
38	CPP specified pass through costs	–	
39	**Recoverable costs excluding financial incentives and wash-ups**		
40	Electricity lines service charge payable to Transpower	6,188	
41	Transpower new investment contract charges	1,714	
42	System operator services	–	
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**		8,375
47			

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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 this 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 23**
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	[year]	–	–
58	CY-4	[year]	–	–
59	CY-3	[year]	–	–
60	CY-2	[year]	–	–
61	CY-1	[year]	–	–
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	**EA Networks**
For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

4(i): Regulatory Asset Base Value (Rolled Forward)

sch ref			RAB 31 Mar 19 ($000)	RAB 31 Mar 20 ($000)	RAB 31 Mar 21 ($000)	RAB 31 Mar 22 ($000)	RAB 31 Mar 23 ($000)
10		**Total opening RAB value**	259,359	268,447	292,650	300,961	321,934
12	*less*	**Total depreciation**	9,530	9,990	10,649	10,873	11,591
14	*plus*	**Total revaluations**	3,831	6,771	4,429	20,799	21,377
16	*plus*	**Assets commissioned**	16,376	29,987	15,501	11,600	12,049
18	*less*	**Asset disposals**	773	1,095	976	444	522
20	*plus*	**Lost and found assets adjustment**	–	–	–	–	–
22	*plus*	**Adjustment resulting from asset allocation**	(816)	(1,470)	6	(109)	43
24		**Total closing RAB value**	268,447	292,650	300,961	321,934	343,290

4(ii): Unallocated Regulatory Asset Base

sch ref			Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
29		**Total opening RAB value**		324,515		321,934
30	*less*					
31		**Total depreciation**		11,757		11,591
32	*plus*					
33		**Total revaluations**		21,549		21,377
34	*plus*					
35		Assets commissioned (other than below)	7,497		7,483	
36		Assets acquired from a regulated supplier	–		–	
37		Assets acquired from a related party	4,566		4,566	
38		**Assets commissioned**		12,063		12,049
39	*less*					
40		Asset disposals (other than below)	517		476	
41		Asset disposals to a regulated supplier	–		–	
42		Asset disposals to a related party	46		46	
43		**Asset disposals**		563		522
45	*plus*	**Lost and found assets adjustment**		–		–
47	*plus*	**Adjustment resulting from asset allocation**				43
49		**Total closing RAB value**		345,807		343,290

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	**EA Networks**
For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref						
52		**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**				
54		CPI_4				1,218
55		CPI_4^{-4}				1,142
56		Revaluation rate (%)				6.65%
58			**Unallocated RAB ***		**RAB**	
59			**($000)**	**($000)**	**($000)**	**($000)**
60		Total opening RAB value	324,515		321,934	
61	*less*	Opening value of fully depreciated, disposed and lost assets	717		717	
63		Total opening RAB value subject to revaluation	323,798		321,217	
64		**Total revaluations**		21,549		21,377
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**		8,861		8,861
69	*plus*	Capital expenditure	12,703		12,703	
70	*less*	Assets commissioned	12,063		12,049	
71	*plus*	Adjustment resulting from asset allocation			(14)	
72		**Works under construction - current disclosure year**		9,501		9,501
74		Highest rate of capitalised finance applied				–

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

sch ref	4(v): Regulatory Depreciation	Unallocated RAB *		RAB	
77					
78		($000)	($000)	($000)	($000)
79	Depreciation - standard	10,242		10,242	
80	Depreciation - no standard life assets	1,515		1,349	
81	Depreciation - modified life assets	–		–	
82	Depreciation - alternative depreciation in accordance with CPP	–		–	
83	**Total depreciation**		11,757		11,591
84					

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					
88					
89					
90					
91					
92					
93					
94					

95 ** include additional rows if needed*

96 4(vii): Disclosure by Asset Category

97 ($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**	14,564	3,672	29,533	53,724	85,832	70,859	37,765	2,629	23,356	321,934
100	*less*	Total depreciation	544	87	1,168	2,112	2,139	2,264	1,714	214	1,349	11,591
101	*plus*	Total revaluations	968	244	1,965	3,563	5,712	4,706	2,500	176	1,543	21,377
102	*plus*	Assets commissioned	1,355	25	222	253	6,856	1,981	911	149	297	12,049
103	*less*	Asset disposals	–	–	–	172	–	120	186	–	44	522
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	43	43
106	*plus*	Asset category transfers	–	–	–	–	–	–	–	–	–	–
107		**Total closing RAB value**	16,343	3,854	30,552	55,256	96,261	75,162	39,276	2,740	23,846	343,290
108												
109		**Asset Life**										
110		Weighted average remaining asset life	32.6	47.8	33.4	29.7	44.0	35.7	25.7	12.6	19.9	(years)
111		Weighted average expected total asset life	45.1	55.0	44.8	45.9	55.1	45.0	36.6	15.7	24.7	(years)

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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 this 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**		27,846	
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	6		*
12		Amortisation of initial differences in asset values	2,076		
13		Amortisation of revaluations	1,997		
14				4,079	
15					
16	*less*	Total revaluations	21,377		
17		Income included in regulatory profit / (loss) before tax but not taxable			*
18		Discretionary discounts and customer rebates	2,999		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax			*
20		Notional deductible interest	5,501		
21				29,877	
22					
23		**Regulatory taxable income**		2,048	
24					
25	*less*	Utilised tax losses			
26		Regulatory net taxable income		2,048	
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		573	
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	49,827		
37	*less*	Amortisation of initial differences in asset values	2,076		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	195		
40		Closing unamortised initial differences in asset values		47,556	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		24	
43					

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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 this 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	271,534	
47				
48		Adjusted depreciation	9,594	
49		Total depreciation	11,591	
50		Amortisation of revaluations		1,997
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**	(16,414)	
61				
62	*plus*	Tax effect of adjusted depreciation	2,686	
63				
64	*less*	Tax effect of tax depreciation	3,476	
65				
66	*plus*	Tax effect of other temporary differences*	333	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	581	
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	(85)	
73				
74	*plus*	Deferred tax cost allocation adjustment	(9)	
75				
76		**Closing deferred tax**		(17,375)
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**	155,496	
84	*less*	Tax depreciation	12,413	
85	*plus*	Regulatory tax asset value of assets commissioned	12,049	
86	*less*	Regulatory tax asset value of asset disposals	217	
87	*plus*	Lost and found assets adjustment	–	
88	*plus*	Adjustment resulting from asset allocation	12	
89	*plus*	Other adjustments to the RAB tax value	–	
90		**Closing sum of regulatory tax asset values**		154,927

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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

sch ref			
7	**5b(i): Summary—Related Party Transactions**	**($000)**	**($000)**
8	**Total regulatory income**		183
9			
10	**Market value of asset disposals**		40
11			
12	Service interruptions and emergencies	513	
13	Vegetation management	47	
14	Routine and corrective maintenance and inspection	906	
15	Asset replacement and renewal (opex)	682	
16	**Network opex**		2,148
17	Business support	281	
18	System operations and network support	200	
19	**Operational expenditure**		2,629
20	Consumer connection	1,330	
21	System growth	1,036	
22	Asset replacement and renewal (capex)	1,773	
23	Asset relocations	96	
24	Quality of supply	57	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	381	
27	**Expenditure on non-network assets**		22
28	**Expenditure on assets**		4,695
29	Cost of financing		–
30	Value of capital contributions		129
31	Value of vested assets		–
32	**Capital Expenditure**		4,566
33	**Total expenditure**		7,195
34			
35	**Other related party transactions**		867

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

37	**Name of related party**	**Nature of opex or capex service provided**	**Total value of transactions ($000)**
38	EA Networks Field Services	Service interruptions and emergencies	513
	EA Networks Field Services	Vegetation management	47
	EA Networks Field Services	Routine and corrective maintenance and inspection	906
	EA Networks Field Services	Asset replacement and renewal (opex)	681
	EA Networks Field Services	Business support	30
	EA Networks Field Services	System operations and network support	190
	EA Networks Field Services	Consumer connection	1,284
	EA Networks Field Services	System growth	560
	EA Networks Field Services	Asset replacement and renewal (capex)	1,642
	EA Networks Field Services	Asset relocations	96
	EA Networks Field Services	Quality of supply	57
	EA Networks Field Services	Legislative and regulatory	–
	EA Networks Field Services	Other reliability, safety and environment	373
	EA Networks Field Services	Expenditure on non-network assets	21
	Ashburton Contracting Ltd	Asset replacement and renewal (capex)	118
39	Ashburton Contracting Ltd	Asset replacement and renewal (opex)	1
40	Ashburton Contracting Ltd	Consumer connection	46
41	Ashburton Contracting Ltd	Expenditure on non-network assets	1
42	Ashburton Contracting Ltd	Other reliability, safety and environment	–
43	Ashburton Contracting Ltd	System growth	476
44	Ashburton District Council	Business support	249
45	Ashburton District Council	System operations and network support	–
46	Ashburton District Council	Asset replacement and renewal (capex)	13
	Other	System operations and network support	7
47	Other	Other reliability, safety and environment	8
48	Other	Business support	2
49	Other	System operations and network support	3
50			
51			
52			
53	**Total value of related party transactions**		7,324
54	** include additional rows if needed*		
55			

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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 this 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									
12									
13									
14									
15									
16	** include additional rows if needed*						–	–	–

17

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

19

sch ref			
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	**EA Networks**
For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref						
7	**5d(i): Operating Cost Allocations**					
8			**Value allocated ($000s)**			
9		**Arm's length deduction**	**Electricity distribution services**	**Non-electricity distribution services**	**Total**	**OVABAA allocation increase ($000s)**
10	**Service interruptions and emergencies**					
11	Directly attributable		586			
12	Not directly attributable	–	–	–	–	–
13	**Total attributable to regulated service**		586			
14	**Vegetation management**					
15	Directly attributable		568			
16	Not directly attributable	–	–	–	–	–
17	**Total attributable to regulated service**		568			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		1,441			
20	Not directly attributable	–	–	–	–	–
21	**Total attributable to regulated service**		1,441			
22	**Asset replacement and renewal**					
23	Directly attributable		1,375			
24	Not directly attributable	–	–	–	–	–
25	**Total attributable to regulated service**		1,375			
26	**System operations and network support**					
27	Directly attributable		4,236			
28	Not directly attributable	–	–	–	–	–
29	**Total attributable to regulated service**		4,236			
30	**Business support**					
31	Directly attributable		1,105			
32	Not directly attributable	–	6,138	863	7,001	–
33	**Total attributable to regulated service**		7,243			
34						
35	**Operating costs directly attributable**		9,311			
36	**Operating costs not directly attributable**	–	6,138	863	7,001	–
37	**Operational expenditure**		15,449			
38						

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	473
Not directly attributable	–
Total attributable to regulated service	473
Recoverable costs	
Directly attributable	7,902
Not directly attributable	–
Total attributable to regulated service	7,902

5d(iii): Changes in Cost Allocations* †

Change in cost allocation 1			**CY-1** ($000)	**Current Year (CY)**
Cost category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–
Rationale for change				

Change in cost allocation 2			**CY-1** ($000)	**Current Year (CY)**
Cost category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–
Rationale for change				

Change in cost allocation 3			**CY-1** ($000)	**Current Year (CY)**
Cost category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–
Rationale for change				

** 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.*
† include additional rows if needed

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	16,343
Not directly attributable	–
Total attributable to regulated service	16,343
Subtransmission cables	
Directly attributable	3,854
Not directly attributable	–
Total attributable to regulated service	3,854
Zone substations	
Directly attributable	30,552
Not directly attributable	–
Total attributable to regulated service	30,552
Distribution and LV lines	
Directly attributable	55,256
Not directly attributable	–
Total attributable to regulated service	55,256
Distribution and LV cables	
Directly attributable	96,261
Not directly attributable	–
Total attributable to regulated service	96,261
Distribution substations and transformers	
Directly attributable	75,162
Not directly attributable	–
Total attributable to regulated service	75,162
Distribution switchgear	
Directly attributable	39,276
Not directly attributable	–
Total attributable to regulated service	39,276
Other network assets	
Directly attributable	2,738
Not directly attributable	2
Total attributable to regulated service	2,740
Non-network assets	
Directly attributable	16,690
Not directly attributable	7,156
Total attributable to regulated service	23,846
Regulated service asset value directly attributable	336,132
Regulated service asset value not directly attributable	7,158
Total closing RAB value	343,290

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

			($000) CY-1	($000) Current Year (CY)
Change in asset value allocation 1				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–
Rationale for change				

			($000) CY-1	($000) Current Year (CY)
Change in asset value allocation 2				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–
Rationale for change				

			($000) CY-1	($000) Current Year (CY)
Change in asset value allocation 3				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–
Rationale for change				

** 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 component.*
† include additional rows if needed

	Company Name	EA Networks
	For Year Ended	31 March 2023

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref			($000)	($000)
7		**6a(i): Expenditure on Assets**		
8		Consumer connection		4,835
9		System growth		1,140
10		Asset replacement and renewal		6,010
11		Asset relocations		202
12		Reliability, safety and environment:		
13		Quality of supply	1,173	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	470	
16		**Total reliability, safety and environment**		1,643
17		**Expenditure on network assets**		13,830
18		Expenditure on non-network assets		377
19				
20		**Expenditure on assets**		14,207
21	*plus*	Cost of financing		
22	*less*	Value of capital contributions		1,504
23	*plus*	Value of vested assets		
24				
25		**Capital expenditure**		12,703

sch ref		($000)
26	**6a(ii): Subcomponents of Expenditure on Assets (where known)**	
27	Energy efficiency and demand side management, reduction of energy losses	
28	Overhead to underground conversion	2,754
29	Research and development	
	Cybersecurity (Commission only)	

sch ref			($000)	($000)
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	($000)	($000)
32		Industry/Large Connection	307	
		New Subdivision	1,906	
		Urban with transformer	254	
		Urban without transformer	50	
		Tariff group change	362	
33		Rural with transformer	1,025	
34		Rural without transformers	285	
35		Safety	646	
36			–	
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		4,835
39				
40	*less*	Capital contributions funding consumer connection expenditure	1,313	
41		**Consumer connection less capital contributions**		3,522

sch ref			System Growth ($000)	Asset Replacement and Renewal ($000)
42		**6a(iv): System Growth and Asset Replacement and Renewal**		
43				
44				
45		Subtransmission	2	–
46		Zone substations	–	240
47		Distribution and LV lines	689	152
48		Distribution and LV cables	178	4,050
49		Distribution substations and transformers	28	467
50		Distribution switchgear	59	610
51		Other network assets	184	491
52		**System growth and asset replacement and renewal expenditure**	1,140	6,010
53	*less*	Capital contributions funding system growth and asset replacement and renewal	–	62
54		**System growth and asset replacement and renewal less capital contributions**	1,140	5,948
55				

sch ref			($000)	($000)
56		**6a(v): Asset Relocations**		
57		*Project or programme**	($000)	($000)
58				
59				
60				
61				
62				
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	202	
65		**Asset relocations expenditure**		202
66	*less*	Capital contributions funding asset relocations	–	
67		**Asset relocations less capital contributions**		202

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

6a(vi): Quality of Supply

	*Project or programme**	($000)	($000)
	11kV Core Network Centres	476	
	OH Rebuild	488	
	RAK 22kV Security Reconfiguration	209	
	** include additional rows if needed*		
	All other projects programmes - quality of supply		
	Quality of supply expenditure		1,173
less	Capital contributions funding quality of supply	129	
	Quality of supply less capital contributions		1,044

6a(vii): Legislative and Regulatory

	*Project or programme**	($000)	($000)
	** include additional rows if needed*		
	All other projects or programmes - legislative and regulatory		
	Legislative and regulatory expenditure		–
less	Capital contributions funding legislative and regulatory		
	Legislative and regulatory less capital contributions		–

6a(viii): Other Reliability, Safety and Environment

	*Project or programme**	($000)	($000)
	Distribution earthing	291	
	SCADA Automation Programme	69	
	** include additional rows if needed*		
	All other projects or programmes - other reliability, safety and environment	110	
	Other reliability, safety and environment expenditure		470
less	Capital contributions funding other reliability, safety and environment	–	
	Other reliability, safety and environment less capital contributions		470

6a(ix): Non-Network Assets

Routine expenditure

	*Project or programme**	($000)	($000)
	Routine Info Tech	224	
	Stock transferred to critical spare	47	
	** include additional rows if needed*		
	All other projects or programmes - routine expenditure	106	
	Routine expenditure		377

Atypical expenditure

	*Project or programme**	($000)	($000)
	** include additional rows if needed*		
	All other projects or programmes - atypical expenditure		
	Atypical expenditure		–
	Expenditure on non-network assets		377

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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 this 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	586	
9	Vegetation management	568	
10	Routine and corrective maintenance and inspection	1,441	
11	Asset replacement and renewal	1,375	
12	**Network opex**		3,970
13	System operations and network support	4,236	
14	Business support	7,243	
15	**Non-network opex**		11,479
16			
17	**Operational expenditure**		15,449
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	*EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*		
20	Energy efficiency and demand side management, reduction of energy losses		7
21	Direct billing*		
22	Research and development		1
23	Insurance		347
24	Cybersecurity (Commission only)		–
25	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	EA Networks
For Year Ended	31 March 2023

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 this 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	41,739	41,854	0%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	3,964	4,835	22%
11	System growth	1,970	1,140	(42%)
12	Asset replacement and renewal	9,310	6,010	(35%)
13	Asset relocations	–	202	–
14	Reliability, safety and environment:			
15	Quality of supply	1,457	1,173	(19%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	389	470	21%
18	**Total reliability, safety and environment**	1,846	1,643	(11%)
19	**Expenditure on network assets**	17,090	13,830	(19%)
20	Expenditure on non-network assets	2,150	377	(82%)
21	Expenditure on assets	19,240	14,207	(26%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,485	586	(61%)
24	Vegetation management	831	568	(32%)
25	Routine and corrective maintenance and inspection	1,015	1,441	42%
26	Asset replacement and renewal	1,325	1,375	4%
27	**Network opex**	4,656	3,970	(15%)
28	System operations and network support	5,290	4,236	(20%)
29	Business support	7,429	7,243	(3%)
30	**Non-network opex**	12,719	11,479	(10%)
31	**Operational expenditure**	17,375	15,449	(11%)
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses	108	–	(100%)
34	Overhead to underground conversion	3,709	2,754	(26%)
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	–	7	–
39	Direct billing	–	–	–
40	Research and development	220	1	(100%)
41	Insurance	341	347	2%
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	EA Networks
For Year Ended	31 March 2023
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 **8(i): Billed Quantities by Price Component**

sch ref	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)
15	General Supply - less than 5 kVA	Ancillary supplies	Standard	49	47
16	General Supply - 20 kVA	Residential and small commercial	Standard	16,031	128,831
17	General Supply - 50 kVA	Residential and small commercial	Standard	1,736	31,604
18	General Supply - 100 kVA	Commercial	Standard	745	61,242
19	General Supply - 150 kVA	Commercial	Standard	300	47,021
	Irrigation	Irrigation	Standard	1,617	182,056
20	Industrial	Industrial	Standard	43	68,222
21	Large Users	Large industrial	Standard	4	43,735
22	Generation	Generation	Standard	4	–
23	Street Lighting	Public streetlighting	Standard	9	1,052
24	differences	NA	Standard	–	473
25	*Add extra rows for additional consumer groups or price category codes as necessary*				
26			**Standard consumer totals**	20,538	564,283
27			**Non-standard consumer totals**	–	–
28			**Total for all consumers**	20,538	564,283

Billed quantities by price component

sch ref	Consumer group name or price category code	Fixed daily charge	Capacity Charge	Demand charge	Fixtures	Irrigation credit	Anytime supply	Controlled 16h supply	Day only supply	Night only supply	Night boost supply	Anytime injection
12	Price component	Fixed daily charge	Capacity Charge	Demand charge	Fixtures	Irrigation credit	Anytime supply	Controlled 16h supply	Day only supply	Night only supply	Night boost supply	Anytime injection
13	Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	Cons	kW	kVA	Fixtures	kW	kWh	kWh	kWh	kWh	kWh	kWh
15	General Supply - less than 5 kVA	49	–	–	–	–	46,583	–	–	–	–	–
16	General Supply - 20 kVA	16,031	–	–	22	–	95,660,424	28,912,353	–	3,591,390	666,405	874,947
17	General Supply - 50 kVA	1,736	–	–	1	–	29,108,678	2,014,228	–	380,316	100,793	209,656
18	General Supply - 100 kVA	745	–	–	16	–	60,563,938	562,486	–	110,410	4,683	59,135
19	General Supply - 150 kVA	300	–	–	–	–	46,876,195	132,704	–	12,372	–	65,687
	Irrigation	–	141,623	–	–	–	182,056,449	–	–	–	–	40,018
20	Industrial	–	–	18,363	–	–	68,070,990	–	120,767	30,467	–	–
21	Large Users	4	9,600	11,927	–	–	43,734,818	–	–	–	–	–
22	Generation	4	–	26,994	–	–	–	–	–	–	–	143,923,709
23	Street Lighting	–	–	–	3,735	–	1,052,165	–	–	–	–	–
24	differences	–	–	–	–	–	473,264	–	–	–	–	46,312
26	Standard consumer totals	18,869	151,223	57,284	3,774	–	527,643,504	31,621,771	120,767	4,124,955	771,881	145,219,464
27	Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–
28	Total for all consumers	18,869	151,223	57,284	3,774	–	527,643,504	31,621,771	120,767	4,124,955	771,881	145,219,464

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

31 **8(ii): Line Charge Revenues ($000) by Price Component**

sch ref	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)
37	General Supply - less than 5 kVA	Ancillary supplies	Standard	$9	–	$9	–
38	General Supply - 20 kVA	Residential and small commercial	Standard	$8,762	–	$7,729	$1,033
39	General Supply - 50 kVA	Residential and small commercial	Standard	$2,510	–	$2,196	$314
40	General Supply - 100 kVA	Commercial	Standard	$4,884	–	$4,230	$654
41	General Supply - 150 kVA	Commercial	Standard	$3,735	–	$3,229	$506
	Irrigation	Irrigation	Standard	$18,381	–	$13,625	$4,756
42	Industrial	Industrial	Standard	$1,811	–	$1,407	$404
43	Large Users	Large industrial	Standard	$1,121	–	$571	$550
44	Generation	Generation	Standard	$407	–	$407	–
45	Street Lighting	Public streetlighting	Standard	$259	–	$255	$4
46	differences	NA	Standard	($25)	–	($25)	–
47	*Add extra rows for additional consumer groups or price category codes as necessary*						
48			**Standard consumer totals**	$41,854	–	$33,633	$8,221
49			**Non-standard consumer totals**	–	–	–	–
50			**Total for all consumers**	$41,854	–	$33,633	$8,221

Line charge revenues ($000) by price component

sch ref	Consumer group name or price category code	Fixed daily charge	Capacity Charge	Demand charge	Fixtures	Irrigation credit	Anytime supply	Controlled 16h supply	Day only supply	Night only supply	Night boost supply	Anytime injection
34	Price component	Fixed daily charge	Capacity Charge	Demand charge	Fixtures	Irrigation credit	Anytime supply	Controlled 16h supply	Day only supply	Night only supply	Night boost supply	Anytime injection
35	Rate (eg, $ per day, $ per kWh, etc.)	$/con/day	$/kW/day	$/kVA/day	$/fixture/day	$/kW/day	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
37	General Supply - less than 5 kVA	$9	–	–	–	–	–	–	–	–	–	–
38	General Supply - 20 kVA	$1,755	–	–	$2	–	$6,591	$405	–	–	$9	–
39	General Supply - 50 kVA	$475	–	–	–	–	$2,006	$28	–	–	$1	–
40	General Supply - 100 kVA	$702	–	–	$1	–	$4,173	$8	–	–	–	–
41	General Supply - 150 kVA	$503	–	–	–	–	$3,230	$2	–	–	–	–
	Irrigation	–	$18,381	–	–	–	–	–	–	–	–	–
42	Industrial	–	–	$1,811	–	–	–	–	–	–	–	–
43	Large Users	$411	$485	$225	–	–	–	–	–	–	–	–
44	Generation	$407	–	–	–	–	–	–	–	–	–	–
45	Street Lighting	–	–	–	$259	–	–	–	–	–	–	–
46	differences	–	–	–	–	–	($25)	–	–	–	–	–
48	Standard consumer totals	$4,262	$18,866	$2,036	$262	–	$15,975	$443	–	–	$10	–
49	Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–
50	Total for all consumers	$4,262	$18,866	$2,036	$262	–	$15,975	$443	–	–	$10	–

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

Check: **OK**

52 **8(iii): Number of ICPs directly billed**

53 **Number of directly billed ICPs at year end**: –

Company Name	EA Networks
For Year Ended	31 March 2023
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.	2,252	2,245	(7)	4
10	All	Overhead Line	Wood poles	No.	25,187	25,358	171	4
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	383	391	8	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	8	9	1	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.	20	20	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	75	75	–	3
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	36	36	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	135	136	1	3
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	12	11	(1)	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	191	189	(2)	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	N/A
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	31	31	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,936	1,938	2	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	–	–	–	N/A
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	302	337	35	4
39	HV	Distribution Cable	Distribution UG PILC	km	4	5	1	3
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.	26	45	19	3
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	2	2	–	3
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	7,699	7,679	(20)	2
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	N/A
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	503	541	38	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,614	4,586	(28)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,918	2,047	129	4
48	HV	Distribution Transformer	Voltage regulators	No.	1	1	–	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	558	577	19	3
50	LV	LV Line	LV OH Conductor	km	59	58	(1)	4
51	LV	LV Cable	LV UG Cable	km	413	434	21	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	316	341	25	4
53	LV	Connections	OH/UG consumer service connections	No.	20,665	20,988	323	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	829	827	(2)	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	2	2	–	4
58	All	Load Control	Relays	No	400	400	–	1
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	EA Networks
For Year Ended	31 March 2023
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)**

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
10	All	Overhead Line	Concrete poles / steel structure	No.	–	2	11	13	198	530	1,159	–	4	9	59	56
11	All	Overhead Line	Wood poles	No.	–	90	166	265	397	2,550	6,181	810	567	1,523	1,138	774
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	0	0	2	38	37	0	58	104	10	11
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	3	1	0	–	1	0	0
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.	–	–	–	1	–	5	–	2	–	3	1	2
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.	–	–	–	–	–	–	–	7	–	15	2	2
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	9	15	12	–	–	–	–	–	–
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	5	1	31	2	7	3	22	3	3
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.	–	–	–	3	2	6	–	–	–	–	–	–
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	2	11	7	4	–	5	5	27
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	1	–	–	2	2	5	–	2	2	–
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	–	1	19	33	85	312	549	57	83	132	61	51
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–
38	HV	Distribution Line	SWER conductor	km	–	–	–	–	–	–	–	–	–	–	–	–
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	–	0	1	34	28	5	4	5	6	5
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	0	4	1	0	–	–	–	–	–
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	4	1	2	3	2	1
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.	1	8	28	55	64	173	442	52	122	246	320	329
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	2	17	49	81	15	10	7	11	11
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	1	5	46	152	232	173	458	184	80	57	184	203
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	17	41	120	102	122	7	5	17	23	28
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	–	–	–	–
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	6	40	71	101	14	9	7	3	9
51	LV	LV Line	LV OH Conductor	km	–	1	2	6	4	15	20	1	1	1	1	1
52	LV	LV Cable	LV UG Cable	km	–	–	0	6	23	56	75	8	9	5	7	5
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	1	1	8	20	44	67	7	7	4	4	4
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	–	–	–	–	–	–
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	–	–	2	–	2	24	10	6
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot	–	–	–	–	–	–	–	–	–	–	–	–
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	–	–	–	–	–	–
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–

sch ref	2005	2006	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	10	–	–	–	1	6	18	36	28	41	–	1	1	7	–	43	12	–	–	–	–	–	2,245		4
11	816	570	705	1,036	931	607	480	398	398	469	496	500	486	525	561	603	556	452	308	–	–	–	25,358		4
12	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
13	0	18	8	8	22	13	6	7	8	8	11	10	–	3	–	8	1	1	0	–	–	–	391		4
14	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
15	0	0	–	–	–	–	–	0	–	1	–	–	–	–	2	0	–	0	1	–	–	–	9		4
16	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
17	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
18	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
19	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
20	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
21	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
22	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
23	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
24	–	1	1	–	2	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	20		4
25	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
26	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
27	7	–	7	–	7	–	5	–	4	–	–	–	–	10	1	5	3	–	–	–	–	–	75		3
28	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	36		4
29	3	9	7	–	–	–	–	9	6	–	–	–	6	8	–	8	2	–	1	–	–	–	136		3
30	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
31	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
32	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	11		3
33	7	21	11	18	1	–	–	5	–	4	8	8	3	40	2	–	–	–	–	–	–	–	189		3
34	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
35	4	–	–	–	1	–	–	2	1	2	–	–	–	5	1	1	–	–	–	–	–	–	31		4
36	36	56	64	59	51	31	23	29	24	27	16	27	11	25	18	24	18	4	12	–	–	–	1,938		4
37	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
38	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
39	4	7	11	6	6	6	11	13	19	8	16	25	26	18	15	11	15	8	27	–	–	–	337		4
40	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5		4
41	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
42	2	1	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	1	20	–	–	–	45		3
43	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	2		3
44	319	285	227	427	565	290	298	311	302	232	210	253	218	49	170	171	180	372	160	–	–	800	7,679		2
45	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
46	6	28	16	27	6	29	11	19	19	25	18	12	23	15	10	10	31	12	21	–	–	–	541		3
47	148	188	296	83	255	206	57	229	138	107	126	171	158	42	49	179	132	230	17	–	–	–	4,586		4
48	40	69	70	76	117	78	91	113	94	58	126	160	59	86	64	56	58	64	86	–	–	–	2,047		4
49	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1		3
50	9	14	14	14	13	19	34	15	26	24	22	11	1	20	7	9	28	16	21	–	–	–	577		3
51	1	1	1	0	1	0	0	0	0	0	0	0	–	0	0	0	0	0	0	–	–	–	58		4
52	8	12	11	10	11	8	18	10	12	15	17	11	16	18	16	16	16	12	3	–	–	–	434		4
53	4	6	7	5	7	6	15	7	8	11	11	10	12	13	10	9	12	10	12	–	–	–	341		4
54	–	–	–	–	–	–	–	–	–	291	463	429	325	310	316	397	311	336	388	–	–	17,422	20,988		3
55	20	57	1	40	10	–	3	66	14	31	56	145	97	53	78	40	20	35	17	–	–	–	827		3
56	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	1		4
57	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
58	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	2		4
59	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	400	400		1
60	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A

Company Name	**EA Networks**
For Year Ended	**31 March 2023**
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	327	4	331
13	33kV	64	5	69
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	1,572	155	1,727
16	6.6kV to 11kV (inclusive—other than SWER)	366	187	553
17	Low voltage (< 1kV)	58	434	492
18	**Total circuit length (for supply)**	2,387	785	3,172
19				
20	Dedicated street lighting circuit length (km)	16	325	341
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			–
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	72	3%	
25	Rural	2,268	95%	
26	Remote only	48	2%	
27	Rugged only	–	–	
28	Remote and rugged	–	–	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	2,387	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	476	15%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	2,403	101%	

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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	Location *	Average number of ICPs in disclosure year	Line charge revenue ($000)
8			
9	Upper Rakaia embedded network (supplied by Orion)	14	14
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	EA Networks
For Year Ended	31 March 2023
Network / Sub-network Name	Total Network

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

8 9e(i): Consumer Connections and Decommissionings

9 *Number of ICPs connected during year by consumer type*

sch ref	Consumer types defined by EDB*	Number of connections (ICPs)
11	General Supply - less than 5 kVA	–
	General Supply - 20 kVA	308
	General Supply - 50 kVA	31
	General Supply - 100 kVA	28
12	General Supply - 150 kVA	3
13	Street Lighting	–
14	Irrigation	20
15	Industrial Supply	1
16	** include additional rows if needed*	
17	**Connections total**	391

18

19 *Number of ICPs decommissioned during year by consumer type*

sch ref	Consumer types defined by EDB*	Number of decommissionings
21	General Supply - less than 5 kVA	1
	General Supply - 20 kVA	56
	General Supply - 50 kVA	7
	General Supply - 100 kVA	2
22	General Supply - 150 kVA	2
23	Street Lighting	–
24	Irrigation	7
25	Industrial Supply	–
26	** include additional rows if needed*	
27	**Decommissionings total**	75

28

29 Distributed generation

sch ref			
30	Number of connections made in year	78	connections
32	Capacity of distributed generation installed in year	0.75	MVA

33

34 9e(ii): System Demand

35

36

sch ref			Demand at time of maximum coincident demand (MW)
37		**Maximum coincident system demand**	
38		GXP demand	155
39	*plus*	Distributed generation output at HV and above	1
40		**Maximum coincident system demand**	156
41	*less*	Net transfers to (from) other EDBs at HV and above	(0)
42		**Demand on system for supply to consumers' connection points**	156

sch ref			Energy (GWh)	
43		**Electricity volumes carried**		
44		Electricity supplied from GXPs	455	
45	*less*	Electricity exports to GXPs	–	
46	*plus*	Electricity supplied from distributed generation	145	
47	*less*	Net electricity supplied to (from) other EDBs	(0)	
48		**Electricity entering system for supply to consumers' connection points**	600	
49	*less*	Total energy delivered to ICPs	564	
51		**Electricity losses (loss ratio)**	36	6.0%
52				
53		**Load factor**	0.44	

54 9e(iii): Transformer Capacity

sch ref		(MVA)
55		
56	Distribution transformer capacity (EDB owned)	598
57	Distribution transformer capacity (Non-EDB owned, estimated)	13
58	**Total distribution transformer capacity**	611
59		
60	**Zone substation transformer capacity**	326

61

	Company Name	EA Networks
	For Year Ended	31 March 2023
	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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

8 **10(i): Interruptions**

sch ref	Interruptions by class	Number of interruptions
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	282
12	Class C (unplanned interruptions on the network)	300
13	Class D (unplanned interruptions by Transpower)	–
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)	2
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	–
19	**Total**	584
20		

sch ref	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	227	73
23			

sch ref	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)	0.0000	0.00
26	Class B (planned interruptions on the network)	0.4587	121.45
27	Class C (unplanned interruptions on the network)	1.3192	116.26
28	Class D (unplanned interruptions by Transpower)	0.0000	0.00
29	Class E (unplanned interruptions of EDB owned generation)	0.0000	0.00
30	Class F (unplanned interruptions of generation owned by others)	0.0000	0.00
31	Class G (unplanned interruptions caused by another disclosing entity)	0.0014	0.30
32	Class H (planned interruptions caused by another disclosing entity)	0.0000	0.00
33	Class I (interruptions caused by parties not included above)	0.0000	0.00
34	**Total**	1.7793	238.01
35			

sch ref	Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
37	Classes B & C (interruptions on the network)	1.7779	237.71
38			

39 **Transitional SAIDI and SAIDI (previous method)**

40 *Where EDBs do not currently record their SAIFI and SAIDI values using the 'multi-count' approach, they shall continue to record their SAIFI and SAIDI values on the same basis that they employed as at 31 March 2023 as 'Transitional SAIFI' and 'Transitional SAIDI' values, in addition to their SAIFI and SAIDI values (Classes B & C) using the 'multi-count approach'.* ***This is a transitional reporting requirement that shall be in place for the 2024, 2025, and 2026 disclosure years.***

sch ref		SAIFI	SAIDI
41	Class B (planned interruptions on the network)		
42	Class C (unplanned interruptions on the network)		
43			

Company Name	**EA Networks**
For Year Ended	**31 March 2023**
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 this ID determination), and so is subject to the assurance report required by section 2.8.

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

Cause	**SAIFI**	**SAIDI**
Lightning	0.0352	1.87
Vegetation	0.2204	48.50
Adverse weather	0.0522	6.70
Adverse environment	0.0027	0.39
Third party interference	0.1477	10.59
Wildlife	0.1113	5.13
Human error	0.1428	1.95
Defective equipment	0.4461	33.95
Cause unknown	0.1608	7.18

Breakdown of third party interference	**SAIFI**	**SAIDI**
Dig-in	–	–
Overhead contact	–	–
Vandalism	–	–
Vehicle damage	–	–
Other	–	–

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

Main equipment involved	**SAIFI**	**SAIDI**
Subtransmission lines	0.0184	6.24
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.4254	110.80
Distribution cables (excluding LV)	0.0149	4.41
Distribution other (excluding LV)	–	–

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

Main equipment involved	**SAIFI**	**SAIDI**
Subtransmission lines	0.1354	6.46
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	1.0991	104.79
Distribution cables (excluding LV)	0.0847	5.01
Distribution other (excluding LV)	–	–

10(v): Fault Rate

Main equipment involved	**Number of Faults**	**Circuit length (km)**	**Fault rate (faults per 100km)**
Subtransmission lines	7.00	389.00	1.80
Subtransmission cables	–	6.12	–
Subtransmission other	–		
Distribution lines (excluding LV)	305.00	1,931.00	15.79
Distribution cables (excluding LV)	7.00	332.00	2.11
Distribution other (excluding LV)	–		
Total	319		

Electricity Distribution Information Disclosure Determination 2012
Consolidated determination as of 18 May 2023
Schedules 5f & 5g

Company Name	EA Networks
Disclosure Date	16 August 2023
Disclosure Year (year ended)	31 March 2023

Table of Contents

Disclosure Template Instructions

This document forms Schedules 5f and 5g to the Electricity Distribution Information Disclosure Determination 2012 (Consolidated determination as of 18 May 2023)
The Schedules take the form of templates 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 the schedule 5f & 5g templates, 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 schedules 5f and 5g templates 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.

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref											
7											
8											
9					**Allocator Metric (%)**		**Value allocated ($000)**				
10	**Line Item***	**Allocation methodology type**	**Cost allocator**	**Allocator type**	**Electricity distribution services**	**Non-electricity distribution services**	**Arm's length deduction**	**Electricity distribution services**	**Non-electricity distribution services**	**Total**	**OVABAA allocation increase ($000)**
11	**Service interruptions and emergencies**										
12										-	
13										-	
14										-	
15										-	
16	**Not directly attributable**						-	-	-	-	-
17	**Vegetation management**										
18										-	
19										-	
20										-	
21										-	
22	**Not directly attributable**						-	-	-	-	-
23	**Routine and corrective maintenance and inspection**										
24										-	
25										-	
26										-	
27										-	
28	**Not directly attributable**						-	-	-	-	-
29	**Asset replacement and renewal**										
30										-	
31										-	
32										-	
33										-	
34	**Not directly attributable**						-	-	-	-	-
35											

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref												
36	**System operations and network support**											
37											-	
38											-	
39											-	
40											-	
41	**Not directly attributable**							-	-	-	-	-
42	**Business support**											
43		Costs related to buildings	ABAA	Floor Area	Proxy	51.15%	48.85%		123	118	241	
44		Other common operating costs	ABAA	Revenue	Proxy	90.90%	9.10%		4,997	500	5,497	
45		Common costs related to IT	ABAA	Staff Computer	Proxy	87.80%	12.20%		950	132	1,082	
46		Common costs related to staff	ABAA	Staff numbers	Proxy	37.50%	62.50%		68	113	181	
47	**Not directly attributable**							-	6,138	863	7,001	-
48												
49	**Operating costs not directly attributable**							-	6,138	863	7,001	-
50												
51	**Pass through and recoverable costs**											
52	**Pass through costs**											
53											-	
54											-	
55											-	
56											-	
57	**Not directly attributable**							-	-	-	-	-
58	**Recoverable costs**											
59											-	
60											-	
61											-	
62											-	
63	**Not directly attributable**							-	-	-	-	-
64	** include additional rows if needed*											

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref					Allocator Metric (%)		Value allocated ($000)				
7											
8											
9					Allocator Metric (%)		Value allocated ($000)				
10	**Line Item***	**Allocation methodology type**	**Allocator**	**Allocator type**	**Electricity distribution services**	**Non-electricity distribution services**	**Arm's length deduction**	**Electricity distribution services**	**Non-electricity distribution services**	**Total**	**OVABAA allocation increase ($000)**
11	**Subtransmission lines**										
12										-	
13										-	
14										-	
15										-	
16	**Not directly attributable**						-	-	-	-	-
17	**Subtransmission cables**										
18										-	
19										-	
20										-	
21										-	
22	**Not directly attributable**						-	-	-	-	-
23	**Zone substations**										
24										-	
25										-	
26										-	
27										-	
28	**Not directly attributable**						-	-	-	-	-
29	**Distribution and LV lines**										
30										-	
31										-	
32										-	
33										-	
34	**Not directly attributable**						-	-	-	-	-

Company Name	**EA Networks**
For Year Ended	**31 March 2023**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref											
35	**Distribution and LV cables**										
36										-	
37										-	
38										-	
39										-	
40	**Not directly attributable**						-	-	-	-	-
41											
42	**Distribution substations and transformers**										
43										-	
44										-	
45										-	
46										-	
47	**Not directly attributable**						-	-	-	-	-
48											
49	**Distribution switchgear**										
50										-	
51										-	
52										-	
53										-	
54	**Not directly attributable**						-	-	-	-	-
55	**Other network assets**										
56	Software	ABAA	Turnover	Proxy	90.90%	9.10%		2	-	2	
57										-	
58										-	
59										-	
60	**Not directly attributable**						-	2	-	2	-
61	**Non-network assets**										
62	Common IT equipment	ABAA	Staff computer	Proxy	87.80%	12.20%		684	95	779	
63	Common office equipment	ABAA	Floor area	Proxy	51.15%	48.85%		2,067	1,974	4,041	
64	Office property and other works	ABAA	Turnover	Proxy	90.90%	9.10%		4,405	441	4,846	
65										-	
66	**Not directly attributable**						-	7,156	2,510	9,666	-
67											
68	**Regulated service asset value not directly attributable**						-	7,158	2,510	9,668	-
69	** include additional rows if needed*										

Company Name	EA Networks
For Year Ended	31 March 2023

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 3 April 2018. 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).

Return on Investment (Schedule 2)

4. Comment on return on investment as disclosed in Schedule 2

ROI for FY23 was 8.40% compared to 9.45% the previous year. The decrease was due to reduced:

- Regulatory Profit of $27.3m is $0.5m (2%) less than FY22 driven largely due to an increase in Operational Expenditure ($1.8m) and increased depreciation ($0.7m) partially offset by increased Revaluations ($0.6m) and Regulatory Income ($0.5m), and reduced tax allowance ($1.2m)
- A higher Regulatory Asset Base requiring increased profits to maintain the same ROI.

The Commerce Commission set prices assuming that CPI would be 2.00% for the 2022-23 year, which would have resulted in $6M revaluation on RAB assets. Actual inflation for the corresponding period was 6.65% (PY: 6.93%), which has resulted in a $21M revaluation of RAB assets.

When schedule 4(iii), calculation of revaluation rate and revaluation of assets, is set to the Commerce Commission forecasted CPI number for the period (2.00%), the ROI drops to 3.54%.

4. Information on reclassified items in accordance with subclause 2.7.1(2)

There has been no re-classification of items in the disclosure year in accordance with the requirements of 2.7.1(2).

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.

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

Regulatory Profit (Schedule 3)

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

Other regulatory income mainly comprises $150k (PY:$205k) of new connection fees. Additional information concerning when new connection fees are charged can be found in EA Networks new connection and extension policy downloadable from: https://www.eanetworks.co.nz/assets/PDFs/Disclosures/Regulatory/Other/e7d903803e/New-Connections-Extensions-PolicyEA-v2.pdf.

The balance of other regulatory income largely relates to solar applications ($235k). The maximum amount EA can charge for solar applications is detailed in the 'Electricity industry participation code 2010 and associated amendments'.

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

No items have been reclassified in accordance with subclause 2.91.(2).

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 Merger and acquisition expenses

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

No items have been reclassified 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.

No merger or acquisition occurred in the reporting period.

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)
Comment on the value of the regulatory asset base (rolled forward) in Schedule 4. During the disclosure year RAB increased by $21.4m. This increase was mainly due to $21.4m total revaluation movement as a result of CPI remaining high in RY23. All assets commissioned, decommissioned and depreciated in the year have followed the requirements of the determination. **information on reclassified items in accordance with subclause 2.7.1(2)** No items have been reclassified in accordance with subclause 2.7.1(2).

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

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

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

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

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

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

Box 5: Regulatory tax allowance: permanent differences
8.1 Income not included in regulatory profit / (loss) before tax but taxable None **8.2 Expenditure or loss in regulatory profit / (loss) before tax but not deductible** Non-Deductible entertainment expenses incurred of $6k. **8.3 Income included in regulatory profit / (loss) before tax but not taxable** None **8.4 Expenditure or loss deductible but not in regulatory profit / (loss) before tax** None

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)	
Tax effect of other temporary differences	**($000)**
Early repayment of new investment contracts	280
Annual leave provision and other employee related cost	53
Total	**333**

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
Comment on cost allocation as disclosed in Schedule 5d ABAA (accounting-based allocation approach) has been applied to allocate not directly attributable costs in the disclosure year in accordance with the IM determination. Proxy cost allocators have been used due to no direct relationship existing between not directly attributable business support operating costs and the way costs are incurred. **Information on reclassified items in accordance with subclause 2.7.1(2)** No items have been reclassified in accordance with subclause 2.7.1(2)

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
Comment on cost allocation as disclosed in Schedule 5e ABAA (accounting-based allocation approach) has been applied to allocate not directly attributable costs in the disclosure year in accordance with the IM determination. Proxy cost allocators have been used due to no direct relationship exiting between not directly attributable non-network asset and the way in which the asset is employed by EA Networks. **Information on reclassified items in accordance with subclause 2.7.1(2)** No items have been reclassified in accordance with subclause 2.7.1(2)

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

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

Projects individually reported in the 2022 AMP. The budget section of the 2022 AMP gives additional detail concerning how projects are individually sectioned for separate disclosure in the AMP.

The materiality threshold applied to identify material projects is $0.8m, which is consistent with the audit materiality level. There are no projects that have exceeded this level of materiality.

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

There has been no re-classification in accordance with subclause 2.7.1(2).

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

13.1 Commentary on assets replacement or renewal reported in 6b(i) of Schedule 6b

Asset replacement or renewal relates to work undertaken to maintain RAB assets in functional order. An example of such maintenance include:

- Replacement of a cross arm but not the pole itself.
- Repairs to a substation fence, but not the replacement of the fence.
- Repairs to distribution transformers, switchgear, pillar boxes and ABS but not their replacements.
- The relocation cost of moving a physical transformer from one location on the network to another, but not the cost of installing a transformer pad and plumbing it into the network.
- Network operational expenditure is managed together collectively.

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

There has been no re-classification 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.

There was no atypical expenditure during the period which exceeded the materiality threshold

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

In line with the determination, expenditure types are compared to the AMP forecast. When an actual expenditure for a disclosure headings expenditure is greater than 110% of the AMP forecast comment is made.

Expenditure on Assets

Total expenditure on assets was $5.0m or 26% lower than forecast and expenditure on network assets was $3.2m or 19% lower than forecast. Non-network assets included key projects which did not proceed and/or were operating costs in nature.

The reduction in network asset expenditure was driven by resourcing and supply chain challenges:

- **Consumer connections -** The target was set using historical information and known demand for consumer connection work in the disclosure year. Actual demand for subdivision and 'other' consumer connections was much higher than expected and resulted in an additional $0.9 million being invested.
- **System growth** – Network centre projects were delayed due to delays in obtaining land access to site the equipment. Delay with the Powerpilot trail implementation of a load control alternative was due to manufacturing delays.
- **Asset replacement and renewal –** Supply chain delays for equipment and resourcing issues adversely affected the ability to meet the targeted investment, especially in underground conversions. The Methven Highway underground conversion was delayed due to negotiations with Waka Kotahi.
- **Quality of Supply -** Actual spending on quality of supply was 19% lower than the forecast. This is primarily due to delays resulting from supply chain and resourcing issues. The forecast also included expenditure for the SCADA – Distribution Automation Project which should have been included as system growth.
- **Other reliability, safety, and environment -** Actual costs for the year include additional expenditure on earthing, resulting from an underspend in this area in prior years.
- **Overhead to underground conversion –** Spend on converting lines from overhead to underground ended $1.0m (26%) under forecast due to a lack of resources to carry out the work in the timeframe projected, leading to work being pushed back beyond FY23.

Operational Expenditure

Total operational expenditure was 11% below forecast. Network operational expenditure was 15% lower than target largely driven by:

- **Service interruptions and emergencies –** The target included a provision for an increased cost of major events based on recent trends, the actual cost of major events was lower than anticipated. While there were two major wind events in July and August, the weather in the remainder of the year was largely settled.

  Faults, by their nature are difficult to predict from year to year, with extreme weather being a large contributor along with unplanned events such as vehicles striking poles.

  Whilst the number of unplanned interruptions on the network of 302 was consistent with 304 in the prior year:
  - SAIFI all class (the average number of supply interruptions per connected consumer) value of 1.32 was 20% lower compared to 1.65 for the previous year.
  - SAIDI all class (the average duration of supply interruptions per connected consumer) value of 116.56 was 10% lower compared to 129.09 for the previous year.

- **Vegetation management -** Whilst greater than FY22, FY23 expenditure was less than target due to resourcing issues. A shift to contracting out vegetation management and the need to appoint a vegetation supervisor to manage the contractor resulted in expenditure below budget.
- **Routine and collective maintenance and inspection -** The higher than planned expenditure reflects a catch-up on inspections from prior years

System operations and network support of $4.2m increased compared to the prior year of $3.7m but was lower than the forecast of $5.3m as several projects were delayed.

Information on reclassified items in accordance with subclause 2.7.1(2)
No items have been reclassified in accordance with subclause 2.6.1(2).

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

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.
Targeted line charges ($41.7 million) closely matched actual line charge revenue ($41.9 million).

15.2 Explanatory comment on reasons for any material differences between target revenue and total billed line charge revenue
No material differences occurred in the 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.

Interruptions by class *(per Schedule 10(i))*	**RY23**	**RY22**	**% Var.**
Class B (planned interruptions on the network)	282	251	12.4%
Class C (unplanned interruptions on the network)	300	304	-1.3%
Class H (planned interruptions caused by another disclosing entity)	2	2	0.0%
Total	**584**	**557**	**4.8%**

Planned interruptions - The increase in planned interruptions was due to a combination of an uninterrupted year (less COVID disruption to work plans), largely benign weather and capital project related work where a lot of the pre outage work had been completed needing the interruptions to commission.

Interruptions restoration - Class C interruptions with a restore time greater than 3 hours decreased to 73 (was 85 in 2022) while overall Class C interruptions decreased by 4 on FY22. This decrease potentially reflects a decrease in both Defective Equipment and third-party interruptions that traditionally have longer durations.

Class C interruptions major contributors
10(ii) SAIDI Class C Interruptions - For the 2023 regulatory year SAIDI caused by vegetation faults was higher than the prior year which itself was unusually high. This reflects a combination of severe winds and a lot of rain

making for soft conditions under foot that saw old (large) fall zone trees damaging the network. Defective equipment continues to be a notable cause of SAIDI with it being more than FY22 although the number of interruptions was less.

10(ii) SAIFI Class C Interruptions - Defective Equipment continues to be a leading contributor to SAIFI. Defective Equipment interruptions in an urban area of overhead network waiting to be converted to underground has contributed to this. A defective class of lightning arrestor has been contributing to interruptions due to failure and a programme of replacement has been initiated over the next four years to phase out this type with more reliable lightning arrestors.

Limitation on reliability information
Even through EA Networks reliability is compliant with ID's quality requirements there are inherent limitations in the ability to collect and record the network reliability information to be disclosed in Schedule 10(1) to 10(iv). Consequently, there is no independent evidence available to support the accuracy of recorded faults, and EA Networks has limited control over the completeness and accuracy of installation control point ('ICP') data included in the SAIDI and SAIFI calculations.

Exemption related to Schedule 10 – Disclosure and auditing of reliability information.
On 26 May 2023, 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 2023 disclosure year, subject to the condition at paragraph 11 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 consider any issues arising out of the EDB's recording of SAIDI, SAIFI and number of interruptions due to successive interruptions.

The Directors of Electricity Ashburton 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 Electricity Ashburton Limited certify that:
Electricity Ashburton Limited has continued to treat successive interruptions as a single event. This approach is the same as what was used in the 2022 disclosure year.

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

17.1 level of insurance
Where it is economically sensible to ensure assets EA Networks has insurance in place. In

practice this means that most items outside of substation fencing will not be insured.

17.2 levels of reserves
EA Networks holds no insurance reserves.

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

No material errors have been identified.

Company Name	EA Networks
For Year Ended	31 March 2023

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 3 April 2018.)

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.2.6.

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

Consistent with the previous year constant price operating and capital expenditure were inflated to reflect forecast nominal prices.

Costs have been prepared using 2023-24 values for labour, plant, and materials. Years after 2023-24 have been escalated by the "Half Year Economic and Fiscal Update 2022" CPI Forecast by the New Zealand Government Treasury published in December 2022. When the forecast ends, the final year CPI value has been used util the period end.
(**Half Year Economic and Fiscal Update 2022 | The Treasury New Zealand**)

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

Consistent with the previous year constant price operating and capital expenditure were inflated to reflect forecast nominal prices.

Costs have been prepared using 2023-24 values for labour, plant, and materials. Years after 2023-24 have been escalated by the "Half Year Economic and Fiscal Update 2022" CPI Forecast by the New Zealand Government Treasury published in December 2022. When the forecast ends, the final year CPI value has been used util the period end.
(**Half Year Economic and Fiscal Update 2022 | The Treasury New Zealand**)

Company Name	EA Networks
For Year Ended	31 March 2023

Schedule 15 Voluntary Explanatory Notes

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)

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 9a and 9b

Continuing improvement in the accuracy of our GIS systems, and an ongoing review and cleanse of data led to corrections in recorded pole population, including identifying streetlight poles and correcting the private ownership status of some poles.

Schedule 10

EA Networks have treated successive interruptions the same way for the 2023 disclosure year as completed for the 2022 disclosure year. The process followed does not recognise successive interruptions following an initial outage as the disclosed SAIFI statistics only take into consideration the total unique ICPs affected by an outage.

EA Networks
Related Party requirements of the Electricity Distribution Information Disclosure Determination 2012 – consolidated 6 July 2023

For the year ended 31 March 2023

Dated 16 August 2023

Requirement 2.3.8 (1) The relationships between the EDB and the related party

This diagram identifies the key related parties Ashburton Contracting Limited, Ashburton District Council, EA Field Services, and EA Fibre.

Ownership of EA Networks

Ashburton District Council (ADC) owns 28,750,000 deferred shares in EA Networks, which have a value of $31.484M.

During the year:
The EDB paid ADC $262k for rates and other regulated services.
ADC paid the EDB $138k for regulatory services.
All transactions with ADC have been undertaken on normal commercial terms.

Ashburton Contracting Limited (ACL). 100% owned by Ashburton District Council and supplies civil contracting services to the EDB.

During the year:
The EDB paid ACL $642k for civil contracting work.
ACL paid the EDB $0.3k for other regulatory services.
All transactions with ACL have been undertaken on normal commercial terms

Inside EA Networks

Field Services Division

During the year the EDB paid Field services $6,401k for electricity contracting related work.

EDB

EA Fibre

During the year the EDB paid EA Fibre $867k lease payments for the use of the communication network.

Other related parties

Other related parties' transactions (not disclosed)

The EDB paid other related parties $20k for various services.
The various services were paid to:
> Orion New Zealand Ltd ($7k) - Paul Munro is Chair of Orion and a Director of EA Networks.
> Cullimore Engineering Ltd ($8k) - Ian Cullimore owns 50% of Cullimore Engineering and is a member of the EA Networks Shareholder Committee.
> ElectraServe Ltd ($2k) - Alister Lilley is a Director of ElectraServe and a member of the EA Networks Shareholder Committee.
> Newlands Group ($3k) - Robert Newland is a Director and shareholder Newlands Group, and a member (Chair from 1 September 2022) of the EA Network Shareholders Committee.

The other related parties paid the EDB $84k for other regulatory services.
The various services wer paid by:
> Electraserve Ltd ($43k) - a related party per above.
> CEO Roger Sutton ($40k) - an employee of EA Networks.
> MHV Water ($1k) - Cole Groves and Paul Munro are Directors of both MHV Water and EA Networks

Related party: Ashburton District Council

What is the relationship between EA Networks and Ashburton District Council?

Ashburton District Council (ADC) is a significant shareholder that holds 28,750,000 deferred shares and do appoint 3 out of 7 members onto EA Networks Shareholders Committee.

The role of the Shareholders Committee and Shareholders Committee ability to control EA Networks

Section 16.22 of Electricity Ashburton Limited, trading as EA Networks, Constitution stops the Shareholders Committee from directing or instructing the Board, or Management, to undertake any actions. The function of the Shareholders Committee shall be:

- To receive reports from the Board of EA Networks so that the Shareholders Committee can report to the shareholders as to whether or not the Board is meeting the reasonable expectations of the shareholders Committee in governing and controlling the Company.
- To appoint the Directors of the Company in accordance with the criteria established by the Shareholders Committee as reviewed and revised from time to time. The criteria established by the Shareholders Committee shall ensure that a balanced Board of Directors comprising people of high business acumen will be appointed as Directors of the Company. The criteria established by the Shareholder Committee will be available to all shareholders of the Company.

Section 19.9 of the Constitution allows each member of the shareholders Committee to have one vote each. In the case of an equality of votes the chairperson shall have a second or casting vote.

ADC Share ownership in EA Networks

ADC owns:

- 100 $1 Rebate shares on the same terms and conditions as all consumers/shareholders who own rebate shares.
- 28,750,000 deferred shares. The deferred shares:
    - hold no voting rights unless EA Networks is subject to sale.
    - have no rights to any distribution unless the company is sold.

What is Ashburton District Councils purpose?

The principal activities of the Ashburton District Council (ADC) are defined in section 10 of the Local Government Act 2002 as

The purpose of local government is –

a. To enable democratic local decision-making and action by, and on behalf of, communities; and
b. To promote social, economic, environmental, and cultural well-being of communities in the present and for the future.

Financial benefits ADC received as an owner of EA Networks

For the disclosure year ADC received no financial benefits due to its ownership interest in EA Networks.

Like all consumers connected to the EDB's network at the qualifying date, ADC received a consumer discount, paid via their electricity retailer. The value of consumer discount was calculated in accordance with EA Networks consumer discount methodology. The consumer discount methodology is downloadable from EA Networks website, www.eanetworks.co.nz.

Requirement 2.3.10: A summary of EA Networks current policy in respect of the procurement of assets or goods or services from any related party.

EA Networks Procurement Policies requires all related parties, excluding EA Fibre and EA Field Services, to tender for work as an independent contractor unrelated to the EDB.

In practice, most services supplied by ADC to EA Networks fall under the Local Government Act 2002. This Act requires the ADC to set uniform annual charges regardless of ownership.

Requirement 2.3.12 (1): A description of how the EDB applies its current policy for the procurement of assets or goods or services from a related party in practice.

The EDB undertakes commercial transactions with ADC using standard terms and conditions.

Requirement 2.3.12 (2): A description of any policies or procedures of the EDB that require or have the effect of requiring a consumer to purchase assets or goods or services from a related party that are related to the supply of the electricity distribution services.

The EDB has no policies or procedures requiring consumers to undertake any purchasing from ADC.

Requirement 2.3.12 (3): Subject to subclause (5), at least one representative example transaction from the disclosure year of how the current policy for the procurement of assets or goods or services from a related party is applied in practice.

The EDB received a rate demand for instalment 3 of 4 in February 2023. The payment:

1. was authorised for payment in accordance with the requirements of the delegated authority policy.
2. Paid on the due date (20 February 2023).

The process used:

- to authorise the rate demand for payment.
- to select the actual payment date of the rate demand.

is consistent with all payments made by the EDB.

Requirement 2.3.12 (4): For each representative example transaction specified in accordance with subclause (3), how and when the EDB last tested the arm's-length terms of those transactions.

The Local Body Act 2002 allows councils to strike rates. The Act sets out how rates must be struck and applied to owners of the property in the area serviced by the Local Body. ADC has complied with the requirements of the Local Body Act. This compliance demonstrates compliance with the arm's-length requirement.

Requirement 2.3.12 (5): Separate representative example transactions where the EDB has applied the current policy for the procurement of assets or goods or services from a related party significantly differently between expenditure categories.

Materially, the Procurement Policy has been applied consistently between expenditure categories.

Related Party: Ashburton Contracting Limited (ACL)

Who is Ashburton Contracting and how is it a related party?

The purpose of ACL

ACL's website states its principal activities include civil services, rural contracting, residential contracting, and vehicle workshop services. Additional information on ACL's activities is on their website: https://ashcon.co.nz.

Ability to control

ACL has no ability to appoint members onto the Shareholders Committees or direct management, Board Members, or the Shareholder Committee to undertake any activity solely due to ACL being a subsidiary of ADC.

Mr Andrew Barlass is a Director of Ashburton Contracting Limited and Chair of Ashburton Electricity Limited trading as EA Networks. Mr Barlass' ability to control Ashburton Contracting Limited is limited to that which a Director would normally discharge their responsibilities.

Financial return to ACL from the EDB

For the disclosure year, ACL has no ownership interest in EA Networks.

Like all consumers connected to the EDB's network at the qualifying date, ACL received a consumer discount, paid via their electricity retailer. The value of consumer discount was calculated in accordance with EA Networks consumer discount methodology. The consumer discount methodology is downloadable from EA Networks website, www.eanetworks.co.nz.

Requirement 2.3.10: A summary of EA Networks current policy in respect of the procurement of assets or goods or services from any related party.

ACL supplies fill for trenching and civil contracting services to Field Services and the EDB. The non-minor section of the procurement policy applies to Civil work awarded to ACL. The non-minor section of the procurement requires:

For electricity contracting and maintenance work, over $50k, work will be tendered out. Evaluation of tenders will be based on the attributes set out in the tender documents and taking into consideration the Health and Safety track record of tenders and the ability of the contractor to perform the required work within the stipulated timeframe.

The EDB and ACL receive no benefits due to EA Networks ownership structure when transacting with each other.

Requirement 2.3.12 (1): A description of how the EDB applies its current policy for the procurement of assets or goods or services from a related party in practice.

The EDB uses normal commercial terms when transacting with ACL. No benefits are given to either party due to the ownership structure.

Requirement 2.3.12 (2): A description of any policies or procedures of the EDB that require or have the effect of requiring a consumer to purchase assets or goods or services from a related party that are related to the supply of the electricity distribution services.

The EDB has no policies or procedures requiring a consumer to purchase assets, goods, and/or services from ACL.

Requirement 2.3.12 (3): Subject to subclause (5), at least one representative example transaction from the disclosure year of how the current policy for the procurement of assets or goods or services from a related party is applied in practice.

On 21 December 2022, progress claim 2 was received related to the Holmes Road project (Job # 685699) for trenching and related works. This invoice was authorised for payment in accordance with the delegated authority policy and coded to the project.

Requirement 2.3.12 (4): For each representative example transaction specified in accordance with subclause (3), how and when the EDB last tested the arm's-length terms of those transactions.

EA Networks procured the services of ACL through the procurement process described below (Requirement 2.3.12(5)). A quote was received from both the approved civil contractors as part of the major works tender process. ACL was awarded the contract based on the materially lower quote price.

Requirement 2.3.12 (5): Separate representative example transactions where the EDB has applied the current policy for the procurement of assets or goods or services from a related party significantly differently between expenditure categories.

EA Networks has proactively applied the procurement policy at a macro level for civil contractors in response to workforce planning uncertainties and the compressed time frames to complete the capital works programme. Rather than tendering each individual project we tendered the non-minor works project collectively as an annual package. Approved civil contractors were invited to submit unit rates for non-minor works contracts (projects with a value greater than $50K).

Related party: EA Fibre

Due to its coverage EA Fibre is the preferred supplier of high-speed communications to the EDB. As EA Fibre is required to stand on its own feet, the EDB is charged for its services at a commercial rate. Currently there are no other high-speed communication networks which can supply the same level of services as EA Fibre supplies the EDB.

Requirement 2.3.10: A summary of EA Networks current policy in respect of the procurement of assets or goods or services from any related party.

EA Networks procurement policy allows high speed communication services to be purchased from anyone able to supply the required service. Currently there is only one supplier of rural fibre services within the EDB network area. The supplier is EA Fibre.

Requirement 2.3.12 (1): A description of how the EDB applies its current policy for the procurement of assets or goods or services from a related party in practice.

At the time of installing the fibre network, and is still the case, EA Fibre is only the supplier able to supply the required service. This means that EA Fibre is the agreed supplier for the high-speed communication network. Consistent with 'large users' of the fibre network the EDB has been charged a daily fee. The fee charged has been calculated using the same principles as another large user on the network.

Requirement 2.3.12 (2): A description of any policies or procedures of the EDB that require or have the effect of requiring a consumer to purchase assets or goods or services from a related party that are related to the supply of the electricity distribution services.

The EDB has no policies or procedures requiring a consumer to purchase assets or goods or services from EA Fibre.

Requirement 2.3.12 (3): Subject to subclause (5), at least one representative example transaction from the disclosure year of how the current policy for the procurement of assets or goods or services from a related party is applied in practice.

The EDB has a long-term financial lease with the fibre business. The present value of the financial lease was recorded in the RAB when the EDB adopted NZ IFRS 16, Leases. The EDB is required to pay an annual fee of $867k to EA Fibre.

Requirement 2.3.12 (4): For each representative example transaction specified in accordance with subclause (3), how and when the EDB last tested the arm's-length terms of those transactions.

There is no other rural supplier of a high-speed fibre networks servicing the Ashburton District to test EDB fibre charges against. As a proxy for realistic commercial return, we examined how another large consumer on the fibre Network's charge was determined and applied the same pricing principles against the EDB charge. The calculation of the EDB and other large users' charges are consistent.

Requirement 2.3.12 (5): Separate representative example transactions where the EDB has applied the current policy for the procurement of assets or goods or services from a related party significantly differently between expenditure categories.

There were no significant differences between expenditure categories.

Related party: Field Services

In formulating our procurement policy, we have considered our geographical location, supply standard required by our consumers and access to critical services during a network emergency. Having considered these key elements we have formed the view that an inhouse contracting service (Field Services) best meet the needs of our consumers/shareholders. Field Services has been sized to meet the daily and emergency requirements of the network, in a cost-effective manner. To this end work undertaken by Field Services is at cost.

Field Services supplies underground, overhead and technical services to the EDB

- The underground department install and maintain electricity distribution network assets located underground.
- The overhead department install and maintain electricity distribution network assets located above ground.
- Technical services undertake work associated with zone substations, protection and transformers.

Requirement 2.3.10: A summary of EA Networks current policy in respect of the procurement of assets or goods or services from any related party.

Our procurement policy requires that overhead, underground and substation work is undertaken by Field Services. If Field Services are unable to complete the work in question it is tendered out.

Work tendered out falls into one of two categories:

Minor works contract

For construction and maintenance work under $50k, associated with electricity and fibre distribution assets a minor tender rate card will be used. One or more contractors may appear on the minor tender rate card, which will be re-tendered every 18 months. Awarding of the minor works to a contractor will be determined on price, ability to meet forecast requirements, and work history of the contactor.

Non-minor works contract

For electricity contracting and maintenance work over $50k, the work will be tendered out. Evaluation of tenders will be based on the attributes set out in the tender documents and taking into consideration the Health and Safety track record of tenders and ability of the contractor to perform the required work within the stipulated timeframe.

Requirement 2.3.12 (1): A description of how the EDB applies its current policy for the procurement of assets or goods or services from a related party in practice.

All contracting work that Field Services can perform is discussed between Field Services and the EDB to identify the resources required to undertake the work. Where Field Services lack the required resources, the work is awarded under the minor works contract or tendered out.

Requirement 2.3.12 (2). A description of any policies or procedures of the EDB that require or have the effect of requiring a consumer to purchase assets or goods or services from a related party that are related to the supply of the electricity distribution services.

EA Networks has no policies requiring a consumer to purchase services from a related party.

Our capital contribution policy requires consumers to contribute to assets which EA Networks own. The customer is free to choose who undertakes any work on their property, provided that the person/entity undertaking the work is qualified to do so.

Consumers required to undertake tree work to protect the network, are free to choose from an approved contractor list.

Our notices to consumers notifying them of work required on their privately-owned networks, state that they are free to choose who undertakes the work.

Requirement 2.3.12 (3) subject to subclause (5), at least one representative example transaction from the disclosure year of how the current policy for the procurement of assets or goods or services from a related party is applied in practice.

A construction project that requires tendering out

Field Services – Project requiring a sub-contactor

Project 13185 : Camrose Estate Stage 10 & 11

1. This project was designed scoped by the EDB.
2. The Underground Manager created a number of work orders instructing Field Services to undertake the required scope of work, as shown below.

Work Order	Description	Stage
675117	Camrose 10&11 Network	Financially Complete
675120	Camrose 10&11 Streetlights	Approved
675121	Camrose 10&11 Fibre	Financially Complete
685699	Holmes Rd OHUG conversion	Financially Complete

3. Field services received the project from the EDB. Field Services General Manager and the Field Services Underground Manager identified that the project required a level of trenching which was outside their abilities.
4. Management of Field Services estimated that the required trenching was above the maximum value allowed under minor contracts and tendered the work using NZ/A33910 as the basis.
5. As described within the ACL section on page 7 EA Networks has proactively applied the procurement policy at a macro level for civil contractors. This contract was awarded under the non-minor works process.
6. Field Services undertook the balance of the required work, which was to install and commission the cable. Labour and plant costs associated with the project was booked to each task as they were incurred. Stock used by Field Services was booked out of the network store and onto the job as required.
7. At the end of each milestone the successful tender send EA Networks claims for work completed. For example: Claim Number 2, which was sent on EA Field Services on 22 December 2022 and paid in January 2023 under the terms of the contract.
8. At the completion of the project the transactions associated with the project were sent to the Underground Manager who reviewed them and approved the cost of the project.

Requirement 2.3.12 (4) for each representative example transaction specified in accordance with subclause (3), how and when the EDB last tested the arm's-length terms of those transactions.

Work undertaken by Field Services for the EDB is carried out at cost, with no internal profit being created.

How and when we have tested the arm's length terms:

Our budgeting process sets a rate card for Field Services work, which recovers their operating costs only. At the end of the year we reviewed internal work carried out by Field Services and determined that no profit was created from work undertaken for the EDB. During the year-end financial audit our auditors reviewed our internal profit calculation and confirmed that no material internal profit was created from internal transactions associated with Field Services.

The rate charged by Field Services for external work is calculated as the internal charge out rate + required markup rate for the job in question. This demonstrates that work charged to external parties incurs the same costs as work carried out for the EDB by Field Services.

In 2022 we tested the charge out rates of Field Services against other contractors which we had engaged. The results found that Field Services charge out rates were lower than the independent contractor.

As our testing of Field Services charge out rates with another contractor demonstrates, the price which Field Services charges the EDB is fair and reasonable.

Requirement 2.3.12 (5) separate representative example transactions where the EDB has applied the current policy for the procurement of assets or goods or services from a related party significantly differently between expenditure categories.

There were no significant differences between expenditure categories.

Related Party: Other Related Parties

Who is included in Other Related Parties and how is each a related party?

The purpose of Other Related Parties

Other related parties included where further information can be found on their website are:

- Orion is an EDB (https://www.oriongroup.co.nz)
- Cullimore Engineering (https://www.cullimore.co.nz)
- Electraserve (https://electraserve.co.nz)
- Newlands Group (https://www.newlands.net.nz/)
- Roger Sutton
- MHV Water (https://www.mhvwater.nz/)

Ability to control

The related parties above have no ability to control EA Networks.

Paul Munro is a director of Orion New Zealand Limited (appointed as Interim Chair on 1 April 2022, and chair on 31 August 2022) and has been a director of Electricity Ashburton Limited trading as EA Networks for the full year. Mr Munro's ability to control Orion New Zealand Limited is limited to that which a director would normally discharge their responsibilities.

Ian Cullimore is a director of Cullimore Engineering Limited and is a member of the EA Networks Shareholder Committee. Mr Cullimore's ability to control Cullimore Engineering Limited is limited to that which a director would normally discharge their responsibilities.

Alister Lilley is a director of ElectraServe Limited and is a member of the EA Networks Shareholder Committee. Mr Lilley's ability to control ElectraServe Limited is limited to that which a director would normally discharge their responsibilities.

Robert Newland is a director and shareholder of Newlands Group and is a member (appointed Chair from 1 September 2022) of the EA Networks Shareholders committee.

Roger Sutton is the CEO of EA Networks which is governed by the Board of Directors.

Cole Groves is a director of MHV Water and is a director of EA Networks.

Financial return to Other Related Parties from the EDB

For the disclosure year, Orion, Cullimore Engineering, Electraserve, Newlands Group, Roger Sutton and MHV Water received no financial benefits due to being a related party.

Requirement 2.3.10: A summary of EA Networks current policy in respect of the procurement of assets or goods or services from any related party.

Orion supplies load management services for all EDB's in the upper South Island. The cost associated with running the load management services is shared among the EDB's that use the service. We also paid Orion for their supply to our upper Rakaia embedded network.

Cullimore Engineering manufacture and supplied pole clamps during the year as a non-recurring purchase.

Electraserve provided emergency work relating to lighting and heat pump repairs to the EA Networks building therefore foregoing routing procurement procedures as per the procurement policy. Electraserve paid EA networks for connection fees and capital contributions during the year.

Newlands transactions largely relate to electrical repairs to a vehicle.

Roger Sutton had one transaction relating to the sale of a company vehicle. Third party quotes were sourced to ensure the sale price was at fair market value.

MHV Water had one transaction relating to co-location fees on an EA Networks zone substation. As this was income to EA Networks the transaction is unrelated to the procurement policy.

The EDB and Orion, Cullimore Engineering, Electraserve, Newlands, Roger Sutton and MHV Water receives no benefits when transacting with each other, due to the related party relationship.

Requirement 2.3.12 (1): A description of how the EDB applies its current policy for the procurement of assets or goods or services from a related party in practice.

The EDB uses normal commercial terms when transacting with Orion, Cullimore Engineering Limited, ElectraServe Limited, Newlands Group, Roger Sutton and MHV Water. No benefits are given to either party due to the ownership structure.

Requirement 2.3.12 (2): A description of any policies or procedures of the EDB that require or have the effect of requiring a consumer to purchase assets or goods or services from a related party that are related to the supply of the electricity distribution services.

The EDB has no policies or procedures requiring a consumer to purchase assets, goods, and/or services from Orion, Cullimore Engineering Limited, ElectraServe Limited, Newlands Group, Roger Sutton or MHV Water.

Requirement 2.3.12 (3): Subject to subclause (5), at least one representative example transaction from the disclosure year of how the current policy for the procurement of assets or goods or services from a related party is applied in practice.

EA Networks received in February 2023 an invoice, NO18414, for delivery charges relating to February and associated wash-up months. This invoice was authorised for payment in accordance with the delegated authority policy and coded to operating costs. The invoice was paid on 20 March 2023.

Requirement 2.3.12 (4): For each representative example transaction specified in accordance with subclause (3), how and when the EDB last tested the arm's-length terms of those transactions.

The service supplied by Orion is not offered by any-other service provider. As a result, we are unable to carry out market testing. EA Networks has a contract in place with Orion, governing the calculation of charges, this contract was put in place before Orion became a related party.

Requirement 2.3.12 (5): Separate representative example transactions where the EDB has applied the current policy for the procurement of assets or goods or services from a related party significantly differently between expenditure categories.

The Services provided by Orion are outside of the scope of the procurement policy.

Schedule 18 Certification for Year-end Disclosures

Clause 2.9.2

We, Andrew David Barlass, and Paul Jason Munro being directors of Electricity Ashburton t/a EA Networks 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; and

b) the historical information used in the preparation of Schedules 8, 9a, 9b, 9c, 9d, 9e, 10, and 14 has been properly extracted from the EA Networks accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained.

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.

Andrew David Barlass
16 August 2023

Paul Jason Munro
16 August 2023

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Map of Anticipated Network Expenditure and Network Constraints

As required by sections 2.3.13 - 2.3.16 the following text details the projects/programmes that represent the largest forecast operational and capital expenditure and the network/equipment constraints that could be addressed by the projects/programmes.

The map is intended to be used in digital form and contains layers that relate to some of the items detailed below. In paper printed form, the map will be very difficult to interpret.

10 Largest (by Value) Operational Projects/Programmes

ID	Name	Description	Timing	Average Value ($)	Location
(OA) 12003	Overhead Repairs to Restore Power	The immediate work required after a fault has occurred on all voltages of the overhead network to restore supply to all affected consumers.	2024-2033	1 154k p.a.	All Line Locations (Map inset)
(OB) * 12024	Inspecting, Organising and Trimming Trees	The inspection of trees, the liaison with tree owners and the subsequent trimming or felling of trees which are considered be a risk to the electricity network.	2024-2033	831k p.a.	All Line Locations (Map inset)
(OF) 12002	Overhead Planned Repairs & Maintenance	Scheduled maintenance of overhead line assets of all voltages. Generally, a consequence of inspections revealing an issue more widespread than a single structure. Work is normally planned the prior year.	2024-2033	528k p.a.	All OH Line Locations (Map inset)
(OC) 11998	ZSS Asset Inspection, Testing & Minor Maintenance	The inspection of zone substation assets, routine testing of those assets, and minor maintenance that arises as an immediate result of those inspections and tests.	2024-2033	368k p.a.	***Zone Substations*** Layer
(OE) 12018	DSS & D Switchgear Planned Maintenance	The planned maintenance of all types of distribution substations and distribution switchgear. Includes ring main units, pole-mounted switches and circuit-breakers, kiosks, and LV switchgear within the kiosks.	2024-2033	273k p.a.	All Distribution Substation Locations
(OG) 12018	Distribution Transformer Refurbishment	When distribution transformers are recovered from service for whatever reason they are inspected and where necessary refurbished to allow continued service at another substation.	2024-2033	183k p.a.	***EA Networks HQ*** Layer

(OD) 12001	**Overhead Inspection, Testing and Minor Maintenance**	The inspection, testing and minor maintenance of overhead line assets of all voltages.	2024-2033	173k p.a.	All OH Line Locations (Map inset)
(OI) 12019	**D Substation & D Switchgear Repairs to Restore Power**	The immediate work required after a fault has occurred on distribution substations and distribution switchgear to restore supply to all affected consumers.	2024-2033	151k p.a.	All Locations
(OH) 12017	**D Substation and D Switchgear Inspection, Testing and Minor Maintenance**	The inspection of distribution substation and distribution transformer assets, routine testing of those assets, and minor maintenance that arises because of those inspections and tests.	2024-2033	138k p.a.	Substations & Workshop
(OJ) 12015	**ZSS Asset Planned Repairs & Maintenance**	Scheduled maintenance of assets within the zone substations. Generally, a consequence of inspections revealing an issue that is not readily resolved during the inspection process and requires additional parts or resources to complete.	2024-2033	133k p.a.	***Zone Substations*** Layer

Few of the items described above have specific locations that can be readily mapped. Zone substations (**OC** - 11998, **OJ** - 12015) are shown explicitly on the map and are on their own layer (as are the zone substation names).

Note that the Average Value detailed in the table is an annual average value for the years that expenditure occurs and not an average value over the entire duration of the project or programme.

The operational expenditure projects/programmes identified above:

Status	Situation
Are not	already subject to a contract. ***** OB (tree work) is currently subject to a non-exclusive agreed rates contract with an unrelated party.
Are	forecast to require the supply of assets or goods or services by a related party. ***** OB (tree work) is forecast to be competitively tendered beyond 2024 to an unrelated party.
Are	currently indicated for supply by a related party.

10 Largest (by Value) Capital Projects/Programmes

ID	Name	Description	Timing	Average Value ($)	Location
(A) 11136, 11058, 11172	Consumer Connection	The addition or modification of assets of all voltages that relate to connecting new or increased loads to the electricity network. This can be the addition of a fuse to a pillar box or the construction of significant 11 kV or 22 kV assets to service a large industrial load or subdivision. These loads appear without advance notice on most occasions.	2024-2033	3 781k p.a.	All Locations
(D) 11704, 11079, 11078, 11059	Unscheduled Projects	This programme of work is to accommodate the unexpected or unscheduled projects that occur when additional information about condition or constraints becomes known. The largest component of this value is the overhead line rebuilds beyond 2024. The likely rebuild candidates have been grouped but not scheduled at this stage.	2024-2033	1 987k p.a.	Predominantly Rural
(B) Various	Urban Underground Conversion	As overhead lines in urban areas reach the end of their useful life, the network is replaced with underground cabling and ground-mounted substations. Multiple projects per year are completed and, on average, sum to the amount identified. This programme of work is due for completion in 2029.	2024-2029	1 748 p.a.	Urban Areas Identified on Map
(C) 700, 701	Decarbonisation & Smart Technologies	Decarbonisation will require additional capacity in various places, but few industries have committed to it. The need to gather additional information on the electrical network and then provide assets that can react to compensate for rapid changes in load or power flow direction are covered by this programme. The initial phases allow for ICP-level metering, control, and communication. This will permit the network to dynamically interact with loads and generators to ensure a stable supply to all consumers. Additional assets, such as control software, batteries, and dynamic VAr compensation are allowed for in later phases of the programme.	2024-2033	1 672k p.a.	All Locations
(J) Various	Rural Underground Conversion	The State Highway network in Mid-Canterbury are high traffic volume routes that have historically had a high number of serious crashes on them. A number of these crashes have involved roadside poles and some of these have been fatal. In conjunction with the NZTA, EA Networks have been replacing end-of-	2024-2025	1 318k p.a.	Largely Ashburton-Methven Highway.

		life overhead distribution lines with underground cable on these routes. The projects included in this programme are mostly on Methven Highway.			
(G) Various	**Subtransmission Lines**	This programme includes new 66kV subtransmission lines being necessary if a second GXP is required.	2030-2031	1 275k p.a.	Rural
(E) Various	**Overhead Line Rebuild**	Known, condition-based overhead line rebuilds of all voltages are included in this category. There is a pool of lines that are becoming candidates for rebuilding (post 2024) but they are yet to be scheduled and therefore not in this category (they are in the D category above).	2024-2033	1 062k p.a.	Rural Line Locations (Map inset)
(F) Various	**Distribution Transformers**	New distribution transformers are required for new or increased load and conversion from 11 kV to 22 kV. The 11 kV to 22 kV conversion work forms a significant proportion of this value and after 2028 will decline significantly.	2024-2033	897k p.a.	All Locations
(H) 12470, & Others	**Ashburton 11kV Core Network**	This programme is for additional reliability, resilience, capacity and security within the Ashburton township urban area. It consists of a series of high capacity 11 kV circuits interconnecting zone substations with network centres (circuit-breaker switchboards) which have multiple feeders radiating from them. The goal is to reduce ICP count per feeder circuit-breaker to less than 250 while increasing network resilience to multiple failures.	2025-2031	841k p.a.	Ashburton Township - *Core Network* Layers
(I) Various	**Non-Network**	Any new or upgraded assets that support the electricity business but are not conducting electricity for supply as part of the distribution network. Examples of Non-Network costs are ICT infrastructure, clothing, buildings, phones, software, vehicles, tools, etc.	2024-2033	426k p.a.	Predominantly *EA Networks HQ* Layer

Not all programmes have specific physical locations that can be readily shown on a map. Those programmes that can be located have been allocated a layer in the pdf document and this can be turned on and off to highlight the location(s) involved.

The capital expenditure projects/programmes identified above:

Status	Situation
Are not	already subject to a contract.
Are	forecast to require the supply of assets or goods or services by a related party.
Are	currently indicated for supply by a related party.

Network or Equipment Constraints Involving Large Operational and/or Capital Projects/Programmes

ID	Name	Description	Project Response	Location
1	Inter-Zone Substation Load Transfer	When operating the distribution network at 11 kV, the ability to transfer load between zone substations (such as during a feeder fault near the start of a feeder) is limited by voltage drop in rural areas and cable capacity in urban areas.	(H), (E) & Others (some not listed above)	*11-22kV Conversion* Layer and *Core Network* Layers
2	Zone Substation Transformer Failure	The failure of a zone substation transformer will either interrupt supply or limit capacity to n-1 levels. Both situations require additional capacity from adjacent zone substations to supply the load that cannot be served from the zone substation with the failed transformer. The availability of an urban Ashburton core 11 kV network and a 22 kV rural network provide this facility while a spare transformer is installed. Some general zone substation work also provides more transformation capacity e.g. a solar farm.	(H), (E), (I) & Others (some not listed above)	*11-22kV Conversion* Layer, *Core Network* Layers, *and Zone Substations* Layer.
3	Sub-transmission Circuit Failure	Loss of a single 66 kV circuit will generally not result in loss of supply. It can however cause lower than ideal sub-transmission voltages and the ability to transfer load at 22 kV or 11 kV is beneficial. Loss of more than one 66 kV circuit (or a single radial 33 kV or 66 kV circuit) will potentially cause loss of supply. These scenarios can be mitigated with additional inter-zone substation transfer capacity or additional subtransmission circuits.	(G), (H) & Others (some not listed above)	*11-22kV Conversion* Layer and *Core Network* Layers
4	Civil Infrastructure Support Failure	During seismic and flooding events, the failure of civil infrastructure such as bridges and roads can cause failure of portions of the electrical network. Additional electrical network paths and capacity can help mitigate this to some degree. Well maintained or new assets also resist these forces better than older assets.	(H), (E), & Others (some not listed above)	*11-22kV Conversion* Layer and *Core Network* Layers. Much of the rural area.
5	Urban 11kV Capacity	The interconnected radial design of the existing Ashburton 11 kV underground network is essentially a traditional overhead line configuration that has served well for several decades. The loading of a number of these circuits is close to reaching full capacity and during faults back-feeding can cause slight overload situations. The addition of a layer of larger 11 kV cables that connect to network switching centres and interconnection to the rural 22 kV network during 11 kV cable faults	(B), (H) & Others (some not listed above)	*Urban UG Conversion* Layer, *11-22kV Conversion* Layer and *Core Network* Layers.

		provides both steady state and contingency capacity to alleviate these limitations.		
6	**Urban 11kV ICP Count/Feeder**	The number of connections per urban 11 kV feeder exceeds the limit set in the EA Networks security standard (some by a large amount). To reduce this to the required level, additional feeders are needed so that for a single cable fault only a limited number of consumers experience the outage. Adding additional feeders to the zone substations would require excessive amounts of cabling to reach the ICPs as well as extensive zone substation rework. The alternative of large core network 11 kV cables connected in closed rings via network centres (new switchboards with additional feeders within the urban network) is a high benefit/value practical solution and advantageous for other constraints as well.	**(B)** & **(H)**	***Urban UG Conversion*** Layer and ***Core Network*** Layers.
7	**GXP Firm Capacity Exceeded**	If a time arises that demand on the Ashburton 220/66 kV grid exit point exceeds the 220 MVA firm capacity for an unacceptable length of time each year, then an additional GXP will be required. At this point in time, it seems to be less likely this will occur within the 10 year AMP planning period. There are projects included within the AMP (towards the end of the planning period) that address this potential eventuality. A second GXP comes with overall capacity benefits but does provide several technical and operational disadvantages that are not apparent with one GXP.	**(G)** & **(I)**	Predominantly Located in Rural Areas. Network-wide impacts.
8	**Low Voltage Network Capacity**	The addition of new or increased load or generation will cause the capacity of LV (low voltage) networks to be tested and in some cases exceeded. The location and timing of this new load on existing cables is unknown. To remedy this, additional LV cables and/or distribution substations will be required. Careful load management using demand management control devices will be able to assist in shifting some of the peak demand, but at some stage additional network assets will still be required.	**(A)**, **(B)**, **(C)**, **(D)**, & **(F)**	Urban Areas.
9	**Asset Condition - Potential Failure**	All assets deteriorate over time and it is critical to proactively manage the asset's condition to ensure it does not fail unexpectedly or catastrophically before it is removed from service at end-of-life. Prudent maintenance strategies ensure that inspections, testing, and either refurbishment or replacement occur in a timely and safe manner.	**(OA)-(OJ)**, **(B)**, **(D)**, **(E)**, & **(J)**	All Locations - Network-wide.

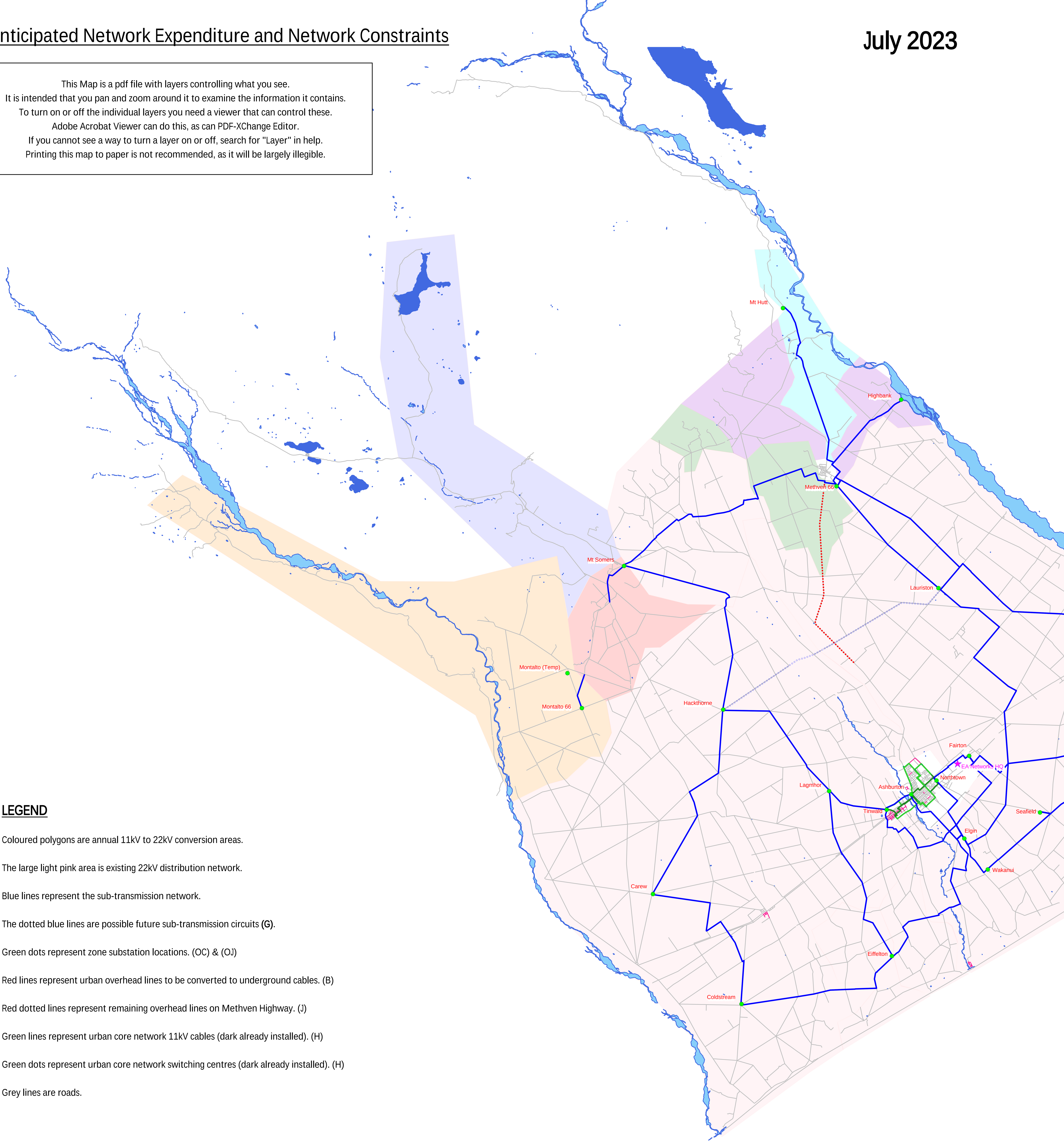
		All the operational expenditure programmes/projects identified above are in some way contributing to the safe and reliable operation of the electricity network – ensuring any failures that do occur are largely unforeseeable or uneconomical to completely mitigate against.		
10	Network Resilience	In order to maintain and increase network resilience there must be both effective maintenance of existing assets to prevent failure in adverse conditions (such as the alpine fault rupturing) and improved/additional assets to assist in recovery from adverse events. All of the projects/programmes identified above contribute in large and small ways to increasing the resilience of the EA Networks electricity network. This ranges from more modern design standards for replacement poles to additional alternative network paths should the primary one be unavailable.	(OA)-(OJ) & (A)-(J)	All Locations - Network-wide.

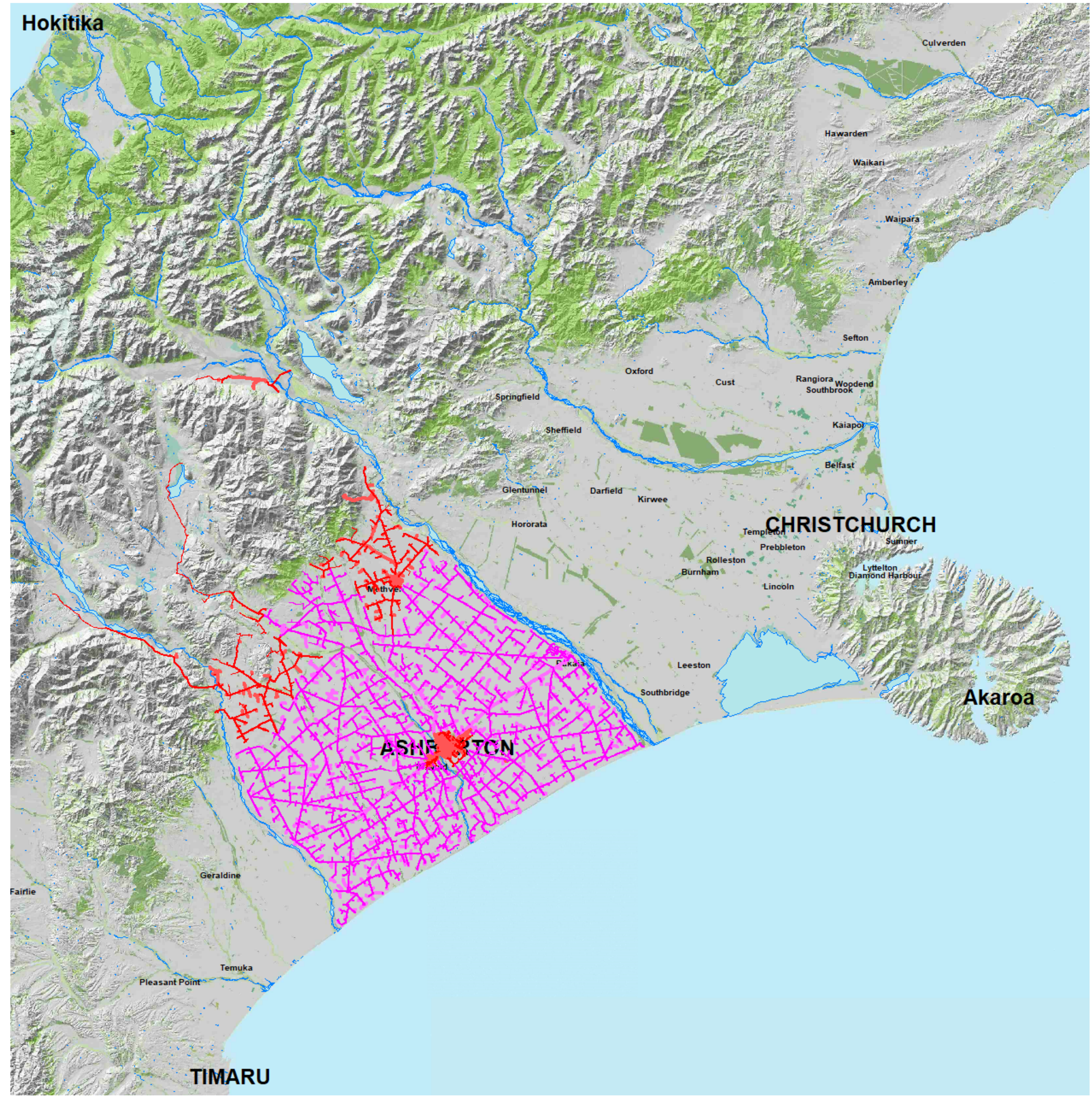
The constraints detailed above are either explicitly identified in the asset management plan or are alluded to in network development project/programme justifications.

Map of Anticipated Network Expenditure and Network Constraints

July 2023

This Map is a pdf file with layers controlling what you see.
It is intended that you pan and zoom around it to examine the information it contains.
To turn on or off the individual layers you need a viewer that can control these.
Adobe Acrobat Viewer can do this, as can PDF-XChange Editor.
If you cannot see a way to turn a layer on or off, search for "Layer" in help.
Printing this map to paper is not recommended, as it will be largely illegible.





Inset showing EA Networks' location in New Zealand context with 22kV (magenta) and 11kV (red) distribution network.
(OA), (OB), (OD), (OF), (OI), (OH), (A), (C), (E), (F),& (G)

LEGEND

- Coloured polygons are annual 11kV to 22kV conversion areas.
- The large light pink area is existing 22kV distribution network.
- Blue lines represent the sub-transmission network.
- The dotted blue lines are possible future sub-transmission circuits **(G)**.
- Green dots represent zone substation locations. (OC) & (OJ)
- Red lines represent urban overhead lines to be converted to underground cables. (B)
- Red dotted lines represent remaining overhead lines on Methven Highway. (J)
- Green lines represent urban core network 11kV cables (dark already installed). (H)
- Green dots represent urban core network switching centres (dark already installed). (H)
- Grey lines are roads.

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Independent Assurance Report

To the Directors of Electricity Ashburton Limited and the Commerce Commission

Assurance report pursuant to Electricity Distribution Information Disclosure Determination 2012 (Consolidated 6 July 2023)

We have completed the reasonable assurance engagement in respect of the compliance of Electricity Ashburton Limited (the "Company") with the Electricity Distribution Information Disclosure Determination 2012 (consolidated 6 July 2023) (the 'Determination') for the disclosure year ended 31 March 2023 where we are required to opine on:

- whether the Company has complied, in all material respects, with the Determination, in preparing the information disclosed under schedules 1 to 4, 5a to 5g, 6a and 6b, 7, 10, the related party transactions information disclosed in Appendix A, and the explanatory notes disclosed in boxes 1 to 11 in Schedule 14 ('the Disclosure Information'); and
- whether the Company's basis for valuation of related party transactions ('valuation of related party transactions'), has complied, in all material respects, with 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').

This assurance report should be read in conjunction with the Commerce Commission's Information Disclosure exemption, issued to all electricity distribution businesses on 26 May 2023 under clause 2.11 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 of them, 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 and has been sourced, where appropriate, 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 13 of Schedule 14, there are inherent limitations in the ability of the Company to collect and record the network reliability information specifically the installation control points ('ICP's') affected by an interruption and the duration of the interruption used in calculating the amounts required to be disclosed in Schedules 10(i) to 10(iv). Consequently, there is no independent evidence available to support the accuracy of the ICP's affected and duration of an interruption. Controls over the accuracy of ICP and interruption data included in the SAIDI and SAIFI outage statistics are limited throughout the year.

There are no practical audit procedures that we could adopt to independently confirm the accuracy of the ICP data used to record the number of ICP's affected and duration of the interruption for the purposes of inclusion in the amounts relating to SAIDI and SAIFI outage statistics set out in Schedules 10(i) to 10(iv).

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Because of the potential effect of the limitations described above, we are unable to form an opinion as to the accuracy and completeness of the data that forms the basis of the compilation of Schedules 10(i) to 10(iv). In this respect alone we have not obtained all the recorded evidence and explanations that we have required.

We have conducted our engagement in accordance with the Standard on Assurance Engagements (SAE) 3100 (Revised) *Compliance Engagements* ("SAE 3100 (Revised)"), issued by the New Zealand Auditing and Assurance Standards Board. An engagement conducted in accordance with SAE (NZ) 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 explanations that we required to provide a basis for our qualified opinion.

Our assurance approach

Overview

Our assurance engagement is designed to obtain reasonable assurance about the Company's compliance, in all material respects, with the Determination and IM Determination.

Quantitative materiality levels are determined for testing purposes within individual schedules included in the Disclosure Information based on the nature of the information set out in the schedules. These thresholds are determined based on our assessment of errors that could have a material impact on key measures within the Disclosure Information:

- Financial information – any impact resulting in +/-100 basis points of the Return of Investment ('ROI')
- Performance based schedules – 5% of non-financial measures
- Related party transactions – 2% of total related party transactions.

When assessing overall material compliance with the Determination, qualitative factors are considered such as the combined impact on ROI and other key measures as well as assessing the arm's length valuation rules on related party transactions, which may impact on users assessment on whether the purpose of Part 4 of the Commerce Act 1986 has been met.

We have determined that there are three key assurance matters:

- Regulatory Asset Base
- Cost and Asset Allocation
- Related Party Transactions

Materiality

The scope of our assurance engagement was influenced by our application of materiality.

Based on our professional judgement, we determined certain quantitative thresholds for materiality. These, together with qualitative considerations, helped us to determine the scope of our assurance engagement, the nature, timing and extent of our assurance procedures and to evaluate the effect of misstatements, both individually and in aggregate on the Disclosure Information as a whole.

Scope
Our procedures included analytical procedures, evaluating the appropriateness of assumptions used and whether they have been consistently applied, agreement of the Disclosure Information to, or reconciling with, source systems and underlying records, an assessment of the significant judgements made by the Company in the preparation of the Disclosure Information and valuing the related party transactions, and evaluation of the overall adequacy of the presentation of supporting information and explanations.

These procedures have been undertaken to form an opinion as to whether the Company has complied, in all material respects, with the Determination in the preparation of the Disclosure Information for the year ended 31 March 2023, and whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

Key Assurance Matters
Key assurance matters are those matters that, in our professional judgement, were of most significance in carrying out the assurance engagement during the current disclosure year. These matters were addressed in the context of our assurance engagement as a whole, and in forming our opinion. We do not provide a separate opinion on these matters. In addition to the matter described in the Basis of Qualified Opinion section of our report, we have determined the matters described below to be Key Assurance Matters.

<table>
<tr><th>Key Assurance Matter</th><th>How our procedures addressed the key assurance matter</th></tr>
<tr><td>

Regulatory asset base
The Regulatory Asset Base (RAB), as set out in Schedule 4, reflects the value of Electricity Ashburton Limited'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 Electricity Ashburton Limited'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.

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We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Determination and the IM Determination.

Our procedures over the regulatory asset base included the following:

Assets commissioned

- 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 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; and
- We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification.

Depreciation

- 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 have performed a reasonableness test to ensure regulatory depreciation expense is calculated in line with IM Determination clause 2.2.5;
- We compared the spreadsheet formula utilised to calculate regulatory depreciation expense with IM Determination clause 2.2.5; and

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</table>

Key Assurance Matter	How our procedures addressed the key assurance matter
	• We compared the standard asset lives by asset category to those set out in the IM Determination. **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; and • We tested the mathematical accuracy of the revaluation calculation performed by management. **Disposals** • We reconciled the disposals, as per the regulatory fixed asset register, to the asset disposals disclosed in the audited annual financial statements and investigated any material reconciling items; and • We inspected the asset disposals within the accounting fixed asset register to ensure disposals in the RAB meet the definition of a disposal per the IMs;
Cost and Asset Allocation The Determination relates to information concerning the supply of electricity distribution services. In addition to the regulated supply of electricity, Electricity Ashburton Limited 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. Electricity Ashburton Limited has applied the Accounting-Based Allocation Approach Methodology (ABAA) utilising proxy cost and asset	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 statements; **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, as amended; • 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, as amended, 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 causal and proxy allocators used in applying the ABAA to not directly attributable costs including inspecting supporting documentation and recalculating proxy allocators;

Key Assurance Matter	How our procedures addressed the key assurance matter
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.	● Understanding why causal relationships could not be identified in allocating some 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.
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. Electricity Ashburton Limited applies the consolidation (or cost-based) approach for demonstrating	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. Our procedures over the related party transactions included the following: **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 the audited financial statements for the year ended 31 March 2023 and to the accounting records, investigating any material differences and determining whether any such differences are justified; and ● 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 inquired with management and applied our understanding of the business to identify the types of transactions accounted for under the consolidation approach, and; ● Agreed the values of those transactions disclosed in Schedule 5(b) to those accounted for after elimination of intercompany profit within Electricity Ashburton Limited's audited financial statements; and ● Considered whether the costs incurred from related parties, under the consolidation approach, were fair and

Key Assurance Matter	How our procedures addressed the key assurance matter
compliance with the general valuation principles under the Determination and the IMs. The determinations presume that where the transaction is valued at the cost normally incurred by the related party, and provided this is fair and reasonable, it may be treated as if it was an arm's length transaction under the consolidation approach (i.e. no profit margin included). For those transactions where the consolidation approach is not applied Electricity Ashburton Limited 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.	reasonable by testing controls around the approval of expenses on a sample basis. For those related party transactions not accounted for under the consolidation approach, we obtained Electricity Ashburton Limited's assessment of the available independent and objective measures used in supporting the arm's length valuation principle and re-performed the calculations and agreed key inputs and assumptions to supporting documentation for a sample of transactions.

Directors Responsibilities

The Directors are responsible on behalf of the Company for compliance with the Determination and the valuation of related party transactions in accordance with the Determination, for the identification of risks that may threaten such compliance, controls that would mitigate those risks, and monitoring the Company's ongoing compliance.

Our Independence and Quality Control

We have complied with the Professional and Ethical Standard 1 *International Code of Ethics for Assurance Practitioners (including International Independence Standards) (New Zealand)* or other professional requirements, or requirements in law or regulation, that are at least as demanding, which include independence and other requirements founded on the fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behaviour.

In accordance with the Professional and Ethical Standard 3 (Amended) *Quality Control for Firms that Perform Audits and Reviews of Financial Statements, and Other Assurance Engagements* or other professional requirements, or requirements in law or regulation, that are at least as demanding, our firm maintains a comprehensive system of quality control including documented policies and procedures regarding compliance with ethical requirements, professional standards, and applicable legal and regulatory requirements.

We are independent of the Company. Our firm carries out other services for the Company in the areas of the annual audit of the Company's financial statements and assurance over compliance with regulatory requirements of the Commerce Act 1986. In addition, certain partners and employees of our firm may deal with the Company on normal terms within the ordinary course of trading activities of the Company. The provision of these other services has not impaired our independence.

Assurance Practitioner's responsibilities

Our responsibility is to express an opinion on whether the Company has complied, in all material respects, with the Determination in the preparation of the Disclosure Information for the disclosure year ended 31 March 2023 and on whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

Our engagement has been conducted in accordance with ISAE (NZ) 3000 (Revised) and SAE 3100 (Revised) which require that we plan and perform our procedures to obtain reasonable assurance about whether the Company has complied in all material respects with the Determination in the preparation of the Disclosure Information for the disclosure year ended 31 March 2023, and whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

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

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 may occur and not be detected. A reasonable assurance engagement for the disclosure year ended 31 March 2023 does not provide assurance on whether compliance with the Determination and the IM Determination will continue in the future.

Use of Report

This report has been prepared for the Directors and the Commerce Commission in accordance with clause 2.8.1(1) of the Determination and is provided solely to assist you in establishing that compliance requirements have been met

Our report should not be used for any other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility for any reliance on this report to anyone other than the Directors of the Company, as a body, and the Commerce Commission, or for any purpose other than that for which it was prepared.

The engagement partner on the assurance engagement resulting in this independent auditor's report is Elizabeth Adriana (Adri) Smit.

PricewaterhouseCoopers.

Chartered Accountants
18 August 2023

Christchurch, New Zealand