COMMERCE COMMISSION NEW ZEALAND

EDB Information Disclosure Requirements
Information Templates
for
Schedules 1–10

Company Name	Eastland Network
Disclosure Date	31 March 2020
Disclosure Year (year ended)	31 March 2020

Templates for Schedules 1–10 excluding 5f–5g

Template Version 4.1. Prepared 21 December 2017

Table of Contents

Disclosure Template Instructions

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

Company Name and Dates

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

Data Entry Cells and Calculated Cells

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

Validation Settings on Data Entry Cells

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

Conditional Formatting Settings on Data Entry Cells

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

Inserting Additional Rows and Columns

The templates for schedules 4, 5b, 5c, 5d, 5e, 6a, 8, 9d, and 9e may require additional rows to be inserted in tables marked 'include additional rows if needed' or similar. Column A schedule references should not be entered in additional rows, and should be deleted from additional rows that are created by copying and pasting rows that have schedule references.
Additional rows in schedules 5c, 6a, and 9e must not be inserted directly above the first row or below the last row of a table. This is to ensure that entries made in the new row are included in the totals.
Schedules 5d and 5e may require new cost or asset category rows to be inserted in allocation change tables 5d(iii) and 5e(ii). Accordingly, cell protection has been removed from rows 77 and 78 of the respective templates to allow blocks of rows to be copied. The four steps to add new cost category rows to table 5d(iii) are: Select Excel rows 69:77, copy, select Excel row 78, insert copied cells. Similarly, for table 5e(ii): Select Excel rows 70:78, copy, select Excel row 79, then insert copied cells.

The template for schedule 8 may require additional columns to be inserted between column P and U. To avoid interfering with the title block entries, these should be inserted to the left of column S. If inserting additional columns, the formulas for standard consumers total, non-standard consumers totals and total for all consumers will need to be copied into the cells of the added columns. The formulas can be found in the equivalent cells of the existing columns.

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

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

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

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

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

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**

SCHEDULE 1: ANALYTICAL RATIOS

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

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

sch ref

7 **1(i): Expenditure metrics**

sch ref		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)
8						
9	**Operational expenditure**	40,266	444	192,262	2,883	51,736
10	Network	18,012	198	86,004	1,289	23,143
11	Non-network	22,254	245	106,259	1,593	28,593
12						
13	**Expenditure on assets**	31,892	351	152,275	2,283	40,976
14	Network	31,104	343	148,514	2,227	39,964
15	Non-network	788	9	3,761	56	1,012
16						

17 **1(ii): Revenue metrics**

sch ref		Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
18			
19	**Total consumer line charge revenue**	133,417	1,470
20	Standard consumer line charge revenue	133,417	1,470
21	Non-standard consumer line charge revenue	–	–
22			

23 **1(iii): Service intensity measures**

sch ref			
24			
25	Demand density	15	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	72	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
27	Connection point density	6	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
28	Energy intensity	11,017	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*
29			

30 **1(iv): Composition of regulatory income**

sch ref		($000)	% of revenue
31			
32	Operational expenditure	11,382	29.72%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	6,711	17.52%
34	Total depreciation	6,248	16.32%
35	Total revaluations	4,044	10.56%
36	Regulatory tax allowance	4,058	10.60%
37	Regulatory profit/(loss) including financial incentives and wash-ups	13,941	36.40%
38	**Total regulatory income**	38,296	
39			

40 **1(v): Reliability**

sch ref			
41			
42	Interruption rate	14.08	*Interruptions per 100 circuit km*

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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

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

sch ref			CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**				
8			**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
9	**ROI – comparable to a post tax WACC**		**%**	**%**	**%**
10		Reflecting all revenue earned	8.02%	7.83%	8.67%
11		Excluding revenue earned from financial incentives	5.98%	6.03%	6.81%
12		Excluding revenue earned from financial incentives and wash-ups	6.07%	6.13%	6.90%
13					
14		**Mid-point estimate of post tax WACC**	5.04%	4.75%	4.27%
15		25th percentile estimate	4.36%	4.07%	3.59%
16		75th percentile estimate	5.72%	5.43%	4.95%
17					
18					
19	**ROI – comparable to a vanilla WACC**				
20		Reflecting all revenue earned	8.61%	8.34%	9.10%
21		Excluding revenue earned from financial incentives	6.57%	6.54%	7.23%
22		Excluding revenue earned from financial incentives and wash-ups	6.66%	6.64%	7.33%
23					
24		**WACC rate used to set regulatory price path**	7.19%	7.19%	7.19%
25					
26		**Mid-point estimate of vanilla WACC**	5.60%	5.26%	4.69%
27		25th percentile estimate	4.92%	4.58%	4.01%
28		75th percentile estimate	6.29%	5.94%	5.37%
29					
30	**2(ii): Information Supporting the ROI**			**($000)**	
31					
32		Total opening RAB value	161,678		
33	*plus*	Opening deferred tax	(8,000)		
34	**Opening RIV**			153,678	
35					
36	**Line charge revenue**			37,712	
37					
38		Expenses cash outflow	18,093		
39	*add*	Assets commissioned	8,529		
40	*less*	Asset disposals	–		
41	*add*	Tax payments	3,693		
42	*less*	Other regulated income	584		
43	**Mid-year net cash outflows**			29,731	
44					
45	**Term credit spread differential allowance**			–	
46					
47		Total closing RAB value	166,070		
48	*less*	Adjustment resulting from asset allocation	(1,931)		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(8,365)		
51	**Closing RIV**			159,637	
52					
53	**ROI – comparable to a vanilla WACC**				9.10%
54					
55		Leverage (%)			42%
56		Cost of debt assumption (%)			3.61%
57		Corporate tax rate (%)			28%
58					
59	**ROI – comparable to a post tax WACC**				8.67%
60					

Company Name	**Eastland Network**
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SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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

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

sch ref

2(iii): Information Supporting the Monthly ROI

Opening RIV	N/A

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

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

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

Year-end ROI – comparable to a vanilla WACC	6.50%
Year-end ROI – comparable to a post tax WACC	6.08%

** 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	–	
Purchased assets – avoided transmission charge	3,746	
Energy efficiency and demand incentive allowance		
Quality incentive adjustment	125	
Other financial incentives		
Financial incentives		3,871
Impact of financial incentives on ROI		1.87%
Input methodology claw-back		
CPP application recoverable costs		
Catastrophic event allowance		
Capex wash-up adjustment	(199)	
Transmission asset wash-up adjustment		
2013–15 NPV wash-up allowance		
Reconsideration event allowance		
Other wash-ups		
Wash-up costs		(199)
Impact of wash-up costs on ROI		–0.10%

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

sch ref

				($000)
7	**3(i): Regulatory Profit**			
8		**Income**		
9			Line charge revenue	37,712
10	*plus*		Gains / (losses) on asset disposals	
11	*plus*		Other regulated income (other than gains / (losses) on asset disposals)	584
12				
13		**Total regulatory income**		38,296
14		**Expenses**		
15	*less*		Operational expenditure	11,382
16				
17	*less*		Pass-through and recoverable costs excluding financial incentives and wash-ups	6,711
18				
19		**Operating surplus / (deficit)**		20,203
20				
21	*less*		Total depreciation	6,248
22				
23	*plus*		Total revaluations	4,044
24				
25		**Regulatory profit / (loss) before tax**		17,999
26				
27	*less*		Term credit spread differential allowance	–
28				
29	*less*		Regulatory tax allowance	4,058
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		13,941
32				

			($000)	
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**			
34	**Pass through costs**			
35		Rates	272	
36		Commerce Act levies	60	
37		Industry levies	73	
38		CPP specified pass through costs	–	
39	**Recoverable costs excluding financial incentives and wash-ups**			
40		Electricity lines service charge payable to Transpower	5,787	
41		Transpower new investment contract charges	89	
42		System operator services	–	
43		Distributed generation allowance	430	
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**			6,711
47				

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

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

sch ref				
48	**3(iii): Incremental Rolling Incentive Scheme**		**($000)**	
49			**CY-1**	**CY**
50			**31 Mar 19**	**31 Mar 20**
51	Allowed controllable opex			
52	Actual controllable opex			
53				
54	Incremental change in year			
55				
56			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
57	CY-5	31 Mar 15		
58	CY-4	31 Mar 16		
59	CY-3	31 Mar 17		
60	CY-2	31 Mar 18		
61	CY-1	31 Mar 19		
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	**Eastland Network**
For Year Ended	**31 March 2020**

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

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

sch ref

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

	RAB	RAB	RAB	RAB	RAB
for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
	($000)	**($000)**	**($000)**	**($000)**	**($000)**
Total opening RAB value	139,164	140,586	151,867	154,613	161,678
less **Total depreciation**	5,667	6,307	5,692	6,089	6,248
plus **Total revaluations**	815	3,020	1,665	2,288	4,044
plus **Assets commissioned**	6,363	7,724	7,061	11,756	8,529
less **Asset disposals**	89	313	289	162	–
plus **Lost and found assets adjustment**	–	–	–	–	–
plus **Adjustment resulting from asset allocation**	–	7,158	(0)	(728)	(1,931)
Total closing RAB value	140,586	151,867	154,613	161,678	166,070

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB *		RAB	
	($000)	**($000)**	**($000)**	**($000)**
Total opening RAB value		162,406		161,678
less				
Total depreciation		6,248		6,248
plus				
Total revaluations		4,062		4,044
plus				
Assets commissioned (other than below)	8,529		8,529	
Assets acquired from a regulated supplier				
Assets acquired from a related party				
Assets commissioned		8,529		8,529
less				
Asset disposals (other than below)				
Asset disposals to a regulated supplier				
Asset disposals to a related party				
Asset disposals		–		–
plus **Lost and found assets adjustment**				
plus **Adjustment resulting from asset allocation**				(1,931)
Total closing RAB value		168,748		166,070

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

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

sch ref						
51						
52	**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**					
53						
54	CPI_4					1,052
55	CPI_4^{-4}					1,026
56	Revaluation rate (%)					2.53%
57						
58			**Unallocated RAB ***		**RAB**	
59			**($000)**	**($000)**	**($000)**	**($000)**
60		Total opening RAB value	162,406		161,678	
61	*less*	Opening value of fully depreciated, disposed and lost assets	2,113		2,113	
62						
63		Total opening RAB value subject to revaluation	160,293		159,565	
64		**Total revaluations**		4,062		4,044
65						

4(iv): Roll Forward of Works Under Construction

sch ref						
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**		874		874
69	*plus*	Capital expenditure	10,353		10,353	
70	*less*	Assets commissioned	8,529		8,529	
71	*plus*	Adjustment resulting from asset allocation			(1,931)	
72		**Works under construction - current disclosure year**		2,698		767
73						
74		Highest rate of capitalised finance applied				
75						

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

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

sch ref

76 ### 4(v): Regulatory Depreciation

sch ref		Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
79	Depreciation - standard	6,248		6,248	
80	Depreciation - no standard life assets				
81	Depreciation - modified life assets				
82	Depreciation - alternative depreciation in accordance with CPP				
83	**Total depreciation**		6,248		6,248

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**	16,822	1,362	22,840	56,226	25,451	16,944	8,324	3,470	10,239	161,678
100	*less*	Total depreciation	689	33	1,010	1,956	785	666	402	275	433	6,248
101	*plus*	Total revaluations	426	35	578	1,423	645	429	211	88	210	4,044
102	*plus*	Assets commissioned	1,233	–	1,288	3,843	559	689	483	174	261	8,529
103	*less*	Asset disposals	–	–	–	–	–	–	–	–	–	–
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	(1,931)	(1,931)
106	*plus*	Asset category transfers	0	0	0	0	0	0	0	0	0	0
107		**Total closing RAB value**	17,792	1,364	23,696	59,536	25,869	17,396	8,615	3,457	8,346	166,070
108												
109		**Asset Life**										
110		Weighted average remaining asset life	35.1	40.4	30.7	37.7	39.5	30.1	24.7	15.5	15.7	(years)
111		Weighted average expected total asset life	55.9	55.0	44.2	55.6	59.2	44.7	38.3	26.6	19.3	(years)

Company Name	**Eastland Network**
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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref					
7	**5a(i): Regulatory Tax Allowance**				**($000)**
8		**Regulatory profit / (loss) before tax**			17,999
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	101	*	
12		Amortisation of initial differences in asset values	1,901		
13		Amortisation of revaluations	823		
14					2,825
15					
16	*less*	Total revaluations	4,044		
17		Income included in regulatory profit / (loss) before tax but not taxable		*	
18		Discretionary discounts and customer rebates			
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax		*	
20		Notional deductible interest	2,289		
21					6,333
22					
23		**Regulatory taxable income**			14,491
24					
25	*less*	Utilised tax losses			
26		Regulatory net taxable income			14,491
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			4,058
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	43,675		
37	*less*	Amortisation of initial differences in asset values	1,901		
38	*plus*	Adjustment for unamortised initial differences in assets acquired			
39	*less*	Adjustment for unamortised initial differences in assets disposed			
40		Closing unamortised initial differences in asset values			41,775
41					
42		Opening weighted average remaining useful life of relevant assets (years)			23
43					

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8

sch ref				
44	**5a(iv): Amortisation of Revaluations**			**($000)**
45				
46		Opening sum of RAB values without revaluations	148,088	
47				
48		Adjusted depreciation	5,425	
49		Total depreciation	6,248	
50		Amortisation of revaluations		823
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**	(8,000)	
61				
62	*plus*	Tax effect of adjusted depreciation	1,519	
63				
64	*less*	Tax effect of tax depreciation	1,833	
65				
66	*plus*	Tax effect of other temporary differences*	3	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	532	
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	–	
73				
74	*plus*	Deferred tax cost allocation adjustment	478	
75				
76		**Closing deferred tax**		(8,365)
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**	75,443	
84	*less*	Tax depreciation	6,546	
85	*plus*	Regulatory tax asset value of assets commissioned	8,529	
86	*less*	Regulatory tax asset value of asset disposals	–	
87	*plus*	Lost and found assets adjustment	–	
88	*plus*	Adjustment resulting from asset allocation	(224)	
89	*plus*	Other adjustments to the RAB tax value	–	
90		**Closing sum of regulatory tax asset values**		77,201

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

sch ref			
7	**5b(i): Summary—Related Party Transactions**	**($000)**	**($000)**
8	**Total regulatory income**		631
9			
10	**Market value of asset disposals**		
11			
12	Service interruptions and emergencies	931	
13	Vegetation management	13	
14	Routine and corrective maintenance and inspection	71	
15	Asset replacement and renewal (opex)	1,484	
16	**Network opex**		2,499
17	Business support	2,381	
18	System operations and network support	–	
19	**Operational expenditure**		4,880
20	Consumer connection	–	
21	System growth	73	
22	Asset replacement and renewal (capex)	393	
23	Asset relocations	–	
24	Quality of supply	–	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	–	
27	**Expenditure on non-network assets**		–
28	**Expenditure on assets**		466
29	Cost of financing		
30	Value of capital contributions		
31	Value of vested assets		
32	**Capital Expenditure**		466
33	**Total expenditure**		5,346
34			
35	**Other related party transactions**		365

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

	Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
37	**Name of related party**	**Nature of opex or capex service provided**	**Total value of transactions ($000)**
38	Eastech	Asset replacement and renewal (capex)	393
39	Eastech	System growth	73
40	Eastech	Service interruptions and emergencies	931
41	Eastech	Vegetation management	13
42	Eastech	Asset replacement and renewal (opex)	63
43	Eastech	Routine and corrective maintenance and inspection	71
44	Eastland Group Limited	Business support	2,381
45	Eastland Generation	Asset replacement and renewal (opex)	1,421
53	**Total value of related party transactions**		5,346

54 ** include additional rows if needed*

55

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

7
8 ### 5c(i): Qualifying Debt (may be Commission only)
9

sch ref	Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
10									
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	**Eastland Network**
For Year Ended	**31 March 2020**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

sch ref	5d(i): Operating Cost Allocations	Value allocated ($000s)				
8						
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		1,362			
12	Not directly attributable				–	
13	**Total attributable to regulated service**		1,362			
14	**Vegetation management**					
15	Directly attributable		1,055			
16	Not directly attributable				–	
17	**Total attributable to regulated service**		1,055			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		994			
20	Not directly attributable				–	
21	**Total attributable to regulated service**		994			
22	**Asset replacement and renewal**					
23	Directly attributable		1,681			
24	Not directly attributable				–	
25	**Total attributable to regulated service**		1,681			
26	**System operations and network support**					
27	Directly attributable		2,605			
28	Not directly attributable			193	193	
29	**Total attributable to regulated service**		2,605			
30	**Business support**					
31	Directly attributable		3,685			
32	Not directly attributable			124	124	
33	**Total attributable to regulated service**		3,685			
34						
35	**Operating costs directly attributable**		11,382			
36	**Operating costs not directly attributable**	–	–	317	317	–
37	**Operational expenditure**		11,382			
38						

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref		
39	**5d(ii): Other Cost Allocations**	
40	**Pass through and recoverable costs**	**($000)**
41	**Pass through costs**	
42	Directly attributable	405
43	Not directly attributable	
44	**Total attributable to regulated service**	405
45	**Recoverable costs**	
46	Directly attributable	6,307
47	Not directly attributable	
48	**Total attributable to regulated service**	6,307
49		

sch ref					
50	**5d(iii): Changes in Cost Allocations* †**				
51				**($000)**	
52	**Change in cost allocation 1**			**CY-1**	**Current Year (CY)**
53	Cost category		Original allocation		
54	Original allocator or line items		New allocation		
55	New allocator or line items		Difference	–	–
56					
57	Rationale for change				
58					
59					
60				**($000)**	
61	**Change in cost allocation 2**			**CY-1**	**Current Year (CY)**
62	Cost category		Original allocation		
63	Original allocator or line items		New allocation		
64	New allocator or line items		Difference	–	–
65					
66	Rationale for change				
67					
68					
69				**($000)**	
70	**Change in cost allocation 3**			**CY-1**	**Current Year (CY)**
71	Cost category		Original allocation		
72	Original allocator or line items		New allocation		
73	New allocator or line items		Difference	–	–
74					
75	Rationale for change				
76					
77					
78	** a change in cost allocation must be completed for each cost allocator change that has occurred in the disclosure year. A movement in an allocator metric is not a change in allocator or component.*				
79	*† include additional rows if needed*				

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

7 **5e(i): Regulated Service Asset Values**

sch ref		Value allocated ($000s) Electricity distribution services
8		
9		
10	**Subtransmission lines**	
11	Directly attributable	17,792
12	Not directly attributable	
13	**Total attributable to regulated service**	17,792
14	**Subtransmission cables**	
15	Directly attributable	1,364
16	Not directly attributable	
17	**Total attributable to regulated service**	1,364
18	**Zone substations**	
19	Directly attributable	23,696
20	Not directly attributable	
21	**Total attributable to regulated service**	23,696
22	**Distribution and LV lines**	
23	Directly attributable	59,536
24	Not directly attributable	
25	**Total attributable to regulated service**	59,536
26	**Distribution and LV cables**	
27	Directly attributable	25,869
28	Not directly attributable	
29	**Total attributable to regulated service**	25,869
30	**Distribution substations and transformers**	
31	Directly attributable	17,396
32	Not directly attributable	
33	**Total attributable to regulated service**	17,396
34	**Distribution switchgear**	
35	Directly attributable	8,615
36	Not directly attributable	
37	**Total attributable to regulated service**	8,615
38	**Other network assets**	
39	Directly attributable	3,457
40	Not directly attributable	
41	**Total attributable to regulated service**	3,457
42	**Non-network assets**	
43	Directly attributable	8,346
44	Not directly attributable	
45	**Total attributable to regulated service**	8,346
46		
47	**Regulated service asset value directly attributable**	166,070
48	**Regulated service asset value not directly attributable**	–
49	**Total closing RAB value**	166,070
50		

51 **5e(ii): Changes in Asset Allocations* †**

sch ref				($000) CY-1	Current Year (CY)
52					
53	**Change in asset value allocation 1**				
54	Asset category		Original allocation		
55	Original allocator or line items		New allocation		
56	New allocator or line items		Difference	–	–
57					
58	Rationale for change				
59					
60					

sch ref				($000) CY-1	Current Year (CY)
61					
62	**Change in asset value allocation 2**				
63	Asset category		Original allocation		
64	Original allocator or line items		New allocation		
65	New allocator or line items		Difference	–	–
66					
67	Rationale for change				
68					
69					

sch ref				($000) CY-1	Current Year (CY)
70					
71	**Change in asset value allocation 3**				
72	Asset category		Original allocation		
73	Original allocator or line items		New allocation		
74	New allocator or line items		Difference	–	–
75					
76	Rationale for change				
77					
78					

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

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**

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

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

sch ref

sch ref			($000)	($000)
7		**6a(i): Expenditure on Assets**		
8		Consumer connection		72
9		System growth		485
10		Asset replacement and renewal		8,104
11		Asset relocations		–
12		Reliability, safety and environment:		
13		Quality of supply	93	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	38	
16		**Total reliability, safety and environment**		131
17		**Expenditure on network assets**		8,792
18		Expenditure on non-network assets		223
19				
20		**Expenditure on assets**		9,015
21	*plus*	Cost of financing		
22	*less*	Value of capital contributions		–
23	*plus*	Value of vested assets		1,338
24				
25		**Capital expenditure**		10,353

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	
29	Research and development	

sch ref			($000)	($000)
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**		
32		Residential	31	
33		Commercial	–	
34		Industrial	41	
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		72
39				
40	*less*	Capital contributions funding consumer connection expenditure		
41		**Consumer connection less capital contributions**		72

sch ref			System Growth ($000)	Asset Replacement and Renewal ($000)
42		**6a(iv): System Growth and Asset Replacement and Renewal**		
43				
44				
45		Subtransmission	–	1,207
46		Zone substations	–	1,528
47		Distribution and LV lines	76	4,113
48		Distribution and LV cables	247	104
49		Distribution substations and transformers	162	572
50		Distribution switchgear	–	413
51		Other network assets	–	168
52		**System growth and asset replacement and renewal expenditure**	485	8,104
53	*less*	Capital contributions funding system growth and asset replacement and renewal		
54		**System growth and asset replacement and renewal less capital contributions**	485	8,104
55				

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

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**

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

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

sch ref				
68				
69		**6a(vi): Quality of Supply**		
70		*Project or programme**	**($000)**	**($000)**
71		11kV Field Recloser Automation Plan - additions	80	
72		SCADA Master Station Development	9	
73		Alternate Massey Rd Control Room (defer from 2018/19)	3	
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply		
78		**Quality of supply expenditure**		93
79	*less*	Capital contributions funding quality of supply		
80		**Quality of supply less capital contributions**		93
81		**6a(vii): Legislative and Regulatory**		
82		*Project or programme**	**($000)**	**($000)**
83				
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory		
90		**Legislative and regulatory expenditure**		–
91	*less*	Capital contributions funding legislative and regulatory		
92		**Legislative and regulatory less capital contributions**		–
93		**6a(viii): Other Reliability, Safety and Environment**		
94		*Project or programme**	**($000)**	**($000)**
95		Service Fuse Boxes & Meter Bds to Replace Galv Meter Box (Asbestos), 100pa from 2017- Safety	38	
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment		
102		**Other reliability, safety and environment expenditure**		38
103	*less*	Capital contributions funding other reliability, safety and environment		
104		**Other reliability, safety and environment less capital contributions**		38
105				
106		**6a(ix): Non-Network Assets**		
107		**Routine expenditure**		
108		*Project or programme**	**($000)**	**($000)**
109		Test Instrument & Safety Equipment,(inc Lone worker 19/20 additional/upgrade)	13	
110		Vehicle Replacement @ $60k each (Ntk)	63	
111		General asset replacement (Ntk)	11	
112		General building capex (ENL office, Eastech, Wairoa Depot)	21	
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure		
116		**Routine expenditure**		108
117		**Atypical expenditure**		
118		*Project or programme**	**($000)**	**($000)**
119		Property Capital Projects (ENL Carnarvon St office refurb)	87	
120		Property Capital Projects (Eastech office refurb)	27	
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure		
126		**Atypical expenditure**		115
127				
128		**Expenditure on non-network assets**		223

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**

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

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

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	1,362	
9	Vegetation management	1,055	
10	Routine and corrective maintenance and inspection	994	
11	Asset replacement and renewal	1,681	
12	**Network opex**		5,091
13	System operations and network support	2,605	
14	Business support	3,685	
15	**Non-network opex**		6,291
16			
17	**Operational expenditure**		11,382
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		
20	Direct billing*		
21	Research and development		
22	Insurance		284
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

This schedule compares actual revenue and expenditure to the previous forecasts that were made for the disclosure year. Accordingly, this schedule requires the forecast revenue and expenditure information from previous disclosures to be inserted.

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

sch ref		Target ($000) [1]	Actual ($000)	% variance
7	**7(i): Revenue**			
8	Line charge revenue	37,261	37,712	1%

sch ref		Forecast ($000) [2]	Actual ($000)	% variance
9	**7(ii): Expenditure on Assets**			
10	Consumer connection	112	72	(36%)
11	System growth	939	485	(48%)
12	Asset replacement and renewal	7,589	8,104	7%
13	Asset relocations	50	–	(100%)
14	Reliability, safety and environment:			
15	Quality of supply	122	93	(24%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	341	38	(89%)
18	**Total reliability, safety and environment**	463	131	(72%)
19	**Expenditure on network assets**	9,153	8,792	(4%)
20	Expenditure on non-network assets	501	223	(56%)
21	Expenditure on assets	9,654	9,015	(7%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,364	1,362	(0%)
24	Vegetation management	1,015	1,055	4%
25	Routine and corrective maintenance and inspection	1,520	994	(35%)
26	Asset replacement and renewal	1,907	1,681	(12%)
27	**Network opex**	5,806	5,091	(12%)
28	System operations and network support	1,269	2,605	105%
29	Business support	4,007	3,685	(8%)
30	**Non-network opex**	5,276	6,291	19%
31	**Operational expenditure**	11,082	11,382	3%
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses		–	–
34	Overhead to underground conversion		–	–
35	Research and development		–	–
36				
37	**7(v): Subcomponents of Operational Expenditure (where known)**			
38	Energy efficiency and demand side management, reduction of energy losses		–	–
39	Direct billing		–	–
40	Research and development		–	–
41	Insurance	274	284	4%

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	Eastland Network Ltd
For Year Ended	31 March 2020
Network / Sub-Network Name	Gisborne & Wairoa

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**

9
10
11 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)	Fixed	Variable Uncontrolled	Variable Controlled	Variable Night (Mass Market)	Variable Evening Peak (TOU)	Variable Morning Peak (TOU)	Variable Off Peak (TOU)	Variable Night (TOU)
12					Price component	Fixed	Variable Uncontrolled	Variable Controlled	Variable Night (Mass Market)	Variable Evening Peak (TOU)	Variable Morning Peak (TOU)	Variable Off Peak (TOU)	Variable Night (TOU)
13					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	Days	kWh	kWh	kWh	kWh	kWh	kWh	kWh
14													
15	PDH0030	Domestic	Standard	13,940	85,389.7	5,088,100	63,113,547	22,267,183	8,967				
16	PDL0030	Domestic	Standard	5,690	36,551.9	2,076,850	27,997,670	8,520,113	34,095				
17	PNH0003	Non-Domestic, High density	Standard	134	638.7	48,910	638,724						
18	PNH0030	Non-Domestic, High density	Standard	1,705	21,649.5	622,325	20,654,206	960,819	34,429				
19	PNH0100	Non-Domestic, High density	Standard	286	20,132.5	104,390	19,589,113	303,158	228,174	2,192	2,907	3,555	3,447
20	PNH0300	Non-Domestic, High density	Standard	71	14,276.1	25,915	14,262,809	13,288	–				
	PTH0300	Non-Domestic, High density	Standard	7	3,480.9	2,555	(82,317)			668,396	1,010,573	1,195,911	688,333
	PNH0500	Non-Domestic, High density	Standard	16	8,460.6	5,840				1,341,828	2,149,366	2,753,393	2,215,967
	PNH1000	Non-Domestic, High density	Standard	23	29,471.8	8,395				4,864,043	7,143,734	9,306,504	8,157,473
	PNH4500	Non-Domestic, High density	Standard	2	12,505.9	730				2,101,745	2,719,407	3,734,455	3,950,306
	PNH6500	Non-Domestic, High density	Standard	1	7,765.8	365				1,134,636	2,053,815	2,426,991	2,150,308
	PNL0003	Non-Domestic, Low density	Standard	127	231.7	46,355	231,692						
	PNL0030	Non-Domestic, Low density	Standard	3,512	18,823.9	1,281,880	17,311,868	1,482,651	29,373				
	PNL0100	Non-Domestic, Low density	Standard	107	4,783.5	39,055	4,670,802	97,846	14,897				
	PNL0300	Non-Domestic, Low density	Standard	22	2,087.4 *	8,030	2,087,427						
	PTL0300	Non-Domestic, Low density	Standard	1	135.6	365				809	68,757	63,991	2,023
	PNL0500	Non-Domestic, Low density	Standard	4	761.7	1,460				132,081	186,896	248,415	194,277
	PNL1000	Non-Domestic, Low density	Standard	1	1,553.0	365				251,394	394,919	512,247	394,439
	PNL4500	Non-Domestic, Low density	Standard	1	13,965.6	365				2,239,240	3,466,795	4,428,855	3,830,730
	PNL6500	Non-Domestic, Low density	Standard	-	0.0	–							
	PNG0500	Generation	Standard	-	0.0	–							
	PNG1000	Generation (Gensets)	Standard	6	0.0	2,190							
	PNG4500	Generation	Standard	1	0.0	365							
	PNG6500	Generation (Waihi)	Standard	1	0.0	365							
	Power Factor Charges	All Customers (If Required)	Standard	-	0.0	–							
25	*Add extra rows for additional consumer groups or price category codes as necessary*												
26			Standard consumer totals	25,658	282,665.7	9,365,170	170,475,541	33,645,058	349,935	12,736,364	19,197,169	24,674,317	21,587,303
27			Non-standard consumer totals	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
28			Total for all consumers	25,658	282,665.7	9,365,170	170,475,541	33,645,058	349,935	12,736,364	19,197,169	24,674,317	21,587,303

29
30

Company Name	**Eastland Network Ltd**
For Year Ended	**31 March 2020**
Network / Sub-Network Name	**Gisborne & Wairoa**

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.

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

32

33

Row	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)	Line charge revenues ($000) by price component: Fixed Component Only	Variable Uncontrolled (Mass Market)	Variable Controlled (Mass Market)	Variable Night (Mass Market)	Variable Evening Peak (TOU)	Variable Morning Peak (TOU)	Variable Off Peak (TOU)	Variable Night (TOU)
34							Price component								
35							Rate (eg, $ per day, $ per kWh, etc.)	$ per day	$ per kWh	$ per kWh	$ per kWh	$ per kWh	$ per kWh	$ per kWh	$ per kWh
36															
37	PDH0030	Domestic	Standard	$13,045		$9,934.7	$3,109.9	$786.3	$10,370.2	$1,887.8	$0.3	$0.0	$0.0	$0.0	$0.0
38	PDL0030	Domestic	Standard	$6,562		$4,980.2	$1,581.7	$327.2	$5,359.6	$873.6	$1.5	$0.0	$0.0	$0.0	$0.0
39	PNH0003	Non-Domestic, High density	Standard	$118		$80.9	$36.7	$23.1	$94.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
40	PNH0030	Non-Domestic, High density	Standard	$3,848		$2,683.4	$1,164.6	$1,589.4	$2,190.4	$67.1	$1.1	$0.0	$0.0	$0.0	$0.0
	PNH0100	Non-Domestic, High density	Standard	$2,244		$1,530.0	$714.3	$805.7	$1,416.6	$14.4	$7.1	$0.1	$0.2	$0.1	$0.1
	PNH0300	Non-Domestic, High density	Standard	$1,260		$874.1	$385.8	$402.0	$857.3	$0.5	$0.0	$0.0	$0.0	$0.0	$0.0
	PTH0300	Non-Domestic, High density	Standard	$209		$147.1	$62.0	$65.1	-$4.8	$0.0	$0.0	$36.4	$51.0	$47.2	$14.2
	PNH0500	Non-Domestic, High density	Standard	$522		$367.2	$155.2	$172.8	$0.0	$0.0	$0.0	$75.4	$112.4	$113.7	$48.1
	PNH1000	Non-Domestic, High density	Standard	$1,588		$1,118.0	$470.5	$380.1	$0.0	$0.0	$0.0	$273.4	$373.6	$384.4	$177.0
	PNH4500	Non-Domestic, High density	Standard	$583		$410.8	$172.1	$82.6	$0.0	$0.0	$0.0	$118.1	$142.2	$154.2	$85.7
	PNH6500	Non-Domestic, High density	Standard	$381		$268.3	$112.6	$62.9	$0.0	$0.0	$0.0	$63.8	$107.4	$100.2	$46.7
	PNL0003	Non-Domestic, Low density	Standard	$62		$42.7	$19.1	$21.9	$39.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	PNL0030	Non-Domestic, Low density	Standard	$5,359		$3,778.7	$1,580.6	$3,302.0	$1,946.4	$110.0	$1.0	$0.0	$0.0	$0.0	$0.0
	PNL0100	Non-Domestic, Low density	Standard	$719		$495.4	$223.3	$301.3	$411.4	$5.5	$0.4	$0.0	$0.0	$0.0	$0.0
	PNL0300	Non-Domestic, Low density	Standard	$265		$183.8	$81.3	$121.8	$143.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	PTL0300	Non-Domestic, Low density	Standard	$16		$11.2	$4.8	$9.5	$0.0	$0.0	$0.0	$0.0	$3.7	$2.7	$0.0
	PNL0500	Non-Domestic, Low density	Standard	$77		$53.7	$23.3	$44.3	$0.0	$0.0	$0.0	$7.7	$10.1	$10.5	$4.4
	PNL1000	Non-Domestic, Low density	Standard	$83		$58.0	$25.2	$16.5	$0.0	$0.0	$0.0	$14.6	$21.4	$21.7	$8.9
	PNL4500	Non-Domestic, Low density	Standard	$633		$441.4	$191.9	$41.3	$0.0	$0.0	$0.0	$130.1	$187.9	$187.8	$86.2
	PNL6500	Non-Domestic, Low density	Standard	–		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	PNG0500	Generation	Standard	–		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	PNG1000	Generation (Gensets)	Standard	$67		$66.7	$0.0	$66.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	PNG4500	Generation	Standard	$28		$28.3	$0.0	$28.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	PNG6500	Generation (Waihi)	Standard	$43		$43.0	$0.0	$43.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	Power Factor Charges	All Customers (If Required)	Standard	–		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
47	*Add extra rows for additional consumer groups or price category codes as necessary*														
48			Standard consumer totals	$37,712.5	$0.0	$27,597.7	$10,114.8	$8,693.8	$22,824.8	$2,959.0	$11.4	$719.6	$1,009.9	$1,022.7	$471.2
49			Non-standard consumer totals	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
50			Total for all consumers	$37,712.5	$0.0	$27,597.7	$10,114.8	$8,693.8	$22,824.8	$2,959.0	$11.4	$719.6	$1,009.9	$1,022.7	$471.2

51

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

53 Number of directly billed ICPs at year end: 7

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**All**

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

8	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.	16,377	17,063	686	3
10	All	Overhead Line	Wood poles	No.	17,943	18,043	100	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	336	336	0	1
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	307	307	(0)	1
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	1	1	(0)	3
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.	26	19	(7)	2
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	3	11	8	2
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	49	45	(4)	2
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	4	2	(2)	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.	1	1	–	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	98	112	14	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	7	7	–	2
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	51	44	(7)	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,392	2,387	(5)	1
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	1	1	–	1
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	34	38	4	1
39	HV	Distribution Cable	Distribution UG PILC	km	102	102	(1)	1
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.	48	38	(10)	2
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	24	15	(9)	1
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	4,369	4,449	80	1
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	73	77	4	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	258	314	56	2
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,002	3,046	44	2
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	579	551	(28)	4
48	HV	Distribution Transformer	Voltage regulators	No.	9	11	2	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	N/A
50	LV	LV Line	LV OH Conductor	km	508	505	(3)	1
51	LV	LV Cable	LV UG Cable	km	269	273	4	1
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	22	22	(0)	1
53	LV	Connections	OH/UG consumer service connections	No.	31,686	26,300	(5,386)	1
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	237	191	(46)	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	814	1,129	315	1
56	All	Capacitor Banks	Capacitors including controls	No	1	1	–	3
57	All	Load Control	Centralised plant	Lot	8	8	–	2
58	All	Load Control	Relays	No	15,683	17,013	1,330	1
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**Gisborne**

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)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	13,253	13,731	478	3
10	All	Overhead Line	Wood poles	No.	13,815	14,029	214	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	269	269	0	1
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	180	180	(0)	1
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	1	1	(0)	3
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.	14	17	3	2
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	3	5	2	2
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	44	42	(2)	2
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	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.	–	–	–	N/A
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	84	86	2	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	5	5	–	2
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	32	32	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,711	1,706	(5)	1
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	29	33	4	1
39	HV	Distribution Cable	Distribution UG PILC	km	87	87	(1)	1
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.	22	23	1	2
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	24	15	(9)	1
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	3,013	3,331	318	1
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	57	61	4	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	204	272	68	2
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	2,054	2,255	201	2
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	459	459	–	4
48	HV	Distribution Transformer	Voltage regulators	No.	7	8	1	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	N/A
50	LV	LV Line	LV OH Conductor	km	374	371	(3)	1
51	LV	LV Cable	LV UG Cable	km	218	222	4	1
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	21	21	(0)	1
53	LV	Connections	OH/UG consumer service connections	No.	25,294	21,329	(3,965)	1
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	191	152	(39)	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	644	969	325	1
56	All	Capacitor Banks	Capacitors including controls	No	1	1	–	3
57	All	Load Control	Centralised plant	Lot	5	5	–	2
58	All	Load Control	Relays	No	15,499	17,013	1,514	1
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**Wairoa**

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

8	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.	3,124	3,332	208	3
10	All	Overhead Line	Wood poles	No.	4,128	4,014	(114)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	67	67	(0)	1
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	127	127	(0)	1
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	0	–	(0)	3
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.	12	2	(10)	2
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	6	6	2
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	5	3	(2)	2
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	4	2	(2)	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.	1	1	–	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	14	26	12	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	2	2	–	2
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	19	12	(7)	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	681	680	(0)	1
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	1	1	–	1
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	5	5	0	1
39	HV	Distribution Cable	Distribution UG PILC	km	15	15	(0)	1
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	15	(11)	2
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	1
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1,356	1,118	(238)	1
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	16	16	–	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	54	42	(12)	2
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	948	791	(157)	2
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	120	92	(28)	4
48	HV	Distribution Transformer	Voltage regulators	No.	2	3	1	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	N/A
50	LV	LV Line	LV OH Conductor	km	134	134	(0)	1
51	LV	LV Cable	LV UG Cable	km	51	52	1	1
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	1	1	(0)	1
53	LV	Connections	OH/UG consumer service connections	No.	6,392	4,971	(1,421)	1
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	46	39	(7)	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	170	160	(10)	1
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	3
57	All	Load Control	Centralised plant	Lot	3	3	–	2
58	All	Load Control	Relays	No	184	–	(184)	1
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	Eastland Network
For Year Ended	31 March 2020
Network / Sub-network Name	All

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					Number of assets at disclosure year end by installation date																																				
8		Disclosure Year (year ended)																																							
9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	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 (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	0	1	88	260	1,827	3,197	2,864	511	1,426	792	242	283	380	242	230	392	409	427	418	441	363	388	393	271	226	378	484	130	0	0	0	0	0	-	17,063		2
11	All	Overhead Line	Wood poles	No.	0	151	2,257	4,457	1,812	1,549	3,005	475	853	247	131	185	157	170	188	287	270	241	211	186	208	151	201	198	110	161	139	43	0	0	0	0	0	-	18,043		2
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-											–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	72	116	71	37	6	7	4	3	11	-	5	4	0	0	-	-	-	-	0	-	0	0	-	0	-	-	-	-	-	-	-	-	336		1
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	0	17	86	61	111	30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	0	-	-	-	-	-	-	-	-	307		1
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-										–		N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-										–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-										–		N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-										–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-										–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-										–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-										–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-										–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	-	-	2	3	5	-	2	-	1	1	-	1	1	1	-	1	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	19		2
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	7	2	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11		2
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.																																			–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	1	5	9	4	1	2	6	1	-	1	2	1	-	4	2	2	1	-	-	-	-	2	1	-	-	-	-	-	-	-	45		2
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																																			–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2		3
30	HV	Zone substation switchgear	33kV RMU	No.																																			–		N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.																																			–		N/A
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1		3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	-	-	29	9	9	5	15	9	4	-	7	-	-	-	-	-	-	12	-	8	-	5	-	-	-	-	-	-	-	-	-	112		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	1	1	-	-	-	-	-	-	-	7		2
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	8	7	1	3	4	9	2	-	2	-	-	-	4	-	-	-	-	-	-	-	-	-	-	3	1	-	-	-	-	-	-	-	44		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	63	86	522	881	348	203	171	11	7	11	4	8	9	7	9	2	1	4	3	2	4	2	8	4	6	6	4	0	-	-	-	-	-	-	2,387		1
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																			–		N/A
38	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1		1
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	0	1	3	6	6	0	1	0	0	0	1	2	1	2	0	1	1	0	0	0	1	2	1	3	3	0	-	-	-	-	-	-	38		1
40	HV	Distribution Cable	Distribution UG PILC	km	-	-	1	8	12	28	23	2	5	4	2	1	2	2	3	1	2	1	1	0	0	0	0	1	1	0	0	-	-	-	-	-	-	-	102		1
41	HV	Distribution Cable	Distribution Submarine Cable	km																																			–		N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser	No.	-	-	-	-	3	5	9	12	-	1	2	1	-	1	1	-	-	-	-	-	-	-	-	2	-	1	-	-	-	-	-	-	-	-	38		2
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	7	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15		1
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	-	210	807	693	429	472	55	123	132	130	116	84	110	92	83	110	106	103	66	75	94	115	67	51	54	47	25	-	-	-	-	-	-	4,449		1
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	2	7	14	7	17	7	9	1	-	5	4	-	-	1	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	77		1
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	-	1	3	7	67	13	39	32	14	7	6	14	12	8	3	6	9	6	7	6	13	23	11	2	5	-	-	-	-	-	-	-	314		2
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	-	83	574	464	329	412	35	99	61	101	102	72	79	44	48	60	62	57	48	64	50	43	32	43	61	22	1	-	-	-	-	-	-	3,046		2
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	8	30	22	32	25	43	52	27	27	26	23	20	29	12	16	22	18	22	17	18	18	18	7	5	14	-	-	-	-	-	-	-	551		3
49	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	5	-	3	-	-	1	-	-	-	1	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11		2
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.																																			–		N/A
51	LV	LV Line	LV OH Conductor	km	7	32	111	163	68	52	49	1	7	4	1	2	0	0	1	1	0	0	0	0	0	0	1	0	0	1	0	0	-	-	-	-	-	-	505		1
52	LV	LV Cable	LV UG Cable	km	0	0	3	20	42	64	38	8	16	14	8	5	5	4	7	6	5	2	3	3	3	1	2	2	3	2	4	0	-	-	-	-	-	-	273		1
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	-	-	1	1	2	6	6	0	2	1	1	0	0	0	1	0	-	-	0	0	0	0	0	-	0	-	-	-	-	-	-	-	-	-	22		1
54	LV	Connections	OH/UG consumer service connections	No.	46	526	1,988	5,084	4,916	4,906	3,900	305	334	321	361	321	273	353	363	287	218	186	235	157	175	159	188	146	157	171	177	47	-	-	-	-	-	-	26,300		1
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	-	-	1	10	19	9	25	3	21	7	6	10	10	1	-	-	2	-	23	4	-	21	6	12	1	-	-	-	-	-	-	-	191		2
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot	-	-	-	1	-	27	129	66	61	41	104	50	65	26	21	24	22	19	35	23	40	161	135	29	23	22	5	-	-	-	-	-	-	-	1,129		1
57	All	Capacitor Banks	Capacitors including controls	No	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1		3
58	All	Load Control	Centralised plant	Lot	-	-	-	-	5	2	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8		2
59	All	Load Control	Relays	No	-	-	-	-	2,308	2,572	4,744	538	1,032	1,163	1,014	462	823	623	935	108	89	50	90	104	61	62	85	50	28	52	19	1	-	-	-	-	-	-	17,013		1
60	All	Civils	Cable Tunnels	km																																			–		N/A

Company Name	Eastland Network
For Year Ended	31 March 2020
Network / Sub-network Name	Gisborne

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	2005	2006
10	All	Overhead Line	Concrete poles / steel structure	No.	–	1	34	165	1,547	2,338	2,684	364	1,047	586	158	202	309	187
11	All	Overhead Line	Wood poles	No.	–	66	1,478	3,937	1,395	1,220	2,411	194	603	190	88	124	104	99
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	72	116	37	5	6	7	4	3	11	–	5	4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	0	17	29	61	49	23	–	–	–	–	–	–	–	–
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	1	1
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.	–	–	–	–	2	3	4	–	2	–	1	1	–	1
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	4	1	–	–	–	–	–	–	–
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.														
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	1	5	9	2	1	2	6	1	–	1
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.														
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
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.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	–	19	9	9	5	15	9	4	–	4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	2	–	–	–	–	–	–	–
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	8	7	1	1	4	1	2	–	2	–	–	–
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0	6	313	699	303	141	166	11	5	7	2	2	6	4
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	0	3	6	4	0	1	0	0	0	1	2
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	1	8	9	21	21	2	5	4	2	1	2	1
41	HV	Distribution Cable	Distribution Submarine Cable	km														
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser	No.	–	–	–	–	–	1	9	10	–	–	1	–	–	–
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	7	–	–	–	–	8	–	–	–	–
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	–	206	517	508	276	335	42	101	98	87	75	65	84
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	2	3	14	7	13	7	7	1	–	1
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	1	2	1	62	13	30	32	11	5	6	10
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	83	334	352	234	307	22	85	45	68	66	56	62
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	8	25	20	23	20	42	49	23	21	21	15	14
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	4	–	3	–	–	–	–	–	–	–	–
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.														
51	LV	LV Line	LV OH Conductor	km	0	2	69	132	59	43	47	1	7	4	1	1	0	0
52	LV	LV Cable	LV UG Cable	km	–	–	1	17	31	47	31	7	16	14	7	4	4	3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	1	1	2	5	6	0	2	1	0	0	0	0
54	LV	Connections	OH/UG consumer service connections	No.	46	526	1,912	3,583	4,063	4,043	3,388	269	270	187	81	205	230	315
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	–	–	16	7	19	3	20	7	3	10
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot	–	–	–	1	–	25	114	60	35	32	85	47	35	21
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	1	–	–	–	–	–	–	–
58	All	Load Control	Centralised plant	Lot	–	–	–	–	5	–	–	–	–	–	–	–	–	–
59	All	Load Control	Relays	No	–	–	–	–	2,308	2,572	4,744	538	1,032	1,163	1,014	462	823	623
60	All	Civils	Cable Tunnels	km														

sch ref	Asset class	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	Concrete poles / steel structure	197	334	358	413	408	433	334	364	347	238	112	179	294	98	–	–	–	–	–	–	13,731		2
11	Wood poles	127	268	178	230	190	160	166	135	185	190	70	86	109	26	–	–	–	–	–		14,029		2
12	Other pole types	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
13	Subtransmission OH up to 66kV conductor	0	0	–	–	–	–	0	–	0	0	–	0	–	–	–	–	–	–	–	–	269		1
14	Subtransmission OH 110kV+ conductor	–	–	–	–	–	–	–	–	–	1	–	0	–	–	–	–	–	–	–	–	180		1
15	Subtransmission UG up to 66kV (XLPE)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1		3
16	Subtransmission UG up to 66kV (Oil pressurised)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
17	Subtransmission UG up to 66kV (Gas pressurised)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
18	Subtransmission UG up to 66kV (PILC)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
19	Subtransmission UG 110kV+ (XLPE)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
20	Subtransmission UG 110kV+ (Oil pressurised)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
21	Subtransmission UG 110kV+ (Gas Pressurised)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
22	Subtransmission UG 110kV+ (PILC)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
23	Subtransmission submarine cable	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
24	Zone substations up to 66kV	1	1	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	17		2
25	Zone substations 110kV+	–	–	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5		2
26	50/66/110kV CB (Indoor)																				–	–		N/A
27	50/66/110kV CB (Outdoor)	2	1	–	4	2	2	1	–	–	–	–	2	–	–	–	–	–	–	–	–	42		2
28	33kV Switch (Ground Mounted)																				–	–		N/A
29	33kV Switch (Pole Mounted)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		3
30	33kV RMU																				–	–		N/A
31	22/33kV CB (Indoor)																				–	–		N/A
32	22/33kV CB (Outdoor)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		3
33	3.3/6.6/11/22kV CB (ground mounted)	–	–	–	–	–	–	12	–	–	–	–	–	–	–	–	–	–	–	–	–	86		3
34	3.3/6.6/11/22kV CB (pole mounted)	–	–	–	–	–	–	–	–	–	1	–	1	1	–	–	–	–	–	–	–	5		2
35	Zone Substation Transformers	3	–	–	–	–	–	–	–	–	–	–	3	–	–	–	–	–	–	–	–	32		4
36	Distribution OH Open Wire Conductor	3	2	1	4	3	2	3	1	7	3	5	6	2	0	–	–	–	–	–		1,706		1
37	Distribution OH Aerial Cable Conductor																				–	–		N/A
38	SWER conductor	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		1
39	Distribution UG XLPE or PVC	1	2	0	1	1	0	0	0	1	2	1	2	3	0	–	–	–	–	–	–	33		1
40	Distribution UG PILC	1	1	2	1	1	0	0	0	0	1	1	0	0	–	–	–	–	–	–	–	87		1
41	Distribution Submarine Cable																				–	–		N/A
42	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser	1	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	23		2
43	3.3/6.6/11/22kV CB (Indoor)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	15		1
44	3.3/6.6/11/22kV Switches and fuses (pole mounted)	72	68	98	98	91	61	63	87	95	59	40	40	42	23	–	–	–	–	–	–	3,331		1
45	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	2	–	–	1	–	–	–	–	–	–	–	–	3	–	–	–	–	–	–	–	61		1
46	3.3/6.6/11/22kV RMU	7	8	3	5	9	3	6	6	13	22	10	2	5	–	–	–	–	–	–	–	272		2
47	Pole Mounted Transformer	40	42	57	57	49	43	51	44	33	23	35	45	21	1	–	–	–	–	–	–	2,255		2
48	Ground Mounted Transformer	20	10	16	19	18	15	11	14	15	17	5	4	14	–	–	–	–	–	–	–	459		3
49	Voltage regulators	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	8		2
50	Ground Mounted Substation Housing																				–	–		N/A
51	LV OH Conductor	1	1	0	0	0	0	0	0	0	0	0	0	0	0	–	–	–	–	–	–	371		1
52	LV UG Cable	5	5	5	2	3	3	3	1	2	2	3	2	2	0	–	–	–	–	–	–	221		1
53	LV OH/UG Streetlight circuit	1	0	–	–	0	0	0	0	0	–	–	–	–	–	–	–	–	–	–	–	21		1
54	OH/UG consumer service connections	317	245	172	155	203	136	135	123	153	122	121	150	139	40	–	–	–	–	–	–	21,329		1
55	Protection relays (electromechanical, solid state and numeric)	9	1	–	–	1	–	23	4	–	11	6	12	–	–	–	–	–	–	–	–	152		2
56	SCADA and communications equipment operating as a single sys	20	16	19	17	32	20	39	159	126	26	18	20	2	–	–	–	–	–	–	–	969		1
57	Capacitors including controls	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1		3
58	Centralised plant	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5		2
59	Relays	935	108	89	50	90	104	61	62	85	50	28	52	19	1	–	–	–	–	–	–	17,013		1
60	Cable Tunnels																				–	–		N/A

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**Wairoa**

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

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	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 (quantity)	No. with default dates	Data accuracy (1–4)
8		Disclosure Year (year ended)			Number of assets at disclosure year end by installation date																																				
10	All	Overhead Line	Concrete poles / steel structure	No.	–	–	54	95	280	859	180	147	379	206	84	81	71	55	33	58	51	14	10	8	29	24	46	33	114	199	190	32	–	–	–	–	–	–	3,332		2
11	All	Overhead Line	Wood poles	No.	–	85	779	520	417	329	594	281	250	57	43	61	53	71	61	19	92	11	21	26	42	16	16	8	40	75	30	17	–	–	–	–	–	–	4,014		2
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–									–	–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	–	–	34	32	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	67		1
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	0	57	–	63	7	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	(0)	127		1
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–									–	–		N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–									–	–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–									–	–		N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–									–	–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–									–	–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–									–	–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–									–	–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–									–	–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	2		2
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	3	1	–	–	–	–	–	–	–	–	–	0	1	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	6		2
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–									–	–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	3		2
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–									–	–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2		3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–									–	–		N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–									–	–		N/A
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1		3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	–	10	–	–	–	–	–	–	–	3	–	–	–	–	–	–	–	–	8	–	5	–	–	–	–	–	–	–	–	–	26		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2		2
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	–	–	–	2	–	8	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	12		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	63	80	209	182	45	62	5	–	3	3	2	6	3	2	6	1	–	0	–	0	1	0	1	1	1	0	2	0	–	–	–	–	–	–	680		1
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–									–	–		N/A
38	HV	Distribution Line	SWER conductor	km	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1		1
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	–	0	–	0	1	0	0	0	0	0	0	0	0	1	–	0	–	0	0	0	0	–	0	1	0	0	–	–	–	–	–	(0)	5		1
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	0	3	6	2	0	0	0	0	0	0	1	2	0	–	–	–	–	0	–	–	0	0	0	–	–	–	–	–	–	–	–	15		1
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–									–	–		N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	3	4	–	2	–	1	1	1	–	1	–	–	–	–	–	–	–	–	–	1	–	1	–	–	–	–	–	–	–	–	15		2
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		1
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	–	4	290	185	153	137	13	22	34	43	41	19	26	20	15	12	8	12	5	12	7	20	8	11	14	5	2	–	–	–	–	–	–	1,118		1
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	4	–	–	4	–	2	–	–	4	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	16		1
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	1	6	5	–	9	–	3	2	–	4	5	–	–	1	–	3	1	–	–	1	1	–	–	–	–	–	–	–	–	–	42		2
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	–	240	112	95	105	13	14	16	33	36	16	17	4	6	3	5	8	5	13	6	10	9	8	16	1	–	–	–	–	–	–	–	791		2
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	5	2	9	5	1	3	4	6	5	8	6	9	2	–	3	–	7	6	4	3	1	2	1	–	–	–	–	–	–	–	–	92		2
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	1	–	–	–	–	1	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	3		2
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–									–	–		N/A
51	LV	LV Line	LV OH Conductor	km	7	31	42	30	9	9	2	1	0	0	0	1	0	0	0	–	–	0	–	–	–	0	1	0	0	0	–	–	–	–	–	–	–	(0)	134		1
52	LV	LV Cable	LV UG Cable	km	0	0	1	4	11	17	7	1	0	0	1	1	1	1	2	1	0	0	0	0	0	0	0	0	0	0	2	–	–	–	–	–	–	–	52		1
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	0	0	0	–	–	0	–	0	–	0	0	–	0	–	–	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	(0)	1		1
54	LV	Connections	OH/UG consumer service connections	No.	–	–	76	1,501	853	863	512	36	64	134	280	116	43	38	46	42	46	31	32	21	40	36	35	24	36	21	38	7	–	–	–	–	–	–	4,971		1
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	1	10	3	2	6	–	1	–	3	–	1	–	–	–	1	–	–	–	–	10	–	–	1	–	–	–	–	–	–	–	39		2
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot	–	–	–	–	–	2	15	6	26	9	19	3	30	5	1	8	3	2	3	3	1	2	9	3	5	2	3	–	–	–	–	–	–	–	160		1
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		3
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	3		2
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		1
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–									–	–		N/A

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**All**

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	307	–	307
12	50kV & 66kV	302	–	302
13	33kV	34	0	34
14	SWER (all SWER voltages)	1	–	1
15	22kV (other than SWER)	–	–	–
16	6.6kV to 11kV (inclusive—other than SWER)	2,387	140	2,526
17	Low voltage (< 1kV)	505	273	778
18	**Total circuit length (for supply)**	3,536	413	3,949
19				
20	Dedicated street lighting circuit length (km)	13	9	22
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			1,000
22				

23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**
24	Urban	187	5%
25	Rural	1,705	48%
26	Remote only	375	11%
27	Rugged only	988	28%
28	Remote and rugged	281	8%
29	Unallocated overhead lines	-	-
30	**Total overhead length**	3,535	100%
31			
32		**Circuit length (km)**	**(% of total circuit length)**
33	Length of circuit within 10km of coastline or geothermal areas (where known)		–
34		**Circuit length (km)**	**(% of total overhead length)**
35	Overhead circuit requiring vegetation management	3,536	100%

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**Gisborne**

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	180	-	180
12	50kV & 66kV	269	-	269
13	33kV	-	-	–
14	SWER (all SWER voltages)	-	-	–
15	22kV (other than SWER)	-	-	–
16	6.6kV to 11kV (inclusive—other than SWER)	1,706	120	1,826
17	Low voltage (< 1kV)	371	221	592
18	**Total circuit length (for supply)**	2,527	340	2,868
19				
20	Dedicated street lighting circuit length (km)	13	8	21
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			700
22				

sch ref			
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**
24	Urban	164	7%
25	Rural	1,342	53%
26	Remote only	291	12%
27	Rugged only	614	24%
28	Remote and rugged	116	5%
29	Unallocated overhead lines	-	–
30	**Total overhead length**	2,527	100%
31			
32		**Circuit length (km)**	**(% of total circuit length)**
33	Length of circuit within 10km of coastline or geothermal areas (where known)		–
34		**Circuit length (km)**	**(% of total overhead length)**
35	Overhead circuit requiring vegetation management	2,527	100%

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**Wairoa**

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	127	-	127
12	50kV & 66kV	32	-	32
13	33kV	34	0	34
14	SWER (all SWER voltages)	1	-	1
15	22kV (other than SWER)	-	-	–
16	6.6kV to 11kV (inclusive—other than SWER)	680	20	701
17	Low voltage (< 1kV)	134	52	186
18	**Total circuit length (for supply)**	1,008	73	1,081
19				
20	Dedicated street lighting circuit length (km)	0	0	1
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			300
22				

23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**
24	Urban	22	2%
25	Rural	363	36%
26	Remote only	84	8%
27	Rugged only	374	37%
28	Remote and rugged	165	16%
29	Unallocated overhead lines		–
30	**Total overhead length**	1,008	100%
31			
32		**Circuit length (km)**	**(% of total circuit length)**
33	Length of circuit within 10km of coastline or geothermal areas (where known)		–
34		**Circuit length (km)**	**(% of total overhead length)**
35	Overhead circuit requiring vegetation management	1,008	100%

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**

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 *	Number of ICPs served	Line charge revenue ($000)
8			
9			
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	**Eastland Network**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**All**

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**			
9	*Number of ICPs connected in year by consumer type*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11	Domestic/Residential		62	
12	Commercial		131	
13	Large Commercial		3	
14	Industrial		-	
15				
16	** include additional rows if needed*			
17	**Connections total**		196	
18				
19	**Distributed generation**			
20	Number of connections made in year		60	**connections**
21	Capacity of distributed generation installed in year		0.21	**MVA**
22	**9e(ii): System Demand**			
23				
24				
25	**Maximum coincident system demand**		**Demand at time of maximum coincident demand (MW)**	
26	GXP demand		58	
27	Distributed generation output at HV and above	*plus*	1	
28	**Maximum coincident system demand**		59	
29	Net transfers to (from) other EDBs at HV and above	*less*		
30	**Demand on system for supply to consumers' connection points**		59	
31	**Electricity volumes carried**		**Energy (GWh)**	
32	Electricity supplied from GXPs		299	
33	Electricity exports to GXPs	*less*	–	
34	Electricity supplied from distributed generation	*plus*	12	
35	Net electricity supplied to (from) other EDBs	*less*	–	
36	**Electricity entering system for supply to consumers' connection points**		311	
37	Total energy delivered to ICPs	*less*	283	
38	**Electricity losses (loss ratio)**		28	9.0%
39				
40	**Load factor**		0.60	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43	Distribution transformer capacity (EDB owned)		220	
44	Distribution transformer capacity (Non-EDB owned, estimated)		48	
45	**Total distribution transformer capacity**		268	
46				
47	**Zone substation transformer capacity**		339	

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**Gisborne**

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**			
9	*Number of ICPs connected in year by consumer type*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11	Domestic/Residential		51	
12	Commercial		106	
13	Large Commercial		2	
14	Industrial		–	
15				
16	** include additional rows if needed*			
17	**Connections total**		159	
18				
19	**Distributed generation**			
20	Number of connections made in year		53	**connections**
21	Capacity of distributed generation installed in year		0.18	**MVA**
22	**9e(ii): System Demand**			
23				
24				
25	**Maximum coincident system demand**		**Demand at time of maximum coincident demand (MW)**	
26	GXP demand		49	
27	Distributed generation output at HV and above	*plus*	1	
28	**Maximum coincident system demand**		50	
29	Net transfers to (from) other EDBs at HV and above	*less*		
30	**Demand on system for supply to consumers' connection points**		50	
31	**Electricity volumes carried**		**Energy (GWh)**	
32	Electricity supplied from GXPs		252	
33	Electricity exports to GXPs	*less*	–	
34	Electricity supplied from distributed generation	*plus*	5	
35	Net electricity supplied to (from) other EDBs	*less*	–	
36	**Electricity entering system for supply to consumers' connection points**		256	
37	Total energy delivered to ICPs	*less*	233	
38	**Electricity losses (loss ratio)**		23	8.9%
39				
40	**Load factor**		0.59	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43	Distribution transformer capacity (EDB owned)		180	
44	Distribution transformer capacity (Non-EDB owned, estimated)		39	
45	**Total distribution transformer capacity**		219	
46				
47	**Zone substation transformer capacity**		286	

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**Wairoa**

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**			
9	*Number of ICPs connected in year by consumer type*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11	Domestic/Residential		11	
12	Commercial		25	
13	Large Commercial		1	
14	Industrial		–	
15				
16	** include additional rows if needed*			
17	**Connections total**		37	
18				
19	**Distributed generation**			
20	Number of connections made in year		7	**connections**
21	Capacity of distributed generation installed in year		0.03	**MVA**
22	**9e(ii): System Demand**			
23				
24				
25	**Maximum coincident system demand**		**Demand at time of maximum coincident demand (MW)**	
26	GXP demand		10	
27	Distributed generation output at HV and above	*plus*	–	
28	**Maximum coincident system demand**		10	
29	Net transfers to (from) other EDBs at HV and above	*less*		
30	**Demand on system for supply to consumers' connection points**		10	
31	**Electricity volumes carried**		**Energy (GWh)**	
32	Electricity supplied from GXPs		47	
33	Electricity exports to GXPs	*less*	–	
34	Electricity supplied from distributed generation	*plus*	7	
35	Net electricity supplied to (from) other EDBs	*less*	–	
36	**Electricity entering system for supply to consumers' connection points**		54	
37	Total energy delivered to ICPs	*less*	49	
38	**Electricity losses (loss ratio)**		5	9.4%
39				
40	**Load factor**		0.65	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43	Distribution transformer capacity (EDB owned)		40	
44	Distribution transformer capacity (Non-EDB owned, estimated)		9	
45	**Total distribution transformer capacity**		49	
46				
47	**Zone substation transformer capacity**		54	

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**Eastland Network Limited/ALL**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)	–	
11	Class B (planned interruptions on the network)	231	
12	Class C (unplanned interruptions on the network)	323	
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)	–	
17	Class H (planned interruptions caused by another disclosing entity)	–	
18	Class I (interruptions caused by parties not included above)	2	
19	**Total**	556	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	201	122
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.34	70.64
27	Class C (unplanned interruptions on the network)	3.10	199.52
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	0.00	0.02
34	**Total**	3.44	270.2
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	3.35	257.66
38			

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**Eastland Network Limited/ALL**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

Row	Cause	SAIFI	SAIDI
42	Lightning	0.16	4.11
43	Vegetation	0.36	44.73
44	Adverse weather	0.29	43.07
45	Adverse environment	0.00	0.12
46	Third party interference	0.11	9.27
47	Wildlife	0.07	4.10
48	Human error	–	–
49	Defective equipment	0.72	56.05
50	Cause unknown	1.39	38.08

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

Row	Main equipment involved	SAIFI	SAIDI
55	Subtransmission lines	0.00	0.25
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	0.33	66.30
69	Distribution cables (excluding LV)	0.01	4.09
60	Distribution other (excluding LV)	–	–

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

Row	Main equipment involved	SAIFI	SAIDI
64	Subtransmission lines	1.09	28.70
65	Subtransmission cables	–	–
66	Subtransmission other	–	–
67	Distribution lines (excluding LV)	1.80	153.74
68	Distribution cables (excluding LV)	0.21	17.08
69	Distribution other (excluding LV)	–	–

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

Row	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
72	Subtransmission lines	14	643	2.18
73	Subtransmission cables	–	0	–
74	Subtransmission other	–		
75	Distribution lines (excluding LV)	291	2,387	12.19
76	Distribution cables (excluding LV)	18	140	12.89
77	Distribution other (excluding LV)	–		
78	**Total**	323		

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**Eastland Network Limited/GIS**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)	–	
11	Class B (planned interruptions on the network)	164	
12	Class C (unplanned interruptions on the network)	234	
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)	–	
17	Class H (planned interruptions caused by another disclosing entity)	–	
18	Class I (interruptions caused by parties not included above)	2	
19	**Total**	400	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	155	79
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.32	62.43
27	Class C (unplanned interruptions on the network)	2.59	139.27
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	0.00	0.03
34	**Total**	2.92	201.7
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	2.73	199.86
38			

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**Eastland Network Limited/GIS**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

Cause	SAIFI	SAIDI
Lightning	0.19	4.86
Vegetation	0.36	47.29
Adverse weather	0.15	18.08
Adverse environment	0.00	0.14
Third party interference	0.09	6.96
Wildlife	0.08	3.75
Human error	–	–
Defective equipment	0.57	35.92
Cause unknown	1.14	22.27

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.00	0.31
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.32	59.53
Distribution cables (excluding LV)	0.01	2.59
Distribution other (excluding LV)	–	–

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	1.01	19.12
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	1.48	114.93
Distribution cables (excluding LV)	0.10	5.23
Distribution other (excluding LV)	–	–

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	11	450	2.45
Subtransmission cables	–	–	–
Subtransmission other	–		
Distribution lines (excluding LV)	209	1,706	12.25
Distribution cables (excluding LV)	14	120	11.70
Distribution other (excluding LV)	–		
Total	234		

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**Eastland Network Limited/WRA**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)	–	
11	Class B (planned interruptions on the network)	67	
12	Class C (unplanned interruptions on the network)	89	
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)	–	
17	Class H (planned interruptions caused by another disclosing entity)	–	
18	Class I (interruptions caused by parties not included above)	–	
19	**Total**	156	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	46	43
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.40	106.32
27	Class C (unplanned interruptions on the network)	5.32	461.48
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	5.72	567.8
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	3.84	359.62
38			

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**
Network / Sub-network Name	**Eastland Network Limited/WRA**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

40

	Cause	SAIFI	SAIDI
41	**Cause**	**SAIFI**	**SAIDI**
42	Lightning	0.02	0.86
43	Vegetation	0.35	33.59
44	Adverse weather	0.86	151.72
45	Adverse environment	–	–
46	Third party interference	0.22	19.30
47	Wildlife	0.05	5.61
48	Human error	–	–
49	Defective equipment	1.36	143.59
50	Cause unknown	2.48	106.81

51

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

53

	Main equipment involved	SAIFI	SAIDI
54	**Main equipment involved**	**SAIFI**	**SAIDI**
55	Subtransmission lines	–	–
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	0.38	95.75
69	Distribution cables (excluding LV)	0.02	10.57
60	Distribution other (excluding LV)	–	–

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

62

	Main equipment involved	SAIFI	SAIDI
63	**Main equipment involved**	**SAIFI**	**SAIDI**
64	Subtransmission lines	1.41	70.37
65	Subtransmission cables	–	–
66	Subtransmission other	–	–
67	Distribution lines (excluding LV)	3.19	322.48
68	Distribution cables (excluding LV)	0.72	68.63
69	Distribution other (excluding LV)	–	–

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

	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
71	**Main equipment involved**	**Number of Faults**	**Circuit length (km)**	**Fault rate (faults per 100km)**
72	Subtransmission lines	3	193	1.55
73	Subtransmission cables	–	0	–
74	Subtransmission other	–		
75	Distribution lines (excluding LV)	82	680	12.05
76	Distribution cables (excluding LV)	4	20	19.96
77	Distribution other (excluding LV)	–		
78	**Total**	89		

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

Company Name	Eastland Network
Disclosure Date	31 March 2020
Disclosure Year (year ended)	31 March 2020

Templates for Schedules 5f & 5g
Template Version 4.1. Prepared 21 December 2017

Table of Contents

Disclosure Template Instructions

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

Instructions for completing schedules 5f & 5g

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

Company Name and Dates

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

Data Entry Cells and Calculated Cells

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

Validation Settings on Data Entry Cells

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

Inserting Additional Rows

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

Schedule References

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

Company Name: **Eastland Network**
For Year Ended: **31 March 2020**

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

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

sch ref	Line Item*	Allocation methodology type	Cost allocator	Allocator type	Allocator Metric (%)		Value allocated ($000)				OVABAA allocation increase ($000)
					Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	
7											
8											
11	**Service interruptions and emergencies**										
12	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
13	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
14	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
15	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
16	**Not directly attributable**						-	-	-	-	-
17	**Vegetation management**										
18	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
19	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
20	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
21	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
22	**Not directly attributable**						-	-	-	-	-
23	**Routine and corrective maintenance and inspection**										
24	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
25	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
26	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
27	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
28	**Not directly attributable**						-	-	-	-	-
29	**Asset replacement and renewal**										
30	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
31	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
32	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
33	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
34	**Not directly attributable**						-	-	-	-	-
35											

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

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

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

sch ref												
36	**System operations and network support**											
37	Engineering Services provided	ABAA	FTEs	Causal	-	100.00%	-	-	317	317	
38	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
39	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
40	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
41	**Not directly attributable**						-	-	317	317	-
42	**Business support**										
43	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
44	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
45	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
46	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
47	**Not directly attributable**						-	-	-	-	-
48											
49	**Operating costs not directly attributable**						-	-	317	317	-
50											
51	**Pass through and recoverable costs**										
52	**Pass through costs**										
53	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
54	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
55	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
56	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
57	**Not directly attributable**						-	-	-	-	-
58	**Recoverable costs**										
59	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
60	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
61	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
62	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
63	**Not directly attributable**						-	-	-	-	-
64	** include additional rows if needed*										

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

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

sch ref	Line Item*	Allocation methodology type	Allocator	Allocator type	Allocator Metric (%)		Value allocated ($000)				OVABAA allocation increase ($000)
					Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	
11	**Subtransmission lines**										
12	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
13	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
14	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
15	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
16	**Not directly attributable**						-	-	-	-	-
17	**Subtransmission cables**										
18	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
19	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
20	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
21	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
22	**Not directly attributable**						-	-	-	-	-
23	**Zone substations**										
24	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
25	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
26	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
27	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
28	**Not directly attributable**						-	-	-	-	-
29	**Distribution and LV lines**										
30	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
31	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
32	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
33	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
34	**Not directly attributable**						-	-	-	-	-

Company Name	**Eastland Network**
For Year Ended	**31 March 2020**

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

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

sch ref											
35	**Distribution and LV cables**										
36	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
37	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
38	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
39	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
40	**Not directly attributable**						-	-	-	-	-
41											
42	**Distribution substations and transformers**										
43	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
44	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
45	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
46	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
47	**Not directly attributable**						-	-	-	-	-
48											
49	**Distribution switchgear**										
50	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
51	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
52	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
53	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
54	**Not directly attributable**						-	-	-	-	-
55	**Other network assets**										
56	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
57	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
58	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
59	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
60	**Not directly attributable**						-	-	-	-	-
61	**Non-network assets**										
62	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
63	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
64	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
65	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
66	**Not directly attributable**						-	-	-	-	-
67											
68	**Regulated service asset value not directly attributable**						-	-	-	-	-
69	** include additional rows if needed*										

Company Name	Eastland Network Limited
For Year Ended	31 March 2020

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).

Box 1: Explanatory comment on return on investment

There are no reclassified items.

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).

Box 2: Explanatory comment on regulatory profit
Material items included in other regulated income included

- Our regulated profit for the year is $13.9m which is an increase compared to regulated income from the previous year.
- Material items included in other regulated income included a settlement of $369k from Farmers Air relating to an incident occurring in 2017 when a plane flew into powerlines and caused a loss of supply to all of Gisborne.

There are no reclassified items.

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 **Error! Reference source not found.**

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

Box 3: Explanatory comment on merger and acquisition expenditure
There were no merger or acquisition expenditure during the year.

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)
The RAB has increased by $4.3m. CPI increased from 1.1% to 1.5% which resulted in an increase in revaluations. Assets commissioned contributed to $8.5m to the RAB but was a significant decrease in assets commissioned in 2019. However, it is in line with years prior to 2019.

The $(1.9m) resulting for asset allocation adjustments is related to the change in use of investment building. Previously ENL used a proportion of properties to store assets etc. ENL no longer require this and are being solely used as investment building and properties in the region.

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

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

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

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

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

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

Box 5: Regulatory tax allowance: permanent differences The amounts are immaterial.

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

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

Box 6: Tax effect of other temporary differences (current disclosure year) The amounts are immaterial.

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 Not applicable

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 No asset allocation has been applied.

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.

Box 9: Explanation of capital expenditure for the disclosure year

Most of the capital expenditure is focused on asset replacement and renewal to maintain the network by replacing aging assets.

Major expenditure items for categories in asset replacement and renewal were:

Tuai 110/11kv zone substation transformer replacement.

Replace 2 Zone Substations at Matawhero.

Planned distribution, Subtransmission and LV pole replacements.

There is no materiality threshold applied to the schedule.

There are no items reclassified during the year.

Capital expenditure for the year was $10.3m compared to $11.4m during 2019.

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

Asset replacement and renewal expenditure related to replacement of components on poles/lines that are not capital in nature. Examples include replacing cross arms and maintenance on painting transformers, oil changes on transformers etc. Asset replacement and renewal is the second largest operational expenditure item after business support. This category also includes $1.41m of avoided cost of distribution that is paid to a generation service who provide the network support which avoid significant upgrade for capacity and security.

There have been no reclassified items during the year.

Variance between forecast and actual expenditure (Schedule 7)

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

Box 11: Explanatory comment on variance in actual to forecast expenditure

CAPITAL EXPENDITURE

Customer Connections variance (-$40k)

This variance relate to unplanned customer driven expenditure category and is not considered material.

System Growth variances (-$454k)

The planned system growth for a 11kv link between Makaraka and Awapuni was completed but came in under budget by $93k. The unplanned growth, particularly unplanned upgrades to existing transformers because of consumer-initiated growth, was less than anticipated, (-$304k).

Asset Replacement and Renewal variances (+$515k)

This overspend is related to additional 11kV pole replacements in Gisborne and Wairoa.

Reliability, Safety and Environment (-$332k)

Quality of Supply, (-$29k)

This variance is considered immaterial.

Other, (-$303k)

This variance is a direct result of galvanised meter box replacements having to be deferred because of a lack of suitable field service resources and retailer agreements for payments.

Non- network Assets (-$278k)

Typical, (-8$k)

This variance is considered immaterial.

Atypical, (-$270k)

This variance relates to the deferral of various non-network building projects in Carnarvon Street and the removal of software replacement that is now being done as part of a larger IT project.

OPERATIONAL EXPENDITURE

Routine and Corrective Maintenance and Inspection (-$526k)

The underspend is due to underspend in routine patrolling of lines and maintenance, alongside minor variances in other various projects.

Asset Replacement and Renewal (-$226k)

The underspend relates to small variances in various planned maintenance on assets.

Vegetation Management (+$40k)

This overspend relates to additional vegetation management in the Gisborne and Wairoa regions.

Service interruptions and emergencies (-$2k)

This variance against budget for this unplanned expenditure category is not considered material.

System operations and network support (+1.3m)

The main reason for the variance was an error in forecasting. The forecast that we planned should never have been $1.269m it should have been $2.101m. This has been reflected in our most recent AMP. Capital on costs that are deducted from the total system operations and network support was deducted twice. With the correct forecast figure there is still roughly a $500k overspend this relates to increased consultancy costs (approx. $200k) due to, Increased direct labour costs (approx. $250k) and other small variances across multiple general ledger accounts.

Business Support (-322k)

Business support is made up of 20 different ledger accounts. The variance is made up of small underspends on most accounts. The underspend was less than 10% so wasn't considered material.

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

There is no material difference between target and actual revenue.

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

Where an interruption to the supply of electricity distribution services is followed by restoration of some customers, and then later by a "successive interruption" to restore all customers, Eastland have only been calculating the relevant SAIFI values based on a single outage, not based on multiple interruptions.

Following clarification from the Commerce Commission, we are now aware that this treatment is inconsistent with the definition of "interruption" in the Default Price Path and Schedule 1.4 of Electricity Distribution Information Disclosure Determination 2012, and has led to SAIFI being underreported in previous years.

The data stated in this year's Schedule 10 is consistent with how Eastland has been treating SAIFI in the past.

The information provided in Schedule 10 has been derived from the records kept by the control room. These processes follow Eastland Outage Data Recording Procedures contained in our Quality Standards Manuals and are typical of industry control room procedures. As these processes are reliant on initial manual paper-based data capture, external verification of completeness of data capture is difficult.

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
Network assets such as the substation buildings, zone sub transformers and switchgear, SCADA, other communications equipment excluding fibre-optic cables are insured but lines, poles and cables are not. These assets are insured for replacement cost to a maximum of $74 million. Eastland Network Limited has no self-insurance cover.

Amendments to previously disclosed information

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

    18.1 a description of each error; and

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

Box 15: Disclosure of amendment to previously disclosed information
There were no amendments to the previously disclosed information.

Company Name Eastland Network

For Year Ended 31 March 2020

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 2.6.6.

2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with 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
This was previously disclosed in the Asset Management Plan in March.

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
This was previously disclosed in the Asset Management Plan in March.

Company Name	Eastland Network
For Year Ended	31 March 2020

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**Error! Reference source not found.**.

   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 18 Certification for Year-end Disclosures

Clause 2.9.2

We, MATANUKU MAHUIKA and JON NICHOLS being directors of Eastland Network 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 Eastland Network Limited's accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained except in the case of recording of outage information contained in Schedule 10. While we believe that sufficient records are maintained, third party verification of the completeness of this data is difficult to achieve.

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.

Director *Director*

16·09·2020 16/9/20

Date *Date*

Deloitte.

INDEPENDENT ASSURANCE REPORT
TO THE DIRECTORS OF EASTLAND NETWORK LIMITED AND THE COMMERCE COMMISSION

The Auditor-General is the auditor of Eastland Network Limited (the 'Company'). The Auditor-General has appointed me, Brett Tomkins, using the staff and resources of Deloitte Limited, to provide an opinion, on his behalf, on:

- whether the information required to be disclosed in accordance with the Electricity Distribution Information Disclosure Determination 2012 as amended by the Information Disclosure exemption: Disclosure and auditing of reliability information within schedule 10, issued by the Commerce Commission on 9 April 2020 (the 'Determination, as amended') for the disclosure year ended 31 March 2020, has been prepared, in all material respects, in accordance with the Determination, as amended.

  The disclosure information required to be reported by the Company, and audited by the Auditor-General, under the Determination, as amended, is in Schedules 1 to 4, 5a to 5g, 6a and 6b, 7, 10 and the explanatory notes in boxes 1 to 11 in Schedule 14 ('the Disclosure Information').

- whether the Company's basis for valuation of related party transactions ('the Related Party Transaction Information') for the disclosure year ended 31 March 2020, has been prepared, in all material respects, in accordance with clause 2.3.6 and 2.3.8 of the Determination, as amended, and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 ('the Input Methodologies Determination').

Opinion

In our opinion:
- 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, in all material respects, with the Determination, as amended; and
- the Related Party Transaction Information complies, in all material respects, with the Determination, as amended and the Input Methodologies Determination.

In forming our opinion, we have obtained sufficient recorded evidence and all the information and explanations we have required.

Basis for opinion

We conducted our engagement in accordance with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised): *Assurance Engagements Other Than Audits or Reviews of Historical Financial Information* and the Standard on Assurance Engagements 3100 (Revised): *Compliance Engagements* issued by the New Zealand Auditing and Assurance Standards Board. Copies of these standards are available on the External Reporting Board's website.

These standards require that we comply with ethical requirements and plan and perform our assurance engagement to provide reasonable assurance about whether the Disclosure Information has been prepared, in all material respects, with the Determination, as amended, and about whether the Related Party Transaction Information has been prepared, in all material respects, with the Determination, as amended and the Input Methodologies Determination. Reasonable assurance is a high level of assurance.

We have performed procedures to obtain evidence about the amounts and disclosures in the Disclosure Information, and the basis of valuation in the Related Party Transaction Information. The procedures selected depend on our judgement, including the assessment of the risks of material misstatement of the Disclosure Information and the Related Party Transaction Information, whether due to fraud, error or non-compliance with the Determination, as amended or the Input Methodologies Determination. In making those risk assessments, we considered internal control relevant to the Company's preparation of the Disclosure Information and the Related Party Transaction Information in order to design procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

Scope and inherent limitations

Because of the inherent limitations of a reasonable assurance engagement, and the test basis of the procedures performed, it is possible that fraud, error or non-compliance may occur and not be detected.

We did not examine every transaction, adjustment or event underlying the Disclosure Information or the Related Party Transaction Information nor do we guarantee complete accuracy of the Disclosure Information or the Related Party Transaction Information. Also we did not evaluate the security and controls over the electronic publication of the Disclosure Information or the Related Party Transaction Information.

The opinion expressed in this independent assurance report has been formed on the above basis.

Key Audit Matters

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

Key audit matter	How our audit addressed the key audit matter
Valuation of related party goods and services at arms-length The basis of valuation of related party transactions are required to be disclosed on Schedule 5b of the disclosure information. The Company receives fault, maintenance and electrical contract services from related parties. The Company also receives administration services provided to the Company by its immediate holding company, Eastland Group Limited, and these services are on-charged in the form of a management fee using an annual allocation of costs. The Company also charges related parties for line charges. The Directors have determined that the related party transactions identified have occurred at arms-length by comparing related party terms and conditions, including pricing, to external transactions and information. Due to the judgements and assumptions associated with the allocation of administration costs to the Company, along with the inherent judgment associated with the valuation of the goods or services on an arms-length basis, these matters have been identified as a key audit matter.	A detailed listing of all transactions impacting the company for the disclosure year ended 31 March 2020 was obtained and compared to the list of entities and transactions included on Schedule 5b. We also obtained management's methodology of how they determined the transactions were related party transactions and their assessment of these transactions at arm's length. Our procedures over the valuation of related party goods and services at arms-length included: *Goods and services (excluding administration services)* • agreed on a sample basis, the transactions listed on Schedule 5b to external transactions and information and tracing the amounts to the terms, conditions and prices of comparative external transactions or information. *Administration services* • obtained the management fees calculation from Group management; • assessed the rationale and basis of the management fees in line with our understanding of the Group; • agreed the the total costs allocated to budgets used to set the management fees and compared to actual spend; • traced the inputs used to perform the calculation to supporting documentation as considered relevant; and • recalculated the allocations and agreed the amount charged to the Company reported on Schedule 5b.
Completeness and accuracy of the non-financial reporting disclosures in relation to the faults data capture (SAIDI/SAIFI) The Information Disclosure Determination defines certain quality measures in relation to the number and duration of interruptions, faults, and causes of faults. These quality measures are expressed in the form of SAIDI and SAIFI values. The Company does not have automated systems for identifying and recording the duration of outages. The Company's policies and procedures require all faults, whether planned or unplanned, to be recorded on manual switching sheets. The switching sheets contain details regarding the class of each outage, calculation of the number of customers affected and total number of minutes for each outage. The information included on the switching sheet is then manually entered into the outages database.	We have obtained an understanding of the Company's methods by which electricity outages and their duration are recorded. We also completed analytical procedures for outage events, including analysing actual outages compared with prior year outages. To assess the completeness of the faults and interruptions used in calculating SAIFI and SAIDI, we performed the following procedures: • On a sample basis we selected work permits and traced details per the work permit to the manual switching sheets and traced the number of customers, number of minutes and the class type to the details recorded in the outages database; • On a sample basis, we selected manual switching sheets without work permits and traced the number of customers, number of minutes and class type to the details recorded in the outages database;

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Key audit matter	How our audit addressed the key audit matter
Where access to the network is required to address the fault and interruption, it is mandatory for a work permit to be completed. Work permits are sequentially numbered and are required to be attached to the manual switching sheets. This is a key audit matter because information on the frequency and duration of outages is an important measure about the reliability of electricity supply. As the Company's process is mostly not system integrated and therefore subject to manual processes without systematic controls, inaccuracies or the omission of faults can potentially have a significant impact on the reliability thresholds against which Company performance is assessed.	• A sample of work permits for April 2020 were selected for testing and traced to the ensure the faults related to the subsequent financial year; and • We have checked whether major storm and outage events recorded in the media were appropriately recorded in the outages database. To assess the accuracy of the calculation of SAIFI and SAIDI, we performed the following procedures: • Using the samples selected above, we recalculated the number of minutes and customers affected and agreed the amounts recalculated to the amounts recorded in the Outages database; • Using the samples selected above we ensured that the faults that did not meet the reporting requirements were correctly excluded from the data used to calculate SAIFI and SAIDI. • Recalculated the normalised SAIDI and SAIFI using the predetermined boundary limits. We have also reviewed the disclosure in Schedule 14 in respect of the treatment of successive interruptions.

Directors' responsibility for the preparation of the Disclosure Information and the Related Party Transaction Information

The Directors of the Company are responsible for preparation of:

- the Disclosure Information in accordance with the Determination, as amended, and
- the Related Party Transaction Information in accordance with the Determination, as amended and the Input Methodologies Determination,

and for such internal control as the Directors determine is necessary to enable the preparation of the Disclosure Information and the Related Party Transaction Information that are free from material misstatement.

Our responsibility for the audit of the Disclosure Information and the Related Party Transaction Information

Our responsibility is to express an opinion that provides reasonable assurance on whether:

- the Disclosure Information has been prepared, in all material respects, in accordance with the Determination, as amended; and
- the Related Party Transaction Information has been prepared, in all material respects, in accordance with the Determination, as amended, and the Input Methodologies Determination.

Independence and quality control

When carrying out the engagement, we complied with:

- the Auditor-General's independence and other ethical requirements, which incorporate the independence and ethical requirements of Professional and Ethical Standard 1 (Revised) issued by the New Zealand Auditing and Assurance Standards Board
- the independence requirements specified in the Determination, as amended; and
- the Auditor-General's quality control requirements, which incorporate the quality control requirements of Professional and Ethical Standard 3 (Amended) issued by the New Zealand Auditing and Assurance Standards Board.

The Auditor-General, and his employees, and Deloitte Limited may deal with the Company on normal terms within the ordinary course of trading activities of the Company. Other than any dealings on normal terms within the ordinary course of business, this engagement, and the annual audit of the Company's financial statements, we have no relationship with or interests in the Company.

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Use of this report

This independent assurance report has been prepared solely for the Directors of the Company and for the Commerce Commission for the purpose of providing those parties with reasonable assurance about whether the Disclosure Information has been prepared, in all material respects, in accordance with the Determination, as amended, and about whether the Related Party Transaction Information has been prepared in all material respects with the Determination, as amended and the Input Methodologies Determination. We disclaim any assumption of responsibility for any reliance on this report to any person other than the Directors of the Company or the Commerce Commission, or for any other purpose than that for which it was prepared.

Deloitte Limited

Brett Tomkins, Partner
For Deloitte Limited
On behalf of the Auditor-General
Wellington, New Zealand
17 September 2020