COMMERCE COMMISSION NEW ZEALAND

EDB Information Disclosure Requirements

Information Templates

for

Schedules 1–10

Company Name	Network Tasman Ltd
Disclosure Date	31 August 2023
Disclosure Year (year ended)	31 March 2023

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

Template Version 5.1. Prepared 24 November 2022

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Company Name	**Network Tasman Ltd**
For Year Ended	**31 March 2023**

SCHEDULE 1: ANALYTICAL RATIOS

This schedule calculates expenditure, revenue and service ratios from the information disclosed. The disclosed ratios may vary for reasons that are company specific and, as a result, must be interpreted with care. The Commerce Commission will publish a summary and analysis of information disclosed in accordance with 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**	19,888	308	100,874	3,496	27,601
10	Network	10,412	161	52,811	1,830	14,450
11	Non-network	9,476	147	48,062	1,666	13,151
12						
13	**Expenditure on assets**	21,153	327	107,291	3,718	29,357
14	Network	20,416	316	103,551	3,589	28,333
15	Non-network	737	11	3,740	130	1,023
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**	57,968	897
20	Standard consumer line charge revenue	62,638	805
21	Non-standard consumer line charge revenue	35,084	971,751
22			

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

sch ref			
24			
25	Demand density - See schedule 15 for corrected calculation.	43	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	176	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
27	Connection point density	11	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
28	Energy intensity	15,481	*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	13,000	34.65%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	12,507	33.33%
34	Total depreciation	7,189	19.16%
35	Total revaluations	12,699	33.85%
36	Regulatory tax allowance	1,608	4.29%
37	Regulatory profit/(loss) including financial incentives and wash-ups	15,915	42.42%
38	**Total regulatory income**	37,519	
39			

40 **1(v): Reliability**

sch ref			
41			
42	Interruption rate	8.87	*Interruptions per 100 circuit km*

Company Name	**Network Tasman Ltd**
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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		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
8		**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
9	**ROI – comparable to a post tax WACC**	**%**	**%**	**%**
10	Reflecting all revenue earned	2.82%	8.30%	7.77%
11	Excluding revenue earned from financial incentives	2.82%	8.30%	7.55%
12	Excluding revenue earned from financial incentives and wash-ups	2.82%	8.39%	7.63%
13				
14	**Mid-point estimate of post tax WACC**	3.72%	3.52%	4.88%
15	25th percentile estimate	3.04%	2.84%	4.20%
16	75th percentile estimate	4.40%	4.20%	5.56%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	3.16%	8.60%	8.29%
21	Excluding revenue earned from financial incentives	3.16%	8.60%	8.06%
22	Excluding revenue earned from financial incentives and wash-ups	3.16%	8.69%	8.15%
23				
24	**WACC rate used to set regulatory price path**	4.57%	4.57%	4.57%
25				
26	**Mid-point estimate of vanilla WACC**	4.05%	3.82%	5.39%
27	25th percentile estimate	3.37%	3.14%	4.71%
28	75th percentile estimate	4.73%	4.50%	6.07%
29				

sch ref					
30	**2(ii): Information Supporting the ROI**			**($000)**	
31					
32		Total opening RAB value	191,545		
33	*plus*	Opening deferred tax	(3,756)		
34	**Opening RIV**			187,789	
35					
36	**Line charge revenue**			37,891	
37					
38		Expenses cash outflow	25,507		
39	*add*	Assets commissioned	13,863		
40	*less*	Asset disposals	1,120		
41	*add*	Tax payments	787		
42	*less*	Other regulated income	(372)		
43	**Mid-year net cash outflows**			39,409	
44					
45	**Term credit spread differential allowance**			–	
46					
47		Total closing RAB value	209,789		
48	*less*	Adjustment resulting from asset allocation	(9)		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(4,577)		
51	**Closing RIV**			205,221	
52					
53	**ROI – comparable to a vanilla WACC**				8.29%
54					
55		Leverage (%)			42%
56		Cost of debt assumption (%)			4.38%
57		Corporate tax rate (%)			28%
58					
59	**ROI – comparable to a post tax WACC**				7.77%
60					

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SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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sch ref

61 2(iii): Information Supporting the Monthly ROI

sch ref		
63	**Opening RIV**	N/A

sch ref		Line charge revenue	Expenses cash outflow	Assets commissioned	Asset disposals	Other regulated income	Monthly net cash outflows
67	April						–
68	May						–
69	June						–
70	July						–
71	August						–
72	September						–
73	October						–
74	November						–
75	December						–
76	January						–
77	February						–
78	March						–
79	**Total**	–	–	–	–	–	–

sch ref		
81	**Tax payments**	N/A
83	**Term credit spread differential allowance**	N/A
85	**Closing RIV**	N/A
88	**Monthly ROI – comparable to a vanilla WACC**	N/A
90	**Monthly ROI – comparable to a post tax WACC**	N/A

92 2(iv): Year-End ROI Rates for Comparison Purposes

sch ref		
94	**Year-end ROI – comparable to a vanilla WACC**	7.99%
96	**Year-end ROI – comparable to a post tax WACC**	7.47%

98 ** 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.*

100 2(v): Financial Incentives and Wash-Ups

sch ref			
102	Net recoverable costs allowed under incremental rolling incentive scheme	834	
103	Purchased assets – avoided transmission charge	–	
104	Energy efficiency and demand incentive allowance		
105	Quality incentive adjustment	(251)	
106	Other financial incentives	–	
107	**Financial incentives**		583
109	**Impact of financial incentives on ROI**		0.23%
111	Input methodology claw-back	–	
112	CPP application recoverable costs	–	
113	Catastrophic event allowance	–	
114	Capex wash-up adjustment	(219)	
115	Transmission asset wash-up adjustment	–	
116	2013–15 NPV wash-up allowance	–	
117	Reconsideration event allowance	–	

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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).

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sch ref			
118	Other wash-ups	–	
119	**Wash-up costs**		(219)
120			
121	**Impact of wash-up costs on ROI**		–0.08%

Company Name	**Network Tasman Ltd**
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SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

sch ref				
7		**3(i): Regulatory Profit**		**($000)**
8		**Income**		
9		Line charge revenue		37,891
10	*plus*	Gains / (losses) on asset disposals		(589)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		217
12				
13		**Total regulatory income**		37,519
14		**Expenses**		
15	*less*	Operational expenditure		13,000
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		12,507
18				
19		**Operating surplus / (deficit)**		12,012
20				
21	*less*	Total depreciation		7,189
22				
23	*plus*	Total revaluations		12,699
24				
25		**Regulatory profit / (loss) before tax**		17,523
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		1,608
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		15,915
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	172	
36		Commerce Act levies	111	
37		Industry levies	125	
38		CPP specified pass through costs	–	
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	9,161	
41		Transpower new investment contract charges	1,113	
42		System operator services	–	
43		Distributed generation allowance	1,825	
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**		12,507
47				

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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).
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sch ref				
48	**3(iii): Incremental Rolling Incentive Scheme**		**($000)**	
49			**CY-1**	**CY**
50			**31 Mar 22**	**31 Mar 23**
51	Allowed controllable opex		–	–
52	Actual controllable opex		–	–
53				
54	Incremental change in year			–
55				
56			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
57	CY-5	31 Mar 18	–	–
58	CY-4	31 Mar 19	–	–
59	CY-3	31 Mar 20	–	–
60	CY-2	31 Mar 21	–	–
61	CY-1	31 Mar 22	782	834
62	**Net incremental rolling incentive scheme**			834
63				
64	**Net recoverable costs allowed under incremental rolling incentive scheme**			834
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			–

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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

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

		RAB	RAB	RAB	RAB	RAB
	for year ended	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**
		($000)	**($000)**	**($000)**	**($000)**	**($000)**
Total opening RAB value		165,522	165,472	174,395	177,306	191,545
less **Total depreciation**		6,807	6,984	6,984	7,346	7,189
plus **Total revaluations**		2,452	4,187	2,650	12,221	12,699
plus **Assets commissioned**		6,557	12,075	8,066	10,506	13,863
less **Asset disposals**		393	332	847	1,050	1,120
plus **Lost and found assets adjustment**		–	–	–	–	–
plus **Adjustment resulting from asset allocation**		(1,859)	(23)	26	(92)	(9)
Total closing RAB value		165,472	174,395	177,306	191,545	209,789

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB *		RAB	
	($000)	**($000)**	**($000)**	**($000)**
Total opening RAB value		193,343		191,545
less				
Total depreciation		7,381		7,189
plus				
Total revaluations		12,818		12,699
plus				
Assets commissioned (other than below)	13,990		13,863	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	–		–	
Assets commissioned		13,990		13,863
less				
Asset disposals (other than below)	1,187		1,120	
Asset disposals to a regulated supplier	–		–	
Asset disposals to a related party	–		–	
Asset disposals		1,187		1,120
plus **Lost and found assets adjustment**		–		–
plus **Adjustment resulting from asset allocation**				(9)
Total closing RAB value		211,583		209,789

** 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.*

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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				1,218
55		CPI_4^{-4}				1,142
56		Revaluation rate (%)				6.65%
57						
58			**Unallocated RAB ***		**RAB**	
59			**($000)**	**($000)**	**($000)**	**($000)**
60		Total opening RAB value	193,343		191,545	
61	*less*	Opening value of fully depreciated, disposed and lost assets	729		722	
62						
63		Total opening RAB value subject to revaluation	192,614		190,823	
64		**Total revaluations**		12,818		12,699
65						
66	**4(iv): Roll Forward of Works Under Construction**					
67			**Unallocated works under construction**		**Allocated works under construction**	
68		**Works under construction—preceding disclosure year**		8,902		8,899
69	*plus*	Capital expenditure	14,615		14,615	
70	*less*	Assets commissioned	13,990		13,863	
71	*plus*	Adjustment resulting from asset allocation			(81)	
72		**Works under construction - current disclosure year**		9,527		9,570
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 *		RAB	
77					
78		($000)	($000)	($000)	($000)
79	Depreciation - standard	6,966		6,854	
80	Depreciation - no standard life assets	415		335	
81	Depreciation - modified life assets	–		–	
82	Depreciation - alternative depreciation in accordance with CPP	–		–	
83	**Total depreciation**		7,381		7,189
84					

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

($000 unless otherwise specified)

sch ref	Asset or assets with changes to depreciation*	Reason for non-standard depreciation (text entry)	Depreciation charge for the period (RAB)	Closing RAB value under 'non-standard' depreciation	Closing RAB value under 'standard' depreciation
86					
87	0	–	–	–	–
88	0	–	–	–	–
89	0	–	–	–	–
90	0	–	–	–	–
91	0	–	–	–	–
92	0	–	–	–	–
93	0	–	–	–	–
94	0	–	–	–	–

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
98												
99		**Total opening RAB value**	8,657	11,334	28,205	27,759	60,800	28,353	10,226	12,832	3,379	191,545
100	*less*	Total depreciation	318	223	780	1,782	1,387	1,184	462	750	303	7,189
101	*plus*	Total revaluations	569	763	1,860	1,836	4,045	1,886	681	853	206	12,699
102	*plus*	Assets commissioned	207	119	2,103	3,369	3,860	2,471	899	453	382	13,863
103	*less*	Asset disposals	6	78	–	216	208	356	14	36	206	1,120
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	10	–	–	–	(4)	(15)	(9)
106	*plus*	Asset category transfers	(112)	125	–	–	(13)	–	(1)	1	–	–
107		**Total closing RAB value**	8,997	12,040	31,388	30,976	67,097	31,170	11,329	13,349	3,443	209,789
108												
109		**Asset Life**										
110		Weighted average remaining asset life	41.6	52.0	36.8	63.8	49.9	51.3	46.3	18.3	21.9	(years)
111		Weighted average expected total asset life	63.0	64.6	50.7	85.5	69.2	71.6	60.4	37.5	29.9	(years)

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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**			17,523
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	81	*	
12		Amortisation of initial differences in asset values	3,238		
13		Amortisation of revaluations	982		
14					4,301
15					
16	*less*	Total revaluations	12,699		
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	3,381		
21					16,081
22					
23		**Regulatory taxable income**			5,743
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			5,743
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			1,608
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	69,149		
37	*less*	Amortisation of initial differences in asset values	3,238		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	39		
40		Closing unamortised initial differences in asset values			65,873
41					
42		Opening weighted average remaining useful life of relevant assets (years)			21
43					

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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				
44	**5a(iv): Amortisation of Revaluations**			**($000)**
45				
46		Opening sum of RAB values without revaluations	160,301	
47				
48		Adjusted depreciation	6,207	
49		Total depreciation	7,189	
50		Amortisation of revaluations		982
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**	(3,756)	
61				
62	*plus*	Tax effect of adjusted depreciation	1,738	
63				
64	*less*	Tax effect of tax depreciation	1,754	
65				
66	*plus*	Tax effect of other temporary differences*	(224)	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	907	
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	(310)	
73				
74	*plus*	Deferred tax cost allocation adjustment	16	
75				
76		**Closing deferred tax**		(4,577)
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**	75,852	
84	*less*	Tax depreciation	6,265	
85	*plus*	Regulatory tax asset value of assets commissioned	14,275	
86	*less*	Regulatory tax asset value of asset disposals	14	
87	*plus*	Lost and found assets adjustment	–	
88	*plus*	Adjustment resulting from asset allocation	47	
89	*plus*	Other adjustments to the RAB tax value	–	
90		**Closing sum of regulatory tax asset values**		83,895

Company Name	**Network Tasman Ltd**
For Year Ended	**31 March 2023**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

This schedule provides information on the valuation of related party transactions, in accordance with clause 2.3.6 of 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

sch ref	5b(i): Summary—Related Party Transactions	($000)	($000)
8	**Total regulatory income**		80
9			
10	**Market value of asset disposals**		–
11			
12	Service interruptions and emergencies	–	
13	Vegetation management	–	
14	Routine and corrective maintenance and inspection	–	
15	Asset replacement and renewal (opex)	–	
16	**Network opex**		–
17	Business support	–	
18	System operations and network support	–	
19	**Operational expenditure**		–
20	Consumer connection	–	
21	System growth	–	
22	Asset replacement and renewal (capex)	–	
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**		–
29	Cost of financing		–
30	Value of capital contributions		–
31	Value of vested assets		–
32	**Capital Expenditure**		–
33	**Total expenditure**		–
34			
35	**Other related party transactions**		

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

sch ref	Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
38			
39			
40			
41			
42			
43			
44			
45			
46			
47			
48			
49			
50			
51			
52			
53	**Total value of related party transactions**		–

54 ** include additional rows if needed*

Company Name	**Network Tasman Ltd**
For Year Ended	**31 March 2023**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

This schedule is only to be completed if, as at the date of the most recently published financial statements, the weighted average original tenor of the debt portfolio (both qualifying debt and non-qualifying debt) is greater than five years.

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

sch ref

7

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

9

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

17

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

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	Network Tasman Ltd
For Year Ended	31 March 2023

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

7 **5d(i): Operating Cost Allocations**

sch ref		Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
8		Value allocated ($000s)				
9		Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
10	**Service interruptions and emergencies**					
11	Directly attributable		1,444			
12	Not directly attributable	–	–	–	–	–
13	**Total attributable to regulated service**		1,444			
14	**Vegetation management**					
15	Directly attributable		1,224			
16	Not directly attributable	–	–	–	–	–
17	**Total attributable to regulated service**		1,224			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		2,593			
20	Not directly attributable	–	–	–	–	–
21	**Total attributable to regulated service**		2,593			
22	**Asset replacement and renewal**					
23	Directly attributable		1,545			
24	Not directly attributable	–	–	–	–	–
25	**Total attributable to regulated service**		1,545			
26	**System operations and network support**					
27	Directly attributable		3,467			
28	Not directly attributable	–	–	–	–	–
29	**Total attributable to regulated service**		3,467			
30	**Business support**					
31	Directly attributable		741			
32	Not directly attributable	–	1,985	1,041	3,026	–
33	**Total attributable to regulated service**		2,726			
34						
35	**Operating costs directly attributable**		11,014			
36	**Operating costs not directly attributable**	–	1,985	1,041	3,026	–
37	**Operational expenditure**		12,999			
38						

Company Name	**Network Tasman Ltd**
For Year Ended	**31 March 2023**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	405
Not directly attributable	3
Total attributable to regulated service	408
Recoverable costs	
Directly attributable	12,099
Not directly attributable	–
Total attributable to regulated service	12,099

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

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

($000)

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

($000)

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

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

Company Name	**Network Tasman Ltd**
For Year Ended	**31 March 2023**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	8,997
Not directly attributable	–
Total attributable to regulated service	8,997
Subtransmission cables	
Directly attributable	12,040
Not directly attributable	–
Total attributable to regulated service	12,040
Zone substations	
Directly attributable	31,388
Not directly attributable	–
Total attributable to regulated service	31,388
Distribution and LV lines	
Directly attributable	29,077
Not directly attributable	1,900
Total attributable to regulated service	30,977
Distribution and LV cables	
Directly attributable	67,097
Not directly attributable	–
Total attributable to regulated service	67,097
Distribution substations and transformers	
Directly attributable	31,170
Not directly attributable	–
Total attributable to regulated service	31,170
Distribution switchgear	
Directly attributable	11,329
Not directly attributable	–
Total attributable to regulated service	11,329
Other network assets	
Directly attributable	13,293
Not directly attributable	55
Total attributable to regulated service	13,348
Non-network assets	
Directly attributable	1,057
Not directly attributable	2,386
Total attributable to regulated service	3,443
Regulated service asset value directly attributable	205,448
Regulated service asset value not directly attributable	4,341
Total closing RAB value	209,789

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

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

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

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

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

Company Name	**Network Tasman Ltd**
For Year Ended	**31 March 2023**

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

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

sch ref				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		1,141
9		System growth		3,416
10		Asset replacement and renewal		6,091
11		Asset relocations		–
12		Reliability, safety and environment:		
13		Quality of supply	2,095	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	602	
16		**Total reliability, safety and environment**		2,697
17		**Expenditure on network assets**		13,345
18		Expenditure on non-network assets		482
19				
20		**Expenditure on assets**		13,827
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		31
23	*plus*	Value of vested assets		819
24				
25		**Capital expenditure**		14,615

26	**6a(ii): Subcomponents of Expenditure on Assets (where known)**		**($000)**
27	Energy efficiency and demand side management, reduction of energy losses		423
28	Overhead to underground conversion		–
29	Research and development		–
	Cybersecurity (Commission only)	Not required until 2024	N/A

30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Consumers 20kVA and less	370	
33		Consumers greater than 20kVA	771	
34			–	
35			–	
36			–	
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		1,141
39				
40	*less*	Capital contributions funding consumer connection expenditure	13	
41		**Consumer connection less capital contributions**		1,128

42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement and**
43			**System Growth**	**Renewal**
44			**($000)**	**($000)**
45		Subtransmission	–	148
46		Zone substations	–	2,759
47		Distribution and LV lines	1,539	17
48		Distribution and LV cables	914	615
49		Distribution substations and transformers	391	40
50		Distribution switchgear	439	54
51		Other network assets	133	2,458
52		**System growth and asset replacement and renewal expenditure**	3,416	6,091
53	*less*	Capital contributions funding system growth and asset replacement and renewal	7	11
54		**System growth and asset replacement and renewal less capital contributions**	3,409	6,080
55				

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

Company Name	**Network Tasman Ltd**
For Year Ended	**31 March 2023**

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

This schedule requires a breakdown of capital expenditure on assets incurred in the disclosure year, including any assets in respect of which capital contributions are received, but excluding assets that are vested assets. Information on expenditure on assets must be provided on an accounting accruals basis and must exclude finance costs.
EDBs must provide explanatory comment on their expenditure on assets in Schedule 14 (Explanatory Notes to Templates).
This information is part of audited disclosure information (as defined in section 1.4 of 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		Pole improvements	309	
72		Feeder & interconnection cables or lines	1,498	
73			–	
74			–	
75			–	
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply	288	
78		**Quality of supply expenditure**		2,095
79	*less*	Capital contributions funding quality of supply	–	
80		**Quality of supply less capital contributions**		2,095
81		**6a(vii): Legislative and Regulatory**		
82		*Project or programme**	**($000)**	**($000)**
83			–	
84			–	
85			–	
86			–	
87			–	
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory	–	
90		**Legislative and regulatory expenditure**		–
91	*less*	Capital contributions funding legislative and regulatory	–	
92		**Legislative and regulatory less capital contributions**		–
93		**6a(viii): Other Reliability, Safety and Environment**		
94		*Project or programme**	**($000)**	**($000)**
95		Platform Transformer to Padmount	402	
96			–	
97			–	
98			–	
99			–	
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment	200	
102		**Other reliability, safety and environment expenditure**		602
103	*less*	Capital contributions funding other reliability, safety and environment	–	
104		**Other reliability, safety and environment less capital contributions**		602
105				
106		**6a(ix): Non-Network Assets**		
107		**Routine expenditure**		
108		*Project or programme**	**($000)**	**($000)**
109		Land & Buildings	78	
110		IT	347	
111		Vehicles, Plant & Equipment	57	
112			–	
113			–	
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure	–	
116		**Routine expenditure**		482
117		**Atypical expenditure**		
118		*Project or programme**	**($000)**	**($000)**
119			–	
120			–	
121			–	
122			–	
123			–	
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure	–	
126		**Atypical expenditure**		–
127				
128		**Expenditure on non-network assets**		482

Company Name	**Network Tasman Ltd**
For Year Ended	**31 March 2023**

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

This schedule requires a breakdown of operational expenditure incurred in the disclosure year.
EDBs must provide explanatory comment on their operational expenditure in Schedule 14 (Explanatory notes to templates). This includes explanatory comment on any atypical operational expenditure and assets replaced or renewed as part of asset replacement and renewal operational expenditure, and additional information on insurance.
This information is part of audited disclosure information (as defined in section 1.4 of 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	1,444	
9	Vegetation management	1,224	
10	Routine and corrective maintenance and inspection	2,593	
11	Asset replacement and renewal	1,545	
12	**Network opex**		6,806
13	System operations and network support	3,467	
14	Business support	2,727	
15	**Non-network opex**		6,194
16			
17	**Operational expenditure**		13,000
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	*EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*		
20	Energy efficiency and demand side management, reduction of energy losses		85
21	Direct billing*		–
22	Research and development		–
23	Insurance		411
24	Cybersecurity (Commission only)	Not required until 2024	N/A
25	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Network Tasman Ltd**
For Year Ended	**31 March 2023**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

This schedule compares actual revenue and expenditure to the previous forecasts that were made for the disclosure year. Accordingly, this schedule requires the forecast revenue and expenditure information from previous disclosures to be inserted.
EDBs must provide explanatory comment on the variance between actual and target revenue and forecast expenditure in Schedule 14 (Mandatory Explanatory Notes). This information is part of the audited disclosure information (as defined in section 1.4 of 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				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	37,822	37,891	0%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	1,175	1,141	(3%)
11	System growth	5,340	3,416	(36%)
12	Asset replacement and renewal	9,040	6,091	(33%)
13	Asset relocations	500	–	(100%)
14	Reliability, safety and environment:			
15	Quality of supply	5,940	2,095	(65%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	575	602	5%
18	**Total reliability, safety and environment**	6,515	2,697	(59%)
19	**Expenditure on network assets**	22,570	13,345	(41%)
20	Expenditure on non-network assets	951	482	(49%)
21	Expenditure on assets	23,521	13,827	(41%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,388	1,444	4%
24	Vegetation management	1,115	1,224	10%
25	Routine and corrective maintenance and inspection	2,377	2,593	9%
26	Asset replacement and renewal	2,125	1,545	(27%)
27	**Network opex**	7,005	6,806	(3%)
28	System operations and network support	3,449	3,467	1%
29	Business support	2,343	2,727	16%
30	**Non-network opex**	5,792	6,194	7%
31	**Operational expenditure**	12,797	13,000	2%
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses	–	423	–
34	Overhead to underground conversion	500	–	(100%)
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	89	85	(4%)
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	407	411	1%
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	**Network Tasman Ltd**
For Year Ended	**31 March 2023**
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8 **8(i): Billed Quantities by Price Component**

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)	0STL	0UNM	1RLANY	1RLDAY	1RLNIT	1RLWSR
12					**Price component**	0STL	0UNM	1RLANY	1RLDAY	1RLNIT	1RLWSR
13					**Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)**	Watts	day	kWh	kWh	kWh	kWh
14											
15	0S	Unmetered Streetlamps	Standard	–	1,825	434,580	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	69	13	–	69	–	–	–	–
17	1RL	15 kVA Capacity	Standard	18,925	104,732	–	–	73,347	2,112	2,045	27,228
18	1RS	15 kVA Capacity	Standard	16,303	144,490	–	–	–	–	–	–
19	1GL	15 kVA Capacity	Standard	3,826	21,556	–	–	–	–	–	–
20	2	20 - 150 kVA Capacity	Standard	2,839	100,396	–	–	–	–	–	–
21	2HLFC	30 kVA Capacity	Standard	–	19	–	–	–	–	–	–
22	2LLFC	150kVA Capacity	Standard	63	508	–	–	–	–	–	–
23	HLF	150kVA Capacity	Standard	4	7,672	–	–	–	–	–	–
24	3.1	Between 150 and 3000kVA	Standard	4	8,433	–	–	–	–	–	–
24	3.3	Between 150 and 3000kVA	Standard	6	8,853	–	–	–	–	–	–
24	3.4	Between 150 and 3000kVA	Standard	179	132,468	–	–	–	–	–	–
24	3.5	Between 150 and 3000kVA	Standard	2	11,907	–	–	–	–	–	–
24	6.1	> 3000,	Non-standard	1	96,270	–	–	–	–	–	–
24	6.2	> 3000,	Non-standard	1	14,455	–	–	–	–	–	–
24	CB	Cobb River Hydro	Non-standard	1	34	–	–	–	–	–	–
24	MAT	Matiri Hydro	Non-standard	1	33	–	–	–	–	–	–
24	Connections	0	Standard	–	–	–	–	–	–	–	–
24	Solar Connections	0	Standard	–	–	–	–	–	–	–	–
24						–	–	–	–	–	–
25	*Add extra rows for additional consumer groups or price category codes as necessary*										
26			**Standard consumer totals**	42,220	542,872	434,580	69	73,347	2,112	2,045	27,228
27			**Non-standard consumer totals**	4	110,792	–	–	–	–	–	–
28			**Total for all consumers**	42,224	653,664	434,580	69	73,347	2,112	2,045	27,228
29											

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8 ### 8(i): Billed Quantities by Price Component

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	1RLGEN	1RSANY	1RSDAY	1RSNIT	1RSWSR	1RSGEN	1GLANY	1GLDAY	1GLNIT	1GLWSR	1GLGEN	2ANY	2DAY
13				kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
15	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	2,619	–	–	–	–	–	–	–	–	–	–	–	–
18	1RS	15 kVA Capacity	Standard	–	105,545	3,189	2,270	33,486	1,977	–	–	–	–	–	–	–
19	1GL	15 kVA Capacity	Standard	–	–	–	–	–	–	18,203	1,112	561	1,680	160	–	–
20	2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	69,106	19,983
21	2HLFC	30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
22	2LLFC	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
23	HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	3.1	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	3.3	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	3.4	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	3.5	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	MAT	Matiri Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	Connections	0	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	Solar Connections	0	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24				–	–	–	–	–	–	–	–	–	–	–	–	–
25	*Add extra rows for additional consumer groups or price category codes*															
26			**Standard consumer totals**	2,619	105,545	3,189	2,270	33,486	1,977	18,203	1,112	561	1,680	160	69,106	19,983
27			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–
28			**Total for all consumers**	2,619	105,545	3,189	2,270	33,486	1,977	18,203	1,112	561	1,680	160	69,106	19,983

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SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8 **8(i): Billed Quantities by Price Component**

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	2NIT	2WSR	2GEN	2LANY	2LDAY	2LNIT	2LWSR	2LGEN	2HANY	2HDAY	2HNIT	2HWSR	2HGEN
13				kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
15	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
18	1RS	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
19	1GL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
20	2	20 - 150 kVA Capacity	Standard	8,302	3,005	1,000	–	–	–	–	–	–	–	–	–	–
21	2HLFC	30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	14	–	–	5	–
22	2LLFC	150kVA Capacity	Standard	–	–	–	378	49	23	58	7	–	–	–	–	–
23	HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	3.1	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	3.3	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	3.4	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	3.5	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	MAT	Matiri Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	Connections	0	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	Solar Connections	0	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24				–	–	–	–	–	–	–	–	–	–	–	–	–
25	*Add extra rows for additional consumer groups or price category codes*															
26			**Standard consumer totals**	8,302	3,005	1,000	378	49	23	58	7	14	–	–	5	–
27			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–
28			**Total for all consumers**	8,302	3,005	1,000	378	49	23	58	7	14	–	–	5	–

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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

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sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	HLFANY	HLFDAY	HLFNIT	HLFWSR	HLFGEN	1RL	1RS	1GL	2	2HLFC	2LLFC	HLF	AnyDem31
13				kWh	kWh	kWh	kWh	kWh	Daily	Daily	Daily	Capacity	Daily	Daily	kVA	kVA
14																
15	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	–	–	–	–	–	18,921	–	–	–	–	–	–	–
18	1RS	15 kVA Capacity	Standard	–	–	–	–	–	–	16,379	–	–	–	–	–	–
19	1GL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	3,795	–	–	–	–	–
20	2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	130,038	–	–	–	–
21	2HLFC	30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	5	–	–	–
22	2LLFC	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	231	–	–
23	HLF	150kVA Capacity	Standard	3,824	2,725	1,065	58	21	–	–	–	–	–	–	2,782	–
24	3.1	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	2,296
24	3.3	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	3.4	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	3.5	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	MAT	Matiri Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	Connections	0	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	Solar Connections	0	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24				–	–	–	–	–	–	–	–	–	–	–	–	–
25	*Add extra rows for additional consumer groups or price category codes*															
26			**Standard consumer totals**	3,824	2,725	1,065	58	21	18,921	16,379	3,795	130,038	5	231	2,782	2,296
27			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–
28			**Total for all consumers**	3,824	2,725	1,065	58	21	18,921	16,379	3,795	130,038	5	231	2,782	2,296
29																

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8 **8(i): Billed Quantities by Price Component**

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	AnyDem33	AnyDem34	AnyDem35	WinDem	kVAr	SD31	SN31	WD31	WN31	SD33	SN33	WD33	WN33
13				kVA	kVA	kVA	kW	kVAr	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh
15	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
18	1RS	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
19	1GL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
20	2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
21	2HLFC	30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
22	2LLFC	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
23	HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	3.1	Between 150 and 3000kVA	Standard	–	–	–	1,462	–	3,490	1,429	2,528	986	–	–	–	–
24	3.3	Between 150 and 3000kVA	Standard	2,450	–	–	1,120	–	–	–	–	–	3,888	1,790	2,236	939
24	3.4	Between 150 and 3000kVA	Standard	–	49,624	–	20,547	124	–	–	–	–	–	–	–	–
24	3.5	Between 150 and 3000kVA	Standard	–	–	3,094	1,252	–	–	–	–	–	–	–	–	–
24	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	MAT	Matiri Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	Connections	0	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	Solar Connections	0	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24				–	–	–	–	–	–	–	–	–	–	–	–	–
25	*Add extra rows for additional consumer groups or price category codes*															
26			**Standard consumer totals**	2,450	49,624	3,094	24,381	124	3,490	1,429	2,528	986	3,888	1,790	2,236	939
27			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–
28			**Total for all consumers**	2,450	49,624	3,094	24,381	124	3,490	1,429	2,528	986	3,888	1,790	2,236	939

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**

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sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	SD34	SN34	WD34	WN34	SD35	SN35	WD35	WN35	3.1GEN	3.3GEN	3.4GEN	3.4GEN	6.1
13				kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	Annual
14																
15	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
18	1RS	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
19	1GL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
20	2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
21	2HLFC	30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
22	2LLFC	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
23	HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	3.1	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	3.3	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	1,933	–	–	–
24	3.4	Between 150 and 3000kVA	Standard	53,819	19,742	43,001	15,906	–	–	–	–	–	–	86	–	–
24	3.5	Between 150 and 3000kVA	Standard	–	–	–	–	4,642	2,117	3,525	1,623	–	–	–	86	–
24	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	1
24	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	MAT	Matiri Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	Connections	0	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24	Solar Connections	0	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
24				–	–	–	–	–	–	–	–	–	–	–	–	–
25	*Add extra rows for additional consumer groups or price category codes*															
26			**Standard consumer totals**	53,819	19,742	43,001	15,906	4,642	2,117	3,525	1,623	–	1,933	86	86	–
27			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	1
28			**Total for all consumers**	53,819	19,742	43,001	15,906	4,642	2,117	3,525	1,623	–	1,933	86	86	1

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SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8 **8(i): Billed Quantities by Price Component**

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	6.2	NDL	NCA Admin G0	NCA Admin G1	NCA Admin G2	NCA Admin G3	CB	MAT	Standard DG Part1A	Standard DG Part1	DG >10kw <100kW	DG >100kw <1000kW
13				Annual	kVA=km	New connection application	New connection application	New connection application	New connection application	Annual	Annual	Per application	Per application	Per application	Per application
15	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–
17	1RL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–
18	1RS	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–
19	1GL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–
20	2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–
21	2HLFC	30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–
22	2LLFC	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–
23	HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–
24	3.1	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–
24	3.3	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–
24	3.4	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–
24	3.5	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–
24	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–
24	6.2	> 3000,	Non-standard	1	–	–	–	–	–	–	–	–	–	–	–
24	CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–
24	MAT	Matiri Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–
24	Connections	0	Standard	–	28,629	–	–	–	–	–	–	–	–	–	–
24	Solar Connections	0	Standard	–	–	–	804	34	10	–	–	442	2	33	–
24				–	–	–	–	–	–	–	–	–	–	–	–
25	*Add extra rows for additional consumer groups or price category codes*														
26			**Standard consumer totals**	–	28,629	–	804	34	10	–	–	442	2	33	–
27			**Non-standard consumer totals**	1	–	–	–	–	–	–	–	–	–	–	–
28			**Total for all consumers**	1	28,629	–	804	34	10	–	–	442	2	33	–

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

Company Name	**Network Tasman Ltd**
For Year Ended	**31 March 2023**
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	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					
							Price component	0STL	0UNM	1RLANY	1RLDAY	1RLNIT	1RLWSR
							Rate (eg, $ per day, $ per kWh, etc.)	0.00121	0.55	0.0534	0.0584	0.0361	0.0358
0S	Unmetered Streetlamps	Standard	$185	–	$143	$41		$185	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	$14	–	$11	$3		–	$14	–	–	–	–
1RL	15 kVA Capacity	Standard	$7,153	$2,788	$4,884	$2,268		–	–	$3,912	$116	$78	$975
1RS	15 kVA Capacity	Standard	$8,541	$3,923	$5,662	$2,880		$1	–	–	–	–	–
1GL	15 kVA Capacity	Standard	$1,820	$638	$1,261	$558		$2	–	–	–	–	–
2	20 - 150 kVA Capacity	Standard	$7,368	$2,728	$5,730	$1,638		$3	–	–	–	–	–
2HLFC	30 kVA Capacity	Standard	$4	$0	$3	$1		–	–	–	–	–	–
2LLFC	150kVA Capacity	Standard	$76	$14	$65	$11		–	–	–	–	–	–
HLF	150kVA Capacity	Standard	$457	$164	$371	$86		–	–	–	–	–	–
3.1	Between 150 and 3000kVA	Standard	$288	$29	$135	$153		–	–	–	–	–	–
3.3	Between 150 and 3000kVA	Standard	$360	$79	$235	$125		–	–	–	–	–	–
3.4	Between 150 and 3000kVA	Standard	$6,817	$1,381	$4,474	$2,343		–	–	–	–	–	–
3.5	Between 150 and 3000kVA	Standard	$423	$91	$279	$144		–	–	–	–	–	–
6.1	> 3000,	Non-standard	$1,570	$27	$207	$1,363		–	–	–	–	–	–
6.2	> 3000,	Non-standard	$511	$41	$211	$300		–	–	–	–	–	–
CB	-	Non-standard	$1,718	–	$1,501	$217		–	–	–	–	–	–
MAT	MAT, CB, EG etc	Non-standard	$88	–	$20	$68		–	–	–	–	–	–
NDL/New	-	Standard	$437	–	$437	–		–	–	–	–	–	–
Solar Connections	-	Standard	$61	–	$61	–		–	–	–	–	–	–
-	-	-	–	–	–	–		–	–	–	–	–	–
Add extra rows for additional consumer groups or price category codes as necessary													
		Standard consumer totals	$34,004	$11,835	$23,752	$10,252		$190	$14	$3,912	$116	$78	$975
		Non-standard consumer totals	$3,887	$68	$1,940	$1,948		–	–	–	–	–	–
		Total for all consumers	$37,891	$11,903	$25,691	$12,200		$190	$14	$3,912	$116	$78	$975

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8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end 4

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

Row	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	1RLGEN	1RSANY	1RSDAY	1RSNIT	1RSWSR	1RSGEN	1GLANY	1GLDAY	1GLNIT	1GLWSR	1GLGEN	2ANY	2DAY
35				0	0.0215	0.0265	0.0042	0.0061	0	0.0215	0.0265	0.0042	0.0061	0	0.0294	0.034
37	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
38	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
39	1RL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
40	1RS	15 kVA Capacity	Standard	–	$2,265	$84	$9	$204	–	–	–	–	–	–	–	–
41	1GL	15 kVA Capacity	Standard	–	–	–	–	–	–	$391	$29	$2	$10	–	–	–
42	2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	$2,030	$679
43	2HLFC	30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
44	2LLFC	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
45	HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	3.1	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	3.3	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	3.4	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	3.5	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	CB	-	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	MAT	MAT, CB, EG etc	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	NDL/New	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	Solar Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	-	-	-	–	–	–	–	–	–	–	–	–	–	–	–	–
47	*Add extra rows for additional consumer groups or price category codes*															
48			**Standard consumer totals**	–	$2,265	$84	$9	$204	–	$391	$29	$2	$10	–	$2,030	$679
49			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–
50			**Total for all consumers**	–	$2,265	$84	$9	$204	–	$391	$29	$2	$10	–	$2,030	$679

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

53 **Number of directly billed ICPs at year end** 4

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.

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

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Row	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	2NIT	2WSR	2GEN	2LANY	2LDAY	2LNIT	2LWSR	2LGEN	2HANY	2HDAY	2HNIT	2HWSR	2HGEN
35				0.0119	0.0161	0	0.1023	0.107	0.0849	0.0891	0	0.189	0.1936	0.1715	0.1757	0
36																
37	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
38	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
39	1RL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
40	1RS	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
41	1GL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
42	2	20 - 150 kVA Capacity	Standard	$99	$48	–	–	–	–	–	–	–	–	–	–	–
43	2HLFC	30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	$3	–	–	$1	–
44	2LLFC	150kVA Capacity	Standard	–	–	–	$39	$5	$2	$5	–	–	–	–	–	–
45	HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	3.1	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	3.3	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	3.4	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	3.5	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	CB	-	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	MAT	MAT, CB, EG etc	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	NDL/New	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	Solar Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	-	-	-	–	–	–	–	–	–	–	–	–	–	–	–	–
47	*Add extra rows for additional consumer groups or price category codes*															
48			**Standard consumer totals**	$99	$48	–	$39	$5	$2	$5	–	$3	–	–	$1	–
49			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–
50			**Total for all consumers**	$99	$48	–	$39	$5	$2	$5	–	$3	–	–	$1	–

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

53 **Number of directly billed ICPs at year end** 4

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.

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

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				HLFANY	HLFDAY	HLFNIT	HLFWSR	HLFGEN	1RL	1RS	1GL	2	2HLFC	2LLFC	HLF	AnyDem31
35	**Consumer group name or price category code**	**Consumer type or types (eg, residential, commercial etc.)**	**Standard or non-standard consumer group (specify)**	0.0067	0.0077	0.0016	0.0012	0	0.3	1	1	0.095	0.3	0.3	0.4022	0.1306
36																
37	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
38	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
39	1RL	15 kVA Capacity	Standard	–	–	–	–	–	$2,072	–	–	–	–	–	–	–
40	1RS	15 kVA Capacity	Standard	–	–	–	–	–	–	$5,978	–	–	–	–	–	–
41	1GL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	$1,385	–	–	–	–	–
42	2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	$4,509	–	–	–	–
43	2HLFC	30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	$1	–	–	–
44	2LLFC	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	$25	–	–
45	HLF	150kVA Capacity	Standard	$26	$21	$2	$0	–	–	–	–	–	–	–	$408	–
46	3.1	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	$109
46	3.3	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	3.4	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	3.5	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	CB	-	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	MAT	MAT, CB, EG etc	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	NDL/New	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	Solar Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	-	-	-	–	–	–	–	–	–	–	–	–	–	–	–	–
47	*Add extra rows for additional consumer groups or price category codes*															
48			**Standard consumer totals**	$26	$21	$2	$0	–	$2,072	$5,978	$1,385	$4,509	$1	$25	$408	$109
49			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–
50			**Total for all consumers**	$26	$21	$2	$0	–	$2,072	$5,978	$1,385	$4,509	$1	$25	$408	$109

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

53 **Number of directly billed ICPs at year end** 4

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.

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

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Row	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	AnyDem33	AnyDem34	AnyDem35	WinDem	kVAr	SD31	SN31	WD31	WN31	SD33	SN33	WD33	WN33
34/35				0.1496	0.1576	0.1496	0.2761	0.2963	0.0034	0.0016	0.0061	0.0016	0.0102	0.0056	0.0263	0.0056
36																
37	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
38	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
39	1RL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
40	1RS	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
41	1GL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
42	2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
43	2HLFC	30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
44	2LLFC	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
45	HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	3.1	Between 150 and 3000kVA	Standard	–	–	–	$147	–	$12	$2	$15	$2	–	–	–	–
46	3.3	Between 150 and 3000kVA	Standard	$134	–	–	$113	–	–	–	–	–	$40	$10	$59	$5
46	3.4	Between 150 and 3000kVA	Standard	–	$2,855	–	$2,071	$13	–	–	–	–	–	–	–	–
46	3.5	Between 150 and 3000kVA	Standard	–	–	$169	$126	–	–	–	–	–	–	–	–	–
46	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	CB	-	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	MAT	MAT, CB, EG etc	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	NDL/New	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	Solar Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	-	-	-	–	–	–	–	–	–	–	–	–	–	–	–	–
47	*Add extra rows for additional consumer groups or price category codes*															
48			**Standard consumer totals**	$134	$2,855	$169	$2,457	$13	$12	$2	$15	$2	$40	$10	$59	$5
49			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–
50			**Total for all consumers**	$134	$2,855	$169	$2,457	$13	$12	$2	$15	$2	$40	$10	$59	$5

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

53 **Number of directly billed ICPs at year end** 4

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.

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

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34				SD34	SN34	WD34	WN34	SD35	SN35	WD35	WN35	3.1GEN	3.3GEN	3.4GEN	3.4GEN	6.1
35	**Consumer group name or price category code**	**Consumer type or types (eg, residential, commercial etc.)**	**Standard or non-standard consumer group (specify)**	0.0102	0.0056	0.0263	0.0056	0.007	0.0043	0.0224	0.0043	0	0	0	0	Annual
36																
37	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
38	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
39	1RL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
40	1RS	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
41	1GL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
42	2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
43	2HLFC	30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
44	2LLFC	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
45	HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	3.1	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	3.3	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	3.4	Between 150 and 3000kVA	Standard	$548	$110	$1,130	$89	–	–	–	–	–	–	–	–	–
46	3.5	Between 150 and 3000kVA	Standard	–	–	–	–	$32	$9	$79	$7	–	–	–	–	–
46	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	$1,570
46	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	CB	-	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	MAT	MAT, CB, EG etc	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	NDL/New	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	Solar Connections	-	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–
46	-	-	-	–	–	–	–	–	–	–	–	–	–	–	–	–
47	*Add extra rows for additional consumer groups or price category codes*															
48			**Standard consumer totals**	$548	$110	$1,130	$89	$32	$9	$79	$7	–	–	–	–	–
49			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	$1,570
50			**Total for all consumers**	$548	$110	$1,130	$89	$32	$9	$79	$7	–	–	–	–	$1,570

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

53 **Number of directly billed ICPs at year end** 4

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	6.2	NDL	NCA Admin G0	NCA Admin G1	NCA Admin G2	NCA Admin G3	CB	MAT	Standard DG Part1A	Standard DG Part1	DG >10kw <100kW	DG >100kw <1000kW	*columns for additional line charge revenues by price component as necessary*
			Annual	7.714143004	125	250	325	400	Annual	Annual	100	200	500	1000	
0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	
0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	
1RL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	
1RS	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	
1GL	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	
2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	
2HLFC	30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	
2LLFC	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	
HLF	150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	
3.1	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	
3.3	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	
3.4	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	
3.5	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	
6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	
6.2	> 3000,	Non-standard	$511	–	–	–	–	–	–	–	–	–	–	–	
CB	-	Non-standard	–	–	–	–	–	–	$1,718	–	–	–	–	–	
MAT	MAT, CB, EG etc	Non-standard	–	–	–	–	–	–	–	$88	–	–	–	–	
NDL/New	-	Standard	–	$221	–	$201	$11	$4	–	–	–	–	–	–	
Solar Connections	-	Standard	–	–	–	–	–	–	–	–	$44	$0	$17	–	
-	-	-	–	–	–	–	–	–	–	–	–	–	–	–	
Add extra rows for additional consumer groups or price category codes															
		Standard consumer totals	–	$221	–	$201	$11	$4	–	–	$44	$0	$17	–	
		Non-standard consumer totals	$511	–	–	–	–	–	$1,718	$88	–	–	–	–	
		Total for all consumers	$511	$221	–	$201	$11	$4			$44	$0	$17	–	

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	4

Company Name	**Network Tasman Ltd**
For Year Ended	**31 March 2023**
Network / Sub-network Name	

SCHEDULE 9a: ASSET REGISTER

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

sch ref

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.	26,321	26,409	88	3
10	All	Overhead Line	Wood poles	No.	1,684	1,721	37	3
11	All	Overhead Line	Other pole types	No.	418	320	(98)	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	281	281	–	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	34	38	4	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	3	3	–	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	4
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	4
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	4
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	4
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	15	14	(1)	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	4
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	9	9	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	109	109	–	4
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	15	15	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	22	22	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	104	104	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	8	8	–	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	27	27	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,887	1,887	–	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	3
37	HV	Distribution Line	SWER conductor	km	–	–	–	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	150	173	23	3
39	HV	Distribution Cable	Distribution UG PILC	km	135	135	–	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	71	72	1	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1,348	1,387	39	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	154	158	4	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	147	152	5	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,829	3,831	2	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	825	853	28	3
48	HV	Distribution Transformer	Voltage regulators	No.	9	9	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	25	25	–	4
50	LV	LV Line	LV OH Conductor	km	490	486	(4)	3
51	LV	LV Cable	LV UG Cable	km	694	712	18	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	4
53	LV	Connections	OH/UG consumer service connections	No.	42,378	43,073	695	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	123	123	–	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	9	9	–	4
57	All	Load Control	Centralised plant	Lot	5	5	–	4
58	All	Load Control	Relays	No	–	–	–	4
59	All	Civils	Cable Tunnels	km	–	–	–	4

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 **Disclosure Year (year ended)** 31 March 2023

Number of assets at disclosure year end by installation date

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
10	All	Overhead Line	Concrete poles / steel structure	No.	1,966	1,250	6,859	6,065	1,957	3,540	993	63	180	124	169	162	91	167	170	155	132	189	134	137
11	All	Overhead Line	Wood poles	No.	–	65	203	186	140	179	178	17	21	9	8	21	3	7	12	11	8	56	13	15
12	All	Overhead Line	Other pole types	No.	–	–	–	68	47	90	51	–	4	1	–	–	1	–	1	4	–	1	–	–
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	96	98	2	10	61	3	3	–	2	2	1	1	–	–	1	–	–	–	–
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	2	1	–	–	–	–	6	–	8	–	–	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	–	–	–	–	1	–	–	2	–	–	–	–	–	–	–	–	–	–	–	–
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	1	2	–	1	4	2	–	–	–	–	–	–	2	–	–	–	–	–	–
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	6	–	–	–	–	–	–	–	1	–	–	–	–	1
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	5	5	14	15	12	1	–	1	2	6	2	1	2	–	–	–	–	–
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	4	5	–	–	–	–	–
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	2	2	10	1	–	–	–	–	–	1	–	–	2	2	–	–	–
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	–	10	18	–	13	–	12	–	9	14	–	–	–	–	–	–
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	2	–	–	–	–	–	2	–	–	–	4	–	–	–
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	2	3	5	5	1	–	–	–	2	–	2	–	2	–	1	–	–	–
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	39	83	461	516	154	274	103	7	7	7	12	12	6	10	3	8	13	34	16	12
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	–	–	–	–	–	13	8	1	2	2	12	6	6	12	10	8	7	4	3	3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	3	23	40	23	2	2	2	12	6	2	4	3	3	2	1	1	1
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	–	–	–	2	–	–	1	2	2	2	–	–	–	4	8	8
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	–	–	–	6	12	11	8	15	16	25	39	43	17	40	33	25	11	19	19
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	1	1	4	3	3	11	3	13	13	6	10	11	13	3	4
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	1	–	–	1	1	1	4	1	4	1	1	1	2	2	3	–
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	14	128	495	469	853	589	36	77	81	64	74	45	38	22	42	45	44	34	46
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	7	82	63	75	14	20	31	30	33	27	42	25	31	24	19	16	4
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	2	–	–	–	–	–	2	–	–	–	–	1	–	–
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	20	–	5	–	–	–	–	–	–	–	–	–	–	–	–	–
51	LV	LV Line	LV OH Conductor	km	–	17	143	118	41	58	12	76	1	1	1	2	2	3	1	1	2	1	1	1
52	LV	LV Cable	LV UG Cable	km	–	–	3	7	87	124	105	8	15	28	27	25	19	18	17	14	18	15	12	9
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	–	–	626	640	829	877	702	597	622	661	595	459	537	464
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	3	2	5	21	–	10	–	10	–	12	14	–	1	1	–	11	–
56	All	SCADA and communications	SCADA and communications equipment operating as a single syst	Lot	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	1	2	2	–	–
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	2	1	–	–	–	–	–	–	–	–	–	2	–	–
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–

Company Name	**Network Tasman Ltd**
For Year Ended	**31 March 2023**
Network / Sub-network Name	

SCHEDULE 9b: ASSET AGE PROFILE

This schedule requires a summary of the age profile (based on year of installation) of the assets that make up the network,

sch ref

8 **Disclosure Year (year ended)** **31 March 2023**

sch ref	Voltage	Asset category	Asset class	Units	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
9																			
10	All	Overhead Line	Concrete poles / steel structure	No.	128	150	203	33	130	70	100	155	117	91	263	466	26,409	–	1
11	All	Overhead Line	Wood poles	No.	14	29	–	–	8	42	84	93	4	6	34	255	1,721	–	1
12	All	Overhead Line	Other pole types	No.	1	–	–	–	–	–	–	–	–	–	–	51	320	–	1
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1	–	–	–	–	–	–	–	–	–	–	–	281	–	2
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	9	–	–	–	–	–	–	7	–	–	4	–	38	–	2
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	3	–	2
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	–	1	–	–	–	–	–	1	–	–	14	–	3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	1	–	–	–	–	–	–	–	–	9	–	4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	–	–	1	–	–	2	5	–	35	109	–	1
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	6	–	–	15	–	4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	2	–	–	–	22	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	8	–	–	12	–	–	–	–	–	8	–	–	104	–	4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	8	–	3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	–	2	–	–	–	–	–	2	–	–	27	–	4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	16	6	2	–	6	8	21	21	20	10	–	–	1,887	–	2
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
38	HV	Distribution Line	SWER conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	5	3	3	–	5	9	8	8	9	3	23	–	173	–	2
40	HV	Distribution Cable	Distribution UG PILC	km	2	1	2	–	–	–	–	–	–	–	–	–	135	–	2
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	4	6	4	5	6	1	8	8	–	–	1	–	72	–	2
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	10	13	25	5	7	13	34	18	10	25	39	849	1,387	–	2
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	4	8	9	–	5	2	5	5	–	8	4	9	158	–	2
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	2	–	–	4	6	15	10	11	7	5	69	152	–	2
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	80	61	27	44	61	36	82	85	11	71	2	75	3,831	–	2
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	19	31	22	28	22	40	38	24	16	42	28	–	853	–	2
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	–	–	–	4	9	–	2
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	–	–	–	–	–	–	–	–	25	–	2
51	LV	LV Line	LV OH Conductor	km	–	1	–	–	1	–	–	–	–	–	–	2	486	–	2
52	LV	LV Cable	LV UG Cable	km	9	11	12	3	14	13	17	16	19	13	18	13	712	–	2
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
54	LV	Connections	OH/UG consumer service connections	No.	460	557	442	447	538	562	529	622	723	643	695	29,246	43,073	–	2
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	6	–	–	14	–	–	–	3	–	10	–	–	123	–	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single syst	Lot	–	–	–	–	–	–	–	–	–	–	–	–	1	–	3
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	1	–	1	–	–	–	–	–	–	9	–	3
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	–	–	–	–	–	–	5	–	4
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4

Company Name	Network Tasman Ltd
For Year Ended	31 March 2023
Network / Sub-network Name	

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref				
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	–	–	–
12	50kV & 66kV	158	–	158
13	33kV	123	41	164
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	19	13	31
16	6.6kV to 11kV (inclusive—other than SWER)	1,872	296	2,167
17	Low voltage (< 1kV)	486	712	1,197
18	**Total circuit length (for supply)**	2,657	1,061	3,719
19				
20	Dedicated street lighting circuit length (km)	–	–	–
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			18
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	176	7%	
25	Rural	2,285	86%	
26	Remote only	70	3%	
27	Rugged only	118	4%	
28	Remote and rugged	8	0%	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	2,657	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,671	45%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	2,657	100%	

Company Name	**Network Tasman Ltd**
For Year Ended	**31 March 2023**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref

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

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

Company Name	**Network Tasman Ltd**
For Year Ended	**31 March 2023**
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref				
8	**9e(i): Consumer Connections and Decommissionings**			
9	*Number of ICPs connected in year by consumer type*			
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**		
11	Consumers 20kVA and less	754		
12	Consumers greater than 20kVA	39		
13		–		
14		–		
15		–		
16	** include additional rows if needed*			
17	**Connections total**	793		
18				
19	*Number of ICPs decommissioned in year by consumer type*			
20	*Consumer types defined by EDB**	**Number of decommissionings**		
21	Consumers 20kVA and less	89		
22	Consumers greater than 20kVA	3		
23		–		
24		–		
25		–		
26	** include additional rows if needed*			
27	**Decommissionings total**	92		
28				
29	**Distributed generation**			
30	Number of connections made in year	371	**connections**	
32	Capacity of distributed generation installed in year	4.17	**MVA**	
33				
34	**9e(ii): System Demand**			
35				
36				
37	**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**		
38	GXP demand	133		
39	*plus* Distributed generation output at HV and above	26		
40	**Maximum coincident system demand**	159		
41	*less* Net transfers to (from) other EDBs at HV and above	30		
42	**Demand on system for supply to consumers' connection points**	129		
43	**Electricity volumes carried**	**Energy (GWh)**		
44	Electricity supplied from GXPs	659		
45	*less* Electricity exports to GXPs	46		
46	*plus* Electricity supplied from distributed generation	173		
47	*less* Net electricity supplied to (from) other EDBs	92		
48	**Electricity entering system for supply to consumers' connection points**	693		
49	*less* Total energy delivered to ICPs	654		
51	**Electricity losses (loss ratio)**	40		5.7%
52				
53	**Load factor**	0.61		
54	**9e(iii): Transformer Capacity**			
55		**(MVA)**		
56	Distribution transformer capacity (EDB owned)	471		
57	Distribution transformer capacity (Non-EDB owned, estimated)	44		
58	**Total distribution transformer capacity**	515		
59				
60	**Zone substation transformer capacity**	396		
61				

Company Name	**Network Tasman Ltd**
For Year Ended	**31 March 2023**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of 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)	4	
11	Class B (planned interruptions on the network)	196	
12	Class C (unplanned interruptions on the network)	128	
13	Class D (unplanned interruptions by Transpower)	2	
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**	330	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	96	32
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	0.05	24.3
26	Class B (planned interruptions on the network)	0.56	154.0
27	Class C (unplanned interruptions on the network)	1.17	121.1
28	Class D (unplanned interruptions by Transpower)	0.05	5.5
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**	1.82	304.9
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	1.73	269.4
38			

Company Name	**Network Tasman Ltd**
For Year Ended	**31 March 2023**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of 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	0.02	2.5
Vegetation	0.00	0.1
Adverse weather	0.28	37.5
Adverse environment	–	–
Third party interference	0.08	12.2
Wildlife	0.14	14.5
Human error	0.09	1.5
Defective equipment	0.20	25.3
Cause unknown	0.35	27.6

Breakdown of third party interference	SAIFI	SAIDI	
Dig-in	n/a	n/a	Not required until 2024
Overhead contact	n/a	n/a	Not required until 2024
Vandalism	n/a	n/a	Not required until 2024
Vehicle damage	n/a	n/a	Not required until 2024
Other	n/a	n/a	Not required until 2024

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.25	54.2
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.29	93.1
Distribution cables (excluding LV)	0.01	3.7
Distribution other (excluding LV)	0.01	3.0

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.41	43.1
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.71	74.5
Distribution cables (excluding LV)	0.03	3.3
Distribution other (excluding LV)	0.01	0.3

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	10	281	3.56
Subtransmission cables	–	41	–
Subtransmission other	–		
Distribution lines (excluding LV)	115	1,887	6.09
Distribution cables (excluding LV)	1	308	0.32
Distribution other (excluding LV)	2		
Total	128		

Company Name	Network Tasman Limited
For Year Ended	31 March 2023

Schedule 14 Mandatory Explanatory Notes

(Guidance Note: This Microsoft Word version of Schedules 14, 14a and 15 is from the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018. Clause references in this template are to that determination)

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

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

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

Return on Investment (Schedule 2)

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

Box 1: Explanatory comment on return on investment

Network Tasman's use of posted discounts has traditionally resulted in a relatively low return on investment. This is because posted discounts reduce NTL's regulated prices/revenues and therefore return on investment.

However, for 2022/23 Network Tasman's return on investment is relatively high when compared to the benchmarks used in the ID regime. Historically high revaluations are the primary driver of this. For 2022/23 revaluations were $12.7m compared to an annual average of $3.5m over the previous 8 years.

See box 10 for reclassifications details.

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

Other income includes Nelson Electricity Limited management fee $49,000 and sundry income of $31,000.

Nelson Electricity Limited sales and the related transmission costs have been excluded from the regulatory profit. These amounts net to zero.

Network Tasman derived an IRIS benefit of +$782,000 in 2021/22. This IRIS benefit was derived in accordance with clause 3.3.1 of the Electricity Distribution Services Input Methodologies Determination 2012.

There have been no changes in classification.

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

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

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

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

Box 3: Explanatory comment on merger and acquisition expenditure

There were no mergers and acquisitions.

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)

There have been the following changes in classification.

Category 2022	***Category 2023***	***$000***	***Explanation***
Distribution & LV Cable	Subtransmission Cable	13	Corrected underground cable classification
Subtransmission Lines	Subtransmission Cable	112	Corrected underground cable classification

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
Expenditure or loss in regulatory profit / (loss) before tax but not deductible - • Non-deductible expenses (non-deductible entertainment expenses)

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)
Loss on disposal of assets temporary difference $867,000 @28% = $242,800, less movement in provisions temporary difference $68,000 @28% = $19,000. Making temporary differences of $223,800.

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
Costs relating to unregulated businesses have been identified and excluded from the regulated business costs. The allocation method is ABAA (Accounting-based allocation approach). This has resulted in a cost allocation of $1,041,000.

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

The allocation method is to ABAA (Accounting-based allocation approach). This has resulted in an asset allocation that reduced the regulatory asset base by $9,000 in the current year.

There is no impact on the asset allocations from the asset reclassifications identified in box 4.

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

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

Box 9: Explanation of capital expenditure for the disclosure year

The materiality threshold of $300,000 has been used when identifying major network projects.

No items have been reclassified.

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

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

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

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

Box 10: Explanation of operational expenditure for the disclosure year

Where a complete asset or a significant part of an asset is replaced or renewed then the expenditure is treated as capital. Where only some minor components are replaced or renewed then the expenditure is treated as operating expenditure.

Expenditure associated with portable generators has been reclassified from Service interruptions and emergencies to Routine and corrective maintenance and inspection.

There was no material atypical expenditure.

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 connection expenditure is basically on target.
- Asset relocations are $500,000 under target. An allowance for undergrounding is budgeted for, but the actual undergrounding only occurs in conjunction with council work. There were no suitable council projects during the year.
- Asset replacement and renewal costs under target by $2.9 million. The main reason for this is the delay in the Motupipi Substation upgrade.
- Reliability, safety and environment – quality of supply is under target by $3.8 million. This is due to the Founders to Wakapuaka 33kV Cable and the 33kV CB's Swamp Road Substation Installation projects being deferred by a year.
- Reliability, safety and environment – Other reliability, safety and environment is close to target.
- System Growth is $1.9 million under target which is due to
  - the Motueka Zone Substation Upgrade project, which is underway, but is behind schedule,
  - the Maruia Feeder 11/22kV Conversion project being on hold as it is dependent on future new load,
  - the New Motueka Ripple Injection Plant project being moved to the next financial year.
- Non-network assets expenditure is $469,000 under target with less software expenditure than expected.

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

Operational Expenditure

- Service interruptions and emergencies costs are 4% ($56,000) over target due to the storms in July and August 2022.
- Vegetation management costs are over target by 10% ($109,000). This is due to the additional vegetation work required to deal with high risk trees after the July and August storms.
- Routine and corrective maintenance and inspection costs are 9% above target. ($216,000) principally due to the reclassification of portable generator costs which were not budgeting in this category.
- Asset replacement and renewal expenditure is 27% ($580,000) below target with the focus moving to other maintenance categories, storm repairs and capital.
- Non-network expenditure is 7% ($402,000) over target. There was more expenditure than plan spent on IT consultancy with the move to SaaS and a focus on cyber security and IT strategy. The was also an additional staff member.

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

For the 2022/23 regulatory year, Network Tasman forecast line charge revenues of $37.8m and recovered actual revenues of $37.9m, a difference of approximately 0.2%.

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

Unplanned SAIDI was 121 for the 2022/23 year. A wind storm event on 12 July 2022 and a major flooding event 17-20 August 2022 resulted in widespread losses of supply to consumers and accumulated 38 SAIDI points. A further 12 SAIDI points resulted from an unexplained outage of the Hope 33kV feeder which interrupted supply to approx 7,000 Richmond, Hope, Brightwater and Wakefield consumers on 12 March 2023.

Planned SAIDI was 154 for the 2022/23 year. Network maintenance works were resumed in catch up mode from the previous year which was disrupted by Covid-19 lockdowns during the year.

SAIFI targets (the average number of interruptions experienced by consumers) were not exceeded during the year. Faults per 100km of line were in line with targets. These results reflect the good condition of the network and the good state of vegetation clearance.

In some circumstances, an unplanned loss of supply event can be followed by restoration of supply and then by a successive interruption as a result of isolating the initial cause, making repairs and completing the permanent restoration of supply to all consumers. Where this occurs, NTL's reported SAIFI records the initial outage and not any subsequent short duration outages required to affect the restoration of supply. NTL's reported SAIDI includes the customer minutes from subsequent short duration outages required to affect the restoration of supply. This treatment is consistent with that of previous years. For the 2023/24, NTL will report two sets of SAIDI and SAIFI figures: those based on the methodology summarised above (existing methodology) and a second set where the effect of subsequent short duration outages are recorded (successive interruption methodology).

SAIDI and SAIFI were well within the Commerce Commission limits.

The percentage of faults not restored within three hours was significantly higher for 2022/23 than in previous years. A significant contributing factor was a high number of long duration feeder outages during the year during major storms.

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 Tasman Limited has material damage cover for all zone sub-stations – buildings and associated equipment, but does not insure the wider distribution network. In addition Network Tasman Limited has public liability, Directors and Officers insurance and failure to supply 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

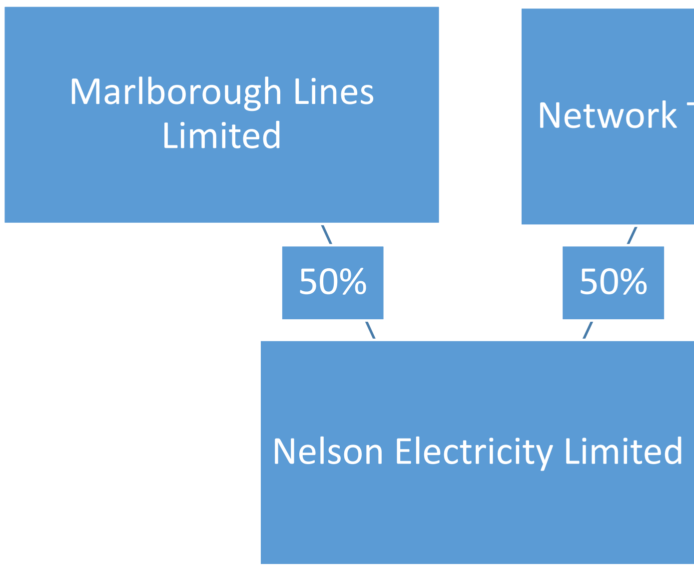
18.2 for each error, reference to the web address where the disclosure made in accordance with clause 2.12.1 is publicly disclosed.

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

Related Party Transactions

Related Party Relationships

Network Tasman Limited and Marlborough Lines Limited both own 50% of Nelson Electricity Limited.



Network Tasman Limited provides engineering and standby services to Nelson Electricity Limited. The charge for this service is $49,200 pa.

Network Tasman Limited also charges Nelson Electricity Limited for the following sundry charges.

	$'000
Billing administration charge	2
Insurance recovery	12
Electricity Authority levy	13
Other sundry	4
Total Annual Charge	**31**

All these charges are included in other regulated income.

Valuation Methodology

The following are the valuation methods used to provide assurance that the related party income transactions comply with 2.3.6(2)

> the value of an asset or good or service sold or supplied in the **related party transaction** must be given a value not less than if that transaction had the

terms of an **arm's-length transaction**;

Nelson Electricity Limited, Network Tasman Limited and Marlborough Lines Limited are all EDBs subject to information disclosure requirements. In addition to the arm's length transaction measures below, there is a commercial tension between the parties, ensuring that they are charging a reasonable amount for the services provided to Nelson Electricity Limited.

Service Support fee for engineering and standby services.

> The fee is set at $49,200 per year. This was partly based on the number of hours estimated to be spent by Network Tasman Limited staff providing services. These hours have been reviewed and are considered a good representation of time currently spent. The hourly rates have also been reviewed and compared to current rates charged by consultants providing similar services. These rates are the same or similar. The standby portion of the charge is considered to be fair for the services Network Tasman Limited provides standby and backup support for.

Billing administration charge

> This charge is only $2,000 per year. This is an administration charge for preparing Nelson Electricity Limited's bill. Given the low value of this charge, it is considered immaterial.

Insurance recovery

> The amount of the insurance recovery ($12,000) is set out in the interconnection agreement and is reviewed annually. This is also low value charge and is not considered material.

Electricity Authority levies

> The Electricity Authority bills Network Tasman Limited for Nelson Electricity Limited's levies. The amount that Network Tasman Limited on-charges Nelson Electricity Limited for these levies is the same as if the Electricity Authority were to bill Nelson Electricity Limited directly. The amount Network Tasman Limited is charged by the Electricity Authority less the amount Network Tasman Limited charges Nelson Electricity Limited is the same amount that Network Tasman Limited would pay if only their levies were charged by Electricity Authority. The rate of the Electricity Authority levies are published in the New Zealand Gazette.

Company Name Network Tasman Limited

For Year Ended 31 March 2023

Schedule 15 Voluntary Explanatory Notes

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

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

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

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

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

3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

1 (iii): Service intensity measures - Demand density links to the “ Maximum coincident system demand” (row 40) instead of “Demand on system for supply to consumers' connection points” (row 42) on schedule 9e. The difference is that the line “Maximum coincident system demand” includes Nelson Electricity Limited (NEL) and “Demand on system for supply to consumers' connection points” excludes NEL. NEL is not a consumer. There are no kms included for NEL and therefore the result is currently distorted. The correct demand density should be 35kW/km.

Demand density	35

10: Report on Network Reliability– The SAIFI calculation has been prepared on a basis consistent with the previous year’s disclosure.

Network Tasman Limited counts SAIFI as follows:

The number of ICPs that experience an interruption when a fault occurs is recorded once and contributes to the SAIFI for that fault. In a few cases, there may be partial restoration of supply to a subset of the affected ICPs, followed by a loss of supply to those same ICPs as the fault finding process takes place. In such a case, the additional ‘on/off’ of the affected ICPs within the outage event does not contribute to the SAIFI count for the outage.

Once all affected ICPs have been restored, any subsequent interruption is recorded as a separate interruption for SAIFI purposes - for example due to further repair work relating to an earlier outage.

SAIFI was within the bounds of expected performance.

For future disclosure years, Network Tasman will also report SAIFI using the successive interruption method as defined in the recently updated Information Disclosure Determination.

networktasman
Your consumer-owned electricity distributor

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Email: info@networktasman.co.nz
Website: www.networktasman.co.nz

Certification for Year-end Disclosures

Clause 2.9.2

We, Michael John MCCLISKIE and Anthony Page REILLY, being directors of Network Tasman Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) the information prepared for the purposes of clauses 2.3.1, 2.3.2, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.7.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination; 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 Network Tasman Limited's accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained.

c) In respect of information concerning assets, costs and revenues valued or disclosed in accordance with clause 2.3.6 of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012, we are satisfied that-
    i. the 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.

Michael John MCCLISKIE

Anthony Page REILLY

25 August 2023

Independent Assurance Report

To the directors of Network Tasman Limited and to the Commerce Commission on the disclosure information for the disclosure year ended 31 March 2023 as required by the Electricity Distribution Information Disclosure Determination 2012 (consolidated 6 July 2023)

The Network Tasman Limited (the company) is required to disclose certain information under the Electricity Distribution Information Disclosure Determination 2012 (consolidated 6 July 2023) (the Determination) and to procure an assurance report by an independent auditor in terms of section 2.8.1 of the Determination.

The Auditor-General is the auditor of the company.

The Auditor-General has appointed me, John Mackey, using the staff and resources of Audit New Zealand, to undertake a reasonable assurance engagement, on his behalf, on whether the information prepared by the company for the disclosure year ended 31 March 2023 (the Disclosure Information) complies, in all material respects, with the Determination.

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

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

This assurance report should be read in conjunction with the Commerce Commission's Information Disclosure exemption, issued to all electricity distribution businesses on 9 June 2023 under clause 2.11.1 of the Determination. The Commerce Commission granted an exemption from the requirement that the assurance report, in respect of the information in schedule 10 of the Determination, must take into account any issues arising out of the company's recording of SAIDI, SAIFI, and number of interruptions due to successive interruptions.

Opinion

In our opinion, in all material respects:

- as far as appears from an examination, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the Company;

- as far as appears from an examination, the information used in the preparation of the Disclosure Information has been properly extracted from the company's accounting and other records, sourced from the company's financial and non-financial systems;
- the Disclosure Information complies, in all material respects, with the Determination; and
- the basis for valuation of related party transactions complies with the Determination and the IM Determination.

Basis for opinion

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

We have obtained sufficient recorded evidence and explanations that we required to provide a basis for our opinion.

Key assurance matters

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

Key Assurance Matter	How our procedures addressed the key assurance matter
Cost allocation The Determination and the IM Determination place a requirement on the Company to allocate indirect costs between its regulated and non-regulated business. The Company has a significant investment property portfolio, a fibre network, and a smart meter network that are not part of the regulated business. The Company does not have separate management teams, or finance and administration teams for the divisions that are not part of the regulated business. Therefore, a portion of their time needs to be allocated to the regulated business.	We obtained an understanding of the Company's cost allocation approach to allocate indirect costs to the regulated and non-regulated business. We confirmed the approach used is in accordance with the Determination and the IM Determination. The procedures we carried out, to satisfy ourselves that indirect costs were correctly allocated, included: • reconciling the regulated and unregulated financial information to the audited financial statements for the year ended 31 March 2023, to identify the costs that required allocation to the regulated business; • reviewing the costs by business unit, based on the nature of the costs and on our understanding of the business, to determine the reasonableness of the directly attributable costs by business unit;

Key Assurance Matter	How our procedures addressed the key assurance matter
The IM Determination sets out the rules and processes for allocating non-directly attributable costs.	• testing a sample of invoices to ensure their classification as either directly attributable or non-directly attributable costs are appropriate and in compliance with the Determination and the IM Determination; • reviewing the Company's judgements in determining and applying appropriate methods to allocate non-directly attributable costs and assessing if the methods comply with the Determination and the IM Determination; and • testing a sample of cost allocation calculations. Having carried out these procedures, we have no matters to report.
Accuracy of the number and duration of electricity outages The Company has a combination of manual and automated systems to identify outages and to record the duration of outages. This outage information is used to prepare the Company's Report on Network Reliability in schedule 10. If this information is inaccurate then the measures of the reliability of the network could be materially misstated. This is a key assurance matter because information on the frequency and duration of outages is an important measure of the reliability of electricity supply. Relatively small inaccuracies can have a significant impact on the reliability thresholds against which the Company's performance is assessed. There can also be significant consequences if the Company breaches the reliability thresholds. The Commerce Commission has issued an Exemption notice which excludes the assurance report from coverage of the information, in schedule 10 of the Determination, for any issues arising out of the Company's recording of SAIDI, SAIFI and number of interruptions due to successive interruptions. We need to ensure that the	We have obtained an understanding of the Company's system to record electricity outages, and their duration. This included review of the Company's definition of interruptions, planned interruptions and major event days. Our procedures to assess the adequacy of the Company's methods to identify and record electricity outages and their duration included: • performing an assessment of the reliability of the manual and automated processes to record the details of interruptions to supply; • obtaining internal and external information on interruptions to supply to gain assurance that interruptions to supply were recorded. Internal and external information sources included works orders for contractors, media reports, and Board minutes; • testing a sample of interruptions to supply to source records to conclude on their accuracy of calculation, and whether they were planned or unplanned, and that the cause of the interruptions was correctly categorised; • checked the SAIDI and SAIFI ratios were correctly calculated in accordance with the Determination and the IM Determination; • obtained explanations for all significant variances to forecast; and

Key Assurance Matter	How our procedures addressed the key assurance matter
Company meets the criteria for the Exemption to apply, including that it makes the necessary disclosures so the exclusion to the assurance opinion applies.	• testing the accuracy of the number of connections to the Electricity Authority's register. With respect to the Exemption, we: • obtained and documented our understanding of the Company's methods by which electricity outages and their duration are recorded where an outage event results in successive interruptions of supply; • compared this to the documented process that the Company followed in the previous year; and • identified potential incidences of successive interruptions of supply to help provide assurance that the Company's methods, by which electricity outages and their duration are recorded where an outage event results in successive interruptions of supply, were the same for both years. Having carried out these procedures and assessed the likelihood of reported electricity outages and their duration being materially misstated in the Disclosure Information, we have no matters to report.
Valuation of related-party transactions at arm's-length The Determination and the IM Determination place a requirement on the Company to value related-party transactions at arm's-length. In other words, the value at which a transaction, with the same terms and conditions, would be entered into between a willing seller and a willing buyer who are unrelated and who are acting independently of each other and pursuing their own best interests. In the absence of an active market for related-party transactions, assignment of an objective arm's-length value to a related-party transaction is difficult. This a key assurance matter because the requirement involves considerable judgement by Company personnel. In turn, verification of the appropriate assignment of an objective arm's-length valuation, to related-party transactions require the	We have obtained an understanding of the Company's approach to identifying and valuing related-party transactions at arm's-length in accordance with the Determination and the IM Determination. The procedures we carried out, to satisfy ourselves that related-party transactions are appropriately valued at a value not greater than arm's-length, included: • testing the completeness of related-parties identified through review of Board minutes, review of Companies Office records, and related-parties identified through detailed testing of transactions and balances in the annual financial statements audit; • reviewing the relevant policies for approval and negotiation of related-party transactions, and testing compliance with them; • reviewing the advice received by the Company from the Commerce Commission on the reasonableness of the approach adopted to determine arm's-length value for related-party transactions with its associates and joint venture;

Key Assurance Matter	How our procedures addressed the key assurance matter
exercise of significant professional judgement by the auditor.	• confirming the Company followed the advice it received from the Commerce Commission on the reasonableness of the approach adopted to report sales of goods and services to its associates and joint venture; and • confirming the material accuracy of related party values disclosed, and compliance of their calculation with the Determination and the IM Determination. Having carried out these procedures, we have no matters to report.

Directors' responsibilities

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

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

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

Auditor's responsibilities

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

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

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

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

Inherent limitations

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

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

Restricted use

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

Independence and quality control

We complied with the Auditor-General's:

- independence and other ethical requirements, which incorporate the requirements of Professional and Ethical Standard 1 International Code of Ethics for Assurance Practitioners (including International Independence Standards) (New Zealand) (PES 1) issued by the New Zealand Auditing and Assurance Standards Board; and

- quality management requirements, which incorporate Professional and Ethical Standard 3 *Quality Management for Firms that perform Audits or Reviews of Financial Statements*, or *Other Assurance or Related Services Engagements* (PES 3) issued by the New Zealand Auditing and Assurance Standards Board. PES 3 requires our firm to design, implement and operate a system of quality management including policies or procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

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

John Mackey
Audit New Zealand
On behalf of the Auditor-General
Christchurch, New Zealand
25 August 2023