COMMERCE COMMISSION NEW ZEALAND

EDB Information Disclosure Requirements
Information Templates
for
Schedules 1–10

Company Name	Network Tasman Limited
Disclosure Date	31 August 2018
Disclosure Year (year ended)	31 March 2018

Templates for Schedules 1–10
Template Version 4.1. Prepared 24 March 2015

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2018**

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**	17,733	277	91,369	3,045	26,695
10	Network	9,828	153	50,639	1,688	14,795
11	Non-network	7,905	123	40,730	1,358	11,900
12						
13	**Expenditure on assets**	9,933	155	51,182	1,706	14,954
14	Network	8,961	140	46,173	1,539	13,490
15	Non-network	972	15	5,009	167	1,463
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**	72,983	1,138
20	Standard consumer line charge revenue	81,572	1,028
21	Non-standard consumer line charge revenue	36,774	1,450,667
22			

23 1(iii): Service intensity measures

sch ref			
24			
25	Demand density	39	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	172	*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	15,595	*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	10,945	24.30%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	12,857	28.55%
34	Total depreciation	6,954	15.44%
35	Total revaluations	1,808	4.01%
36	Regulatory tax allowance	1,173	2.60%
37	Regulatory profit/(loss) including financial incentives and wash-ups	14,920	33.12%
38	**Total regulatory income**	45,041	
39			

40 1(v): Reliability

sch ref			
41			
42	Interruption rate	7.76	*Interruptions per 100 circuit km*

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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		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
8		**31 Mar 16**	**31 Mar 17**	**31 Mar 18**
9	**ROI – comparable to a post tax WACC**	**%**	**%**	**%**
10	Reflecting all revenue earned	7.83%	9.59%	8.70%
11	Excluding revenue earned from financial incentives	5.65%	7.61%	6.75%
12	Excluding revenue earned from financial incentives and wash-ups	5.65%	7.73%	6.88%
13				
14	**Mid-point estimate of post tax WACC**	5.37%	4.77%	5.04%
15	25th percentile estimate	4.66%	4.05%	4.36%
16	75th percentile estimate	6.09%	5.48%	5.72%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	8.48%	10.14%	9.29%
21	Excluding revenue earned from financial incentives	6.30%	8.15%	7.35%
22	Excluding revenue earned from financial incentives and wash-ups	6.30%	8.27%	7.47%
23				
24	**WACC rate used to set regulatory price path**	7.19%	7.19%	7.19%
25				
26	**Mid-point estimate of vanilla WACC**	6.02%	5.31%	5.60%
27	25th percentile estimate	5.30%	4.59%	4.92%
28	75th percentile estimate	6.74%	6.03%	6.29%
29				

sch ref				
30	**2(ii): Information Supporting the ROI**		**($000)**	
31				
32	Total opening RAB value	164,637		
33	*plus* Opening deferred tax	(1,171)		
34	**Opening RIV**		163,466	
35				
36	**Line charge revenue**		45,046	
37				
38	Expenses cash outflow	23,802		
39	*add* Assets commissioned	6,386		
40	*less* Asset disposals	355		
41	*add* Tax payments	732		
42	*less* Other regulated income	(5)		
43	**Mid-year net cash outflows**		30,570	
44				
45	**Term credit spread differential allowance**		–	
46				
47	Total closing RAB value	165,522		
48	*less* Adjustment resulting from asset allocation	0		
49	*less* Lost and found assets adjustment	–		
50	*plus* Closing deferred tax	(1,612)		
51	**Closing RIV**		163,909	
52				
53	**ROI – comparable to a vanilla WACC**			9.29%
54				
55	Leverage (%)			44%
56	Cost of debt assumption (%)			4.80%
57	Corporate tax rate (%)			28%
58				
59	**ROI – comparable to a post tax WACC**			8.70%
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**	6.58%
96	**Year-end ROI – comparable to a post tax WACC**	5.99%

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	–	
103	Purchased assets – avoided transmission charge	4,230	
104	Energy efficiency and demand incentive allowance	–	
105	Quality incentive adjustment	–	
106	Other financial incentives	–	
107	**Financial incentives**		4,230
109	**Impact of financial incentives on ROI**		1.95%
111	Input methodology claw-back	–	
112	Recoverable customised price-quality path costs	–	
113	Catastrophic event allowance	–	
114	Capex wash-up adjustment	(272)	
115	Transmission asset wash-up adjustment	–	
116	2013–2015 NPV wash-up allowance	–	
117	Reconsideration event allowance	–	
118	Other wash-ups	–	
119	**Wash-up costs**		(272)
121	**Impact of wash-up costs on ROI**		–0.12%

Company Name	**Network Tasman Limited**
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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

3(i): Regulatory Profit

		($000)
	Income	
	Line charge revenue	45,046
plus	Gains / (losses) on asset disposals	(139)
plus	Other regulated income (other than gains / (losses) on asset disposals)	134
	Total regulatory income	45,041
	Expenses	
less	Operational expenditure	10,945
less	Pass-through and recoverable costs excluding financial incentives and wash-ups	12,857
	Operating surplus / (deficit)	21,239
less	Total depreciation	6,954
plus	Total revaluations	1,808
	Regulatory profit / (loss) before tax	16,093
less	Term credit spread differential allowance	–
less	Regulatory tax allowance	1,173
	Regulatory profit/(loss) including financial incentives and wash-ups	14,920

3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups

	($000)	
Pass through costs		
Rates	207	
Commerce Act levies	82	
Industry levies	137	
CPP specified pass through costs	–	
Recoverable costs excluding financial incentives and wash-ups		
Electricity lines service charge payable to Transpower	10,394	
Transpower new investment contract charges	203	
System operator services	–	
Distributed generation allowance	1,834	
Extended reserves allowance	–	
Other recoverable costs excluding financial incentives and wash-ups	–	
Pass-through and recoverable costs excluding financial incentives and wash-ups		12,857

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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 17**	**31 Mar 18**
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 13	–	–
58	CY-4	31 Mar 14	–	–
59	CY-3	31 Mar 15	–	–
60	CY-2	31 Mar 16	–	–
61	CY-1	31 Mar 17	–	–
62	**Net incremental rolling incentive scheme**			–
63				
64	**Net recoverable costs allowed under incremental rolling incentive scheme**			–

65	**3(iv): Merger and Acquisition Expenditure**	
70		**($000)**
66	Merger and acquisition expenditure	–
67		
68	*Provide commentary on the benefits of merger and acquisition expenditure to the electricity distribution business, including required disclosures in accordance with section 2.7, in Schedule 14 (Mandatory Explanatory Notes)*	

69	**3(v): Other Disclosures**	
70		**($000)**
71	Self-insurance allowance	–

Company Name	**Network Tasman Limited**
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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 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**
	($000)	**($000)**	**($000)**	**($000)**	**($000)**
Total opening RAB value	150,493	155,232	161,816	163,098	164,637
less **Total depreciation**	6,574	6,778	6,937	6,779	6,954
plus **Total revaluations**	2,307	130	948	3,531	1,808
plus **Assets commissioned**	9,280	13,773	7,777	5,612	6,386
less **Asset disposals**	274	541	506	825	355
plus **Lost and found assets adjustment**	–	–	–	–	–
plus **Adjustment resulting from asset allocation**	0	(0)	0	–	0
Total closing RAB value	155,232	161,816	163,098	164,637	165,522

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB *		RAB	
	($000)	**($000)**	**($000)**	**($000)**
Total opening RAB value		164,697		164,637
less				
Total depreciation		7,015		6,954
plus				
Total revaluations		1,808		1,808
plus				
Assets commissioned (other than below)	6,386		6,386	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	–		–	
Assets commissioned		6,386		6,386
less				
Asset disposals (other than below)	355		355	
Asset disposals to a regulated supplier	–		–	
Asset disposals to a related party	–		–	
Asset disposals		355		355
plus **Lost and found assets adjustment**		–		–
plus **Adjustment resulting from asset allocation**				0
Total closing RAB value		165,521		165,522

** 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.
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sch ref			Unallocated RAB *		RAB	
51						
52		**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**				
53						
54		CPI_4				1,011
55		CPI_4^{-4}				1,000
56		Revaluation rate (%)				1.10%
57						
58			**Unallocated RAB ***		**RAB**	
59			**($000)**	**($000)**	**($000)**	**($000)**
60		Total opening RAB value	164,697		164,637	
61	*less*	Opening value of fully depreciated, disposed and lost assets	302		302	
62						
63		Total opening RAB value subject to revaluation	164,395		164,335	
64		**Total revaluations**		1,808		1,808
65						

4(iv): Roll Forward of Works Under Construction

sch ref			Unallocated works under construction		Allocated works under construction	
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**		2,741		2,741
69	*plus*	Capital expenditure	5,908		5,908	
70	*less*	Assets commissioned	6,386		6,386	
71	*plus*	Adjustment resulting from asset allocation			–	
72		**Works under construction - current disclosure year**		2,263		2,263
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	
78		($000)	($000)	($000)	($000)
79	Depreciation - standard	6,781		6,720	
80	Depreciation - no standard life assets	234		234	
81	Depreciation - modified life assets	–		–	
82	Depreciation - alternative depreciation in accordance with CPP	–		–	
83	**Total depreciation**		7,015		6,954
84					

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

($000 unless otherwise specified)

sch ref	Asset or assets with changes to depreciation*	Reason for non-standard depreciation (text entry)	Depreciation charge for the period (RAB)	Closing RAB value under 'non-standard' depreciation	Closing RAB value under 'standard' depreciation
87					
88	There are no assets with changes to depreciation				
89					
90					
91					
92					
93					
94					

95 ** include additional rows if needed*

96 4(vii): Disclosure by Asset Category

97 **($000 unless otherwise specified)**

sch ref			Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
99		**Total opening RAB value**	8,106	9,531	22,082	24,353	52,862	23,091	7,607	13,909	3,096	164,637
100	*less*	Total depreciation	278	196	797	1,787	1,444	1,011	377	868	196	6,954
101	*plus*	Total revaluations	89	105	244	268	582	254	83	149	34	1,808
102	*plus*	Assets commissioned	39	–	1,418	1,524	691	1,328	429	382	575	6,386
103	*less*	Asset disposals	2	–	–	46	7	204	3	11	82	355
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
106	*plus*	Asset category transfers	–	–	120	(2)	2	–	–	(120)	–	–
107		**Total closing RAB value**	7,954	9,440	23,067	24,310	52,686	23,458	7,739	13,441	3,427	165,522
108												
109		**Asset Life**										
110		Weighted average remaining asset life	38.4	48.7	27.3	30.7	45.2	32.0	31.3	17.7	23.4	(years)
111		Weighted average expected total asset life	58.5	56.1	39.6	58.9	60.4	51.2	42.2	33.8	31.4	(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**			16,093	
9					
10	*plus*	Income not included in regulatory profit / (loss) before tax but taxable	2		*
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible	10		*
12		Amortisation of initial differences in asset values	3,239		
13		Amortisation of revaluations	639		
14				3,890	
15					
16	*less*	Total revaluations	1,808		
17		Income included in regulatory profit / (loss) before tax but not taxable	–		*
18		Discretionary discounts and customer rebates	10,467		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax	147		*
20		Notional deductible interest	3,372		
21				15,794	
22					
23	**Regulatory taxable income**			4,189	
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income		4,189	
27					
28		Corporate tax rate (%)	28%		
29	**Regulatory tax allowance**			1,173	
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	85,386		
37	*less*	Amortisation of initial differences in asset values	3,239		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	5		
40		Closing unamortised initial differences in asset values		82,141	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		26	
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).
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sch ref				
44		**5a(iv): Amortisation of Revaluations**		**($000)**
46		Opening sum of RAB values without revaluations	150,425	
48		Adjusted depreciation	6,315	
49		Total depreciation	6,954	
50		Amortisation of revaluations		639
52		**5a(v): Reconciliation of Tax Losses**		**($000)**
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)**
60		**Opening deferred tax**	(1,171)	
62	*plus*	Tax effect of adjusted depreciation	1,768	
64	*less*	Tax effect of tax depreciation	1,269	
66	*plus*	Tax effect of other temporary differences*	(4)	
68	*less*	Tax effect of amortisation of initial differences in asset values	907	
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year	–	
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year	23	
74	*plus*	Deferred tax cost allocation adjustment	(7)	
76		**Closing deferred tax**		(1,612)
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).*		
81		**5a(viii): Regulatory Tax Asset Base Roll-Forward**		
82				**($000)**
83		**Opening sum of regulatory tax asset values**	62,022	
84	*less*	Tax depreciation	4,532	
85	*plus*	Regulatory tax asset value of assets commissioned	6,332	
86	*less*	Regulatory tax asset value of asset disposals	665	
87	*plus*	Lost and found assets adjustment	–	
88	*plus*	Adjustment resulting from asset allocation	(23)	
89	*plus*	Other adjustments to the RAB tax value	–	
90		**Closing sum of regulatory tax asset values**		63,134

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SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

This schedule provides information on the valuation of related party transactions, in accordance with section 2.3.6 and 2.3.7 of the ID 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

sch ref	5b(i): Summary—Related Party Transactions	($000)
8	Total regulatory income	68
9	Operational expenditure	
10	Capital expenditure	
11	Market value of asset disposals	
12	Other related party transactions	

13 **5b(ii): Entities Involved in Related Party Transactions**

sch ref	Name of related party	Related party relationship
15	Nelson Electricity Ltd	50% owned by Network Tasman Limited
16		
17		
18		
19		

20 ** include additional rows if needed*

21 **5b(iii): Related Party Transactions**

sch ref	Name of related party	Related party transaction type	Description of transaction	Value of transaction ($000)	Basis for determining value
23	Nelson Electricity Ltd	Sales	Management services fee for engineering support	49	ID clause 2.3.7(2)(b)
24	Nelson Electricity Ltd	Sales	Electricity Authority levies on-charged	13	ID clause 2.3.7(2)(c)
25	Nelson Electricity Ltd	Sales	Sundry income	5	ID clause 2.3.7(2)(c)
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					

38 ** include additional rows if needed*

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2018**

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	Cost of executing an interest rate swap	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	44%	
24	Average opening and closing RAB values		
25	**Attribution Rate (%)**		–
26			
27	**Term credit spread differential allowance**		–

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2018**

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(i): Operating Cost Allocations

	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
	Value allocated ($000s)				
Service interruptions and emergencies					
Directly attributable		1,169			
Not directly attributable		–		–	
Total attributable to regulated service		1,169			
Vegetation management					
Directly attributable		948			
Not directly attributable		–		–	
Total attributable to regulated service		948			
Routine and corrective maintenance and inspection					
Directly attributable		1,824			
Not directly attributable		–		–	
Total attributable to regulated service		1,824			
Asset replacement and renewal					
Directly attributable		2,125			
Not directly attributable		–		–	
Total attributable to regulated service		2,125			
System operations and network support					
Directly attributable		2,052			
Not directly attributable		–		–	
Total attributable to regulated service		2,052			
Business support					
Directly attributable		2,827			
Not directly attributable		–		–	
Total attributable to regulated service		2,827			
Operating costs directly attributable		10,945			
Operating costs not directly attributable	–	–	–	–	–
Operational expenditure		10,945			

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	426
Not directly attributable	–
Total attributable to regulated service	426
Recoverable costs	
Directly attributable	12,431
Not directly attributable	–
Total attributable to regulated service	12,431

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

Change in cost allocation 1			($000) 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				

Change in cost allocation 2			($000) 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				

Change in cost allocation 3			($000) 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 Limited**
For Year Ended	**31 March 2018**

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	7,954
Not directly attributable	–
Total attributable to regulated service	7,954
Subtransmission cables	
Directly attributable	9,440
Not directly attributable	–
Total attributable to regulated service	9,440
Zone substations	
Directly attributable	23,067
Not directly attributable	–
Total attributable to regulated service	23,067
Distribution and LV lines	
Directly attributable	24,310
Not directly attributable	–
Total attributable to regulated service	24,310
Distribution and LV cables	
Directly attributable	52,686
Not directly attributable	–
Total attributable to regulated service	52,686
Distribution substations and transformers	
Directly attributable	23,458
Not directly attributable	–
Total attributable to regulated service	23,458
Distribution switchgear	
Directly attributable	7,739
Not directly attributable	–
Total attributable to regulated service	7,739
Other network assets	
Directly attributable	13,441
Not directly attributable	–
Total attributable to regulated service	13,441
Non-network assets	
Directly attributable	3,427
Not directly attributable	–
Total attributable to regulated service	3,427
Regulated service asset value directly attributable	165,522
Regulated service asset value not directly attributable	–
Total closing RAB value	165,522

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

			($000) CY-1	Current Year (CY)
Change in asset value allocation 1				
Asset category	0	Original allocation	–	–
Original allocator or line items	0	New allocation	–	–
New allocator or line items	0	Difference	–	–
Rationale for change				

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

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

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

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2018**

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

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

sch ref

7

8 Have costs been allocated in aggregate using ACAM in accordance with clause 2.1.1(3) of the IM Determination? **Yes**

9

sch ref	Line Item*	Allocation methodology type	Cost allocator	Allocator type	Allocator Metric (%)		Value allocated ($000)				OVABAA allocation increase ($000)
11					Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	
12	**Service interruptions and emergencies**										
13	all				100.00%					-	
14										-	
15										-	
16										-	
17	**Not directly attributable**						-	-	-	-	-
18	**Vegetation management**										
19	all				100.00%					-	
20										-	
21										-	
22										-	
23	**Not directly attributable**						-	-	-	-	-
24	**Routine and corrective maintenance and inspection**										
25	all				100.00%					-	
26										-	
27										-	
28										-	
29	**Not directly attributable**						-	-	-	-	-
30	**Asset replacement and renewal**										
31	all				100.00%					-	
32										-	
33										-	
34										-	
35	**Not directly attributable**						-	-	-	-	-
36											

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2018**

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

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

sch ref												
37	**System operations and network support**											
38		all				100.00%					-	
39											-	
40											-	
41											-	
42	**Not directly attributable**							-	-	-	-	-
43	**Business support**											
44		all				100.00%					-	
45											-	
46											-	
47											-	
48	**Not directly attributable**							-	-	-	-	-
49												
50	**Operating costs not directly attributable**							-	-	-	-	-
51												
52	**Pass through and recoverable costs**											
53	**Pass through costs**											
54		all				100.00%					-	
55											-	
56											-	
57											-	
58	**Not directly attributable**							-	-	-	-	-
59	**Recoverable costs**											
60		all				100.00%					-	
61											-	
62											-	
63											-	
64	**Not directly attributable**							-	-	-	-	-
65	** include additional rows if needed*											

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2018**

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

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

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

sch ref

7		
8	Have assets been allocated in aggregate using ACAM in accordance with clause 2.1.1(3) of the IM Determination?	Yes
9		

sch ref					Allocator Metric (%)		Value allocated ($000)				
10–11	**Line Item***	**Allocation methodology type**	**Allocator**	**Allocator type**	**Electricity distribution services**	**Non-electricity distribution services**	**Arm's length deduction**	**Electricity distribution services**	**Non-electricity distribution services**	**Total**	**OVABAA allocation increase ($000)**
12	**Subtransmission lines**										
13	all				100.00%					-	
14										-	
15										-	
16										-	
17	**Not directly attributable**						-	-	-	-	-
18	**Subtransmission cables**										
19	all				100.00%					-	
20										-	
21										-	
22										-	
23	**Not directly attributable**						-	-	-	-	-
24	**Zone substations**										
25	all				100.00%					-	
26										-	
27										-	
28										-	
29	**Not directly attributable**						-	-	-	-	-
30	**Distribution and LV lines**										
31	all				100.00%					-	
32										-	
33										-	
34										-	
35	**Not directly attributable**						-	-	-	-	-

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2018**

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

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

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

sch ref												
36	**Distribution and LV cables**											
37		all				100.00%					-	
38											-	
39											-	
40											-	
41	**Not directly attributable**							-	-	-	-	-
42												
43	**Distribution substations and transformers**											
44		all				100.00%					-	
45											-	
46											-	
47											-	
48	**Not directly attributable**							-	-	-	-	-
49												
50	**Distribution switchgear**											
51		all				100.00%					-	
52											-	
53											-	
54											-	
55	**Not directly attributable**							-	-	-	-	-
56	**Other network assets**											
57		all	-	-	-	100.00%	-		-	-	-	
58						-			-	-	-	
59											-	
60											-	
61	**Not directly attributable**							-	-	-	-	-
62	**Non-network assets**											
63		all				100.00%					-	
64											-	
65											-	
66											-	
67	**Not directly attributable**							-	-	-	-	-
68												
69	**Regulated service asset value not directly attributable**							-	-	-	-	-
70	** include additional rows if needed*											

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2018**

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

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

sch ref

sch ref			($000)	($000)
7		**6a(i): Expenditure on Assets**		
8		Consumer connection		661
9		System growth		1,242
10		Asset replacement and renewal		1,994
11		Asset relocations		867
12		Reliability, safety and environment:		
13		Quality of supply	378	
14		Legislative and regulatory	343	
15		Other reliability, safety and environment	46	
16		**Total reliability, safety and environment**		767
17		**Expenditure on network assets**		5,531
18		Expenditure on non-network assets		600
19				
20		**Expenditure on assets**		6,131
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		372
23	*plus*	Value of vested assets		149
24				
25		**Capital expenditure**		5,908

sch ref		($000)
26	**6a(ii): Subcomponents of Expenditure on Assets (where known)**	
27	Energy efficiency and demand side management, reduction of energy losses	–
28	Overhead to underground conversion	580
29	Research and development	–

sch ref				($000)	($000)
30		**6a(iii): Consumer Connection**			
31		*Consumer types defined by EDB**			
32		Consumers 20kVA and less		244	
33		Consumers greater than 20kVA		417	
34			–	–	
35			–	–	
36			–	–	
37		** include additional rows if needed*			
38		**Consumer connection expenditure**			661
39					
40	*less*	Capital contributions funding consumer connection expenditure		16	
41		**Consumer connection less capital contributions**			645

sch ref			System Growth ($000)	Asset Replacement and Renewal ($000)
42		**6a(iv): System Growth and Asset Replacement and Renewal**		
43				
44				
45		Subtransmission	–	16
46		Zone substations	285	212
47		Distribution and LV lines	37	1,219
48		Distribution and LV cables	255	57
49		Distribution substations and transformers	279	248
50		Distribution switchgear	252	181
51		Other network assets	134	61
52		**System growth and asset replacement and renewal expenditure**	1,242	1,994
53	*less*	Capital contributions funding system growth and asset replacement and renewal	–	71
54		**System growth and asset replacement and renewal less capital contributions**	1,242	1,923
55				

sch ref				($000)	($000)
56		**6a(v): Asset Relocations**			
57		*Project or programme**			
58			0	–	
59			–	–	
60			–	–	
61			–	–	
62			–	–	
63		** include additional rows if needed*			
64		All other projects or programmes - asset relocations		867	
65		**Asset relocations expenditure**			867
66	*less*	Capital contributions funding asset relocations		285	
67		**Asset relocations less capital contributions**			582

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2018**

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		–	
72		–	
73		–	
74		–	
75		–	
76	** include additional rows if needed*		
77	All other projects programmes - quality of supply	378	
78	**Quality of supply expenditure**		378
79	*less* Capital contributions funding quality of supply	–	
80	**Quality of supply less capital contributions**		378
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	343	
90	**Legislative and regulatory expenditure**		343
91	*less* Capital contributions funding legislative and regulatory	–	
92	**Legislative and regulatory less capital contributions**		343
93	**6a(viii): Other Reliability, Safety and Environment**		
94	*Project or programme**	**($000)**	**($000)**
95		–	
96		–	
97		–	
98		–	
99		–	
100	** include additional rows if needed*		
101	All other projects or programmes - other reliability, safety and environment	46	
102	**Other reliability, safety and environment expenditure**		46
103	*less* Capital contributions funding other reliability, safety and environment	–	
104	**Other reliability, safety and environment less capital contributions**		46
105			
106	**6a(ix): Non-Network Assets**		
107	**Routine expenditure**		
108	*Project or programme**	**($000)**	**($000)**
109	0	–	
110	0	–	
111		–	
112		–	
113		–	
114	** include additional rows if needed*		
115	All other projects or programmes - routine expenditure	600	
116	**Routine expenditure**		600
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**		600

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2018**

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	1,169	
9	Vegetation management	948	
10	Routine and corrective maintenance and inspection	1,824	
11	Asset replacement and renewal	2,125	
12	**Network opex**		6,066
13	System operations and network support	2,052	
14	Business support	2,827	
15	**Non-network opex**		4,879
16			
17	**Operational expenditure**		10,945
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		66
20	Direct billing*		–
21	Research and development		–
22	Insurance		279
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2018**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

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

sch ref		Target ($000) [1]	Actual ($000)	% variance
7	**7(i): Revenue**			
8	Line charge revenue	44,483	45,046	1%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	520	661	27%
11	System growth	3,107	1,242	(60%)
12	Asset replacement and renewal	2,903	1,994	(31%)
13	Asset relocations	640	867	35%
14	Reliability, safety and environment:			
15	Quality of supply	943	378	(60%)
16	Legislative and regulatory	420	343	(18%)
17	Other reliability, safety and environment	300	46	(85%)
18	**Total reliability, safety and environment**	1,663	767	(54%)
19	**Expenditure on network assets**	8,833	5,531	(37%)
20	Expenditure on non-network assets	520	600	15%
21	Expenditure on assets	9,353	6,131	(34%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,061	1,169	10%
24	Vegetation management	990	948	(4%)
25	Routine and corrective maintenance and inspection	1,850	1,824	(1%)
26	Asset replacement and renewal	2,333	2,125	(9%)
27	**Network opex**	6,234	6,066	(3%)
28	System operations and network support	1,936	2,052	6%
29	Business support	2,987	2,827	(5%)
30	**Non-network opex**	4,923	4,879	(1%)
31	**Operational expenditure**	11,157	10,945	(2%)
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses	–	–	–
34	Overhead to underground conversion	640	580	(9%)
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	55	66	20%
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	273	279	2%
42				

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

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

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

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

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
15	0S	Unmetered Streetlamps	Standard	25	2,340
16	0UNM	Unmetered Supplies	Standard	86	15
17	1	15 kVA Capacity	Standard	36,490	244,629
18	2	20 - 150 kVA Capacity	Standard	2,716	95,654
19	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	2	13
20	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	41	291
21	HLF	High Load Factor, 15-150kVA Capacity	Standard	54	10,626
22	31	Between 150 and 3000kVA	Standard	4	10,084
23	33	Between 150 and 3000kVA	Standard	4	8,729
	34	Between 150 and 3000kVA	Standard	151	113,299
	35	Between 150 and 3000kVA	Standard	2	13,192
	6.1	> 3000,	Non-standard	1	104,504
	6.2	> 3000,	Non-standard	1	13,756
	CB	Cobb River Hydro	Non-standard	1	83
	-	-	[Select one]	-	-
	-	-	[Select one]	-	-
	-	-	[Select one]	-	-
	-	-	[Select one]	-	-
25	*Add extra rows for additional consumer groups or price category codes as necessary*				
26			**Standard consumer totals**	39,575	498,872
27			**Non-standard consumer totals**	3	118,343
28			**Total for all consumers**	39,578	617,215

Billed quantities by price component

sch ref	Consumer group name or price category code	0STL	0UNM	1ANY	1DAY	1NIT	1OPK	1WSR	2ANY	2DAY	2NIT
12	**Price component**	0STL	0UNM	1ANY	1DAY	1NIT	1OPK	1WSR	2ANY	2DAY	2NIT
13	**Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)**	W/day	Daily	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
15	0S	547,945	–	–	–	–	–	–	–	–	–
16	0UNM	–	83	–	–	–	–	–	–	–	–
17	1	9,447	–	178,230	2,166	4,026	696	59,511	–	–	–
18	2	7,085	–	–	–	–	–	–	67,411	17,044	7,576
19	2HLFC	–	–	–	–	–	–	–	–	–	–
20	2LLFC	–	–	–	–	–	–	–	–	–	–
21	HLF	–	–	–	–	–	–	–	–	–	–
22	31	–	–	–	–	–	–	–	–	–	–
23	33	–	–	–	–	–	–	–	–	–	–
	34	–	–	–	–	–	–	–	–	–	–
	35	–	–	–	–	–	–	–	–	–	–
	6.1	–	–	–	–	–	–	–	–	–	–
	6.2	–	–	–	–	–	–	–	–	–	–
	CB	–	–	–	–	–	–	–	–	–	–
	-	–	–	–	–	–	–	–	–	–	–
	-	–	–	–	–	–	–	–	–	–	–
	-	–	–	–	–	–	–	–	–	–	–
	-	–	–	–	–	–	–	–	–	–	–
26	**Standard consumer totals**	564,477	83	178,230	2,166	4,026	696	59,511	67,411	17,044	7,576
27	**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–
28	**Total for all consumers**	564,477	83	178,230	2,166	4,026	696	59,511	67,411	17,044	7,576

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)
0S	Unmetered Streetlamps	Standard	$232	–	$158	$74
0UNM	Unmetered Supplies	Standard	$16	–	$11	$5
1	15 kVA Capacity	Standard	$21,308	–	$14,627	$6,681
2	20 - 150 kVA Capacity	Standard	$9,685	–	$7,017	$2,668
2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	$1	–	$1	–
2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	$34	–	$25	$9
HLF	High Load Factor, 15-150kVA Capacity	Standard	$726	–	$558	$168
31	Between 150 and 3000kVA	Standard	$351	–	$147	$204
33	Between 150 and 3000kVA	Standard	$426	–	$261	$165
34	Between 150 and 3000kVA	Standard	$6,854	–	$4,315	$2,539
35	Between 150 and 3000kVA	Standard	$625	–	$370	$255
6.1	> 3000,	Non-standard	$2,128	–	$216	$1,912
6.2	> 3000,	Non-standard	$564	–	$232	$332
NDL/New Connections	New Connections, NDL	Standard	$436	–	$436	–
Embedded generators	Cobb, Pupu etc	Non-standard	$1,660	–	$1,333	$327
0	0	[Select one]	–	–	–	–
Add extra rows for additional consumer groups or price category codes as necessary						
		Standard consumer totals	$40,694	–	$27,926	$12,768
		Non-standard consumer totals	$4,352	–	$1,781	$2,571
		Total for all consumers	$45,046	–	$29,707	$15,339

Line charge revenues ($000) by price component

Price component	0STL	0UNM	1ANY	1DAY	1NIT	1OPK	1WSR	2ANY	2DAY	2NIT
Rate (eg, $ per day, $ per kWh, etc.)	$0.116/W/day	$0.53 / day	9.15	10.07	3.05	7.12	4.22	8.07	8.89	2.68
0S	$232	–	–	–	–	–	–	–	–	–
0UNM	–	$16	–	–	–	–	–	–	–	–
1	$4	–	$16,397	$220	$123	$50	$2,528	$1	–	–
2	$3	–	$15	–	$1	–	–	$5,465	$1,529	$205
2HLFC	–	–	–	–	–	–	–	–	–	–
2LLFC	–	–	–	–	–	–	–	$1	–	–
HLF	–	–	$4	–	–	–	–	–	–	–
31	–	–	–	–	–	–	–	–	–	–
33	–	–	–	–	–	–	–	–	–	–
34	–	–	–	–	–	–	–	–	–	–
35	–	–	–	–	–	–	–	–	–	–
6.1	–	–	–	–	–	–	–	–	–	–
6.2	–	–	–	–	–	–	–	–	–	–
NDL/New Connections	–	–	–	–	–	–	–	–	–	–
Embedded generators	–	–	–	–	–	–	–	–	–	–
0	–	–	–	–	–	–	–	–	–	–
Standard consumer totals	$239	$16	$16,416	$220	$124	$50	$2,528	$5,467	$1,529	$205
Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–
Total for all consumers	$239	$16	$16,416	$220	$124	$50	$2,528	$5,467	$1,529	$205

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8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end 7

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
Information is also required on the number of ICPs that are included in each consumer group or price category code, and

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)	2OPK	2WSR	2LANY	2LDAY	2LNIT	2LOPK	2LWSR	2HANY	2HDAY	2HNIT	2HOPK	2HWSR	HLFANY	HLFDAY	HLFNIT	HLFOPK
12/13				c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh
14																			
15	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
17	1	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
18	2	20 - 150 kVA Capacity	Standard	289	3,333	–	–	–	–	–	–	–	–	–	–	–	–	–	–
19	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	–	–	–	–	–	–	9	–	–	–	4	–	–	–	–
20	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	–	–	206	22	14	–	49	–	–	–	–	–	–	–	–	–
21	HLF	High Load Factor, 15-150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	4,525	4,547	1,520	–
22	31	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
23	33	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	34	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	35	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
25	*Add extra rows for additional consumer groups or price category codes as necessary*																		
26			**Standard consumer totals**	289	3,333	206	22	14	–	49	9	–	–	–	4	4,525	4,547	1,520	–
27			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
28			**Total for all consumers**	289	3,333	206	22	14	–	49	9	–	–	–	4	4,525	4,547	1,520	–

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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
Information is also required on the number of ICPs that are included in each consumer group or price category code, and

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

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	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	2OPK	2WSR	2LANY	2LDAY	2LNIT	2LOPK	2LWSR	2HANY	2HDAY	2HNIT	2HOPK	2HWSR	HLFANY	HLFDAY	HLFNIT	HLFOPK
34/35				6.3	3.73	12.11	12.93	6.72	10.34	7.77	16.83	17.65	11.44	15.06	12.49	2.27	2.47	0.71	1.77
36																			
37	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
38	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
39	1	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
40	2	20 - 150 kVA Capacity	Standard	$18	$125	$2	–	–	–	–	–	–	–	–	$1	$1	–	–	–
41	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	–	–	–	–	–	–	$1	–	–	–	–	–	–	–	–
	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	–	–	$23	$3	$1	–	$4	–	–	–	–	–	–	–	–	–
	HLF	High Load Factor, 15-150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	$103	$113	$11	–
	31	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	33	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	34	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	35	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
42	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
43	NDL/New Connections	New Connections, NDL	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
44	Embedded generators	Cobb, Pupu etc	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
45	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
47	*Add extra rows for additional consumer groups or price category codes as necessary*																		
48			**Standard consumer totals**	$18	$125	$25	$3	$1	–	$4	$1	–	–	–	$1	$104	$113	$11	–
49			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
50			**Total for all consumers**	$18	$125	$25	$3	$1	–	$4	$1	–	–	–	$1	$104	$113	$11	–

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

53 **Number of directly billed ICPs at year end** 7

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
Information is also required on the number of ICPs that are included in each consumer group or price category code, and

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)	HLFWSR	GENA	1	2	2HLFC	2LLFC	HLF	AnyDem31	AnyDem33	AnyDem34	AnyDem35	RCPD	kVAr	SD31	SN31	WD31
12				HLFWSR	GENA	1	2	2HLFC	2LLFC	HLF	AnyDem31	AnyDem33	AnyDem34	AnyDem35	RCPD	kVAr	SD31	SN31	WD31
13	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	c/kWh	c/kWh	Daily	kVA per Day	Daily	Daily	kVA per Day	kVA / day	kVA / day	kVA / day	kVA / day	kW / day	kVAr / day	c/kWh	c/kWh	c/kWh
14																			
15	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
17	1	15 kVA Capacity	Standard	–	–	36,256	–	–	–	–	–	–	–	–	–	–	–	–	–
18	2	20 - 150 kVA Capacity	Standard	–	–	–	122,706	–	–	–	–	–	–	–	–	–	–	–	–
19	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
20	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	–	–	–	–	–	37	–	–	–	–	–	–	–	–	–	–
21	HLF	High Load Factor, 15-150kVA Capacity	Standard	34	–	–	–	–	–	3,403	–	–	–	–	–	–	–	–	–
22	31	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	2,432	–	–	–	1,541	–	3,969	1,667	3,107
23	33	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	2,335	–	–	1,210	–	–	–	–
	34	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	43,489	–	17,789	194	–	–	–
	35	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	3,739	1,856	–	–	–	–
	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
25	*Add extra rows for additional consumer groups or price category codes as necessary*																		
26			**Standard consumer totals**	34	–	36,256	122,706	–	37	3,403	2,432	2,335	43,489	3,739	22,396	194	3,969	1,667	3,107
27			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
28			**Total for all consumers**	34	–	36,256	122,706	–	37	3,403	2,432	2,335	43,489	3,739	22,396	194	3,969	1,667	3,107

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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
Information is also required on the number of ICPs that are included in each consumer group or price category code, and

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

32

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34				HLFWSR	GENA	1	2	2HLFC	2LLFC	HLF	AnyDem31	AnyDem33	AnyDem34	AnyDem35	RCPD	kVAr	SD31	SN31	WD31
35	**Consumer group name or price category code**	**Consumer type or types (eg, residential, commercial etc.)**	**Standard or non-standard consumer group (specify)**	1.02	0	15 c/day	5.18 c/kVA/day	15 c/day	15 c/day	39.85 c/kVA/day	12.39	15.02	15.8	15.02	33.96	25.45	0.44	0.24	0.79
36																			
37	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
38	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
39	1	15 kVA Capacity	Standard	–	–	$1,985	–	–	–	–	–	–	–	–	–	–	–	–	–
40	2	20 - 150 kVA Capacity	Standard	–	–	–	$2,320	–	–	–	–	–	–	–	–	–	–	–	–
41	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	–	–	–	–	–	$2	–	–	–	–	–	–	–	–	–	–
	HLF	High Load Factor, 15-150kVA Capacity	Standard	–	–	–	–	–	–	$495	–	–	–	–	–	–	–	–	–
	31	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	$110	–	–	–	$191	–	$18	$4	$25
	33	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	$128	–	–	$150	–	–	–	–
	34	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	$2,508	–	$2,205	$18	–	–	–
	35	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	–	$205	$230	–	–	–	–
	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
42	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
43	NDL/New Connections	New Connections, NDL	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
44	Embedded generators	Cobb, Pupu etc	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
45	0	0	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
47	*Add extra rows for additional consumer groups or price category codes as necessary*																		
48			**Standard consumer totals**	–	–	$1,985	$2,320	–	$2	$495	$110	$128	$2,508	$205	$2,776	$18	$18	$4	$25
49			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
50			**Total for all consumers**	–	–	$1,985	$2,320	–	$2	$495	$110	$128	$2,508	$205	$2,776	$18	$18	$4	$25

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

53 **Number of directly billed ICPs at year end** 7

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
Information is also required on the number of ICPs that are included in each consumer group or price category code, and

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)	WN31	SD33	SN33	WD33	WN33	SD34	SN34	WD34	WN34	SD35	SN35	WD35	WN35	6.1	6.2	NDL
12/13				c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	Annual	Annual	kVA=km
14																			
15	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
17	1	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
18	2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
19	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
20	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
21	HLF	High Load Factor, 15-150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
22	31	Between 150 and 3000kVA	Standard	1,341	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
23	33	Between 150 and 3000kVA	Standard	–	4,035	1,777	2,127	790	–	–	–	–	–	–	–	–	–	–	–
	34	Between 150 and 3000kVA	Standard	–	–	–	–	–	47,000	16,763	36,469	13,067	–	–	–	–	–	–	–
	35	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	5,112	2,246	4,050	1,784	–	–	–
	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	CB	Cobb River Hydro	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	30,302
	-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	-	-	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
25	*Add extra rows for additional consumer groups or price category codes as necessary*																		
26			**Standard consumer totals**	1,341	4,035	1,777	2,127	790	47,000	16,763	36,469	13,067	5,112	2,246	4,050	1,784	–	–	–
27			**Non-standard consumer totals**	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
28			**Total for all consumers**	1,341	4,035	1,777	2,127	790	47,000	16,763	36,469	13,067	5,112	2,246	4,050	1,784	–	–	–

29
30

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
Information is also required on the number of ICPs that are included in each consumer group or price category code, and

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)	WN31	SD33	SN33	WD33	WN33	SD34	SN34	WD34	WN34	SD35	SN35	WD35	WN35	6.1	6.2	NDL
			0.24	1.35	0.71	3.45	0.71	1.35	0.71	3.45	0.71	0.91	0.57	2.95	0.57	Annual	Annual	7.714143
0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
1	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
HLF	High Load Factor, 15-150kVA Capacity	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
31	Between 150 and 3000kVA	Standard	$3	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
33	Between 150 and 3000kVA	Standard	–	$55	$13	$74	$6	–	–	–	–	–	–	–	–	–	–	–
34	Between 150 and 3000kVA	Standard	–	–	–	–	–	$639	$121	$1,269	$94	–	–	–	–	–	–	–
35	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–	–	$47	$13	$120	$10	–	–	–
6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	$2,128	–	–
6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	$564	–
NDL/New Connections	New Connections, NDL	Standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	$234
Embedded generators	Cobb, Pupu etc	Non-standard	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
0	0	[Select one]	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category codes as necessary																		
		Standard consumer totals	$3	$55	$13	$74	$6	$639	$121	$1,269	$94	$47	$13	$120	$10	–	–	$234
		Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–	–	$2,128	$564	–
		Total for all consumers	$3	$55	$13	$74	$6	$639	$121	$1,269	$94	$47	$13	$120	$10	$2,128	$564	$234

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	7

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2018**
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
Information is also required on the number of ICPs that are included in each consumer group or price category code, and

sch ref

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

columns for

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	NCA Admin G0	NCA Admin G1	NCA Admin G2	NCA Admin G3	CB	Standard DG Part1A	Standard DG Part1	DG >10kw <100kW
13				New connection application	New connection application	New connection application	New connection application	Annual	Per application	Per application	Per application
15	0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–
16	0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–
17	1	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–
18	2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–
19	2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	–	–	–	–	–	–	–
20	2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	–	–	–	–	–	–	–	–
21	HLF	High Load Factor, 15-150kVA Capacity	Standard	–	–	–	–	–	–	–	–
22	31	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–
23	33	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–
	34	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–
	35	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–
	6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–
	6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–
	CB	Cobb River Hydro	Non-standard	–	–	–	–	1,653,826	–	–	–
	-	-	[Select one]	–	661	52	12	–	163	–	2
	-	-	[Select one]	–	–	–	–	–	–	–	–
	-	-	[Select one]	–	–	–	–	–	–	–	–
	-	-	[Select one]	–	–	–	–	–	–	–	–
25	*Add extra rows for additional consumer groups or price category codes as necessary*										
26			**Standard consumer totals**	–	–	–	–	–	–	–	–
27			**Non-standard consumer totals**	–	–	–	–	1,653,826	–	–	–
28			**Total for all consumers**	–	–	–	–	1,653,826	–	–	–

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2018**
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
Information is also required on the number of ICPs that are included in each consumer group or price category code, and

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)	NCA Admin G0	NCA Admin G1	NCA Admin G2	NCA Admin G3	CB	Standard DG Part1A	Standard DG Part1	DG >10kw <100kW
			125	250	325	400	Annual	100	200	500
0S	Unmetered Streetlamps	Standard	–	–	–	–	–	–	–	–
0UNM	Unmetered Supplies	Standard	–	–	–	–	–	–	–	–
1	15 kVA Capacity	Standard	–	–	–	–	–	–	–	–
2	20 - 150 kVA Capacity	Standard	–	–	–	–	–	–	–	–
2HLFC	Domesitic low user, 20 or 30 kVA Capacity	Standard	–	–	–	–	–	–	–	–
2LLFC	Domesitic low user, 40-150kVA Capacity	Standard	–	–	–	–	–	–	–	–
HLF	High Load Factor, 15-150kVA Capacity	Standard	–	–	–	–	–	–	–	–
31	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–
33	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–
34	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–
35	Between 150 and 3000kVA	Standard	–	–	–	–	–	–	–	–
6.1	> 3000,	Non-standard	–	–	–	–	–	–	–	–
6.2	> 3000,	Non-standard	–	–	–	–	–	–	–	–
NDL/New Connections	New Connections, NDL	Standard	–	$164	$16	$5	–	$16	–	$1
Embedded generators	Cobb, Pupu etc	Non-standard	–	–	–	–	$1,660	–	–	–
0	0	[Select one]	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category codes as necessary										
		Standard consumer totals	–	$164	$16	$5	–	$16	–	$1
		Non-standard consumer totals	–	–	–	–	$1,660	–	–	–
		Total for all consumers	–	$164	$16	$5	$1,660	$16	–	$1

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	7

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2018**
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.	25,917	25,987	70	3
10	All	Overhead Line	Wood poles	No.	1,449	1,491	42	3
11	All	Overhead Line	Other pole types	No.	529	540	11	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	27	27	–	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	15	–	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.	101	102	1	4
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	9	9	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	20	20	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	95	99	4	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.	25	25	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,893	1,894	1	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	113	122	9	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.	61	62	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.	1,266	1,279	13	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	184	186	2	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	96	102	6	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,815	3,817	2	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	678	701	23	3
48	HV	Distribution Transformer	Voltage regulators	No.	11	11	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	26	25	(1)	4
50	LV	LV Line	LV OH Conductor	km	504	502	(2)	3
51	LV	LV Cable	LV UG Cable	km	613	629	16	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	4
53	LV	Connections	OH/UG consumer service connections	No.	39,299	39,861	562	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	141	141	–	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single syster	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	9	10	1	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

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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 2018

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940–1949	1950–1959	1960–1969	1970–1979	1980–1989	1990–1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
9																											
10	All	Overhead Line	Concrete poles / steel structure	No.	2,267	1,253	6,859	6,065	1,957	3,540	993	63	180	124	169	162	91	167	170	155	132	189	134	137	128	150	203
11	All	Overhead Line	Wood poles	No.	–	76	203	186	140	179	178	17	21	9	8	21	3	7	12	11	8	56	13	15	14	29	–
12	All	Overhead Line	Other pole types	No.	59	34	56	129	47	90	51	–	4	1	–	–	1	–	1	4	–	1	–	–	1	–	–
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	95	98	2	10	61	3	3	–	2	2	1	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	–	–	–	9	–	–
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.	–	3	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	–	8	14	–	–	–	–	–	–	8	–	–
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	117	83	461	517	154	274	103	7	7	7	12	12	6	10	3	8	13	34	16	12	16	6	2
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	5	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	2	1	2
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	–	2	3	–	1	4	2	2	–	–	–	4	8	8	4	6	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	–	1	4	15	17	11	8	15	16	25	39	43	17	40	33	25	11	19	19	10	13	25
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	2	–	2	4	3	3	15	5	14	18	7	23	23	15	4	4	6	12	11
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	1	–	–	1	1	1	4	1	4	1	1	–	1	2	3	–	–	2	–
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	18	63	164	548	498	846	578	35	74	82	62	67	42	37	22	42	43	41	31	40	70	43	23
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	4	9	79	122	71	14	17	29	28	28	23	42	26	31	23	18	16	4	18	30	14
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	–	24	149	119	41	58	12	78	1	1	1	2	2	3	1	1	2	1	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	9	11	12
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	460	557	442
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	3	–	2	2	17	43	–	13	–	12	2	8	16	–	–	–	–	–	–	6	–	–
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	1	2	2	1	–	–	–	–
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 Limited**
For Year Ended	**31 March 2018**
Network / Sub-network Name	

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8		**Disclosure Year (year ended)**	31 March 2018								
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**2016**	**2017**	**2018**	**No. with age unknown**	**Items at end of year**	**No. with default dates**	**Data accuracy (1–4)**
10	All	Overhead Line	Concrete poles / steel structure	No.	33	130	70	466	25,987	–	1
11	All	Overhead Line	Wood poles	No.	–	8	42	235	1,491	–	1
12	All	Overhead Line	Other pole types	No.	–	–	11	50	540	–	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	–	–	–	–	27	–	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	–	–	–	15	–	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	35	102	–	1
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	9	–	4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	–	20	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	12	–	4	–	99	–	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	–	–	–	25	–	4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	–	6	8	–	1,894	–	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	9	–	122	–	2
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	–	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.	5	6	1	–	62	–	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.	5	7	13	848	1,279	–	2
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	5	2	8	186	–	2
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	4	6	69	102	–	2
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	16	2	2	328	3,817	–	3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	13	9	23	10	701	–	3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	6	11	–	2
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	25	–	2
51	LV	LV Line	LV OH Conductor	km	–	1	–	2	502	–	2
52	LV	LV Cable	LV UG Cable	km	3	14	13	13	629	–	2
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	–	–	2
54	LV	Connections	OH/UG consumer service connections	No.	447	538	562	29,246	39,861	–	2
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	4	13	–	–	141	–	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	1	–	3
57	All	Capacitor Banks	Capacitors including controls	No	1	–	1	–	10	–	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 Limited**
For Year Ended	**31 March 2018**
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	30	153
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	113	13	126
16	6.6kV to 11kV (inclusive—other than SWER)	1,781	245	2,026
17	Low voltage (< 1kV)	502	629	1,131
18	**Total circuit length (for supply)**	2,677	917	3,594
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	188	7%	
25	Rural	2,294	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**	2,677	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	46%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	2,667	100%	

Company Name	Network Tasman Limited
For Year Ended	31 March 2018

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref	Location *	Number of ICPs served	Line charge revenue ($000)
8			
9	None		
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 Limited**
For Year Ended	**31 March 2018**
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**

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

sch ref			Number of connections (ICPs)	
10		*Consumer types defined by EDB**		
11		Consumers 20kVA and less	616	
12		Consumers greater than 20kVA	26	
13				
14				
15				
16		** include additional rows if needed*		
17		**Connections total**	642	
18				
19		**Distributed generation**		
20		Number of connections made in year	150	**connections**
21		Capacity of distributed generation installed in year	0.58	**MVA**

22 **9e(ii): System Demand**

sch ref			Demand at time of maximum coincident demand (MW)	
23				
24				
25		**Maximum coincident system demand**		
26		GXP demand	107	
27	*plus*	Distributed generation output at HV and above	32	
28		**Maximum coincident system demand**	139	
29	*less*	Net transfers to (from) other EDBs at HV and above	19	
30		**Demand on system for supply to consumers' connection points**	120	
31		**Electricity volumes carried**	**Energy (GWh)**	
32		Electricity supplied from GXPs	627	
33	*less*	Electricity exports to GXPs	78	
34	*plus*	Electricity supplied from distributed generation	206	
35	*less*	Net electricity supplied to (from) other EDBs	94	
36		**Electricity entering system for supply to consumers' connection points**	661	
37	*less*	Total energy delivered to ICPs	617	
38		**Electricity losses (loss ratio)**	43	6.6%
39				
40		**Load factor**	0.63	

41 **9e(iii): Transformer Capacity**

sch ref		(MVA)
42		
43	Distribution transformer capacity (EDB owned)	410
44	Distribution transformer capacity (Non-EDB owned, estimated)	44
45	**Total distribution transformer capacity**	454
46		
47	**Zone substation transformer capacity**	381

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2018**
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)	2	
11	Class B (planned interruptions on the network)	147	
12	Class C (unplanned interruptions on the network)	126	
13	Class D (unplanned interruptions by Transpower)	4	
14	Class E (unplanned interruptions of EDB owned generation)	–	
15	Class F (unplanned interruptions of generation owned by others)	–	
16	Class G (unplanned interruptions caused by another disclosing entity)	–	
17	Class H (planned interruptions caused by another disclosing entity)	–	
18	Class I (interruptions caused by parties not included above)	–	
19	**Total**	279	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	85	41
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	0.05	16.5
26	Class B (planned interruptions on the network)	0.28	71.4
27	Class C (unplanned interruptions on the network)	1.03	160.7
28	Class D (unplanned interruptions by Transpower)	1.60	237.8
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**	2.96	486.3
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	1.27	191.3
38			
39	**Quality path normalised reliability limit**	**SAIFI reliability limit**	**SAIDI reliability limit**
40	SAIFI and SAIDI limits applicable to disclosure year*	1.57	148.3
41	** not applicable to exempt EDBs*		

Company Name	**Network Tasman Limited**
For Year Ended	**31 March 2018**
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.

42 ### 10(ii): Class C Interruptions and Duration by Cause

		SAIFI	SAIDI
44	**Cause**		
45	Lightning	0.00	0.1
46	Vegetation	0.01	1.1
47	Adverse weather	0.46	108.0
48	Adverse environment	–	–
49	Third party interference	0.05	5.8
50	Wildlife	0.02	1.8
51	Human error	0.01	0.1
52	Defective equipment	0.26	26.3
53	Cause unknown	0.22	17.5

55 ### 10(iii): Class B Interruptions and Duration by Main Equipment Involved

		SAIFI	SAIDI
57	**Main equipment involved**		
58	Subtransmission lines	–	–
59	Subtransmission cables	–	–
60	Subtransmission other	–	–
61	Distribution lines (excluding LV)	0.23	66.3
62	Distribution cables (excluding LV)	0.03	3.8
63	Distribution other (excluding LV)	0.03	1.3

64 ### 10(iv): Class C Interruptions and Duration by Main Equipment Involved

		SAIFI	SAIDI
66	**Main equipment involved**		
67	Subtransmission lines	0.31	28.4
68	Subtransmission cables	–	–
69	Subtransmission other	0.02	4.7
70	Distribution lines (excluding LV)	0.55	114.5
71	Distribution cables (excluding LV)	0.12	10.4
72	Distribution other (excluding LV)	0.03	2.6

73 ### 10(v): Fault Rate

		Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
74	**Main equipment involved**			
75	Subtransmission lines	4	281	1.42
76	Subtransmission cables	–	30	–
77	Subtransmission other	1		
78	Distribution lines (excluding LV)	102	1,894	5.39
79	Distribution cables (excluding LV)	12	257	4.67
80	Distribution other (excluding LV)	7		
81	**Total**	126		

Company Name	Network Tasman Limited
For Year Ended	31 March 2018

Schedule 14 Mandatory Explanatory Notes

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

2. This schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. Information provided in boxes 1 to 12 of this schedule is part of the audited disclosure information, and so is subject to the assurance requirements specified in section 2.8.

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

Return on Investment (Schedule 2)

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

Box 1: Explanatory comment on return on investment

There have been no changes in classification.

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 Ltd management fee $49,000 and sundry income of $85,000.

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

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 were the following changes in classification.

Category 2017	*Category 2018*	*$000*	*Explanation*
Distribution & LV Lines	Distribution & LV Cable	2	Cable expenditure was incorrectly classified as Line.
Other Network Assets	Zone Substations	120	Zone Substation switchgear was incorrectly classified as Other Network Assets
		122	

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

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

- Use of money interest received

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

- Non-deductible expenses

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

- RAB revaluation

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

- Line charge discounts
- Movement in provisions

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 disposals of assets temporary difference \$133,000 @28% = \$37,000 and Movement in provisions temporary difference -\$147,000 @28% = \$-41,000 Making temporary differences of \$-4,000.

Related party transactions: disclosure of related party transactions (Schedule 5b)

10. In the box below, provide descriptions of related party transactions beyond those disclosed on Schedule 5b including identification and descriptions as to the nature of directly attributable costs disclosed under subclause 2.3.6(1)(b).

Box 7: Related party transactions
The management services fee of \$49,000 is for providing engineering support to Nelson Electricity Limited. On charge of Electricity Authority levies and other sundry charges to Nelson Electricity Limited \$19,000.

Cost allocation (Schedule 5d)

11. 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 8: Cost allocation
Costs relating to unregulated businesses have been identified and excluded from the unallocated costs. Therefore all costs are directly attributable to the Electricity Distribution Services business.

Asset allocation (Schedule 5e)

12. 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 9: Commentary on asset allocation

The not directly attributable assets relate to assets constructed in 2004/2005. A calculation was done at the time to identify the share of costs that related to the EDB business. These assets have been fully depreciated in the 2017/18 year so there is now no difference in the allocated and unallocated RAB.

Only directly attributable assets have been commissioned since 2005.

There has been no reclassification of assets.

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

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

Box 10: Explanation of capital expenditure for the disclosure year

The materiality threshold of $1million has been used when identifying major network projects.

No items have been reclassified.

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

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

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

    14.3 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 11: 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.

No items have been reclassified.

There was no material atypical expenditure.

Variance between forecast and actual expenditure (Schedule 7)

15. 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 12: Explanatory comment on variance in actual to forecast expenditure

Capital Expenditure

- Customer connection expenditure is above target due to higher than expected customer growth.
- System growth is significantly below target principally due a delay with the 23MVA 66/11kV Transformers project due to a manufacturing error resulting in the transformers being returned for correction.
- Asset replacement and renewal is below target due to some of the major projects being delayed. The 35mm PILC HV Cable Replacement project has been delayed as further cable condition information has come to hand requiring further research. The Motupipi Substation Upgrade has been delayed as the resources are required for the higher priority new Wakapuaka Substation. The HV Conductor Replacement project was delayed due to planning and gearing up for the work taking longer than expected.
- Asset relocations are above target with an unbudgeted undergrounding project arising from NZTA requirements. A matching customer contribution was received for this project.
- Reliability, safety and environment – quality of supply is below target with some projects delayed until the next financial year. The 1MVA Generator Replacement was delayed as more design for the replacement generator was required. The 33kV CB's Swamp Road Substation project was delayed due to resources being reprioritised.
- Reliability, safety and environment – legislative and regulatory is a 18% under budget with a portion of the main project being completed in the beginning of the next financial year.
- Other reliability, safety and environment is below target due to a $140,000 project being cancelled and the transformer bunding project being delayed until the following year. This is underway now.
- The expenditure on non-network assets is above target due to unbudgeted office refurbishment brought about by increasing staff numbers.

Box 12: Explanatory comment on variance in actual to forecast expenditure - continued

Operational Expenditure

- Service interruptions and emergencies costs are more than target due to repairs required from ex-cyclones Fehi and Gita.
- Vegetation management is below target with slightly less vegetation expenditure than anticipated.
- Routine and corrective maintenance and inspection costs are close to target.
- Asset replacement and renewal expenditure is less than target as this work required less resourcing than anticipated due to being concentrated closer to the main depot than in previous years.
- Non-network expenditure is close to target.

Information relating to revenues and quantities for the disclosure year

16. In the box below provide-

16.1 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

16.2 explanatory comment on reasons for any material differences between target revenue and total billed line charge revenue.

Box 13: Explanatory comment relating to revenue for the disclosure year

The variance between actual revenue and target was (1%). Revenue is above target as there are more ICPs connected during the year, and more customers than expected on high rate tariffs.

Network Reliability for the Disclosure Year (Schedule 10)

17. In the box below, comment on network reliability for the disclosure year, as disclosed in Schedule 10.

Network SAIDI minutes (average duration of supply interruptions per connected consumer, excluding Transpower planned and unplanned faults) were 232 minutes against a target of 150 minutes (186 minutes in 2016/17). The target is made of 75 minutes for unplanned outages and 75 minutes for planned outages.

Planned outage SAIDI was below target at 71 minutes.

Unplanned outage SAIDI was impacted by ex-cyclones Fehi and Gita that occurred in February 2018. These events caused 18 and 85 SAIDI minutes respectively. Without these events, unplanned SAIDI would have been well below target at 58 minutes. Network Tasman continues to focus on planned maintenance on the network and vegetation control to ensure improvement of the long-term safety and reliability of the electricity network.

Overall, the Commerce Commission targets for reliability were not breached.

Insurance cover

18. In the box below, provide details of any insurance cover for the assets used to provide electricity distribution services, including-

    18.1 The EDB's approaches and practices in regard to the insurance of assets used to provide electricity distribution services, including the level of insurance;

    18.2 In respect of any self insurance, the level of reserves, details of how reserves are managed and invested, and details of any reinsurance.

Box 15: Explanation of insurance cover

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

Amendments to previously disclosed information

19. 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:

    19.1 a description of each error; and

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

Box 16: Disclosure of amendment to previously disclosed information

There are no amendments to previously disclosed information, other than in the 2017 Information Disclosure Sch 4 where the asset lives should have been -

4(vii): Disclosure by Asset Category

	Distribution and LV lines
Asset Life	
Weighted average remaining asset life	29.1
Weighted average expected total asset life	58.9

This amendment was noted on the 2017 Information Disclosures on the Network Tasman Ltd website.

Company Name	Network Tasman Limited
For Year Ended	31 March 2018

Schedule 14a Mandatory Explanatory Notes on Forecast Information

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

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

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

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

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts
An inflation factor of 2.13% has been applied from the 2019 year.

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

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

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts
An inflation factor of 2.46% has been applied from the 2019 year.

Company Name	Network Tasman Limited
For Year Ended	31 March 2018

Schedule 15 Voluntary Explanatory Notes

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

    1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1 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 system demand” (row 28) instead of “Demand on system for supply to consumers' connection points” (row 30) on schedule 9c. The difference is that the line “Maximum coincident system demand” includes Nelson Electricity Ltd (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 33kW/km.

Demand density	33

2(i): Return on Investment - Line discounts of $10.5 million are excluded from the regulatory profit and therefore also the ROI. If these discounts had been included, the ROI would have been 3.43% instead of 9.29%.

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Your consumer-owned electricity distributor

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Certification for Year-beginning Disclosures

Clause 2.9.1

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 following attached information of Network Tasman Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Network Tasman Limited's corporate vision and strategy and are documented in retained records.

Michael John MCCLISKIE

Anthony Page REILLY

31 August 2018

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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; and

In respect of related party costs and revenues recorded in accordance with subclauses 2.3.6(1) (when valued in accordance with clause 2.2.11(5)(h)(ii) of the Electricity Distribution Services Input Methodologies Determination 2010), 2.3.6(1)(f) and 2.3.7(2)(b), we certify that, having made all reasonable enquiry, including enquiries of our related parties, we are satisfied that to the best of our knowledge and belief the costs and revenues recorded for related party transactions reasonably reflect the price or prices that would have been paid or received had these transactions been at arm's-length.

Michael John MCCLISKIE

Anthony Page REILLY

31 August 2018

Independent Assurance Report

To the directors of Network Tasman Limited and the Commerce Commission

The Auditor-General is the auditor of Network Tasman Limited (the company). The Auditor-General has appointed me, Ian Lothian, using the staff and resources of Audit New Zealand, to provide an opinion, on his behalf, on whether the information disclosed in schedules 1 to 4, 5a to 5g, 6a and 6b, 7, the system average interruption duration index ("SAIDI") and system average interruption frequency index ("SAIFI") information disclosed in Schedule 10 and the explanatory notes in boxes 1 to 12 in Schedule 14 ("the Disclosure Information") for the disclosure year ended 31 March 2018, have been prepared, in all material respects, in accordance with the Electricity Distribution Information Disclosure Determination 2012 (the "Determination").

Directors' responsibility for the Disclosure Information

The directors of the company are responsible for preparation of the Disclosure Information in accordance with the Determination, and for such internal control as the directors determine is necessary to enable the preparation of the Disclosure Information that is free from material misstatement.

Our responsibility for the Disclosure Information

Our responsibility is to express an opinion on whether the Disclosure Information has been prepared, in all material respects, in accordance with the Determination.

Basis of opinion

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

These standards require that we comply with ethical requirements and plan and perform our assurance engagement to provide reasonable assurance about whether the Disclosure Information has been prepared in all material respects in accordance with the Determination.

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

Use of this report

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

Scope and inherent limitations

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

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

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

Independence and quality control

When carrying out the engagement, we complied with the Auditor-General's:

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

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

We also complied with the independence requirements specified in the Determination.

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

Opinion

In our opinion:

- as far as appears from an examination of them, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the company;
- as far as appears from an examination, the information used in the preparation of the Disclosure Information has been properly extracted from the company's accounting and other records and has been sourced, where appropriate, from the company's financial and non-financial systems; and
- the Disclosure Information has been prepared, in all material respects, in accordance with the Determination.

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

Ian Lothian
Audit New Zealand
On behalf of the Auditor-General
Christchurch, New Zealand
31 August 2018