

Information Disclosure

Assessment Period

1 April 2023 – 31 March 2024

1. Introduction

Firstlight Network is the electricity lines company for Tairāwhiti and Wairoa. We own and maintain the poles, wires and underground cabling used by electricity retailers to supply customers with electricity.

We also own the region's high-voltage electricity transmission network (the steel poles and towers that connect our region to the national grid).

We're a team of people who, with our contractors, are responsible for keeping the lights on across 12,000 square kilometres of the East Coast.

We have a strong focus on sustainability. This includes installing a regionwide network of electric vehicle chargers, planning for new energy opportunities, and ensuring we can continue delivering a reliable service as the way people use electricity changes and grows.

On 1 April 2023, First Group (now Clarus) took over ownership of the Eastland Network from Eastland Group. Firstlight Network is part of Clarus and is owned by Igneo Infrastructure Partners.

Clarus is one of New Zealand's largest energy groups, with brands that touch many parts of the energy supply chain – from energy transmission and distribution to retail supply and even storage.

2. Date prepared

The Information Disclosures were prepared on 29 August 2024.

**EDB Information Disclosure Requirements
Information Templates**

**Schedules 1–10
excluding 5f–5h**

Company Name	Firstlight Network Limited
Disclosure Date	31 August 2024
Disclosure Year (year ended)	31 March 2024

Templates for Schedules 1–10 excluding 5f–5h
Prepared 29 August 2024

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Disclosure Template Instructions

This document forms Schedules 1–10 to the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC 2.

The Schedules take the form of templates for use by EDBs when making disclosures under clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, and 2.5.2 of the Electricity Distribution Information Disclosure Determination 2012.

Company Name and Dates

To prepare the templates for disclosure, the supplier's company name should be entered in cell C8, the date of the last day of the current (disclosure) year should be entered in cell C12, and the date on which the information is disclosed should be entered in cell C10 of the CoverSheet worksheet.

The cell C12 entry (current year) is used to calculate disclosure years in the column headings that show above some of the tables and in labels adjacent to some entry cells. It is also used to calculate the 'For year ended' date in the template title blocks (the title blocks are the light green shaded areas at the top of each template).

The cell C8 entry (company name) is used in the template title blocks.

Dates should be entered in day/month/year order (Example -"1 April 2023").

Data Entry Cells and Calculated Cells

Data entered into this workbook may be entered only into the data entry cells. Data entry cells are the bordered, unshaded areas (white cells) in each template. Under no circumstances should data be entered into the workbook outside a data entry cell.

In some cases, where the information for disclosure is able to be ascertained from disclosures elsewhere in the workbook, such information is disclosed in a calculated cell.

Validation Settings on Data Entry Cells

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

Conditional Formatting Settings on Data Entry Cells

Schedule 2 cells G79 and I79:L79 will change colour if the total cashflows do not equal the corresponding values in table 2(ii).

Schedule 4 cells P99:P106 and P107 will change colour if the RAB values do not equal the corresponding values in table 4(ii).

Schedule 9b columns AA to AE (2013 to 2017) contain conditional formatting. The data entry cells for future years are hidden (are changed from white to yellow).

Schedule 9b cells in rows 10 to 60 of the column "Items at end of year (quantity)" will change colour if the total assets at year end for each asset class does not equal the corresponding values in column I in Schedule 9a.

Schedule 9c cell G30 will change colour if G30 (overhead circuit length by terrain) does not equal G18 (overhead circuit length by operating voltage).

Inserting Additional Rows and Columns

The schedule 4, 5b, 5c, 5d, 5e, 6a, 8, 9d, and 9e templates may require additional rows to be inserted in tables marked 'include additional rows if needed' or similar. Column A schedule references should not be entered in additional rows, and should be deleted from additional rows that are created by copying and pasting rows that have schedule references.

Additional rows in the schedule 5c, 6a, and 9e templates must not be inserted directly above the first row or below the last row of a table. This is to ensure that entries made in the new row are included in the totals.

The schedule 5d and 5e templates may require new cost or asset category rows to be inserted in allocation change tables 5d(iii) and 5e(ii). Accordingly, cell protection has been removed from rows 77 and 78 of the respective templates to allow blocks of rows to be copied. The four steps to add new cost category rows to table 5d(iii) are: Select Excel rows 69:77, copy, select Excel row 78, insert copied cells. Similarly, for table 5e(ii): Select Excel rows 70:78, copy, select Excel row 79, then insert copied cells.

The template for schedule 8 may require additional columns to be inserted between column L and Q, and between U and AF. If inserting additional columns, headings will need to be copied into the added columns. Additionally, the formulas for standard consumers total, non-standard consumers totals and total for all consumers will need to be copied into the cells of the added columns. The column headings and formulas can be found in the equivalent cells of the existing columns.

Disclosures by Sub-Network

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

Description of Calculation References

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

Worksheet Completion Sequence

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

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

SCHEDULE 1: ANALYTICAL RATIOS

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

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

sch ref

7 1(i): Expenditure metrics

	Expenditure per GWh energy delivered to ICPs (\$/GWh)	Expenditure per average no. of ICPs (\$/ICP)	Expenditure per MW maximum coincident system demand (\$/MW)	Expenditure per km circuit length (\$/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers (\$/MVA)
Operational expenditure	50,982	576	224,657	3,758	64,261
Network	25,504	288	112,384	1,880	32,146
Non-network	25,479	288	112,273	1,878	32,115
Expenditure on assets	48,506	548	213,744	3,575	61,139
Network	45,059	509	198,555	3,321	56,794
Non-network	3,447	39	15,189	254	4,345

17 1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs (\$/GWh)	Revenue per average no. of ICPs (\$/ICP)
Total consumer line charge revenue	101,301	1,145
Standard consumer line charge revenue	101,301	1,145
Non-standard consumer line charge revenue	-	-

23 1(iii): Service intensity measures

Demand density	17	Maximum coincident system demand per km of circuit length (for supply) (kW/km)
Volume density	74	Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)
Connection point density	7	Average number of ICPs per km of circuit length (for supply) (ICPs/km)
Energy intensity	11,301	Total energy delivered to ICPs per average number of ICPs (kWh/ICP)

30 1(iv): Composition of regulatory income

	(\$000)	% of revenue
Operational expenditure	14,942	49.83%
Pass-through and recoverable costs excluding financial incentives and wash-ups	4,932	16.45%
Total depreciation	7,840	26.15%
Total revaluations	8,417	28.07%
Regulatory tax allowance	224	0.75%
Regulatory profit/(loss) including financial incentives and wash-ups	10,465	34.90%
Total regulatory income	29,986	

40 1(v): Reliability

Interruption rate	26.08	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 this ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).

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

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

sch ref

2(i): Return on Investment		CY-2	CY-1	Current Year CY
		%	%	%
7	2(i): Return on Investment			
9	ROI – comparable to a post tax WACC			
10	Reflecting all revenue earned	9.41%	7.97%	4.61%
11	Excluding revenue earned from financial incentives	9.37%	7.97%	4.78%
12	Excluding revenue earned from financial incentives and wash-ups	9.37%	8.01%	4.81%
14	Mid-point estimate of post tax WACC	3.52%	4.88%	6.05%
15	25th percentile estimate	2.84%	4.20%	5.37%
16	75th percentile estimate	4.20%	5.56%	6.73%
19	ROI – comparable to a vanilla WACC			
20	Reflecting all revenue earned	9.71%	8.27%	5.31%
21	Excluding revenue earned from financial incentives	9.66%	8.27%	5.48%
22	Excluding revenue earned from financial incentives and wash-ups	9.66%	8.31%	5.51%
24	WACC rate used to set regulatory price path	4.57%	4.57%	4.57%
26	Mid-point estimate of vanilla WACC	3.82%	5.39%	6.75%
27	25th percentile estimate	3.14%	4.71%	6.07%
28	75th percentile estimate	4.50%	6.07%	7.43%
30	2(ii): Information Supporting the ROI	(\$'000)		
32	Total opening RAB value	209,446		
33	plus Opening deferred tax	(14,444)		
34	Opening RIV		195,003	
36	Line charge revenue		29,690	
38	Expenses cash outflow	19,874		
39	add Assets commissioned	12,573		
40	less Asset disposals	40		
41	add Tax payments	(3,957)		
42	less Other regulated income	295		
43	Mid-year net cash outflows		28,155	
45	Term credit spread differential allowance		–	
47	Total closing RAB value	222,587		
48	less Adjustment resulting from asset allocation	30		
49	less Lost and found assets adjustment	–		
50	plus Closing deferred tax	(18,624)		
51	Closing RIV		203,933	
53	ROI – comparable to a vanilla WACC			5.31%
55	Leverage (%)			42%
56	Cost of debt assumption (%)			5.97%
57	Corporate tax rate (%)			28%
59	ROI – comparable to a post tax WACC			4.61%

Company Name
For Year Ended

Firstlight Network Limited
31 March 2024

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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sch ref

2(iii): Information Supporting the Monthly ROI

61								
62								
63	Opening RIV							N/A
64								
65								
66		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	-	-	-	-	-	-	-

80
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81 Tax payments N/A

82
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83 Term credit spread differential allowance N/A

84
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85 Closing RIV N/A

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88 Monthly ROI – comparable to a vanilla WACC N/A

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90 Monthly ROI – comparable to a post tax WACC N/A

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

91
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92 Year-end ROI – comparable to a vanilla WACC 5.47%

93
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94 Year-end ROI – comparable to a post tax WACC 4.76%

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96 * 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.

97
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2(v): Financial Incentives and Wash-Ups

100								
101								
102	IRIS incentive adjustment					(293)		
103	Purchased assets – avoided transmission charge							
104	Energy efficiency and demand incentive allowance							
105	Quality incentive adjustment					(164)		
106	Other financial incentives							
107	Financial incentives							(457)

108
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109 Impact of financial incentives on ROI -0.17%

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 | | | | | | | |

111 Input methodology claw-back

Company Name
For Year Ended

Firstlight Network Limited
31 March 2024

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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

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sch ref

112	CPP application recoverable costs		
113	Catastrophic event allowance		
114	Capex wash-up adjustment	(81)	
115	Transmission asset wash-up adjustment		
116	2013–15 NPV wash-up allowance		
117	Reconsideration event allowance		
118	Other wash-ups		
119	Wash-up costs		(81)
120			
121	Impact of wash-up costs on ROI		-0.03%

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

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

sch ref

7	3(i): Regulatory Profit		(\$000)
8	Income		
9	Line charge revenue	29,690	
10	plus Gains / (losses) on asset disposals	(3)	
11	plus Other regulated income (other than gains / (losses) on asset disposals)	298	
12			
13	Total regulatory income	29,986	
14	Expenses		
15	less Operational expenditure	14,942	
16			
17	less Pass-through and recoverable costs excluding financial incentives and wash-ups	4,932	
18			
19	Operating surplus / (deficit)	10,111	
20			
21	less Total depreciation	7,840	
22			
23	plus Total revaluations	8,417	
24			
25	Regulatory profit / (loss) before tax	10,689	
26			
27	less Term credit spread differential allowance	-	
28			
29	less Regulatory tax allowance	224	
30			
31	Regulatory profit/(loss) including financial incentives and wash-ups	10,465	
32			
33	3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups		(\$000)
34	Pass through costs		
35	Rates	250	
36	Commerce Act levies	104	
37	Industry levies	88	
38	CPP specified pass through costs	-	
39	Recoverable costs excluding financial incentives and wash-ups		
40	Electricity lines service charge payable to Transpower	4,416	
41	Transpower new investment contract charges	75	
42	System operator services	-	
43	Distributed generation allowance	-	
44	Extended reserves allowance	-	
45	Other recoverable costs excluding financial incentives and wash-ups	-	
46	Pass-through and recoverable costs excluding financial incentives and wash-ups	4,932	
47			
48	3(iv): Merger and Acquisition Expenditure		
49			(\$000)
50	Merger and acquisition expenditure		
51			
52	<i>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)</i>		
53	3(v): Other Disclosures		
54			(\$000)
55	Self-insurance allowance		

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

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

sch ref

	RAB CY-4 (\$000)	RAB CY-3 (\$000)	RAB CY-2 (\$000)	RAB CY-1 (\$000)	RAB CY (\$000)
4(i): Regulatory Asset Base Value (Rolled Forward)					
Total opening RAB value	161,678	166,070	172,870	188,035	209,446
less Total depreciation	6,248	6,483	6,504	7,106	7,840
plus Total revaluations	4,044	2,518	11,955	12,500	8,417
plus Assets commissioned	8,529	10,983	9,630	16,078	12,573
less Asset disposals	-	-	88	24	40
plus Lost and found assets adjustment	-	-	(21)	(38)	-
plus Adjustment resulting from asset allocation	(1,931)	(219)	193	-	30
Total closing RAB value	166,070	172,870	188,035	209,446	222,587

	Unallocated RAB *		RAB	
	(\$000)	(\$000)	(\$000)	(\$000)
4(ii): Unallocated Regulatory Asset Base				
Total opening RAB value		212,590		209,446
less Total depreciation		7,840		7,840
plus Total revaluations		8,417		8,417
plus Assets commissioned (other than below)	1,281		1,281	
Assets acquired from a regulated supplier	-		-	
Assets acquired from a related party	11,292		11,292	
Assets commissioned		12,573		12,573
less Asset disposals (other than below)	(36)		40	
Asset disposals to a regulated supplier	-		-	
Asset disposals to a related party	3,089		-	
Asset disposals		3,053		40
plus Lost and found assets adjustment		-		-
plus Adjustment resulting from asset allocation				30
Total closing RAB value		222,688		222,587

* 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.

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

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

sch ref

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4(iii): Calculation of Revaluation Rate and Revaluation of Assets

CPI _t	1,267
CPI _{t-4}	1,218
Revaluation rate (%)	4.02%

	Unallocated RAB *		RAB	
	(\$000)	(\$000)	(\$000)	(\$000)
Total opening RAB value	212,590		209,446	
less Opening value of fully depreciated, disposed and lost assets	3,356		212	
Total opening RAB value subject to revaluation	209,234		209,234	
Total revaluations		8,417		8,417

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction		Allocated works under construction	
Works under construction—preceding disclosure year		355		355
plus Capital expenditure	14,111		14,111	
less Assets commissioned	12,573		12,573	
plus Adjustment resulting from asset allocation			-	
Works under construction - current disclosure year		1,893		1,893
Highest rate of capitalised finance applied				-

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

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

sch ref

76 **4(v): Regulatory Depreciation**

	Unallocated RAB *		RAB	
	(\$000)	(\$000)	(\$000)	(\$000)
79 Depreciation - standard	6,538		6,538	
80 Depreciation - no standard life assets	1,302		1,302	
81 Depreciation - modified life assets				
82 Depreciation - alternative depreciation in accordance with CPP				
83 Total depreciation		7,840		7,840

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

(\$000 unless otherwise specified)

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

* include additional rows if needed

96 **4(vii): Disclosure by Asset Category**

(\$000 unless otherwise specified)

	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	22,040	1,597	31,387	77,410	30,507	20,479	10,431	6,575	9,020	209,446
100 less Total depreciation	822	42	1,207	2,419	941	812	493	590	513	7,840
101 plus Total revaluations	885	64	1,262	3,113	1,227	823	419	264	360	8,417
102 plus Assets commissioned	1,491	-	747	6,411	827	775	390	650	1,281	12,573
103 less Asset disposals	-	-	-	-	-	-	-	-	40	40
104 plus Lost and found assets adjustment	-	-	-	-	-	-	-	-	-	-
105 plus Adjustment resulting from asset allocation	-	-	-	-	-	-	-	-	29	29
106 plus Asset category transfers	-	-	-	-	-	-	-	-	-	-
107 Total closing RAB value	23,595	1,619	32,189	84,515	31,620	21,265	10,748	6,900	10,137	222,587
109 Asset Life										
110 Weighted average remaining asset life	37.6	36.4	31.8	39.0	37.8	29.1	24.3	13.2	14.2	(years)
111 Weighted average expected total asset life	54.1	52.8	43.6	53.9	56.9	43.0	36.6	20.8	21.4	(years)

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 1.0

sch ref

		(\$000)	
7	5a(i): Regulatory Tax Allowance		
8	Regulatory profit / (loss) before tax		10,689
9			
10	<i>plus</i> Income not included in regulatory profit / (loss) before tax but taxable	-	*
11	Expenditure or loss in regulatory profit / (loss) before tax but not deductible	5	*
12	Amortisation of initial differences in asset values	1,901	
13	Amortisation of revaluations	1,372	
14			3,277
15			
16	<i>less</i> Total revaluations	8,417	
17	Income included in regulatory profit / (loss) before tax but not taxable	-	*
18	Discretionary discounts and customer rebates	-	*
19	Expenditure or loss deductible but not in regulatory profit / (loss) before tax	-	*
20	Notional deductible interest	4,750	
21			13,167
22			
23	Regulatory taxable income		799
24			
25	<i>less</i> Utilised tax losses	-	
26	Regulatory net taxable income		799
27			
28	Corporate tax rate (%)	28%	
29	Regulatory tax allowance		224

* Workings to be provided in Schedule 14

5a(ii): Disclosure of Permanent Differences

In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i).

5a(iii): Amortisation of Initial Difference in Asset Values

(\$000)

36	Opening unamortised initial differences in asset values	36,073	
37	<i>less</i> Amortisation of initial differences in asset values	1,901	
38	<i>plus</i> Adjustment for unamortised initial differences in assets acquired	-	
39	<i>less</i> Adjustment for unamortised initial differences in assets disposed	-	
40	Closing unamortised initial differences in asset values		34,172
41			
42	Opening weighted average remaining useful life of relevant assets (years)		19
43			

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 1.0

sch ref

44	5a(iv): Amortisation of Revaluations		(\$000)
45			
46	Opening sum of RAB values without revaluations	171,772	
47			
48	Adjusted depreciation	6,467	
49	Total depreciation	7,840	
50	Amortisation of revaluations		1,372
51			
52	5a(v): Reconciliation of Tax Losses		(\$000)
53			
54	Opening tax losses		
55	plus Current period tax losses		
56	less Utilised tax losses		
57	Closing tax losses		-
58	5a(vi): Calculation of Deferred Tax Balance		(\$000)
59			
60	Opening deferred tax	(14,444)	
61			
62	plus Tax effect of adjusted depreciation	1,811	
63			
64	less Tax effect of tax depreciation	5,350	
65			
66	plus Tax effect of other temporary differences*	(51)	
67			
68	less Tax effect of amortisation of initial differences in asset values	532	
69			
70	plus Deferred tax balance relating to assets acquired in the disclosure year	-	
71			
72	less Deferred tax balance relating to assets disposed in the disclosure year	139	
73			
74	plus Deferred tax cost allocation adjustment	80	
75			
76	Closing deferred tax		(18,624)
77			
78	5a(vii): Disclosure of Temporary Differences		
79	<i>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).</i>		
80			
81	5a(viii): Regulatory Tax Asset Base Roll-Forward		(\$000)
82			
83	Opening sum of regulatory tax asset values	78,285	
84	less Tax depreciation	19,107	
85	plus Regulatory tax asset value of assets commissioned	9,633	
86	less Regulatory tax asset value of asset disposals	534	
87	plus Lost and found assets adjustment	46	
88	plus Adjustment resulting from asset allocation	315	
89	plus Other adjustments to the RAB tax value	485	
90	Closing sum of regulatory tax asset values		69,123

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

sch ref

	(\$000)	(\$000)
5b(i): Summary—Related Party Transactions		
Total regulatory income		3,493
Market value of asset disposals		–
Service interruptions and emergencies	2,945	
Vegetation management	1,829	
Routine and corrective maintenance and inspection	2,175	
Asset replacement and renewal (opex)	145	
Network opex		7,094
Business support	2,465	
System operations and network support	1,339	
Non-network solutions provided by a related party or third party	–	
Operational expenditure		10,898
Consumer connection	30	
System growth	124	
Asset replacement and renewal (capex)	12,116	
Asset relocations	–	
Quality of supply	330	
Legislative and regulatory	230	
Other reliability, safety and environment	109	
Expenditure on non-network assets		233
Expenditure on assets		13,172
Cost of financing		
Value of capital contributions		
Value of vested assets		
Capital expenditure		13,172
Total expenditure		24,071
Other related party transactions		

Not Required before DY2025

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

Name of related party	Nature of opex or capex service provided	Total value of transactions (\$000)
First Gas Limited	Business support	2,428
Directors	Business support	37
Gas Services NZ Midco Limited	Service interruptions and emergencies	2,945
Gas Services NZ Midco Limited	Vegetation management	1,829
Gas Services NZ Midco Limited	Routine and corrective maintenance and inspection	2,175
Gas Services NZ Midco Limited	Asset replacement and renewal (opex)	145
Gas Services NZ Midco Limited	System operations and network support	1,339
Gas Services NZ Midco Limited	Consumer connection	30
Gas Services NZ Midco Limited	System growth	124
Gas Services NZ Midco Limited	Asset replacement and renewal (capex)	12,116
Gas Services NZ Midco Limited	Asset relocations	–
Gas Services NZ Midco Limited	Quality of supply	330
Gas Services NZ Midco Limited	Legislative and regulatory	230
Gas Services NZ Midco Limited	Other reliability, safety and environment	109
Gas Services NZ Midco Limited	Expenditure on non-network assets	233
Total value of related party transactions		24,071

* include additional rows if needed

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

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

Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
* include additional rows if needed						-	-	-

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

Gross term credit spread differential								
Total book value of interest bearing debt								
Leverage			42%					
Average opening and closing RAB values								
Attribution Rate (%)								
Term credit spread differential allowance								

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

		Value allocated (\$000s)				
		Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase (\$000s)
7	5d(i): Operating Cost Allocations					
8						
9						
10	Service interruptions and emergencies					
11	Directly attributable		2,945			
12	Not directly attributable				-	
13	Total attributable to regulated service		2,945			
14	Vegetation management					
15	Directly attributable		1,829			
16	Not directly attributable				-	
17	Total attributable to regulated service		1,829			
18	Routine and corrective maintenance and inspection					
19	Directly attributable		2,175			
20	Not directly attributable				-	
21	Total attributable to regulated service		2,175			
22	Asset replacement and renewal					
23	Directly attributable		526			
24	Not directly attributable				-	
25	Total attributable to regulated service		526			
26	Non-network solutions provided by a related party or third party <i>Not required before DY2025</i>					
27	Directly attributable					
28	Not directly attributable				-	
29	Total attributable to regulated service		-			
30	System operations and network support					
31	Directly attributable		2,792			
32	Not directly attributable				-	
33	Total attributable to regulated service		2,792			
34	Business support					
35	Directly attributable		4,676			
36	Not directly attributable				-	
37	Total attributable to regulated service		4,676			
38						
39	Operating costs directly attributable		14,942			
40	Operating costs not directly attributable	-	-	-	-	-
41	Operational expenditure		14,942			
42						

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

43 **5d(ii): Other Cost Allocations**

	(\$000)
44 Pass through and recoverable costs	
45 Pass through costs	
46 Directly attributable	441
47 Not directly attributable	
48 Total attributable to regulated service	441
49 Recoverable costs	
50 Directly attributable	4,490
51 Not directly attributable	
52 Total attributable to regulated service	4,490

54 **5d(iii): Changes in Cost Allocations* †**

		(\$000)	
		CY-1	Current Year (CY)
56 Change in cost allocation 1			
57 Cost category			
58 Original allocator or line items			
59 New allocator or line items			
		Original allocation	
		New allocation	
		Difference	-
60			
61 Rationale for change			

		(\$000)	
		CY-1	Current Year (CY)
65 Change in cost allocation 2			
66 Cost category			
67 Original allocator or line items			
68 New allocator or line items			
		Original allocation	
		New allocation	
		Difference	-
69			
70 Rationale for change			

		(\$000)	
		CY-1	Current Year (CY)
74 Change in cost allocation 3			
75 Cost category			
76 Original allocator or line items			
77 New allocator or line items			
		Original allocation	
		New allocation	
		Difference	-
78			
79 Rationale for change			

82 * 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.
83 † include additional rows if needed

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated (\$000s)
Electricity distribution services	
Subtransmission lines	
Directly attributable	23,595
Not directly attributable	
Total attributable to regulated service	23,595
Subtransmission cables	
Directly attributable	1,619
Not directly attributable	
Total attributable to regulated service	1,619
Zone substations	
Directly attributable	32,189
Not directly attributable	
Total attributable to regulated service	32,189
Distribution and LV lines	
Directly attributable	84,515
Not directly attributable	
Total attributable to regulated service	84,515
Distribution and LV cables	
Directly attributable	31,620
Not directly attributable	
Total attributable to regulated service	31,620
Distribution substations and transformers	
Directly attributable	21,265
Not directly attributable	
Total attributable to regulated service	21,265
Distribution switchgear	
Directly attributable	10,748
Not directly attributable	
Total attributable to regulated service	10,748
Other network assets	
Directly attributable	6,900
Not directly attributable	
Total attributable to regulated service	6,900
Non-network assets	
Directly attributable	10,137
Not directly attributable	
Total attributable to regulated service	10,137
Regulated service asset value directly attributable	222,587
Regulated service asset value not directly attributable	-
Total closing RAB value	222,587

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

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

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

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

sch ref

	(\$000)	(\$000)
6a(i): Expenditure on Assets		
Consumer connection		30
System growth		124
Asset replacement and renewal		12,384
Asset relocations		-
Reliability, safety and environment:		
Quality of supply	330	
Legislative and regulatory	230	
Other reliability, safety and environment	109	
Total reliability, safety and environment		669
Expenditure on network assets		13,206
Expenditure on non-network assets		1,010
Expenditure on assets		14,217
plus Cost of financing		
less Value of capital contributions		106
plus Value of vested assets		
Capital expenditure		14,111
6a(ii): Subcomponents of Expenditure on Assets (where known)		(\$000)
Energy efficiency and demand side management, reduction of energy losses		
Overhead to underground conversion		487
Research and development		
6a(iii): Consumer Connection		
<i>Consumer types defined by EDB*</i>	(\$000)	(\$000)
Residential	30	
Commercial		
Industrial		
<i>* include additional rows if needed</i>		
Consumer connection expenditure		30
less Capital contributions funding consumer connection expenditure		
Consumer connection less capital contributions		30
6a(iv): System Growth and Asset Replacement and Renewal		
	System Growth	Asset Replacement and Renewal
	(\$000)	(\$000)
Subtransmission	25	2,012
Zone substations	-	750
Distribution and LV lines	99	7,558
Distribution and LV cables	-	397
Distribution substations and transformers	-	840
Distribution switchgear	-	268
Other network assets	-	559
System growth and asset replacement and renewal expenditure	124	12,384
less Capital contributions funding system growth and asset replacement and renewal	106	
System growth and asset replacement and renewal less capital contributions	19	12,384
6a(v): Asset Relocations		
<i>Project or programme*</i>	(\$000)	(\$000)
[Description of material project or programme]		
[Description of material project or programme]		
[Description of material project or programme]		
[Description of material project or programme]		
[Description of material project or programme]		
<i>* include additional rows if needed</i>		
All other projects or programmes - asset relocations		
Asset relocations expenditure		-
less Capital contributions funding asset relocations		
Asset relocations less capital contributions		-

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

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

sch ref

69				
70	6a(vi): Quality of Supply			
71	<i>Project or programme*</i>		(\$000)	(\$000)
72	11kV Field Recloser Automation Plan - additions		83	
73	SCADA Rural Automation -development		47	
74	Comms Replace Voice DMR servers		1	
75	Generator purchase (350kVA Container)		66	
75	110kVa generator trailer and install		87	
76	Mahia Radiator Refurbishment		46	
77	<i>* include additional rows if needed</i>			
78	All other projects programmes - quality of supply			
79	Quality of supply expenditure			330
80	less Capital contributions funding quality of supply			
81	Quality of supply less capital contributions			330
82	6a(vii): Legislative and Regulatory			
83	<i>Project or programme*</i>		(\$000)	(\$000)
84	AUFLS/ Protection Relay install		214	
85	SCADA Switching & Outage Management System		16	
89	<i>* include additional rows if needed</i>			
90	All other projects or programmes - legislative and regulatory			
91	Legislative and regulatory expenditure			230
92	less Capital contributions funding legislative and regulatory			
93	Legislative and regulatory less capital contributions			230
94	6a(viii): Other Reliability, Safety and Environment			
95	<i>Project or programme*</i>		(\$000)	(\$000)
96	Replace Galv Meter Box (Asbestos)		3	
97	Replace11kV SWGR Tokomaru Bay		68	
98	Zone Substation Tolaga Bay, Puha Install Sepa Units		38	
101	<i>* include additional rows if needed</i>			
102	All other projects or programmes - other reliability, safety and environment			
103	Other reliability, safety and environment expenditure			109
104	less Capital contributions funding other reliability, safety and environment			
105	Other reliability, safety and environment less capital contributions			109
106				
107	6a(ix): Non-Network Assets			
108	Routine expenditure			
109	<i>Project or programme*</i>		(\$000)	(\$000)
110	Vehicle Replacement		103	
111	General asset replacement (Ntk)		1	
112	General building capex (FNL office, Eastech, Wairoa Depot)		122	
113	Property Capital Projects Wairoa office rebuild		7	
114	Transition Software Setup		777	
115	<i>* include additional rows if needed</i>			
116	All other projects or programmes - routine expenditure			
117	Routine expenditure			1,010
118	Atypical expenditure			
119	<i>Project or programme*</i>		(\$000)	(\$000)
120	[Description of material project or programme]			
121	[Description of material project or programme]			
122	[Description of material project or programme]			
123	[Description of material project or programme]			
124	[Description of material project or programme]			
125	<i>* include additional rows if needed</i>			
126	All other projects or programmes - atypical expenditure			
127	Atypical expenditure			-
128				
129	Expenditure on non-network assets			1,010

Company Name **Firstlight Network Limited**
 For Year Ended **31 March 2024**

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

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

sch ref

		(\$000)	(\$000)
7	6b(i): Operational Expenditure <i>Required for DY2024 and DY2025 only</i>		
8	Service interruptions and emergencies	2,945	
9	Vegetation management	1,829	
10	Routine and corrective maintenance and inspection	2,175	
11	Asset replacement and renewal	526	
12	Network opex		7,475
13	Non-network solutions provided by a related party or third party <i>Required for DY2025 only</i>		
14	System operations and network support	2,792	
15	Business support	4,676	
16	Non-network opex		7,468
17			
18	Operational expenditure		14,942
19	6b(i): Operational Expenditure <i>Not Required before DY2026</i>		
20	Service interruptions and emergencies:		
21	Vegetation-related		
22	Other		
23	Total service interruptions and emergencies	-	
24	Vegetation management:		
25	Assessment and notification costs		
26	Felling or trimming vegetation - in-zone		
27	Felling or trimming vegetation - out-of-zone		
28	Other		
29	Total vegetation management	-	
30			
31	Routine and corrective maintenance and inspection:		

Company Name **Firstlight Network Limited**
 For Year Ended **31 March 2024**

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

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

sch ref

32	Asset replacement and renewal		
33	Network opex		–
34	Non-network solutions provided by a related party or third party		
35	System operations and network support		
36	Business support		
37	Non-network opex		–
38			
39	Operational expenditure		–
40	6b(ii): Subcomponents of Operational Expenditure (where known)		
41	Energy efficiency and demand side management, reduction of energy losses		
42	Direct billing*		
43	Research and development		
44	Insurance		366
45	* Direct billing expenditure by suppliers that directly bill the majority of their consumers		

Company Name

Firstlight Network Limited

For Year Ended

31 March 2024

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

EDBs must provide explanatory comment on the variance between actual and target revenue and forecast expenditure in Schedule 14 (Mandatory Explanatory Notes).

This information is part of the audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8. For the purpose of this audit, target revenue and forecast expenditures only need to be verified back to previous disclosures.

sch ref

7 (i): Revenue		Target (\$000) ¹	Actual (\$000)	% variance
7				
8	Line charge revenue	29,928	29,690	(1%)
7 (ii): Expenditure on Assets		Forecast (\$000) ²	Actual (\$000)	% variance
9				
10	Consumer connection	141	30	(79%)
11	System growth	1,274	124	(90%)
12	Asset replacement and renewal	12,594	12,384	(2%)
13	Asset relocations	51	–	(100%)
14	Reliability, safety and environment:			
15	Quality of supply	203	330	63%
16	Legislative and regulatory	184	230	25%
17	Other reliability, safety and environment	191	109	(43%)
18	Total reliability, safety and environment	578	669	16%
19	Expenditure on network assets	14,638	13,207	(10%)
20	Expenditure on non-network assets	311	1,010	225%
21	Expenditure on assets	14,949	14,217	(5%)
7 (iii): Operational Expenditure				
22				
23	Service interruptions and emergencies	2,615	2,945	13%
24	Vegetation management	1,636	1,829	12%
25	Routine and corrective maintenance and inspection	3,059	2,175	(29%)
26	Asset replacement and renewal	859	526	(39%)
27	Network opex	8,169	7,475	(8%)
28	Non-network solutions provided by a related party or third party <i>Not Required before DY2025</i>	–	–	–
29	System operations and network support	2,264	2,792	23%
30	Business support	4,000	4,676	17%
31	Non-network opex	6,264	7,468	19%
32	Operational expenditure	14,433	14,942	4%
7 (iv): Subcomponents of Expenditure on Assets (where known)				
33				
34	Energy efficiency and demand side management, reduction of energy losses	–	–	–
35	Overhead to underground conversion	–	487	–
36	Research and development	–	–	–
37				
7 (v): Subcomponents of Operational Expenditure (where known)				
38				
39	Energy efficiency and demand side management, reduction of energy losses	–	–	–
40	Direct billing	–	–	–
41	Research and development	–	–	–
42	Insurance	–	366	–
43				

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

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. EDBs should feel free to adjust the page break of this schedule to assist with readability if needed.

sch ref

8(i): Billed Quantities by Price Component

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

Consumer group name or price category code		Standardised connection types	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Billed quantities by price component <i>Not Required after DY2024</i>							
						Fixed Component Only	Variable Uncontrolled	Variable Controlled	Variable Evening Peak (TOU)	Variable Morning Peak	Variable Off Peak	Variable Night (TOU)	
						\$ per day	\$ per kWh	\$ per kWh	\$ per kWh	\$ per kWh	\$ per kWh	\$ per kWh	
DOMLFC	Domestic	Standard		12,226	63,261	4,474,823	24,181,030	13,196,977	–	8,441,390	17,442,082	–	
DOMSTD	Domestic	Standard		8,181	70,659	2,994,141	26,906,958	14,002,003	–	9,193,139	20,557,247	–	
COM0500	Non-Domestic, Commercial	Standard		4,632	39,263	1,695,141	28,657,353	2,214,471	–	3,075,202	7,315,483	–	
COM100	Non-Domestic, Commercial	Standard		432	22,743	157,928	36,087,565	307,559	–	1,766,153	4,601,354	–	
COM0300	Non-Domestic, Commercial	Standard		121	20,574	44,408	9,997,146	–	1,671,990	2,819,173	3,516,720	2,568,850	
COM0500	Non-Domestic, Commercial	Standard		23	10,743	8,509	–	–	1,665,179	2,692,676	3,354,282	3,030,962	
COM1000	Non-Domestic, Commercial	Standard		24	33,382	8,784	–	–	5,431,932	8,037,023	10,448,701	9,464,711	
COM4500	Non-Domestic, Industrial	Standard		3	26,134	1,098	–	–	4,325,841	5,979,640	8,001,135	7,827,712	
COM6500	Non-Domestic, Industrial	Standard		1	4,486	366	–	–	530,215	1,372,254	1,496,082	1,087,167	
GEN1000	Security - Gemsets	Standard		5	–	–	–	–	–	–	–	–	
GEN4500	Generation - Matawai Hydro	Standard		1	–	366	–	–	–	–	–	–	
GEN6500	Generation - Waipi Hydro	Standard		1	121	366	120,822	–	–	–	–	–	
GENCN01	Generation - Te Ihi	Standard		0	10	152	9,519	–	–	–	–	–	
OTH0003	Non-Domestic, Commercial	Standard		79	206	29,067	205,895	–	–	–	–	–	
DUMK	Unmetered	Standard		173	1,476	1,933,116	1,425,719	–	–	–	–	–	
STLGM	Metered	Standard		32	33	88,938	32,810	–	–	–	–	–	
<i>Add extra rows for additional consumer groups or price category codes as necessary</i>													
Standard consumer totals					25,934	293,091	11,437,203	105,654,819	29,721,010	13,625,157	43,376,651		23,979,442
Non-standard consumer totals					–	–	–	–	–	–	–	–	–
Total for all consumers					25,934	293,091	11,437,203	105,654,819	29,721,010	13,625,157	43,376,651		23,979,442

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. EDBs should feel free to adjust the page break of this schedule to assist with readability if needed.

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

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Line charge revenues (\$000) by price component Not Required after DY2024

Price component

Rate (eg. \$ per day, \$ per kWh, etc.)

Fixed Component Only	Variable Uncontrolled	Variable Controlled	Variable Evening Peak (TOU)	Variable Morning Peak	Variable Off Peak	Variable Night (TOU)
\$ per day	\$ per kWh	\$ per kWh	\$ per kWh	\$ per kWh	\$ per kWh	\$ per kWh
\$2,014	\$2,694	\$1,292	–	\$1,340	\$1,539	–
\$5,956	\$1,147	\$321	–	\$651	\$577	–
\$3,910	\$919	\$46	–	\$181	\$173	–
\$1,381	\$730	\$9	–	\$146	\$153	–
\$762	\$411	–	\$63	\$99	\$98	\$40
\$344	–	–	\$37	\$53	\$55	\$38
\$692	–	–	\$112	\$156	\$161	\$81
\$240	–	–	\$112	\$145	\$155	\$83
\$103	–	–	\$17	\$42	\$37	\$15
–	–	–	–	–	–	–
\$23	–	–	–	–	–	–
\$41	–	–	–	–	–	–
\$3	–	–	–	–	–	–
\$15	\$22	–	–	–	–	–
\$131	\$103	–	–	–	–	–
\$6	\$3	–	–	–	–	–
\$15,619	\$6,052	\$1,668	\$342	\$2,816	\$2,947	\$247
–	–	–	–	–	–	–
\$15,619	\$6,052	\$1,668	\$342	\$2,816	\$2,947	\$247

Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year
DOMAFC	Domestic	Standard	\$8,878
DOMSTD	Domestic	Standard	\$8,651
COM050	Non-Domestic, Commercial	Standard	\$5,229
COM0100	Non-Domestic, Commercial	Standard	\$2,440
COM0300	Non-Domestic, Commercial	Standard	\$1,473
COM0500	Non-Domestic, Commercial	Standard	\$515
COM1000	Non-Domestic, Commercial	Standard	\$1,203
COM4500	Non-Domestic, Industrial	Standard	\$735
COM6500	Non-Domestic, Industrial	Standard	\$214
GEN1000	Security - Gensets	Standard	–
GEN4500	Generation - Matawai Hydro	Standard	\$23
GEN6500	Generation - Waikato Hydro	Standard	\$44
GENC01	Generation - Te Ihi	Standard	\$4
OTH0003	Non-Domestic, Commercial	Standard	\$37
DUML	Unmetered	Standard	\$234
STLGM	Metered	Standard	\$9
<i>Add extra rows for additional consumer groups or price category codes as necessary</i>			
Standard consumer totals			\$29,690
Non-standard consumer totals			–
Total for all consumers			\$29,690

Total distribution line charge revenue	Total transmission line charge revenue
Not Required after DY2024	Not Required after DY2024
7,094	3,185
7,598	1,051
4,658	571
1,999	440
993	479
304	151
842	361
640	95
168	46
–	–
23	–
44	–
4	–
33	4
190	45
7	1
\$25,259	\$4,431
–	–
\$25,259	\$4,431

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end

Check OK

Company Name	Firstlight Network Limited
For Year Ended	31 March 2024
Network / Sub-network Name	GIS

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

9a: Asset Register

	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1-4)
8	All	Overhead Line	Concrete poles / steel structure	No.	14,441	14,717	276	2
9	All	Overhead Line	Wood poles	No.	13,323	13,012	(311)	2
10	All	Overhead Line	Other pole types	No.	-	-	-	N/A
11	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	269	269	0	2
12	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	180	178	(2)	2
13	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	1	1	0	2
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	N/A
17	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	N/A
21	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	N/A
22	HV	Zone substation Buildings	Zone substations up to 66kV	No.	17	17	-	2
23	HV	Zone substation Buildings	Zone substations 110kV+	No.	5	5	-	2
24	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	42	43	1	2
26	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	N/A
27	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	-	2
28	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	N/A
29	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	N/A
30	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	-	2
31	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	86	82	(4)	2
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	5	12	7	2
33	HV	Zone Substation Transformer	Zone Substation Transformers	No.	24	21	(3)	2
34	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,706	1,692	(14)	2
35	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	N/A
36	HV	Distribution Line	SWER conductor	km	-	-	-	2
37	HV	Distribution Cable	Distribution UG XLPE or PVC	km	35	42	7	2
38	HV	Distribution Cable	Distribution UG PILC	km	86	91	5	2
39	HV	Distribution Cable	Distribution Submarine Cable	km	1	-	(1)	2
40	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	30	29	(1)	2
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (indoor)	No.	15	13	(2)	2
42	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	3,328	3,364	36	2
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	63	60	(3)	2
44	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	246	240	(6)	2
45	HV	Distribution Transformer	Pole Mounted Transformer	No.	2,267	2,297	30	2
46	HV	Distribution Transformer	Ground Mounted Transformer	No.	470	477	7	2
47	HV	Distribution Transformer	Voltage regulators	No.	6	8	2	2
48	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	N/A
49	LV	LV Line	LV OH Conductor	km	371	383	12	2
50	LV	LV Cable	LV UG Cable	km	224	240	16	2
51	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	8	13	5	2
52	LV	Connections	OH/UG consumer service connections	No.	21,329	21,819	490	2
53	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	152	198	46	2
54	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	969	1,074	105	2
55	All	Capacitor Banks	Capacitors including controls	No.	1	1	-	3
56	All	Load Control	Centralised plant	Lot	5	5	-	2
57	All	Load Control	Relays	No.	17,013	16,039	(974)	1
58	All	Civils	Cable Tunnels	km	-	-	-	N/A

Company Name	Firstlight Network Limited
For Year Ended	31 March 2024
Network / Sub-network Name	WRA

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

9a: Asset Register

sch ref	Voltage	Asset category	Asset class	Units	Items at start of	Items at end of	Net change	Data accuracy
					year (quantity)	year (quantity)		(1-4)
8	All	Overhead Line	Concrete poles / steel structure	No.	3,681	3,813	132	2
9	All	Overhead Line	Wood poles	No.	3,693	3,530	(163)	2
10	All	Overhead Line	Other pole types	No.	-	-	-	N/A
11	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	67	67	(0)	2
12	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	127	124	(3)	2
13	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	0	0	2
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	N/A
17	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	N/A
21	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	N/A
22	HV	Zone substation Buildings	Zone substations up to 66kV	No.	2	-	(2)	2
23	HV	Zone substation Buildings	Zone substations 110kV+	No.	6	-	(6)	2
24	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	2
25	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	3	4	1	2
26	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	2
27	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	2	2	-	2
28	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	2
29	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	2
30	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	1	1	-	2
31	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	26	26	-	2
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	2	1	(1)	2
33	HV	Zone Substation Transformer	Zone Substation Transformers	No.	12	14	2	2
34	HV	Distribution Line	Distribution OH Open Wire Conductor	km	680	678	(2)	2
35	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	N/A
36	HV	Distribution Line	SWER conductor	km	1	1	(0)	2
37	HV	Distribution Cable	Distribution UG XLPE or PVC	km	5	5	0	2
38	HV	Distribution Cable	Distribution UG PILC	km	15	16	1	2
39	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	N/A
40	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	14	15	1	2
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	2	2	2
42	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1,089	1,109	20	2
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	16	16	-	2
44	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	41	40	(1)	2
45	HV	Distribution Transformer	Pole Mounted Transformer	No.	789	795	6	2
46	HV	Distribution Transformer	Ground Mounted Transformer	No.	95	106	11	2
47	HV	Distribution Transformer	Voltage regulators	No.	3	2	(1)	2
48	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	N/A
49	LV	LV Line	LV OH Conductor	km	134	132	(2)	2
50	LV	LV Cable	LV UG Cable	km	53	55	2	2
51	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	1	-	(1)	2
52	LV	Connections	OH/UG consumer service connections	No.	4,971	4,985	14	2
53	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	39	42	3	2
54	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	160	162	2	2
55	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	N/A
56	All	Load Control	Centralised plant	Lot	3	3	-	2
57	All	Load Control	Relays	No.	118	118	-	N/A
58	All	Civils	Cable Tunnels	km	-	-	-	N/A

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.

9b: Asset Age Profile		Number of assets at disclosure year end by installation date																												No. with age unknown	Items at end of year	No. with default dates	Data accuracy [1-4]											
8	Disclosure Year (year ended)																																											
9	Voltage	Asset category	Asset class	Units	pre-1940	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1989-1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025							
10	All	Overhead Line	Concrete poles / steel structure	No.	-	3	30	161	1,554	2,314	2,663	380	1,037	590	159	192	321	195	192	327	347	409	409	429	327	364	362	224	109	175	293	217	225	338	244	107	-	-	14,717	2				
11	All	Overhead Line	Wood poles	No.	-	57	1,181	3,007	1,138	1,119	2,805	190	575	188	85	124	95	98	127	265	173	228	189	157	161	130	178	184	62	82	110	207	145	185	195	72	-	-	13,012	2				
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-		
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	72	115	30	5	6	7	4	3	11	-	5	4	0	0	-	-	-	-	0	-	0	0	-	0	-	-	-	-	0	0	-	-	-	-	269	2		
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	0	17	29	59	49	32	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	178	2			
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	1	2			
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-		
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	
26	HV	Zone substation switchgear	50/66/110kV CB (indoor)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	4	1	3	2	2	-	3	5	4	6	2	-	-	2	2	2	-	-	-	-	3	-	2	-	-	-	-	-	-	-	-	-	43	2		
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-		
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-		
31	HV	Zone substation switchgear	22/33kV CB (indoor)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	17	16	5	9	-	-	9	10	-	-	4	-	4	-	-	-	-	-	4	-	-	-	-	1	-	-	-	-	-	-	3	-	-	-	82	2	
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	1	1	1	-	-	-	-	1	-	1	-	1	6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	2	
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	-	2	1	2	4	1	2	-	1	1	-	2	1	-	-	-	-	-	-	-	-	-	-	3	-	1	-	-	-	-	-	-	-	-	21	2		
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0	6	298	685	302	133	162	11	5	7	2	2	5	4	3	2	1	4	3	2	3	1	7	2	5	5	2	2	4	11	10	5	-	-	-	1,692	2			
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	
38	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	0	0	3	6	5	0	1	0	0	0	1	2	1	2	0	1	2	0	1	2	0	0	0	1	2	1	3	2	1	1	1	3	0	-	-	42	2		
40	HV	Distribution Cable	Distribution UG PILC	km	-	1	8	9	21	21	3	5	4	2	1	2	1	1	1	2	1	1	1	0	0	0	0	0	0	0	1	4	0	0	-	-	1	-	-	-	91	2		
41	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser	No.	-	-	1	-	-	2	5	1	3	4	1	-	1	-	-	-	-	-	-	-	-	-	1	-	-	2	-	1	1	5	1	-	-	-	-	29	2			
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (indoor)	No.	-	-	-	1	-	11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33	2		
44	HV	Distribution switchgear	3.3/6.6/11/22kV switches and fuses (pole mounted)	No.	-	-	193	472	465	249	322	40	95	93	64	72	63	110	51	60	82	83	65	51	51	82	89	73	41	59	64	75	65	60	54	21	-	-	-	3,364	2			
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	5	5	3	7	3	14	14	1	-	5	-	1	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	2	
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	-	3	3	5	51	6	21	21	1	7	2	12	3	8	3	5	4	2	2	2	2	7	20	8	11	6	8	6	9	3	1	-	-	-	240	2		
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	-	76	304	304	218	238	20	80	43	53	47	75	47	48	42	53	59	34	51	43	57	43	31	36	46	33	65	32	53	42	24	-	-	-	2,297	2			
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	7	15	15	19	28	30	52	27	11	30	12	27	20	7	15	18	11	13	12	14	13	17	13	8	16	23	12	10	4	-	-	-	-	477	2			
49	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	3	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	2		
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A	-	
51	LV	LV Line	LV OH Conductor	km	0	2	71	133	59	46	50	1	8	5	1	1	0	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	-	383	2
52	LV	LV Cable	LV UG Cable	km	-	-	1	17	33	49	33	7	17	14	8	5	4	3	6	5	2	3	3	3	3	1	2	2	3	2	3	2	2	4	1	0	-	-	-	-	240	2		
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	-	-	1	1	0	4	4	0	1																															

Company Name	Firstlight Network Limited
For Year Ended	31 March 2024
Network / Sub-network Name	ALL

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

9	9c: Overhead Lines and Underground Cables			
10				
11	Circuit length by operating voltage (at year end)	Overhead (km)	Underground (km)	Total circuit length (km)
12	> 66kV	302	–	302
13	50kV & 66kV	301	1	303
14	33kV	34	0	34
15	SWER (all SWER voltages)	1	–	1
16	22kV (other than SWER)	–	–	–
17	6.6kV to 11kV (inclusive—other than SWER)	2,371	156	2,527
18	Low voltage (< 1kV)	514	295	809
19	Total circuit length (for supply)	3,524	452	3,976
20				
21	Dedicated street lighting circuit length (km)	13	–	13
22	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			
23				
24	Overhead circuit length by terrain (at year end)	Circuit length (km)	(% of total overhead length)	
25	Urban	187	5%	
26	Rural	1,502	43%	
27	Remote only	305	9%	
28	Rugged only	1,174	33%	
29	Remote and rugged	345	10%	
30	Unallocated overhead lines	11	0%	
31	Total overhead length	3,524	100%	
32				
33		Circuit length (km)	(% of total circuit length)	
34	Length of circuit within 10km of coastline or geothermal areas (where known)	1,778	45%	
35				
36		Circuit length (km)	(% of total overhead length)	
37	Overhead circuit requiring vegetation management	3,524	100%	Not required after DY2025
38				
39		Total newly identified throughout the disclosure year	Total remaining at high risk at the disclosure year-end	
40	Number of overhead circuit sites at high risk from vegetation damage		–	Not required before DY2026
41				
42	Breakdown of overhead circuit sites at high risk from vegetation damage at disclosure year-end	Number of overhead circuit sites at high risk from vegetation damage at disclosure year-end	Number of overhead circuit sites involving critical assets at disclosure year-end	
43	[Single tree]			Not required before DY2026
44	[Single tree - Urban]			Not required before DY2026
45	[Single tree - Rural]			Not required before DY2026
46	[Row of trees]			Not required before DY2026
47	[Span between two poles (X metres)]			Not required before DY2026
48	[Other]			Not required before DY2026
49	Total number of sites	–	–	Not required before DY2026
50	* Insert new rows in table above Total line as necessary			

Company Name	Firstlight Network Limited
For Year Ended	31 March 2024
Network / Sub-network Name	GIS

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

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9c: Overhead Lines and Underground Cables

Circuit length by operating voltage (at year end)

	Overhead (km)	Underground (km)	Total circuit length (km)
> 66kV	178	–	178
50kV & 66kV	269	1	271
33kV	–	–	–
SWER (all SWER voltages)	–	–	–
22kV (other than SWER)	–	–	–
6.6kV to 11kV (inclusive—other than SWER)	1,693	134	1,826
Low voltage (< 1kV)	382	240	622
Total circuit length (for supply)	2,522	375	2,897

Dedicated street lighting circuit length (km)	13	–	13
Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			

Overhead circuit length by terrain (at year end)

	Circuit length (km)	(% of total overhead length)
Urban	165	7%
Rural	1,197	47%
Remote only	253	10%
Rugged only	750	30%
Remote and rugged	147	6%
Unallocated overhead lines	10	0%
Total overhead length	2,522	100%

	Circuit length (km)	(% of total circuit length)
Length of circuit within 10km of coastline or geothermal areas (where known)	1,308	45%

	Circuit length (km)	(% of total overhead length)	
Overhead circuit requiring vegetation management	2,522	100%	Not required after DY2025

	Total newly identified throughout the disclosure year	Total remaining at high risk at the disclosure year-end	
Number of overhead circuit sites at high risk from vegetation damage		–	Not required before DY2026

Breakdown of overhead circuit sites at high risk from vegetation damage at disclosure year-end

Category of overhead circuit site	Number of overhead circuit sites at high risk from vegetation damage at disclosure year-end	Number of overhead circuit sites involving critical assets at disclosure year-end	
[Single tree]			Not required before DY2026
[Single tree - Urban]			Not required before DY2026
[Single tree - Rural]			Not required before DY2026
[Row of trees]			Not required before DY2026
[Span between two poles (X metres)]			Not required before DY2026
[Other]			Not required before DY2026
Total number of sites	–	–	Not required before DY2026

* Insert new rows in table above Total line as necessary

Company Name	Firstlight Network Limited
For Year Ended	31 March 2024
Network / Sub-network Name	WRA

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	9c: Overhead Lines and Underground Cables			
10				
11	Circuit length by operating voltage (at year end)	Overhead (km)	Underground (km)	Total circuit length (km)
12	> 66kV	124	–	124
13	50kV & 66kV	32	–	32
14	33kV	34	0	34
15	SWER (all SWER voltages)	1	–	1
16	22kV (other than SWER)	–	–	–
17	6.6kV to 11kV (inclusive—other than SWER)	679	22	701
18	Low voltage (< 1kV)	132	55	187
19	Total circuit length (for supply)	1,003	77	1,080
20				
21	Dedicated street lighting circuit length (km)	–	–	–
22	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			
23				
24	Overhead circuit length by terrain (at year end)	Circuit length (km)	(% of total overhead length)	
25	Urban	23	2%	
26	Rural	305	30%	
27	Remote only	52	5%	
28	Rugged only	424	42%	
29	Remote and rugged	198	20%	
30	Unallocated overhead lines	1	0%	
31	Total overhead length	1,003	100%	
32				
33		Circuit length (km)	(% of total circuit length)	
34	Length of circuit within 10km of coastline or geothermal areas (where known)	470	44%	
35				
36		Circuit length (km)	(% of total overhead length)	
37	Overhead circuit requiring vegetation management	1,003	100%	Not required after DY2025
38		Total newly identified throughout the disclosure year	Total remaining at high risk at the disclosure year-end	
39	Number of overhead circuit sites at high risk from vegetation damage		–	Not required before DY2026
40				
41	Breakdown of overhead circuit sites at high risk from vegetation damage at disclosure year-end			
42	Category of overhead circuit site	Number of overhead circuit sites at high risk from vegetation damage at disclosure year-end	Number of overhead circuit sites involving critical assets at disclosure year-end	
43	[Single tree]			Not required before DY2026
44	[Single tree - Urban]			Not required before DY2026
45	[Single tree - Rural]			Not required before DY2026
46	[Row of trees]			Not required before DY2026
47	[Span between two poles (X metres)]			Not required before DY2026
48	[Other]			Not required before DY2026
49	Total number of sites	–	–	Not required before DY2026
50	* Insert new rows in table above Total line as necessary			

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref

	Location *	Average number of ICPs in disclosure year	Line charge revenue (\$000)
8			
9			
10			
11			
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19			
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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	Firstflight Network Limited
For Year Ended	31 March 2024
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

8 9e(i): Consumer Connections and Decommissionings

9 Number of ICPs connected during year by consumer type

10 Consumer types defined by EDB*

11 Domestic/Residential	
12 Commercial	
13 Large Commercial	
14 Industrial	
15 GENCN01	

16 * include additional rows if needed

17 Connections total

Number of connections (ICPs)

11	198
12	118
13	8
14	-
15	1

325

19 Number of ICPs decommissioned during year by consumer type

20 Consumer types defined by EDB*

21 Domestic/Residential	
22 Commercial	
23 Large Commercial	
24 Industrial	
25	0

26 * include additional rows if needed

27 Decommissionings total

Number of decommissionings

21	41
22	32
23	2
24	-
25	-

75

29 Distributed generation

30 Number of connections made in year

31 Capacity of distributed generation installed in year

106 connections

1 MVA

33 9e(ii): System Demand

36 Maximum coincident system demand

37 GXP demand

38 plus Distributed generation output at HV and above

39 Maximum coincident system demand

40 less Net transfers to (from) other EDBs at HV and above

41 Demand on system for supply to consumers' connection points

Demand at time of maximum coincident demand (MW)

37	64
38	2
39	67
40	-
41	67

42 Electricity volumes carried

43 Electricity supplied from GXPs

44 less Electricity exports to GXPs

45 plus Electricity supplied from distributed generation

46 less Net electricity supplied to (from) other EDBs

47 Electricity entering system for supply to consumers' connection points

48 less Total energy delivered to ICPs

49 Electricity losses (loss ratio)

Energy (GWh)

43	304	
44	-	
45	16	
46	-	
47	321	
48	293	
49	27	8.6%

51 Load factor

0.55

52 9e(iii): Transformer Capacity

54 Distribution transformer capacity (EDB owned)

55 Distribution transformer capacity (Non-EDB owned)

56 Total distribution transformer capacity

(MVA)

54	233
55	55
56	288

(MVA)

59 Zone substation transformer capacity (EDB owned)

60 Zone substation transformer capacity (Non-EDB owned)

61 Total zone substation transformer capacity

59	337
60	-
61	337

Company Name	Firstflight Network Limited
For Year Ended	31 March 2024
Network / Sub-network Name	Gisborne

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

8	9e(i): Consumer Connections and Decommissionings		
9	Number of ICPs connected during year by consumer type		
10		Number of	
11	Consumer types defined by EDB*	connections (ICPs)	
12	Domestic/Residential	187	
13	Commercial	102	
14	Large Commercial	6	
15	Industrial	-	
16	GENCNO1	1	
17	* include additional rows if needed		
18	Connections total	296	
19	Number of ICPs decommissioned during year by consumer type		
20		Number of	
21	Consumer types defined by EDB*	decommissionings	
22	Domestic/Residential	33	
23	Commercial	25	
24	Large Commercial	2	
25	Industrial	-	
26	* include additional rows if needed		
27	Decommissionings total	60	
28			
29	Distributed generation		
30	Number of connections made in year	100	connections
31	Capacity of distributed generation installed in year	1	MVA
32			
33	9e(ii): System Demand		
34			
35		Demand at time	
36	Maximum coincident system demand	of maximum	
37	GXP demand	coincident	
38	plus Distributed generation output at HV and above	demand (MW)	
39	Maximum coincident system demand	56	
40	less Net transfers to (from) other EDBs at HV and above	1	
41	Demand on system for supply to consumers' connection points	57	
42			
43	Electricity volumes carried	Energy (GWh)	
44	Electricity supplied from GXPs	255	
45	less Electricity exports to GXPs	-	
46	plus Electricity supplied from distributed generation	3	
47	less Net electricity supplied to (from) other EDBs	-	
48	Electricity entering system for supply to consumers' connection points	258	
49	less Total energy delivered to ICPs	236	
50	Electricity losses (loss ratio)	21	8.2%
51	Load factor	0.52	
52	9e(iii): Transformer Capacity		
53		(MVA)	
54	Distribution transformer capacity (EDB owned)	188	
55	Distribution transformer capacity (Non-EDB owned)	46	
56	Total distribution transformer capacity	234	
57			
58		(MVA)	
59	Zone substation transformer capacity (EDB owned)	284	
60	Zone substation transformer capacity (Non-EDB owned)	-	
61	Total zone substation transformer capacity	284	

Company Name	Firstflight Network Limited
For Year Ended	31 March 2024
Network / Sub-network Name	Wairoa

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

8	9e(i): Consumer Connections and Decommissionings		
9	Number of ICPs connected during year by consumer type		
10			Number of connections (ICPs)
11	Consumer types defined by EDB*		
12	Domestic/Residential		11
13	Commercial		16
14	Large Commercial		2
15	Industrial		-
16	* include additional rows if needed		
17	Connections total		29
18	Number of ICPs decommissioned during year by consumer type		
19			Number of decommissionings
20	Consumer types defined by EDB*		
21	Domestic/Residential		8
22	Commercial		7
23	Large Commercial		-
24	Industrial		-
25	* include additional rows if needed		
26	Decommissionings total		15
27	Distributed generation		
28	Number of connections made in year		6 connections
29	Capacity of distributed generation installed in year		0 MVA
30			
31			
32			
33	9e(ii): System Demand		
34			
35			Demand at time of maximum coincident demand (MW)
36	Maximum coincident system demand		
37	GXP demand		7
38	plus Distributed generation output at HV and above		4
39	Maximum coincident system demand		12
40	less Net transfers to (from) other EDBs at HV and above		-
41	Demand on system for supply to consumers' connection points		12
42	Electricity volumes carried		Energy (GWh)
43	Electricity supplied from GXPs		50
44	less Electricity exports to GXPs		-
45	plus Electricity supplied from distributed generation		13
46	less Net electricity supplied to (from) other EDBs		-
47	Electricity entering system for supply to consumers' connection points		63
48	less Total energy delivered to ICPs		58
49	Electricity losses (loss ratio)		5 8.1%
50			
51	Load factor		0.62
52	9e(iii): Transformer Capacity		
53			(MVA)
54	Distribution transformer capacity (EDB owned)		44
55	Distribution transformer capacity (Non-EDB owned)		10
56	Total distribution transformer capacity		54
57			
58			(MVA)
59	Zone substation transformer capacity (EDB owned)		54
60	Zone substation transformer capacity (Non-EDB owned)		-
61	Total zone substation transformer capacity		54

Company Name	Firstlight Network Limited
For Year Ended	31 March 2024
Network / Sub-network Name	ALL

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 **10(i): Interruptions**

9 **Interruptions by class**

	Number of interruptions
10 Class A (planned interruptions by Transpower)	
11 Class B (planned interruptions on the network)	313
12 Class C (unplanned interruptions on the network)	724
13 Class D (unplanned interruptions by Transpower)	
14 Class E (unplanned interruptions of EDB owned generation)	
15 Class F (unplanned interruptions of generation owned by others)	
16 Class G (unplanned interruptions caused by another disclosing entity)	
17 Class H (planned interruptions caused by another disclosing entity)	
18 Class I (interruptions caused by parties not included above)	
19 Total	1,037

21 **Interruption restoration**

	≤3Hrs	>3hrs
22 Class C interruptions restored within	385	339

24 **SAIFI and SAIDI by class**

	SAIFI	SAIDI
25 Class A (planned interruptions by Transpower)		
26 Class B (planned interruptions on the network)	0.5111	122.1992
27 Class C (unplanned interruptions on the network)	3.8266	470.8738
28 Class D (unplanned interruptions by Transpower)		
29 Class E (unplanned interruptions of EDB owned generation)		
30 Class F (unplanned interruptions of generation owned by others)		
31 Class G (unplanned interruptions caused by another disclosing entity)		
32 Class H (planned interruptions caused by another disclosing entity)		
33 Class I (interruptions caused by parties not included above)		
34 Total	4.34	593.1

36 **Normalised SAIFI and SAIDI**

	Normalised SAIFI	Normalised SAIDI
37 Classes B & C (interruptions on the network)	3.6986	530.3128

Not required after DY2024

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

	SAIFI	SAIDI
40 Class B (planned interruptions on the network)	0.5111	122.1992
41 Class C (unplanned interruptions on the network)	3.4324	470.8738

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

Company Name **Firstlight Network Limited**

For Year Ended **31 March 2024**

Network / Sub-network Name **ALL**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

Cause

- Lightning
- Vegetation
- Adverse weather
- Adverse environment
- Third party interference
- Wildlife
- Human error
- Defective equipment
- Cause unknown
- Other cause
- Unknown

SAIFI	SAIDI
0.0952	10.6097
0.5048	90.2287
0.2020	43.3596
0.1587	101.1427
0.4874	29.7654
0.2887	18.7691
0.0964	2.4608
1.2945	124.2332
0.6989	50.3046
-	-
-	-

Not required after DY2024

Not required before DY2025

Not required before DY2025

Breakdown of third party interference

- Dig-in
- Overhead contact
- Vandalism
- Vehicle damage
- Other

SAIFI	SAIDI
0.0002	0.0822
0.0012	0.3025
-	-
0.1732	20.0262
0.3128	9.3545

Breakdown of vegetation interruptions (vegetation cause)

- In-zone
- Out-of-zone

SAIFI	SAIDI
-	-
-	-

Not required before DY2026

Not required before DY2026

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

Main equipment involved

- Subtransmission lines
- Subtransmission cables
- Subtransmission other
- Distribution lines (excluding LV)
- Distribution cables (excluding LV)
- Distribution other (excluding LV)

SAIFI	SAIDI
0.0031	0.8244
-	-
-	-
0.5073	121.1674
0.0007	0.2074
-	-

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

Main equipment involved

- Subtransmission lines
- Subtransmission cables
- Subtransmission other
- Distribution lines (excluding LV)
- Distribution cables (excluding LV)
- Distribution other (excluding LV)

SAIFI	SAIDI
1.3505	56.5137
-	-
-	-
2.2775	391.3410
0.1986	23.0191
-	-

10(v): Fault Rate

Main equipment involved

- Subtransmission lines
- Subtransmission cables
- Subtransmission other
- Distribution lines (excluding LV)
- Distribution cables (excluding LV)
- Distribution other (excluding LV)

Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
17	638	2.66
-	2	-
-	-	-
693	2,371	29.23
14	156	8.99
-	-	-
Total	724	

Company Name	Firstlight Network Limited
For Year Ended	31 March 2024
Network / Sub-network Name	Gisborne

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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8 **10(i): Interruptions**

9 **Interruptions by class**

	Number of interruptions
10 Class A (planned interruptions by Transpower)	
11 Class B (planned interruptions on the network)	246
12 Class C (unplanned interruptions on the network)	565
13 Class D (unplanned interruptions by Transpower)	
14 Class E (unplanned interruptions of EDB owned generation)	
15 Class F (unplanned interruptions of generation owned by others)	
16 Class G (unplanned interruptions caused by another disclosing entity)	
17 Class H (planned interruptions caused by another disclosing entity)	
18 Class I (interruptions caused by parties not included above)	
19 Total	811

20 **Interruption restoration**

	≤3Hrs	>3hrs
22 Class C interruptions restored within	288	277

24 **SAIFI and SAIDI by class**

	SAIFI	SAIDI
25 Class A (planned interruptions by Transpower)		
26 Class B (planned interruptions on the network)	0.3981	106.4287
27 Class C (unplanned interruptions on the network)	3.2940	436.7998
28 Class D (unplanned interruptions by Transpower)		
29 Class E (unplanned interruptions of EDB owned generation)		
30 Class F (unplanned interruptions of generation owned by others)		
31 Class G (unplanned interruptions caused by another disclosing entity)		
32 Class H (planned interruptions caused by another disclosing entity)		
33 Class I (interruptions caused by parties not included above)		
34 Total	3.6921	543.2285

36 **Normalised SAIFI and SAIDI**

	Normalised SAIFI	Normalised SAIDI	
37 Classes B & C (interruptions on the network)	3.0616	459.9908	Not required after DY2024

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

	SAIFI	SAIDI
40 Class B (planned interruptions on the network)	0.3981	106.4287
41 Class C (unplanned interruptions on the network)	3.0546	436.7998

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

Company Name **Firstlight Network Limited**For Year Ended **31 March 2024**Network / Sub-network Name **Gisborne****SCHEDULE 10: REPORT ON NETWORK RELIABILITY**

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

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

Lightning
Vegetation
Adverse weather
Adverse environment
Third party interference
Wildlife
Human error
Defective equipment
Cause unknown
Other cause
Unknown

SAIFI SAIDI

0.0828	9.6008
0.4823	77.7832
0.1475	28.9007
0.1771	123.3547
0.5380	28.2107
0.3134	18.5087
0.1127	2.5753
0.7796	93.8211
0.6606	54.0445
–	–
–	–

Not required after DY2024

Not required before DY2025

Not required before DY2025

Breakdown of third party interference

Dig-in
Overhead contact
Vandalism
Vehicle damage
Other

SAIFI SAIDI

0.0002	0.1009
0.0013	0.3442
–	–
0.1526	16.2868
0.3839	11.4788

Breakdown of vegetation interruptions (vegetation cause)

In-zone
Out-of-zone

SAIFI SAIDI

–	–
–	–

Not required before DY2026

Not required before DY2026

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

Subtransmission lines
Subtransmission cables
Subtransmission other
Distribution lines (excluding LV)
Distribution cables (excluding LV)
Distribution other (excluding LV)

SAIFI SAIDI

0.0038	1.0116
–	–
–	–
0.3942	105.4171
–	–
–	–

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

Subtransmission lines
Subtransmission cables
Subtransmission other
Distribution lines (excluding LV)
Distribution cables (excluding LV)
Distribution other (excluding LV)

SAIFI SAIDI

1.1467	52.2592
–	–
–	–
1.9459	360.2433
0.2014	24.2973
–	–

10(v): Fault Rate**Main equipment involved**

Subtransmission lines
Subtransmission cables
Subtransmission other
Distribution lines (excluding LV)
Distribution cables (excluding LV)
Distribution other (excluding LV)

Main equipment involved	Circuit length (km)		Fault rate (faults per 100km)
	Number of Faults		
Subtransmission lines	11	447	2.46
Subtransmission cables	–	1	–
Subtransmission other	–	–	–
Distribution lines (excluding LV)	544	1,692	32.14
Distribution cables (excluding LV)	10	134	7.47
Distribution other (excluding LV)	–	–	–
Total	565		

Company Name	Firstlight Network Limited
For Year Ended	31 March 2024
Network / Sub-network Name	Wairoa

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 10(i): Interruptions

9 Interruptions by class

	Number of interruptions
10 Class A (planned interruptions by Transpower)	
11 Class B (planned interruptions on the network)	67
12 Class C (unplanned interruptions on the network)	159
13 Class D (unplanned interruptions by Transpower)	
14 Class E (unplanned interruptions of EDB owned generation)	
15 Class F (unplanned interruptions of generation owned by others)	
16 Class G (unplanned interruptions caused by another disclosing entity)	
17 Class H (planned interruptions caused by another disclosing entity)	
18 Class I (interruptions caused by parties not included above)	
19 Total	226

21 Interruption restoration

	≤3Hrs	>3hrs
22 Class C interruptions restored within	97	62

24 SAIFI and SAIDI by class

	SAIFI	SAIDI
25 Class A (planned interruptions by Transpower)		
26 Class B (planned interruptions on the network)	1.0090	191.6458
27 Class C (unplanned interruptions on the network)	6.1720	620.9223
28 Class D (unplanned interruptions by Transpower)		
29 Class E (unplanned interruptions of EDB owned generation)		
30 Class F (unplanned interruptions of generation owned by others)		
31 Class G (unplanned interruptions caused by another disclosing entity)		
32 Class H (planned interruptions caused by another disclosing entity)		
33 Class I (interruptions caused by parties not included above)		
34 Total	7.1809	812.5682

36 Normalised SAIFI and SAIDI

	Normalised SAIFI	Normalised SAIDI	
37 Classes B & C (interruptions on the network)	5.2494	663.1062	Not required after DY2024

39 Transitional SAIFI and SAIDI (previous method)

	SAIFI	SAIDI
40 Class B (planned interruptions on the network)	1.0090	191.6458
41 Class C (unplanned interruptions on the network)	5.3977	620.9223

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

Company Name **Firstlight Network Limited**

For Year Ended **31 March 2024**

Network / Sub-network Name **Wairoa**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

Cause

- Lightning
- Vegetation
- Adverse weather
- Adverse environment
- Third party interference
- Wildlife
- Human error
- Defective equipment
- Cause unknown
- Other cause
- Unknown

SAIFI	SAIDI
0.1499	15.0525
0.6038	145.0335
0.4418	107.0308
0.0777	3.3300
0.2646	36.6117
0.1801	19.9161
0.0248	1.9567
3.5617	258.1557
0.8676	33.8353
-	-
-	-

Not required after DY2024
Not required before DY2025
Not required before DY2025

Breakdown of third party interference

- Dig-in
- Overhead contact
- Vandalism
- Vehicle damage
- Other

SAIFI	SAIDI
-	-
0.0004	0.1187
-	-
0.2642	36.4930
-	-

Breakdown of vegetation interruptions (vegetation cause)

- In-zone
- Out-of-zone

SAIFI	SAIDI
-	-
-	-

Not required before DY2026
Not required before DY2026

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

Main equipment involved

- Subtransmission lines
- Subtransmission cables
- Subtransmission other
- Distribution lines (excluding LV)
- Distribution cables (excluding LV)
- Distribution other (excluding LV)

SAIFI	SAIDI
-	-
-	-
-	-
1.0052	190.5253
0.0037	1.1205
-	-

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

Main equipment involved

- Subtransmission lines
- Subtransmission cables
- Subtransmission other
- Distribution lines (excluding LV)
- Distribution cables (excluding LV)
- Distribution other (excluding LV)

SAIFI	SAIDI
2.2482	75.2488
-	-
-	-
3.7375	528.2829
0.1863	17.3906
-	-

10(v): Fault Rate

Main equipment involved

- Subtransmission lines
- Subtransmission cables
- Subtransmission other
- Distribution lines (excluding LV)
- Distribution cables (excluding LV)
- Distribution other (excluding LV)

Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
-	0	-
-	-	-
149	678	21.97
4	22	18.29
-	-	-
Total	159	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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10(vi): Worst-performing feeders (unplanned) *Not required before DY2025*

SAIDI

Rank	Feeder name	Unplanned SAIDI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

¹ Extend table as necessary to disclose all worst-performing feeders

SAIFI

Rank	Feeder name	Unplanned SAIFI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

¹ Extend table as necessary to disclose all worst-performing feeders

Customer Impact

Rank	Feeder name	Customer Impact Ratio	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

¹ Extend table as necessary to disclose all worst-performing feeders

Appendix A - Information Disclosure for Related Parties

Assessment Period

1 April 2023 – 31 March 2024

1. Introduction

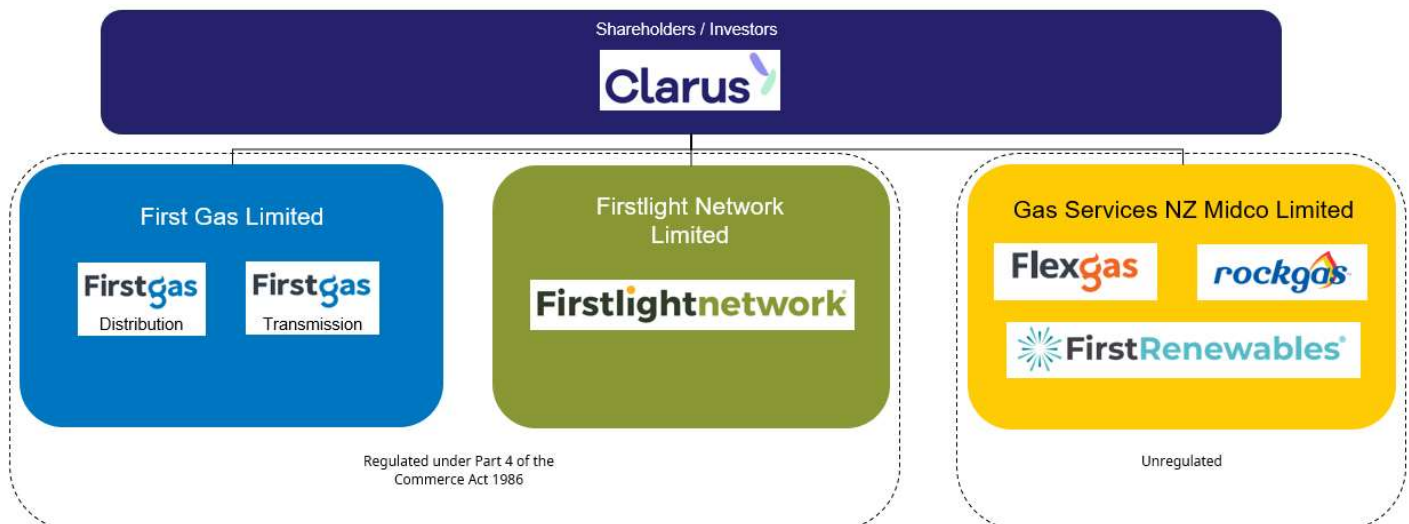
Firstlight Network (Firstlight) is the electricity lines company for Tairāwhiti and Wairoa. We own and maintain the poles, wires, transformers and underground cabling used by electricity retailers to supply customers with electricity.

We also own the region’s high-voltage electricity transmission network (the steel poles and towers that connect our region to the national grid).

We’re a team of people who, with our contractors, are responsible for keeping the lights on for 26,000 customers across 12,000 square kilometres of Tairāwhiti and Wairoa.

On 1 April 2023, Firstgas Group (now Clarus) took over ownership of Eastland Network Limited from Eastland Group. Firstlight Network is part of Clarus and is owned by Igneo Infrastructure Partners.

Clarus is one of New Zealand’s largest energy groups, with brands that touch many parts of the energy supply chain – from energy transmission and distribution to retail supply and storage.



2. Information Disclosure requirements

This disclosure is made on behalf of Firstlight. Firstlight procures operations and maintenance (O&M) services from its related party, Gas Services New Zealand Midco Limited (GSNZ Midco). Firstlight also procures corporate support services from Firstgas. The extent of these and other purchases from companies within the Clarus group means that Firstlight procures more than 65% of its operating expenditure (Opex) and capital expenditure (Capex) from related parties.

Given this use of related parties, Firstlight is subject to the full disclosure requirements for related parties under the Electricity Distribution Information Disclosure Determination 2012 (ID Determination) issued by the Commerce Commission.

The related party information disclosed on the following pages has been prepared in accordance with sections 2.3.8, 2.3.10, 2.3.12 and 2.3.13 of the ID Determination. It:

- Provides a summary of related party relationships and transactions
- Provides a summary of the Clarus procurement policy and describes how this policy is applied in practice by Firstlight
- Describes policies and procedures that require consumers to purchase goods or services from related parties
- Provides representative examples of how the procurement policy has been applied for related party purchases and how arm's length terms were tested
- Provides a map of anticipated network expenditure and constraints

This disclosure was prepared on 29 August 2024 and where required, has been audited as part of the annual information disclosure process.

A copy of the full procurement policy and associated guidelines has been provided to the Commerce Commission as required under section 2.3.11 of the ID Determination.

3. Summary of Firstlight's related party relationships and transactions

Clause 2.3.8 of the ID Determination requires that:

“if an EDB has had related party transactions involving a procurement from a related party during that disclosure year, the EDB must publicly disclose a diagram or a description that shows the connection between the EDB and the related parties with which it has had related party transactions in the disclosure year, including for each of those related parties-

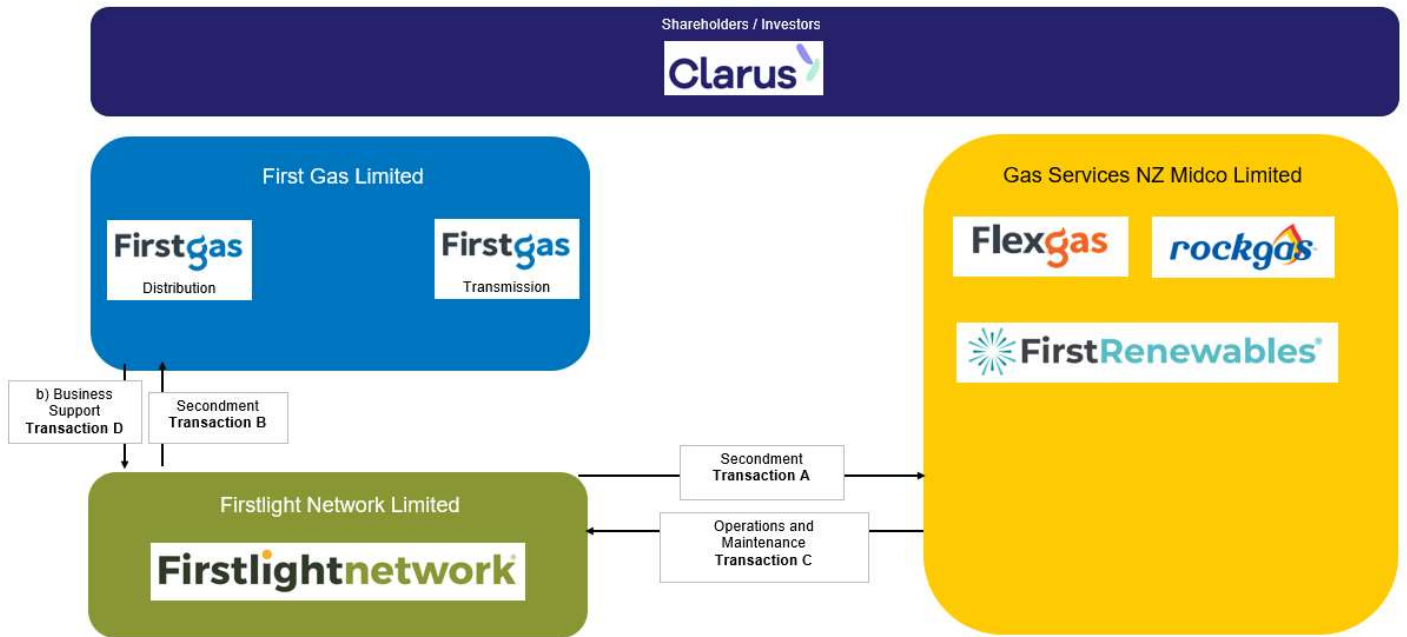
- (1) the relationship between the EDB and the related party
- (2) the principal activities of the related party
- (3) the total annual expenditure incurred by the EDB with the related party.

In FY2024, Firstlight:

- Seconded staff to GSNZ Midco to undertake operations and maintenance services across Clarus.
- Seconded staff to Firstgas to undertake business support services across Clarus.
- Procured operations and maintenance (O&M) services from its related party, Gas Services New Zealand (Midco) Limited (GSNZ Midco)
- Procured corporate function services from Firstgas under the terms of the Corporate Function and Secondment Services Agreement (CFSA.)

Firstlight provides unregulated services to GSNZ Midco. In the FY2024 disclosure period, Firstlight seconded staff to GSNZ Midco and Firstgas. The supply of these unregulated services was valued using independent and objective measures.

These related party transactions are illustrated in Figure 2.



The following table describes the connection between Firstlight and its related parties with which it has had transactions with during the 2024 disclosure year. A breakdown of these transactions is also provided in schedule 5b of our Information Disclosure schedules.

Table 1: The nature and extent of related party transactions in disclosure year 2024

Related Party	Nature of relationship	Principle activities of the related party	FY2024 expenditure/revenue between Firstlight and its related party
GSNZ Midco (Transaction A)	Firstlight and GSNZ Midco have the same ultimate shareholders	Firstlight seconded staff to GSNZ Midco to provide operations and maintenance services	Unregulated income received of \$3.457 million is included in Schedule 5b for the provision of these services. This unregulated income is included in <i>total regulatory income</i> in Schedule 5b (and is not included in Schedule 2 or Schedule 3 as it is non-regulatory in nature)
Firstgas (Transaction B)	Firstgas and Firstlight have the same ultimate shareholders	Firstlight seconded staff to Firstgas to provide regulated gas transmission and gas distribution services	Unregulated income received of \$0.036 million
GSNZ Midco (Transaction C)	Firstlight and GSNZ Midco have the same ultimate shareholders	Firstlight acquired operations and maintenance services from GSNZ Midco.	Network Capex \$12.940 million Non-Network Capex \$0.233 million Network Opex \$7.094 million System operations Opex and Network support Opex \$1.339 million
Firstgas (Transaction D)	Firstgas and Firstlight have the same ultimate shareholders	Firstgas provided corporate function services to Firstlight	\$2.465 million including \$0.037 million Directors Fees

Gas Services (Midco) New Zealand Limited

GSNZ Midco and Firstlight are part of the wider Clarus group of companies and have the same ultimate shareholders. GSNZ Midco owns Gas Services, a contracting company providing operations and maintenance services.

In the 2024 disclosure year, GSNZ Midco provided 93% of the Firstlight total Capex and 56% of all Operating Expenditure (Opex) under an Operations and Maintenance agreement (O&M agreement).

Services provided under the O&M agreement include:

- Management of the Firstlight business operations
- Asset management
- Health, safety and environment management
- Land and planning management
- Design and engineering services
- Scheduling and completing field works
- Incident and emergency response
- Provision of non-network assets such as plant and equipment (if required).

Operations and Maintenance (O&M) Agreement

Firstlight procures almost all of its network capital expenditure, most of its network Opex, and all its system operations and network support (SONS) expenditure from GSNZ Midco. These services are provided by Gas Services in accordance with the terms and conditions of the O&M agreement between Firstlight and GSNZ Midco.

While Firstlight owns the network and non-network assets and provides the electricity distribution services across Tairāwhiti and Wairoa, under the O&M agreement, GSNZ Midco manages the operation of the assets, carries out an agreed Capital and Maintenance works programme, responds to incidents and emergencies, and provides system operations and network support services to Firstlight.

Costs incurred under the O&M agreement are directly attributable to Firstlight.

Corporate Function and Secondment Services Agreements (CFSA).

Firstlight contracts business support services from Firstgas under the Corporate Functions and Secondment Services Agreement (the CFSA), a shared services arrangement provides economies of scale and scope across Clarus.

Since Firstgas was the first regulated business owned by Clarus, this entity was chosen as the provider of corporate service across the group.

As with the O&M agreement, we have applied EBIT margins to the costs of goods sold (i.e., seconded staff and corporate functions) and used benchmarking to confirm that the value of the services supplied to Firstlight by Firstgas was not more than the terms of an arm's length transaction.

The CFSA requires Firstgas to carry out all corporate functions in a competent, diligent, and expeditious manner. While no specific service standards apply to corporate functions, as might be the case in a commercially negotiated agreement, the CFSA puts a process in place for Firstlight to review performance and communicate any concerns back to Firstgas.

Since the provision of business support is combined across Clarus, any issues affecting the performance of Firstgas under the CFSA will likely also affect other companies within the group.

Summary of Clarus' procurement policy

Clause 2.3.10 of the ID Determination requires that:

“if an EDB has had related party transactions involving a procurement from a related party during that disclosure year, the EDB must publicly disclose:

(1) a summary of its current policy in respect of the procurement of assets or goods or services from any related party; or

(2) a summary of alternative documentation which is equivalent to a procurement policy in respect of the procurement of assets or goods or services from any related party.

Pursuant to clause 2.3.10(2), this section provides a summary of our procurement policy and guidelines.

Firstlight's electricity network spans Tairāwhiti and Wairoa districts. We require specialist personnel, contractors, and materials to operate and manage this extensive network in a safe and reliable manner.

To maximise our cost efficiency while managing our networks, Clarus has an overarching procurement policy that applies to all companies within the group. This policy requires we *“source, engage and manage suppliers in a professional and transparent manner within a consistent framework to achieve best value for Clarus.”* This Policy provides guiding principles for all procurement by, or on behalf of Clarus.

In this section, we summarise the procurement principles that underpin the procurement policy and the procurement methods employed by Clarus. Procurement of goods and services from GSNZ Midco under the O&M agreement must abide by the Clarus procurement policy.

Procurement principles

Anyone procuring goods and services for Firstlight must be familiar with and apply the following procurement principles:

Principle	Description
Health & Safety First	The health and safety of staff and suppliers must be taken into consideration when procuring goods and/or services.
Open and Effective Competition	Firstlight purchasing must be conducted in a manner that encourages competition amongst suppliers.
Get the best for Clarus	Making quality decisions that consider the life of the contract (or whole-of-life cost) not just selecting the lowest price.
Play by the Rules	Building trust and relationships with suppliers and keeping a reputation as a fair buyer.

These principles all contribute to producing efficient and effective infrastructure for the long-term benefit of our business and our customers. While we seek competitive outcomes, we believe consumers equally value least-cost over the lifetime of the asset and Firstlight always places the health and safety of our employees and contractors above other criteria. For example, we may not select the lowest price quote or tender if the supplier cannot meet our safety and quality standards or if the life-cycle cost of the asset is higher than other options.

The competitive process

Whilst Clarus encourages competition amongst suppliers through our procurement process, to some extent this is governed by the value of the goods / services to be supplied and the availability of suppliers to meet our needs. This includes being suitably qualified to work on the electricity network.

Low-cost purchases will be supported, at a minimum, with quotations from several suppliers. High value works will be supported by an open competitive process such as a request for proposal or invitation to tender where possible.

The Policy recognises that in some instances sole sourcing may be the only procurement option available. "Sole sourcing" refers to where a competitive procurement process, such as a tender or quote requests, cannot be used or there would be no benefit from going through a competitive process. This will generally be because only one supplier, to the best of our knowledge and belief, can deliver the required good(s) and/or service(s). In the relatively specialised field of electricity distribution operations and maintenance, this is not an uncommon situation.

Other typical reasons for selecting sole sourcing include:

- Availability / workload within pool of approved suppliers: Particularly with professional services where we have already negotiated rates and have a pool of 3 – 5 suppliers. To ensure that work is allocated to avoid resource conflict, it may be acceptable to sole source smaller projects
- Exclusivity: Where Firstlight is already committed to an exclusive contract for the procurement of such goods or services for a set time period (for example the O&M Agreement with GSNZ Midco)
- OEM / warranty arrangement: Where sole source is required contractually.

The sole sourcing procurement option requires formal justification and approval in line with delegated authorities.

Monitoring and compliance

The Clarus procurement team is responsible for monitoring compliance with the procurement policy for Firstlight and reporting any breaches of this policy to the Executive. The procurement team will undertake reviews of Clarus' procurement activity especially around the compliance with the policy and the application of procurement processes. Reviews may include review of the procurement process undertaken by GSNZ Midco acting on the behalf of Firstlight under the O&M agreement.

Failure within Clarus to comply with the provisions of the procurement policy is a breach of an employee's Code of Conduct & Performance & Conduct Policy. Any instances of reported non-compliance will be investigated and may lead to disciplinary action.

Clarus has a whistle blower policy that provides an avenue for employees to raise concerns about misconduct or wrongdoing. Misconduct or wrongdoing includes failure to abide by the procurement policy and the whistle blower policy enables anyone to report identified breaches of the procurement policy.

Application of the procurement policy

Clause 2.3.12 of the ID Determination requires that:

“if an EDB has had related party transactions involving a procurement from a related party during that disclosure year, the EDB must publicly disclose-

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

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

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

(4) for each representative example transaction specified in accordance with subclause

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

Pursuant to clause 2.3.12 (1), the following section describes how Firstlight has applied the Clarus procurement policy in respect of the procurement of goods or services from a related party.

In the 2024 disclosure period, Firstlight has procured goods and services from GSNZ Midco under the O&M agreement.

Firstlight has contracted GSNZ Midco as the sole provider of operations and maintenance services for the network. GSNZ Midco acts on behalf of Firstlight when project managing and purchasing required goods and services while carrying out its responsibilities under the O&M agreement.

The section considers the procurement of goods and services under the O&M contract.

Purchase of Opex and Capex services from our related party GSNZ Midco

The procurement policy puts emphasis on making decisions to achieve the best outcomes for Firstlight and its customers whilst keeping our staff, contractors, and assets free from harm. We manage long-life assets and require specialist personnel, contractors, and materials to operate and manage this extensive network in a safe and reliable manner.

Under the O&M agreement, Firstlight has contracted GSNZ Midco to manage the operational functions, maintain the network assets, implement and feed into the Asset Management Plan (AMP), and provide system operations and network support functions. From time to time, Firstlight may also procure non-network assets from GSNZ Midco. These assets are provided under the service agreement as they relate to the ongoing maintenance of the distribution network or management of the assets on the distribution network. GSNZ Midco acts on behalf of Firstlight when project managing and purchasing required goods and services in the course of carrying out its responsibilities under the O&M agreement.

As discussed above, our first step in ensuring we are achieving the best for our customers and businesses was to enter into an Operations and Maintenance (O&M) agreement.

The O&M agreement with GSNZ Midco provides a range of expertise and experience guiding and supporting our electricity distribution business. This expertise and experience is vital in maintaining and expanding the network and also in the planning process both annually and long-term.

Provisions within the O&M agreement align with Firstlight procurement principles to ensure on-going value of the agreement to our customers. These include:

- Planning to ensure O&M works plans align with Firstlight requirements efficiently and in a cost-effective manner. This may include benchmarking of costs to ensure the O&M agreement continues to meet efficiency targets and is compliant with the related party rules for regulated businesses
- Service level agreements including a range of key performance indicators that are linked to payments
- Provisions around meeting stringent safety standards.

To give an idea of how the O&M agreement works in practice, we consider the annual process:

- Planning
- Challenge and benchmarking process
- Execution of works including monitoring and reporting
- Completion of works

At the end of each year, Firstlight conducts an annual review of the process.

Planning

Planning is an important part of the procurement process. It determines the anticipated work plan for the year and highlights resource requirements, whether they be personnel or materials.

Each year, Firstlight management work with the Chief Operations Officer (COO) of GSNZ Midco to develop and update the long-term Asset Management Plan (AMP). The AMP provides the asset management framework for the Firstlight network and includes guidance on the expected annual works plan. The AMP is reviewed and approved by Clarus management and the Firstlight Board of Directors.

The AMP is part of the long-term planning for the network. It supports the Firstlight business plan and the operations and maintenance (O&M) plan. GSNZ Midco provides Firstlight with the long-term O&M plan to meet the network development and maintenance section of the business plan. The O&M plan includes indicative resourcing and costings and works plans. This must be agreed by both parties and the O&M agreement outlines the resolution process.

The COO of GSNZ Midco provides a budget to Firstlight to complete the annual works plan as required under the O&M agreement.

Challenge and benchmarking process

While GSNZ Midco is a related party of Firstlight, the O&M agreement is structured as if it was between two separate legal entities, with different ownership interests, and operating on an arm's length basis. Each party acknowledges that a key objective of Firstlight in appointing GSNZ Midco to deliver the O&M is to ensure value for money and continuous improvement in delivery and value.

In practice, this means that Firstlight may accept in full or challenge any part of the budget provided by GSNZ Midco. Firstlight may subject all or part of the annual budget to a benchmarking procedure undertaken by an independent expert.

The Benchmark will:

- Compare the O&M Services and Service Fee, including the component parts of the Service Fee, with the services, charges and margins being obtained under other similar service contracts in New Zealand and / or good international market services, charges and margins for third parties
- Assess, in light of this comparison, whether:
 - o The scope of the O&M Services being provided is necessary to meet the Service Standards and
 - o The Service Fee, including the component parts of the Service Fee, is market competitive and otherwise meets the Information Disclosure Determination requirements.

Under the O&M agreement, we anticipate that prices charged by GSNZ Midco will not change significantly from year to year (unless there is strong evidence that input costs have permanently changed). This is consistent with a competitive market where companies with long-term contracts in place (such as the O&M agreement and CFSA) tend to set prices for longer terms. This gives service providers greater certainty to invest in staff and equipment required to fulfill the contract terms over the duration of the contract. For FY2024 Firstlight engaged independent experts to:

- Confirm the margin charged by GSNZ Midco under the O&M agreement was within the range of providers of similar services
- Cross-checked that GSNZ Midco costs remain efficient and consistent with the input prices Firstlight would have paid in an arm's length transaction by completing benchmarking against others in the industry.

Whilst we do not anticipate GSNZ Midco would need to significantly change prices within the contract period, we recognise that the onus remains on Firstlight to ensure that costs from related party transactions remain consistent with input prices that we would have paid in an arm's length transaction. The Commission has noted that there is some risk that long-term contracts can become out of date with current market practices and prices and Firstlight has actively considered this risk through our benchmarking process this year.

For RY2024, our O&M agreement remains aligned with current market practices and prices. This was last tested in April 2023 when we engaged an independent expert to:

- Consider changes in market practices or pricing for similar services and how this may affect arm's length margins
- Conduct a sample of relevant margin data to ensure no substantive and permanent change has occurred in the market since margins were established under the O&M Agreement for RY2024.

Firstlight continued to cross-check that our costs remain efficient and consistent with the input prices Firstlight would have paid in an arm's length transaction by completing benchmarking against others in the industry.

Execution of works including monitoring and reporting

Once the O&M budget has been agreed, GSNZ Midco undertakes responsibility to complete the works to the service level required. Significant large-scale projects are managed by the GSNZ Midco projects team. Projects of this nature often require additional resources and expertise. GSNZ Midco will source services and materials as required and in line with the Clarus procurement policy.

The COO of GSNZ Midco reports monthly to Firstlight on progress against the works plan and budget for services provided under the O&M agreement. From time-to-time works may be required by Firstlight that are outside of the budgeted plan. Any change to the annual work plan is negotiated between GSNZ Midco and Firstlight. Any additional remedial works GSNZ Midco recommend are either included in the current year's workplan, with agreement from Firstlight or included in the annual works budget for following years.

The costs GSNZ Midco incurs undertaking the responsibilities of the O&M agreement are charged to Firstlight monthly and include a commercial mark up to enable a reasonable commercial profit.

Completion of works

The completion of works is managed within GSNZ Midco. GSNZ Midco will process any project close out documentation and update maintenance records within Clarus information systems. If the project was a Capex project, Firstlight will capitalise the project once GSNZ Midco notifies that the assets have been commissioned.

Corporate Function and Secondment Services Agreement (CFSA)

Total corporate function costs across Clarus are allocated based on the expected time spent on each service for Firstgas, Firstlight and GSNZ Midco activities. To apportion the direct costs and staff time to service activities within Clarus, management determines the split of Firstlight business support between the regulated and unregulated business within the Group.

Policies that require consumers to purchase goods or services from Firstlight's related parties

Section 2.3.12 of the ID Determination requires that:

within 5 months after the end of each disclosure year, if an EDB has had related party transactions involving a procurement from a related party during that disclosure year, the EDB must publicly disclose-

(2) a description of any policies or procedures of the EDB that require or have the effect of requiring a consumer to purchase assets or goods or services from a related party that are related to the supply of the gas transmission services;

To work on or near the Firstlight network, a contractor must be deemed competent and authorised to complete the work undertaken to meet operating standard requirements. This is very specialised work, and we require any work to be completed GSNZ Midco

Customers that contribute to the cost of new developments or upgrades on our network are therefore required to use GSNZ Midco to complete the works. Our capital contribution policy is available at <https://www.firstlightnetwork.co.nz/tell-me-about/firstlight-network/regulatory-information/>.

Representative examples of how the procurement policy is applied

Regulatory requirements

Section 2.3.12 of the ID Determination for the EDB specify that:

within 5 months after the end of each disclosure year, if an EDB has had related party transactions involving a procurement from a related party during that disclosure year, the EDB must publicly disclose-

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

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

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

Representative examples

Firstlight sources a range of services from GSNZ Midco to manage the network operations and complete the work plan each year. Firstlight's corporate functions including Information Services, Legal, Health and Safety, Finance and Commercial and Regulatory are sourced from Firstgas. The Clarus procurement policy for all expenditure is applied under the O&M agreement and CFSA agreement. This is summarised in the table below.

Table 2: Representative example transactions of costs in Schedule 5b

Expenditure category	Representative example	Procurement method	How and when were the arm's length terms last tested
<p>All network Capex categories</p> <p>All network Opex categories</p> <p>System operations and network support</p> <p>Non-network assets</p>	<p>Network Opex and Capex and system operations and network support across the network.</p> <p>We provide example below of procurement undertaken by GSNZ Midco on our behalf under the O&M agreement</p>	<p>Direct procurement from a 'sole supplier' under the existing O&M agreement.</p>	<p>The arm's length terms were tested as part of a benchmarking process that was undertaken during the 2024 disclosure year.</p> <p>In RY2023 Firstlight engaged an independent expert to benchmark:</p> <ul style="list-style-type: none"> - The margins applied to the costs of O&M services provided by GSNZ Midco to Firstlight - Total service costs against comparable businesses. <p>The margin benchmarking compared services supplied by GSNZ Midco to companies providing similar services across New Zealand.</p> <p>Benchmarking against comparable businesses indicated that Firstlight costs are aligned with our peers and the wider market. This demonstrates that the cost of the underlying service is consistent with the input price that Firstlight would have paid in an arm's length transaction.</p> <p>Benchmarking was undertaken with the permission of GSNZ Midco.</p> <p>Benchmarking is allowed for under the O&M agreement.</p>
<p>Business Support Opex</p>	<p>Corporate Services and IT Services for Firstlight Network. Payable by Management Fee which is set prior to regulatory year.</p> <p>Monthly Management Fee issued providing breakdown of services. Inclusive in the Management Fee are Directors Fees</p> <p>We provide below a schedule of services undertaken under the CFSA agreement.</p>	<p>Direct procurement from a 'sole supplier' under the existing CFSA agreement.</p>	<p>The arm's length terms were tested as part of a benchmarking process that was undertaken during the 2023 disclosure year.</p> <p>In RY2023 in preparation for Firstlight engaged an independent expert to benchmark:</p> <ul style="list-style-type: none"> - The margins applied to the costs of Business Support services provided to Firstlight <p>Benchmarking undertaken against comparable businesses indicated that Firstlight costs are aligned with our peers and the wider market. This demonstrates that the cost of the underlying service is consistent with the input price that Firstlight would have paid in an arm's length transaction.</p>



Example of procurement undertaken by GSNZ Midco on our behalf

Firstlight procures a range of services from GSNZ Midco. These services may have different characteristics and involve different procurement choices within the policy to suit the work undertaken. The process will remain consistent with the project management and reporting requirements within GSNZ Midco, and with monthly reporting against the budget and works plan provided to the Clarus executive team.

The following example of a project undertaken by GSNZ Midco for Firstlight illustrating the procurement process.

Project name:	Ngatapa Pole Replacement Stage 1
Project date	The scope was issued in October 2023 with works completed in November 2023
Project or work order number:	4000.C.0200.01.03
Project expenditure (estimated)	\$0.07 million
Project cost type	Asset Replacement and Renewal Capex
Project managed by:	GSNZ Midco acting on behalf of Firstlight under the O&M agreement.
Subcontractors:	Electrinet managed the delivery of the project. Works were completed under the terms and rates specified in the service agreement with Electrix.

Planning

Leading into RY2024, it was identified that there were poles earmarked for replacement, in particular the Ngatapa area. The AMP for RY2024 had included \$1.6 million in the asset replacement and renewal Capex forecast for the ongoing replacement of 11KV poles in the Gisborne region.

The AMP is approved by Firstlight's Chief Executive Officer and the Clarus Board of Directors. Once approved, work plans are finalised for the upcoming year.

Completion of works

The scope of works and plan included supply and upgrade of existing 8 poles, 2 stud poles and 1 low voltage pole. Also included in the works was to carry out the 11KV maintenance in the area. The scope was reviewed by GSNZ Midco and Electrinet and the report reviewed by GSNZ Midco's project manager and engineers.

Once the project began, project costs were paid and tracked within the financial system after approval by the project manager. Project costs and progress were monitored by the GSNZ Midco project team and reported to the Chief Operating Officer for GSNZ Midco. Progress against projects and budgeted costs is reported to the Firstlight executive team monthly.

Market testing

Electrinet were selected as the supplier to carry out the works using the sole sourcing approach. Electrinet have specialist expertise in the Tairāwhiti region and are the incumbent supplier of O&M services for Firstlight. Electrinet were the preferred supplier due to:-

- Their experience on working on our network and within our systems
- Their base in the Tairāwhiti region

Outcomes:

The project was completed in time and within budget

Corporate Function Services undertaken as per the CFSA agreement

Area	Description
Executive Management Team	Executive Management of Firstlight Network
Finance	Ensuring Firstlight Network's financial management and results are correctly accounted for and reported. Services include accounts payable, accounts receivable, fixed assets, treasury, tax, and financial reporting. This includes maintaining the finance system and providing training to staff raising purchase orders or completing timesheets
Legal	Provision of legal services and contract management to Firstlight Network
Information Services	Information Services is split into two focus area, improvement and run. Improvement is an integral part of the solutions team who works closely with the Continuous Improvement team to deliver business excellence, value, and optimization. Run covers the day to day support of the IT systems used by Firstlight Network. These include everything from the data centre to Desktop, Business Systems, Office Systems, Telephony, Networks, and the Service Desk function.
People and Performance	Provision of Human Resources, Recruitment, Payroll, Internal Communications, Staff Engagement and Culture, Learning and Development
Commercial and Regulation	Commercial and Regulatory support for Firstlight Network. Including:- <ul style="list-style-type: none"> - Completing and filing all regulatory disclosures on behalf of Firstlight - Regulatory and Policy advocacy in Firstlight interests - Office Management support for Firstlight - Marketing Support - External Communications
Health and Safety, Environment and Quality	Provision of HSEQ and Risk Management services for Firstlight Network
Procurement, Stores and Facilities	This team manage the following functions:- <ul style="list-style-type: none"> - Facilities: All tasks and activities associated with managing operated facilities - Purchasing: Provide purchasing support, stock ordering, fleet management, supply contracts, associated credit applications, new vendor approvals, prequalification, and general purchasing activities - Stores: Manage and maintain inventory to facilitate the day to day maintenance activities of the business. Inwards and outwards goods as well as managing project and emergency materials.
Operations Management Team	Provision of oversight and management of operations of the Electricity Distribution Business
Maintenance Services	Support services for Firstlight Networks Operational Teams, such as Maximo management, and permit co-ordination.

Map of anticipated network expenditure and constraints

Section 2.3.13 of the ID Determination requires that:

within 5 months after the end of each disclosure year, where an EDB has had related party transactions involving a procurement from a related party during that disclosure year, the EDB must publicly disclose a map of its electricity distribution service territory, which includes-

(1) subject to clause 2.3.15, a brief explanatory description of the 10 largest forecast operational expenditure projects in the AMP planning period and the likely timing, value and location of the projects;

(2) subject to clause 2.3.15, a brief explanatory description of the 10 largest forecast capital expenditure projects in the AMP planning period and the likely timing, value and location of the projects;

(3) subject to clause 2.3.16, a brief explanatory description of possible future network or equipment constraints and their location, where the responses to the constraints would involve one of the 10 largest future operational expenditure projects in the AMP planning period; and

(4) subject to clause 2.3.16, a brief explanatory description of possible future network or equipment constraints and their location, where the responses to the constraints would involve one of the 10 largest future capital expenditure projects in the AMP planning period.

Section 2.3.14 further specifies the map must:

(1) identify whether the forecast or possible operational expenditure or capital expenditure is-

(a) already subject to a contract and, if so, whether that contract is with a related party;

(b) forecast to require the supply of assets or goods or services by a related party; or

(c) currently not indicated for supply by a related party; and

(2) be consistent with the AMP information specified in-

(a) clause 11.8.3 of Attachment A on network or equipment constraints; and

(b) clause 11.8.4 of Attachment A on the projected impact of demand management initiatives.

The largest Opex activities and Capex projects in the AMP planning period are provided below. Further information is available in the annual AMP or AMP update available on the Firstlight website.

Largest Opex activities

Figure 3 sets out the location of the largest ten activities in the AMP planning period (RY2024-RY2033), with greater detail in Table 3. All network Opex is forecast to be completed by our related party, Gas Services New Zealand Midco Limited (GSNZ Midco) under the Operations and Management (O&M) agreement between Firstlight and GSNZ Midco. GSNZ Midco manages a number of third-party contractors to deliver this network Opex. All activities are network related works, and none are a result of future network or equipment constraints.

Figure 3: Map showing largest Opex projects in the planning period (RY24-RY33)

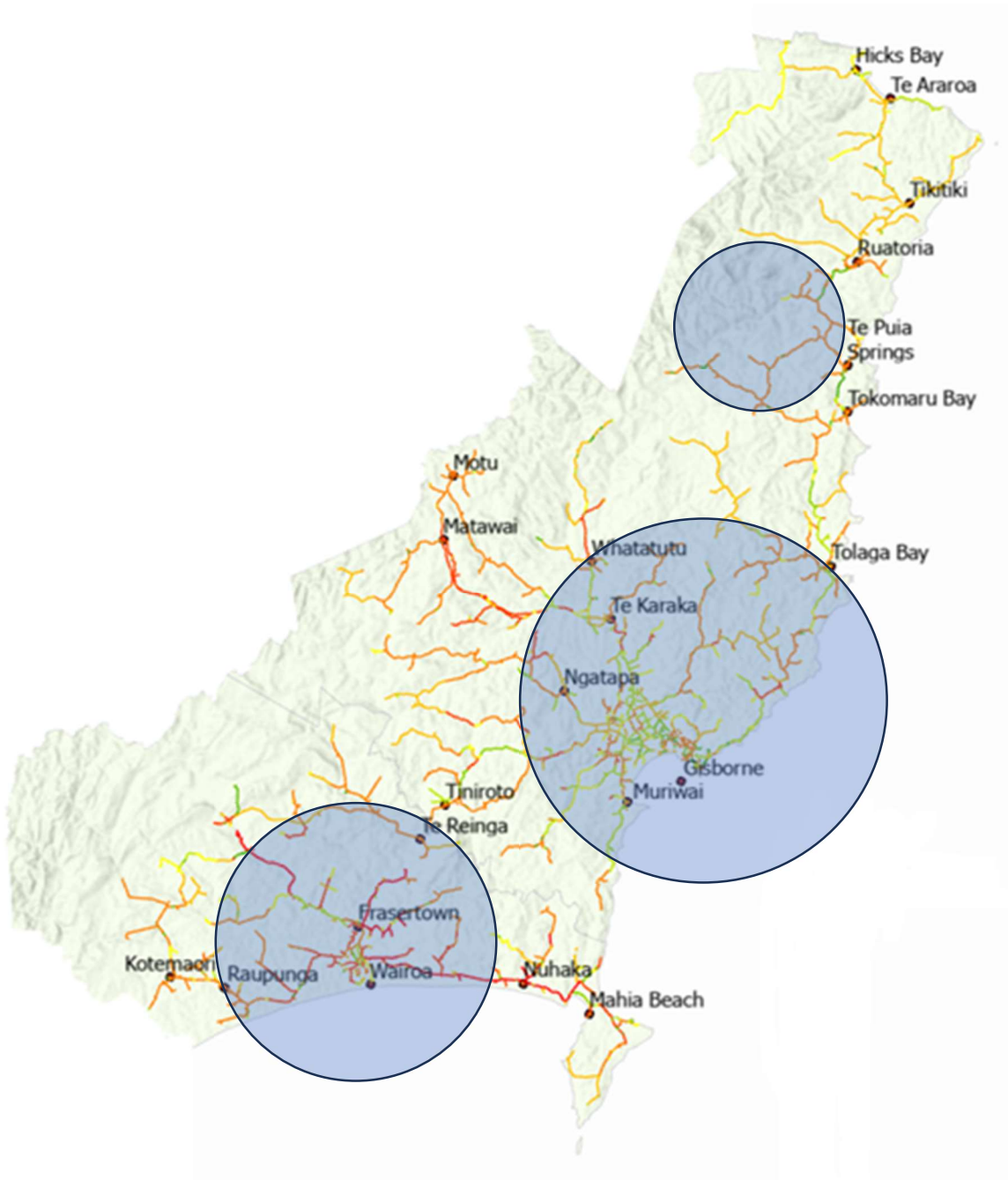


Table 3: 10 largest Opex projects in the planning period (RY24-RY33)

Activity	Description	Region	Total Cost (constant)	Period
11kV Tree Control Program Northern	Routine vegetation management	Gisborne	\$6 million	RY24-RY33
11kV Tree Control Program Southern	Routine vegetation management	Wairoa	\$6 million	RY24-RY33
11kV Patrols & general maintenance	Routine corrective maintenance and inspection	Network Wide	\$3.1 million	RY24-RY33
Zone SubAverage Routine Maintenance/major maint	Routine corrective maintenance and inspection	Network Wide	\$1.7 million	RY24-RY33
110kV Inspections & routine maint	Routine corrective maintenance and inspection	Network Wide	\$1.6 million	RY24-RY33
Zone Sub Grounds Maintenance	Routine corrective maintenance and inspection	Network Wide	\$1.5 million	RY24-RY33
Subtransmission - Vegetation Control	Routine vegetation management	Network Wide	\$1.2 million	RY24-RY33
GIS-TOK 110kV - Patrols	Routine corrective maintenance and inspection	Gisborne	\$1 million	RY24-RY33
110kV Condition Assessment Report	Routine corrective maintenance and inspection	Network Wide	\$0.9 million	RY24-RY33
Zone Substation Building Maintenance (paint/spouting/doors/windows)	Routine corrective maintenance and inspection	Network Wide	\$0.8 million	RY24-RY33

Largest Capex activities

Figure 4 sets out the location of the largest ten activities in the AMP planning period (RY2024-RY2033), with greater detail in Table 4. All network Capex is forecast to be completed by our related party, Gas Services New Zealand Midco Limited (GSNZ Midco) under the Operations and Management (O&M) agreement between Firstlight and GSNZ Midco. GSNZ Midco manages a number of third-party contractors to deliver this network Opex. All activities are network related works, and none are a result of future network or equipment constraints.

Figure 4: Heatmap illustrating largest Capex projects in the planning period (RY24-RY33)



Table 4: 10 largest Capex projects in the planning period (RY24-RY33)

Activity	Description	Region	Total Cost (constant)	Period
11kV Replacement Poles	Asset Replacement and Renewal	Gisborne	\$15.9 million	RY24-RY33
Red Tagged Pole Project	Accelerated pole replacement programme	Network Wide	\$12.6 million	RY24-RY33
Thermal Upgrade Project	Capacity strengthening on the 110KV circuits	Gisborne	\$9.2 million	RY24-RY32
11kV Pole Replacements Wairoa	Asset Replacement and Renewal	Wairoa	\$8.9 million	RY24-RY33
Replacement 50kV poles	Asset Replacement and Renewal	Network Wide	\$6.3 million	RY24-RY33
11kV Replacement 50 poles (fault & premature failure)	Asset Replacement and Renewal	Network Wide	\$5.8 million	RY24-RY33
Replace 11kV SWGR Tokomaru Bay, Matawhero, Kaiti, Kiwi & Parkinson	Asset Replacement and Renewal	Gisborne	\$3.3 million	RY24-RY33
Conductor replacement	Asset Replacement and Renewal	Gisborne	\$3.1 million	RY24-RY33
Wairoa Reconfiguration	System Growth	Wairoa	\$3.1 million	RY25-RY33
New Generators - Security of Supply - 780kVA	Reliability, Safety and Environment	Network Wide	\$3 million	RY25-RY29

Company Name	<u>Firstlight Network Limited</u>
For Year Ended	<u>31 March 2024</u>

Schedule 14 Mandatory Explanatory Notes

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

1. This schedule requires EDBs to provide explanatory notes to information provided in accordance with clauses 2.3.1, 2.4.21, 2.4.22, and subclauses 2.5.1(1)(f), and 2.5.2(1)(e).
2. This schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. Information provided in boxes 1 to 11 of this schedule is part of the audited disclosure information, and so is subject to the assurance requirements specified in section 2.8.
3. Schedule 15 (Voluntary Explanatory Notes to Schedules) provides for EDBs to give additional explanation of disclosed information should they elect to do so.

Return on Investment (Schedule 2)

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

Box 1: Explanatory comment on return on investment

In RY2024, the vanilla ROI was 5.28%. This is below the ROI of 8.27% reported for RY2023. This decrease in ROI is primarily due to a decrease in Assets Commissioned compared with RY2024. Reclassified items are noted in box 10 below and have no impact on ROI.

In RY2023, the mid-point estimate of vanilla and post tax WACC values were incorrect. Correct values included in RY2024 in the CY-1 column.

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

Our regulated profit including financial incentives and wash-ups for the year is \$10.4m which is a 31% decrease compared to regulated profit in FY23. The \$4.6m decrease is attributable to a \$2.05m increase in operational expenditure, \$4.08m decrease in revaluation, and \$795k increase in depreciation.

Material items included in other regulated income were electricity sales income from gensets, LCE rebate processing fee, vehicle lease, compensation receipts and new connections fees.

Reclassified items are noted in box 10 below and have no impact on regulated profit.

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 merger or acquisition expenditure during the year.

Value of the Regulatory Asset Base (Schedule 4)

7. In the box below, comment on the value of the regulatory asset base (rolled forward) in Schedule 4. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 4: Explanatory comment on the value of the regulatory asset based (rolled forward)

The RAB has increased from \$209.4m to \$222.6m, an increase of 6.3%. Assets commissioned in RY24 of \$12.6m was 22% lower than RY23 of \$16.08m due largely to the capital remedial works required as a result of Cyclones Hale and Gabrielle in January and February 2023 respectively. Carry over WIP was also higher than RY23 and coupled with underspend in system growth were the main drivers of the reduced value of assets commissioned in RY24. The CPI adjustment of 4.02% in RY24 was also considerably lower than that of 6.65% in RY23.

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

There was a immaterial permanent difference for entertainment expenses.

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

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

Box 6: Tax effect of other temporary differences (current disclosure year)

The amounts are immaterial.

Cost allocation (Schedule 5d)

10. In the box below, comment on cost allocation as disclosed in Schedule 5d. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 7: Cost allocation

Reclassified items are noted in box 10 below.

Asset allocation (Schedule 5e)

11. In the box below, comment on asset allocation as disclosed in Schedule 5e. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 8: Commentary on asset allocation

No asset allocation has been applied and items reclassified.

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

12.2 information on reclassified items in accordance with subclause 2.7.1.

Box 9: Explanation of capital expenditure for the disclosure year

Capital expenditure is focused on asset replacement and renewal to maintain the network by replacing aging assets and contributed \$12.4m of total expenditure of \$14.2m or 87%. Non-network expenditure of \$1.01m included some one-off transitional costs as Firstlight was acquired by Clarus (formerly Firstgas Group) on 31 March 2023. System Growth projects were 90% under forecast pending scopes of work being completed and landowner consents.

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

- Red tag poles accelerated replacement project
- 11kV pole replacements in Gisborne and Wairoa regions
- Cyclone Gabrielle restorative and remedial work
- Subtransmission grillage and foundations replacements
- Conductor replacements Gisborne and Wairoa regions

There is no materiality threshold applied to the schedule

There are no items reclassified during the year.

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

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

- 13.2 Information on reclassified items in accordance with subclause 2.7.1(2);
- 13.3 Commentary on any material atypical expenditure included in operational expenditure disclosed in Schedule 6b, a including the value of the expenditure the purpose of the expenditure, and the operational expenditure categories the expenditure relates to.

Box 10: Explanation of operational expenditure for the disclosure year

Operational expenditure is broken down to Network opex relating to network maintenance (\$7.5m) and non-network opex supporting the business operations (\$7.5m).

Network opex consists of four standard categories: Asset replacement and renewal, service interruptions and emergencies, vegetation management and routine and corrective maintenance and inspection.

The major component of asset replacement and renewal expenditure is the avoided cost of distribution charges paid to Eastland Generation Limited. This provides network security in the form of distributed generation from Waihi Hydro and avoids electricity distribution capital expenditure due to the provision of alternate security services.

Service interruptions and emergencies expenditure was 13% or \$330k above target for RY24. The region was once again heavily affected by adverse weather conditions, and this resulted in overspend in service interruptions.

Non-network opex expenditure of \$7.5m was comprised of \$2.8m on system operations and network support (SONS) and business support costs of \$4.7m. Business support costs were \$676k over budget. The main drivers of this overspend were the reclassification of software/licence costs and telecommunication costs coupled with one-off transition and payroll payments. Overspends to budget on consultancy fees, marketing/communication fees and audit fees. These overspends were partially offset by a reduction in business support management fee as this is now split between business support and network support. SONS expenditure was \$528k over budget. As noted above, management fee is now split between the business support and network operational components and this along with overspends in payroll and travel costs were largely attributable to overspend on budget. Offsets were treatment of software and licencing fees that had historically been included as SONS costs but have been reclassified as deemed more appropriate to be classed as business support along with telecommunication costs.

Variance between forecast and actual expenditure (Schedule 7)

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

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

CAPITAL EXPENDITURE

Customer Connections variance (-\$111k)

This variance relates to an underspend on low voltage switchgear allowance for new installations.

System Growth variances (-\$1,150k)

The main drivers of underspend were the Mahia extension project that has been put on hold pending scopes of work and landowner consents, progress on thermal upgrade has been impacted by supply chain issues and second injection point Gisborne project has also been on hold pending further investigations at to best options.

Asset Replacement and Renewal variances (-\$209k)

Asset replacement and renewal expenditure was within 2% of budget. Underspends in distribution switchgear and other network assets primarily being deferment of lock upgrade project were offset by overspends in transformer replacements.

Reliability, Safety and Environment +\$92k

Overspends were observed in 11kV field recloser automation plan, SCADA rural automation, protection relay installations offset partially by underspends in Zone Sub sepa unit replacements.

Asset Relocations (-\$51k)

\$51k was set aside based on historical averages. Expenditure in any year could vary materially

Non- network Assets +699k

This variance relates primarily to transition setup costs including Maximo & GIS software, two vehicle replacements and Carnarvon Street Office refurbishment.

OPERATIONAL EXPENDITURE

Asset Replacement & Renewal (-\$333k)

Asset Replacement and Renewal underspent by \$333k or 39%. Underspends on budget included 110kV Zone Substation maintenance (-\$50k), 400V OH Service Fuse Base & Carrier replacement (-\$48k), TX Earthing system repairs (-\$42k) and comms maintenance/calibration (-\$42k).

Routine & Corrective Maintenance & Inspection (-\$884k)

Costs in this area were underspent to budget by 29%. This was primarily due to underspends in 11kV patrols and general maintenance (-\$270k), general unscheduled tower/line repairs (-\$117k), 110kV inspections and routine maintenance (-\$102k) and zone sub repairs (-\$87k).

Service Interruption & Emergencies +\$330k

2024 again saw a number of adverse weather events causing damage to the Network and as a result saw an overspend in this category. The main drivers of the overspend were observed in 11kV defect fault repairs (+251k), 400V fault repairs (+\$264k).

Vegetation Management +\$193

The introduction of timewriting to opex in RY24 saw a large increase on initial calculations and this resulted in a \$345k variance to budget. This was partially offset by a \$138k underspend in tree control program North.

System Operations & Network Support Costs +528k

The main drivers of overspend to budget were payroll, management fees and travel costs. The composition of the management fee is now broken down and reported as business support and SONS costs where historically it has been budgeted for as a business support cost. These overspends were offset by reallocation of software/licence fees and telecommunication costs to business support, these costs have historically been budgeted for as SONS costs.

Business Support Costs +\$676k

Business support overspends were largely attributable to reclassification of software/licence fees, payroll costs, consultancy fees, audit fees and one-off transition costs.

Information relating to revenues and quantities for the disclosure year

15. In the box below provide-

15.1 a comparison of the target revenue disclosed before the start of the disclosure year, in accordance with clause 2.4.1 and subclause 2.4.3(3) to

total billed line charge revenue for the disclosure year, as disclosed in Schedule 8; and

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

<p>Box 12: Explanatory comment relating to revenue for the disclosure year There is no material difference between target and actual revenue.</p>
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Network Reliability for the Disclosure Year (Schedule 10)

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

Box 13: Commentary on network reliability for the disclosure year

Weather events		
Financial year	Events	% change
RY20	14	
RY21	27	93%
RY22	32	19%
RY23	44	38%
RY24	38	-14%

**RY23 witnessed 35 weather event days excluding 9 weather days in cyclone Gabrielle*

Gisborne and Wairoa have seen a significant rise in weather events in recent years. Compared to the RY22, the number of weather events days increased by 38% in RY23. This trend continued in RY24, with a 9% increase. (excluding Cyclone Gabrielle weather event days in RY23).

These intensified weather events have led to several challenges for Firstlight Network. SAIDI increased by 4% compared to RY23. The number of outages also rose by 13%, outages lasting longer than 3 hours increased by 19%. Limited access to fault locations due to adverse weather conditions was a major factor in these extended outages.

Slips caused by adverse environment have increased by 167% compared to RY23 which were responsible for 46 outages in RY24, contributing significantly to both SAIDI and the number of extreme weather days. Defective equipment was the leading cause of the outages in RY24, accounting for 26%, followed by Adverse environment contributing to 21%, followed by vegetation contributing 19% of the total SAIDI.

Note- RY23 figures exclude Cyclone Gabrielle, as it's a rare 1 in 550-year event

The data stated in this year's Schedule 10 is consistent with how Firstlight has been treating SAIDI and SAIFI in the past and as in the past SAIDI and SAIFI calculations for Information Disclosures uses a different way of normalising customer minutes leading to different reported SAIDI and SAIFI to those in Annual Compliance Statement.

The information provided in Schedule 10 has been derived from the records kept by the control room. These processes follow Firstlight Outage Data Recording Procedures contained in our Quality Standards Manuals and are typical of industry control room procedures. There are inherent limitations in the ability to collect and record the network reliability information to be disclosed in Schedule 10(i) to 10(iv). Consequently, there is no independent evidence available to support the accuracy and completeness of recorded faults, and Firstlight has limited control over the accuracy and completeness of installation control point (ICP) data included in the SAIDI and SAIFI calculations.

Insurance cover

17. In the box below, provide details of any insurance cover for the assets used to provide electricity distribution services, including-
- 17.1 The EDB's approaches and practices in regard to the insurance of assets used to provide electricity distribution services, including the level of insurance;
- 17.2 In respect of any self-insurance, the level of reserves, details of how reserves are managed and invested, and details of any reinsurance.

Box 14: Explanation of insurance cover

Network assets such as the substation buildings, zone sub transformers and switchgear, SCADA, other communications equipment excluding fibre-optic cables are insured but lines, poles and cables are not. These assets are insured for replacement cost to a maximum of \$79 million.

Firstlight Network Limited has no self-insurance cover.

Amendments to previously disclosed information

18. In the box below, provide information about amendments to previously disclosed information disclosed in accordance with clause 2.12.1 in the last 7 years, including:
- 18.1 a description of each error; and
- 18.2 for each error, reference to the web address where the disclosure made in accordance with clause 2.12.1 is publicly disclosed.

Box 15: Disclosure of amendment to previously disclosed information

There were no amendments to the previously disclosed information.

Company Name Firstlight Network Limited

For Year Ended 31 March 2024

Schedule 14a Mandatory Explanatory Notes on Forecast Information

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

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.
2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

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

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

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

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

Company Name Firstlight Network Limited

For Year Ended 31 March 2024

Schedule 15 Voluntary Explanatory Notes

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

1. This schedule enables EDBs to provide, should they wish to-
 - 1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1 and 2.5.2.
 - 1.2 information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.
2. Information in this schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.
3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Unallocated RAB disposals to a related party are made up of investment properties that were sold to Eastland Investment Property Limited.

In 2021 a private binding ruling relating to depreciation was obtained. In March 2024, Inland Revenue provided clarification on the application of the binding ruling that was in place in the prior period. This has resulted in high tax depreciation in schedule 5a.

Regulatory depreciation in schedule 4a has been split between standard and no standard life assets in RY24. Total depreciation has all been disclosed as standard depreciation historically.



Independent Assurance Report

To the Directors of Firstlight Network Limited and the Commerce Commission

Assurance report pursuant to the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC 2

We have undertaken a reasonable assurance engagement in respect of the compliance of Firstlight Network Limited (the “Company”) with the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC 2, (the “Determination”) for the disclosure year ended 31 March 2024 where we are required to opine on:

- whether the Company has complied, in all material respects, with the Determination, in preparing the information disclosed under schedules 1 to 4, 5a to 5g, 6a and 6b, 7, 10, the related party transactions disclosed in Appendix A, and the explanatory notes disclosed in boxes 1 to 11 in Schedule 14 (the ‘Disclosure Information’); and
- whether the Company’s basis for valuation of related party transactions (‘valuation of related party transactions’), has complied, in all material respects, with clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 23 April 2024) (“the IM Determination”).

Qualified Opinion

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

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

Basis for Qualified Opinion

As describe in Box 13 of Schedule 14, there are inherent limitations in the ability of the Company to collect and record the network reliability information specifically the installation control points (“ICPs”) affected by an interruption and the duration of the interruption used in calculating the amounts required to be disclosed in Schedule 10(i) to 10(iv). Consequently, there is no independent evidence available to support the accuracy and completeness of the ICPs affected and duration of an interruption. Controls over the accuracy and completeness of ICPs and interruption data included in the SAIDI and SAIFI outage statistics are limited throughout the year.

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

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



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

We believe the evidence we have obtained is sufficient and appropriate to provide a basis for our qualified opinion.

Our assurance approach

Overview

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

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

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

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

We have determined that there are two key assurance matters:

- Regulatory Asset Base
- Related Party Transactions.

Materiality

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

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

Scope

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

These procedures have been undertaken to form an opinion as to whether the Company has complied, in all material respects, with the Determination in the preparation of the Disclosure Information for the year ended 31 March 2024, and whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.



Key Assurance Matters

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

Key Assurance Matter	How our procedures addressed the key assurance matter
<p>Regulatory Asset Base</p> <p>The Regulatory Asset Base (RAB), as set out in Schedule 4, reflects the value of the Firstlight Network Limited’s electricity distribution assets. These are valued using an indexed historic cost methodology prescribed by the Determination. It is a measure which is used widely and is key to measuring the Firstlight Network Limited’s return on investment and therefore important when monitoring financial performance or setting electricity distribution prices.</p> <p>The RAB inputs, as set out in the IM Determination, are similar to those used in the measurement of fixed assets in the financial statements, however, there are a number of different requirements and complexities which require careful consideration.</p> <p>Due to the importance of the RAB within the regulatory regime, the incentives to overstate the RAB value, and complexities within the regulations, we have considered it to be a key area of focus.</p>	<p>We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Determination and the IM Determination.</p> <p>Our procedures over the regulatory asset base included the following:</p> <p>Assets commissioned</p> <ul style="list-style-type: none"> • We inspected the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the Determination, which are required to be removed from the RAB; • We reconciled the assets commissioned, as per the regulatory fixed asset register, to the asset additions disclosed in the audited annual financial statements and investigated any material reconciling items; and • We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification. <p>Depreciation</p> <ul style="list-style-type: none"> • For assets with no standard asset lives we assessed the reasonableness of the lives used by reference to the accounting depreciation rates used in preparing the financial statements; • We compared the spreadsheet formula utilised to calculate regulatory depreciation expense with IM Determination clause 2.2.5; and • We compared the standard asset lives by asset category to those set out in the IM Determination. <p>Revaluation</p> <ul style="list-style-type: none"> • We recalculated the revaluation rate set out in the IM Determination using the relevant Consumer Price Index indices taken from the Statistics New Zealand website; and • We tested the mathematical accuracy of the revaluation calculation performed by management.



Key Assurance Matter	How our procedures addressed the key assurance matter
<p>Related party transactions</p> <p>Disclosures over related party transactions including related party relationships, procurement policies/processes, application of these policies/processes and examples of market testing of transaction terms as required under the Determination and the IM Determination are set out in Appendix A.</p> <p>The Determination and the IM Determination require the Company to value its transactions with related parties, disclosed in Schedule 5b, in accordance with the principles-based approach to the arm's length valuation rule. This rule states that the value of goods or services acquired from a related party cannot be greater than if it had been acquired under the terms of an arm's length transaction with an unrelated party, nor may it exceed the actual cost to the related party. A sale or supply to a related party cannot be valued at an amount less than if it had been sold or supplied under the terms of an arm's-length transaction with an unrelated party.</p> <p>Arm's-length valuation, as defined in the IM Determination, is the value at which a transaction, with the same terms and conditions, would be entered into between a willing seller and a willing buyer who are unrelated and who are acting independently of each other and pursuing their own best interests.</p> <p>Firstlight Network Limited is required to use an objective and independent measure to demonstrate compliance with the arm's-length principle. In the absence of an active market for similar transactions, assigning an objective arm's</p>	<p>Disposals</p> <ul style="list-style-type: none"> We considered the nature of the asset disposals within the accounting fixed asset register and tested a sample of RAB disposals to ensure disposals in the RAB meet the definition of a disposal per the IM Determination. <p>We have obtained an understanding of the compliance requirements relevant to related party transactions as set out in the Determination and the IM Determination. We have ensured Schedule 5(b) and Appendix A includes all required disclosures including current procurement policies, descriptions of how they are applied in practice, representative example transactions and when and how market testing was last performed.</p> <p>Our procedures over the related party transactions included the following:</p> <p>Completeness and accuracy of related party relationships and transactions</p> <p>We have tested the completeness and accuracy of the related party relationships and transactions by:</p> <ul style="list-style-type: none"> Agreeing the disclosures within Schedule 5(b) to the underlying financial records for the year ended 31 March 2024, investigating any material differences and determining whether any such differences are justified; and Applying our understanding of the business structure against the related party definition in IM Determination clause 1.1.4(2)(b) to assess management's identification of any "unregulated parts" of the entity. <p>Practical application of procurement policies</p> <ul style="list-style-type: none"> Testing a sample of operating expenditure and capital expenditure transactions disclosed in Schedule 5(b) by inspecting supporting documentation to determine compliance with the disclosed procurement policy and practices. <p>Arm's length valuation rule</p> <p>We obtained Firstlight Network Limited's assessment of available independent and objective measures used in supporting the arm's length valuation principal and performed the following procedures:</p> <p>Obtained the report from the management's expert and for a sample:</p> <ul style="list-style-type: none"> Evaluated the accuracy of the quoted amounts used by the management's expert to perform the



Key Assurance Matter	How our procedures addressed the key assurance matter
<p>length value to a related party transaction is difficult and requires significant judgement.</p> <p>Management appointed a management expert to assist with benchmarking certain classes of expenditure to demonstrate compliance with the arm's-length principle.</p> <p>We have identified related party transactions at arm's-length as a key assurance matter due to the judgement involved</p>	<p>benchmarking by agreeing it to the related party quote;</p> <ul style="list-style-type: none"> • Evaluated the accuracy of the benchmark amount by agreeing the value in the report to the underlying management's expert's workbooks; • Evaluated management's assessment of the management's expert's output; and • Assessed whether the related party transaction values fell within an acceptable range. Qualitative factors were considered in determining the appropriate acceptable range. <p>For expenditure classes not included in the management expert's report, we have:</p> <ul style="list-style-type: none"> • Reperformed the calculations and agreed key inputs and assumptions to supporting documentation; and • Where benchmarking or other market information was used as independent and objective measures, we assessed whether the related party transaction values fell within a reasonable range. Qualitative factors were considered in determining the appropriate acceptable range.

Directors' Responsibilities

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

Our Independence and Quality Management

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

We apply Professional and Ethical Standard 3 *Quality Management for Firms that Perform Audits or Reviews of Financial Statements, or Other Assurance or Related Services Engagements*, which requires our firm to design, implement and operate a system of quality management including policies or procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

We are independent of the Company. Our firm carries out other services for the Company in the areas of compliance with the Electricity Distribution Default Price-Quality Path Determination 2020, independent appraiser of related party transactions, other assurance around compliance with Commerce Act requirements and our capacity as auditors. The provision of these other services has not impaired our independence.



Assurance Practitioner's responsibilities

Our responsibility is to express an opinion on whether the Company has complied, in all material respects, with the Determination in the preparation of the Disclosure Information for the disclosure year ended 31 March 2024 and on whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

Our engagement has been conducted in accordance with ISAE (NZ) 3000 (Revised) and SAE 3100 (Revised) which require that we plan and perform our procedures to obtain reasonable assurance about whether the Company has complied in all material respects with the Determination in the preparation of the Disclosure Information for the disclosure year ended 31 March 2024, and whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

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

Inherent Limitations

Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error or non-compliance may occur and not be detected. A reasonable assurance engagement for the disclosure year ended 31 March 2024 does not provide assurance on whether compliance with the Determination and the IM Determination will continue in the future.

Use of Report

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

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

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

A handwritten signature in black ink that reads 'Price Waterhouse Coopers'.

Chartered Accountants
30 August 2024

Christchurch, New Zealand