COMMERCE COMMISSION
NEW ZEALAND

EDB Information Disclosure Requirements
Information Templates

Schedules 1–10
excluding 5f–5h

Company Name	MainPower New Zealand
Disclosure Date	31 August 2026
Disclosure Year (year ended)	31 March 2026

Templates for Schedules 1–10 excluding 5f–5h
Prepared 2 June 2026

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Disclosure Template Instructions

This document forms Schedules 1–10 to the Electricity Distribution Information Disclosure (Non-material) Amendment Determination 2026 [2026] NZCC 21.

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, as amended.

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 in the subnetwork box at the top of the sheet.

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

Cell colouring

1. White: Data entry
2. **Yellow: Formula/Blank/Empty columns**
3. Dark grey: Blank/Empty columns

Note: The template for the new Schedule 3a is in a new layout to improve data entry and processing. These schedules follow the same colour formatting as other schedules, with white cells requiring data entry.

Company Name	**MainPower New Zealand**
For Year Ended	**31 March 2026**

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

sch ref		Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
8						
9	**Operational expenditure**	42,838	576	231,105	5,043	42,165
10	Network	15,196	204	81,982	1,789	14,958
11	Non-network	27,641	371	149,122	3,254	27,207
12						
13	**Expenditure on assets**	66,543	894	358,991	7,833	65,497
14	Network	63,290	850	341,443	7,450	62,295
15	Non-network	3,253	44	17,549	383	3,202
16						

17 ## 1(ii): Revenue metrics

sch ref		Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
18			
19	**Total consumer line charge revenue**	124,975	1,679
20	Standard consumer line charge revenue	128,476	1,636
21	Non-standard consumer line charge revenue	61,470	2,001,496
22			

23 ## 1(iii): Service intensity measures

sch ref			
24			
25	Demand density	22	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	118	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
27	Connection point density	9	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
28	Energy intensity	13,438	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*
29			

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

sch ref		($000)	% of revenue
31			
32	Operational expenditure	26,701	33.58%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	12,286	15.45%
34	Total depreciation	17,007	21.39%
35	Total revaluations	10,950	13.77%
36	Regulatory tax allowance	5,847	7.35%
37	Regulatory profit/(loss) including financial incentives and wash-ups	28,623	36.00%
38	**Total regulatory income**	79,514	
39			

40 ## 1(v): Reliability

sch ref			
41			
42	Interruption rate	28.44	*Interruptions per 100 circuit km*

Company Name	**MainPower New Zealand**
For Year Ended	**31 March 2026**

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
ROI – comparable to a post tax WACC	%	%	%
Reflecting all revenue earned	5.29%	4.94%	7.48%
Excluding revenue earned from financial incentives	5.29%	4.94%	7.48%
Excluding revenue earned from financial incentives and wash-ups	5.59%	4.94%	7.48%
Mid-point estimate of post tax WACC	6.05%	6.18%	5.90%
25th percentile estimate	5.37%	5.50%	5.17%
75th percentile estimate	6.73%	6.86%	6.62%
ROI – comparable to a vanilla WACC			
Reflecting all revenue earned	5.99%	5.66%	8.12%
Excluding revenue earned from financial incentives	5.99%	5.66%	8.12%
Excluding revenue earned from financial incentives and wash-ups	5.99%	5.66%	8.12%
WACC rate used to set regulatory price path			
Mid-point estimate of vanilla WACC	6.75%	6.90%	6.53%
25th percentile estimate	6.07%	6.22%	5.81%
75th percentile estimate	7.43%	7.58%	7.26%

2(ii): Information Supporting the ROI

			($000)	
	Total opening RAB value	358,369		
plus	Opening deferred tax	(12,189)		
Opening RIV			346,180	
Line charge revenue			77,898	
	Expenses cash outflow	38,987		
add	Assets commissioned	35,480		
less	Asset disposals	370		
add	Tax payments	3,632		
less	Other regulated income	1,617		
Mid-year net cash outflows			76,113	
Term credit spread differential allowance			–	
	Total closing RAB value	387,355		
less	Adjustment resulting from asset allocation	(67)		
less	Lost and found assets adjustment	–		
plus	Closing deferred tax	(14,404)		
Closing RIV			373,018	
ROI – comparable to a vanilla WACC				8.12%
	Leverage (%)			41%
	Cost of debt assumption (%)			5.56%
	Corporate tax rate (%)			28%
ROI – comparable to a post tax WACC				7.48%

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Company Name	**MainPower New Zealand**
For Year Ended	**31 March 2026**

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).

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

sch ref

2(iii): Information Supporting the Monthly ROI

Opening RIV	N/A

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

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

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

Year-end ROI – comparable to a vanilla WACC	7.87%
Year-end ROI – comparable to a post tax WACC	7.23%

** these year-end ROI values are comparable to the ROI reported in pre 2012 disclosures by EDBs and do not represent the Commission's current view on ROI.*

2(v): Financial Incentives and Wash-Ups

IRIS incentive adjustment			
Purchased assets – avoided transmission charge			
Innovation and non-traditional solutions recovered amount			
Quality incentive adjustment			
Other CPP financial incentives			
Financial incentives		–	
Impact of financial incentives on ROI		–	
Input methodology claw-back			
CPP application recoverable costs			
CPP Urgent project allowance			Not Required before DY
Reopener event allowance			Not Required before DY
Wash-up draw down amount			Not Required before DY
Other CPP wash-ups			
Wash-up costs		–	
Impact of wash-up costs on ROI		–	

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		Company Name	MainPower New Zealand
		For Year Ended	31 March 2026

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		77,898	
10	*plus*	Gains / (losses) on asset disposals		334	
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		1,283	
12					
13		**Total regulatory income**		79,514	
14		**Expenses**			
15	*less*	Operational expenditure		26,701	
16					
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		12,286	
18					
19		**Operating surplus / (deficit)**		40,527	
20					
21	*less*	Total depreciation		17,007	
22					
23	*plus*	Total revaluations		10,950	
24					
25		**Regulatory profit / (loss) before tax**		34,470	
26					
27	*less*	Term credit spread differential allowance		–	
28					
29	*less*	Regulatory tax allowance		5,847	
30					
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		28,623	
32					
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**		**($000)**	
34		**Pass through costs**			
35		Electricity lines service charge payable to Transpower	10,283		Not Required before DY
36		Transpower new investment contract charges	1,270		Not Required before DY
37		System operator services			Not Required before DY
38		Rates	373		
39		Commerce Act levies	62		
40		Industry levies	298		
41		CPP or DPP specified pass-through costs	–		
42		**Recoverable costs excluding financial incentives and wash-ups**			
43		Independent engineer costs			Not Required before DY
44		FENZ levies			Not Required before DY
45		Extended reserves allowance			
46		Other CPP recoverable costs excluding financial incentives and wash-ups			
47		**Pass-through and recoverable costs excluding financial incentives and wash-ups**		12,286	
48					
49		**3(iv): Merger and Acquisition Expenditure**			
50				**($000)**	
51		Merger and acquisition expenditure		–	
52					
53		*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)*			
54		**3(v): Other Disclosures**			
55				**($000)**	
56		Self-insurance allowance		3,381	

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SCHEDULE 3a: REPORT ON INCREMENTAL ROLLING INCENTIVE SCHEME

This schedule requires information on the calculation of IRIS incentive amounts. All non-exempt EDBs must complete this section.

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.

Please note; only the white cells should be filled in (i.e. F7 - J7, F10 - J12, F15 - J17). Forecast values should be filled in for all years, actual values should be filled in for all years where known.

Section	Row	Context	Category1	Category2	RY1	RY2	RY3	RY4	RY5	Total over / (under) spend
3a: Incremental Rolling Incentive Scheme	7		**Current Year**	**Current Year**	CY-2	CY-1	CY	CY+1	CY+2	

Section	Row	Context	Category1	Category2	RY1 ($000)	RY2 ($000)	RY3 ($000)	RY4 ($000)	RY5 ($000)	Total over / (under) spend
3a: Incremental Rolling Incentive Scheme	10		Opex incentive amounts	Forecast opex						
3a: Incremental Rolling Incentive Scheme	11		Opex incentive amounts	Actual opex						
3a: Incremental Rolling Incentive Scheme	12	+	Opex incentive amounts	Plus lease payments						
3a: Incremental Rolling Incentive Scheme	13		Opex incentive amounts	Actual opex for IRIS	-	-	-	-	-	
3a: Incremental Rolling Incentive Scheme	14		Opex incentive amounts	Expenditure variance to opex allowance	-	-	-	-	-	-
3a: Incremental Rolling Incentive Scheme	15		Capex incentive amounts	Forecast aggregate value of commissioned assets						
3a: Incremental Rolling Incentive Scheme	16		Capex incentive amounts	Actual commissioned assets						
3a: Incremental Rolling Incentive Scheme	17	-	Capex incentive amounts	Less right-of-use assets						
3a: Incremental Rolling Incentive Scheme	18		Capex incentive amounts	Actual commissioned assets for IRIS	-	-	-	-	-	
3a: Incremental Rolling Incentive Scheme	19		Capex incentive amounts	Expenditure variance to commissioned assets allowance	-	-	-	-	-	-

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Company Name	**MainPower New Zealand**
For Year Ended	**31 March 2026**

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

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

sch ref

sch ref	4(i): Regulatory Asset Base Value (Rolled Forward)	RAB CY-4 ($000)	RAB CY-3 ($000)	RAB CY-2 ($000)	RAB CY-1 ($000)	RAB CY ($000)
10	**Total opening RAB value**	264,152	289,687	316,293	342,441	358,369
11						
12	*less* **Total depreciation**	14,104	15,184	16,381	17,424	17,007
13						
14	*plus* **Total revaluations**	18,107	19,298	12,564	8,495	10,950
15						
16	*plus* **Assets commissioned**	21,843	22,746	31,341	25,500	35,480
17						
18	*less* **Asset disposals**	224	23	919	537	370
19						
20	*plus* **Lost and found assets adjustment**	–	–	–	–	–
21						
22	*plus* **Adjustment resulting from asset allocation**	(87)	(229)	(457)	(105)	(67)
23						
24	**Total closing RAB value**	289,687	316,293	342,441	358,369	387,355
25						

sch ref	4(ii): Unallocated Regulatory Asset Base		Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
29	**Total opening RAB value**			364,682		358,369
30	*less*					
31	**Total depreciation**			17,007		17,007
32	*plus*					
33	**Total revaluations**			11,144		10,950
34	*plus*					
35	Assets commissioned out of WUC	Not Required before DY2026	34,731		34,731	
36	Assets acquired (other than below)	Not Required before DY2026	749		749	
37	Assets acquired from a regulated supplier					
38	Assets acquired from a related party					
39	**Assets commissioned**			35,480		35,480
40	*less*					
41	Asset disposals (other than below)		370		370	
42	Asset disposals to a regulated supplier					
43	Asset disposals to a related party					
44	**Asset disposals**			370		370
45						
46	*plus* **Lost and found assets adjustment**					
47						
48	*plus* **Adjustment resulting from asset allocation**					(67)
49						
50	**Total closing RAB value**			393,929		387,355

** The 'unallocated RAB' is the total value of those assets used wholly or partially to provide electricity distribution services without any allowance being made for the allocation of costs to services provided by the supplier that are not electricity distribution services. The RAB value represents the value of these assets after applying this cost allocation. Neither value includes works under construction.*

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Company Name	**MainPower New Zealand**
For Year Ended	**31 March 2026**

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

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

sch ref							
52							
53		**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**					
54							
55		CPI_4					1,339
56		CPI_4^{-4}					1,299
57		Revaluation rate (%)					3.08%
58							
59				**Unallocated RAB ***		**RAB**	
60				**($000)**	**($000)**	**($000)**	**($000)**
61		Total opening RAB value		364,682		358,369	
62	*less*	Opening value of fully depreciated, disposed and lost assets		2,780		2,780	
63							
64		Total opening RAB value subject to revaluation		361,902		355,588	
65		**Total revaluations**			11,144		10,950
66							
67		**4(iv): Roll Forward of Works Under Construction**					
68				**Unallocated works under construction**		**Allocated works under construction**	
69		**Works under construction—preceding disclosure year**	Not Required before DY2026		9,895		9,895
70	*plus*	WUC capital expenditure	Not Required before DY2026				
71		WUC acquired from a regulated supplier	Not Required before DY2026	275		275	
72		WUC acquired from a related party	Not Required before DY2026				
73		WUC capital expenditure - other	Not Required before DY2026	41,201		41,201	
74		Total WUC capital expenditure	Not Required before DY2026	41,476		41,476	
75	*less*	WUC capital contributions	Not Required before DY2026	5,364		5,364	
76	*less*	WUC other revenue	Not Required before DY2026				
77	*less*	Assets commissioned out of WUC	Not Required before DY2026	34,731		34,731	
78	*plus*	Adjustment resulting from asset allocation	Not Required before DY2026				
79		**Works under construction - current disclosure year**	Not Required before DY2026		11,277		11,277
80							
81		Highest rate of capitalised finance applied					
82							

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Company Name	**MainPower New Zealand**
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SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.

EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

83 4(v): Regulatory Depreciation

sch ref		Unallocated RAB *		RAB	
85		($000)	($000)	($000)	($000)
86	Depreciation - standard	13,109		13,109	
87	Depreciation - no standard life assets	3,898		3,898	
88	Depreciation - modified life assets				
89	Depreciation - alternative depreciation in accordance with CPP				
90	**Total depreciation**		17,007		17,007
91					

92 4(vi): Disclosure of Changes to Depreciation Profiles

($000 unless otherwise specified)

sch ref	Asset or assets with changes to depreciation*	Reason for non-standard depreciation (text entry)	Depreciation charge for the period (RAB)	Closing RAB value under 'non-standard' depreciation	Closing RAB value under 'standard' depreciation
94					
95					
96					
97					
98					
99					
100					
101					

102 ** include additional rows if needed*

103 4(vii): Disclosure by Asset Category

104 **($000 unless otherwise specified)**

sch ref			Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
106		**Total opening RAB value**	20,521	1,581	48,804	79,478	78,678	52,422	26,285	14,476	36,123	358,369
107	*less*	Total depreciation	523	48	1,625	3,401	3,485	2,344	1,043	639	3,898	17,007
108	*plus*	Total revaluations	632	49	1,502	2,420	2,423	1,609	809	444	1,062	10,950
109	*plus*	Assets commissioned	6,126	–	7,206	8,788	4,784	2,340	1,797	2,662	1,777	35,480
110	*less*	Asset disposals	–	–	–	–	–	–	–	–	370	370
111	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
112	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	(5)	(62)	(67)
113	*plus*	Asset category transfers										–
114		**Total closing RAB value**	26,756	1,581	55,888	87,284	82,399	54,027	27,849	16,938	34,633	387,355
115												
116		**Asset Life**										
117		Weighted average remaining asset life	44.1	33.4	40.2	38.4	32.2	33.4	31.0	34.6	20.4	(years)
118		Weighted average expected total asset life	53.0	45.4	52.5	47.6	46.9	47.4	41.3	39.3	26.4	(years)

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for
Identification

Company Name	**MainPower New Zealand**
For Year Ended	**31 March 2026**

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 2.8

sch ref					
7	**5a(i): Regulatory Tax Allowance**				**($000)**
8		**Regulatory profit / (loss) before tax**			34,470
9					
10	*plus*	Income not included in regulatory profit / (loss) before tax but taxable	–	*	
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible	–	*	
12		Amortisation of initial differences in asset values	1,048		
13		Amortisation of revaluations	3,995		
14		**Total**			5,043
15					
16	*less*	Total revaluations	10,950		
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	7,681		
21		**Total**			18,630
22					
23		**Regulatory taxable income**			20,883
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			20,883
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			5,847
30					
31	*	Workings to be provided in Schedule 14			
32	**5a(ii): Disclosure of Permanent Differences**				
33		In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i).			
34	**5a(iii): Amortisation of Initial Difference in Asset Values**				**($000)**
35					
36		Opening unamortised initial differences in asset values	5,262		
37	*less*	Amortisation of initial differences in asset values	1,048		
38	*plus*	Adjustment for unamortised initial differences in assets acquired			
39	*less*	Adjustment for unamortised initial differences in assets disposed			
40		Closing unamortised initial differences in asset values			4,214
41					
42		Opening weighted average remaining useful life of relevant assets (years)			5
43					

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Company Name	**MainPower New Zealand**
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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref				
44	**5a(iv): Amortisation of Revaluations**			**($000)**
45				
46		Opening sum of RAB values without revaluations	282,891	
47				
48		Adjusted depreciation	13,012	
49		Total depreciation	17,007	
50		Amortisation of revaluations		3,995
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**	(12,189)	
61				
62	*plus*	Tax effect of adjusted depreciation	3,643	
63				
64	*less*	Tax effect of tax depreciation	5,555	
65				
66	*plus*	Tax effect of other temporary differences*	(45)	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	294	
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	(17)	
73				
74	*plus*	Deferred tax cost allocation adjustment	19	
75				
76		**Closing deferred tax**		(14,404)
77				
78	**5a(vii): Disclosure of Temporary Differences**			
79		*In Schedule 14, Box 6, provide descriptions and workings of items recorded in the asterisked category in Schedule 5a(vi) (Tax effect of other temporary differences).*		
80				
81	**5a(viii): Regulatory Tax Asset Base Roll-Forward**			
82				**($000)**
83		**Opening sum of regulatory tax asset values**	299,144	
84	*less*	Tax depreciation	19,840	
85	*plus*	Regulatory tax asset value of assets commissioned	38,118	
86	*less*	Regulatory tax asset value of asset disposals	309	
87	*plus*	Lost and found assets adjustment	–	
88	*plus*	Adjustment resulting from asset allocation	–	
89	*plus*	Other adjustments to the RAB tax value	–	
90		**Closing sum of regulatory tax asset values**		317,113

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Company Name	**MainPower New Zealand**
For Year Ended	**31 March 2026**

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

sch ref		($000)	($000)
7	**5b(i): Summary—Related Party Transactions**		
8	**Total regulatory income**		
9			
10	**Market value of asset disposals**		
11			
12	Service interruptions and emergencies	–	
13	Vegetation management	–	
14	Routine and corrective maintenance and inspection	–	
15	Asset replacement and renewal (opex)	552	
16	**Network opex**		552
17	Business support	2,948	
18	System operations and network support	–	
19	Non-network solutions provided by a related party or third party	–	
20	**Operational expenditure**		3,500
21	Consumer connection	–	
22	System growth	–	
23	Asset replacement and renewal (capex)	–	
24	Asset relocations	–	
25	Quality of supply	–	
26	Legislative and regulatory	–	
27	Other reliability, safety and environment	–	
28	**Expenditure on non-network assets**		–
29	**Expenditure on assets**		–
30	Cost of financing		
31	Value of capital contributions		
32	Value of vested assets		
33	**Capital Expenditure**		–
34	**Total expenditure**		3,500
35			
36	**Other related party transactions**		

37 **5b(iii): Total Opex and Capex Related Party Transactions**

sch ref	Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
39	Board Fees	Business support	426
40	Key Mangement Personnel	Business support	2,522
41	Hiko Power Engineering Limited	Asset replacement and renewal (opex)	552
42		[Select one]	
43		[Select one]	
44		[Select one]	
45		[Select one]	
46		[Select one]	
47		[Select one]	
48		[Select one]	
49		[Select one]	
50		[Select one]	
51		[Select one]	
52		[Select one]	
53		[Select one]	
54	Total value of related party transactions		3,500
55	** include additional rows if needed*		

Company Name	**MainPower New Zealand**
For Year Ended	**31 March 2026**

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

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
Total						–	–	–

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

Gross term credit spread differential		–
Total book value of interest bearing debt		
Leverage	41%	
Average opening and closing RAB values		
Attribution Rate (%)		–
Term credit spread differential allowance		–

	Company Name	**MainPower New Zealand**
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SCHEDULE 5d: REPORT ON COST ALLOCATIONS

This schedule provides information on the allocation of operational costs. EDBs must provide explanatory comment on their cost allocation in Schedule 14 (Mandatory Explanatory Notes), including on the impact of any reclassifications.

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

sch ref

7	**5d(i): Operating Cost Allocations**					
8			**Value allocated ($000s)**			
9		**Arm's length deduction**	**Electricity distribution services**	**Non-electricity distribution services**	**Total**	**OVABAA allocation increase ($000s)**
10	**Service interruptions and emergencies**					
11	Directly attributable		2,233			
12	Not directly attributable				–	
13	**Total attributable to regulated service**		2,233			
14	**Vegetation management**					
15	Directly attributable		1,784			
16	Not directly attributable				–	
17	**Total attributable to regulated service**		1,784			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		5,454			
20	Not directly attributable				–	
21	**Total attributable to regulated service**		5,454			
22	**Asset replacement and renewal**					
23	Directly attributable					
24	Not directly attributable				–	
25	**Total attributable to regulated service**		–			
26	**Non-network solutions provided by a related party or third party**					
27	Directly attributable					
28	Not directly attributable				–	
29	**Total attributable to regulated service**		–			
30	**System operations and network support**					
31	Directly attributable		8,226			
32	Not directly attributable		3,990	2,078	6,068	
33	**Total attributable to regulated service**		12,217			
34	**Business support**					
35	Directly attributable		2,396			
36	Not directly attributable		2,617	770	3,386	
37	**Total attributable to regulated service**		5,012			
38						
39	**Operating costs directly attributable**		20,094			
40	**Operating costs not directly attributable**	–	6,607	2,847	9,454	–
41	**Operational expenditure**		26,701			
42						

Company Name	MainPower New Zealand
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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**	
44	**Pass through and recoverable costs**	**($000)**
45	**Pass through costs**	
46	Directly attributable	734
47	Not directly attributable	
48	**Total attributable to regulated service**	734
49	**Recoverable costs**	
50	Directly attributable	11,553
51	Not directly attributable	
52	**Total attributable to regulated service**	11,553
53		

sch ref				
54	**5d(iii): Changes in Cost Allocations* †**			
55			**($000)**	
56	**Change in cost allocation 1**		**CY-1**	**Current Year (CY)**
57	Cost category	Original allocation		
58	Original allocator or line items	New allocation		
59	New allocator or line items	Difference	–	–
60				
61	Rationale for change			
62				
63				
64			**($000)**	
65	**Change in cost allocation 2**		**CY-1**	**Current Year (CY)**
66	Cost category	Original allocation		
67	Original allocator or line items	New allocation		
68	New allocator or line items	Difference	–	–
69				
70	Rationale for change			
71				
72				
73			**($000)**	
74	**Change in cost allocation 3**		**CY-1**	**Current Year (CY)**
75	Cost category	Original allocation		
76	Original allocator or line items	New allocation		
77	New allocator or line items	Difference	–	–
78				
79	Rationale for change			
80				
81				

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*

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Company Name	**MainPower New Zealand**
For Year Ended	**31 March 2026**

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		
7	**5e(i): Regulated Service Asset Values**	
8		**Value allocated ($000s)**
9		**Electricity distribution services**
10	**Subtransmission lines**	
11	Directly attributable	26,756
12	Not directly attributable	
13	**Total attributable to regulated service**	26,756
14	**Subtransmission cables**	
15	Directly attributable	1,581
16	Not directly attributable	
17	**Total attributable to regulated service**	1,581
18	**Zone substations**	
19	Directly attributable	55,888
20	Not directly attributable	
21	**Total attributable to regulated service**	55,888
22	**Distribution and LV lines**	
23	Directly attributable	87,284
24	Not directly attributable	
25	**Total attributable to regulated service**	87,284
26	**Distribution and LV cables**	
27	Directly attributable	82,399
28	Not directly attributable	
29	**Total attributable to regulated service**	82,399
30	**Distribution substations and transformers**	
31	Directly attributable	54,027
32	Not directly attributable	
33	**Total attributable to regulated service**	54,027
34	**Distribution switchgear**	
35	Directly attributable	27,849
36	Not directly attributable	
37	**Total attributable to regulated service**	27,849
38	**Other network assets**	
39	Directly attributable	16,938
40	Not directly attributable	
41	**Total attributable to regulated service**	16,938
42	**Non-network assets**	
43	Directly attributable	
44	Not directly attributable	34,633
45	**Total attributable to regulated service**	34,633
46		
47	**Regulated service asset value directly attributable**	352,722
48	**Regulated service asset value not directly attributable**	34,633
49	**Total closing RAB value**	387,355
50		

51	**5e(ii): Changes in Asset Allocations* †**				
52				**($000)**	
53	**Change in asset value allocation 1**			**CY-1**	**Current Year (CY)**
54	Asset category		Original allocation		
55	Original allocator or line items		New allocation		
56	New allocator or line items		Difference	–	–
57					
58	Rationale for change				
59					
60					
61				**($000)**	
62	**Change in asset value allocation 2**			**CY-1**	**Current Year (CY)**
63	Asset category		Original allocation		
64	Original allocator or line items		New allocation		
65	New allocator or line items		Difference	–	–
66					
67	Rationale for change				
68					
69					
70				**($000)**	
71	**Change in asset value allocation 3**			**CY-1**	**Current Year (CY)**
72	Asset category		Original allocation		
73	Original allocator or line items		New allocation		
74	New allocator or line items		Difference	–	–
75					
76	Rationale for change				
77					
78					

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

80 *† include additional rows if needed*

Company Name	**MainPower New Zealand**
For Year Ended	**31 March 2026**

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				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		9,706
9		System growth		15,289
10		Asset replacement and renewal		13,010
11		Asset relocations		–
12		Reliability, safety and environment:		
13		Quality of supply	350	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	1,095	
16		**Total reliability, safety and environment**		1,445
17		**Expenditure on network assets**		39,449
18		Expenditure on non-network assets		2,028
19				
20		**Expenditure on assets**		41,476
21	*plus*	Cost of financing		
22	*less*	Value of capital contributions		5,364
23	*plus*	Value of vested assets		
24				
25		**Capital expenditure**		36,113
26		**6a(ii): Subcomponents of Expenditure on Assets (where known)**		**($000)**
27		Energy efficiency and demand side management, reduction of energy losses		
28		Overhead to underground conversion		
29		Research and development		
31		**6a(iii): Consumer Connection**		
32		*Consumer types defined by EDB**	**($000)**	**($000)**
33		Commercial	725	
34		Council Pumping	1	
35		Generation	301	
36		Irrigation	–	
37		Residential	8,346	
37		Street Lighting	332	
38		** include additional rows if needed*		
39		**Consumer connection expenditure**		9,706
40				
41	*less*	Capital contributions funding consumer connection expenditure	5,039	
42		**Consumer connection less capital contributions**		4,667

43		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset**
44			**System Growth**	**Replacement and Renewal**
45			**($000)**	**($000)**
46		Subtransmission	–	42
47		Zone substations	8,698	298
48		Distribution and LV lines	5,935	8,460
49		Distribution and LV cables	655	951
50		Distribution substations and transformers	–	2,127
51		Distribution switchgear	–	446
52		Other network assets	–	686
53		**System growth and asset replacement and renewal expenditure**	15,289	13,010
54	*less*	Capital contributions funding system growth and asset replacement and renewal	–	325
55		**System growth and asset replacement and renewal less capital contributions**	15,289	12,685
56				

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

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Company Name	MainPower New Zealand
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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)
69				
70	**6a(vi): Quality of Supply**			
71		*Project or programme**	($000)	($000)
72		Reinforcement - Zone substations	–	
73		Reinforcement - Distribution and LV lines	46	
		Reinforcement - Distribution and LV cables	(0)	
		Reinforcement - Other	106	
		Major Projects - Zone substations	197	
		Major Projects - Distribution and LV lines	–	
74		Major Projects - Distribution and LV cables	–	
75		Major Projects - Other	–	
76		[Description of material project or programme]	–	
77		** include additional rows if needed*		
78		All other projects programmes - quality of supply		
79		**Quality of supply expenditure**		350
80	*less*	Capital contributions funding quality of supply		
81		**Quality of supply less capital contributions**		350
82	**6a(vii): Legislative and Regulatory**			
83		*Project or programme**	($000)	($000)
84		[Description of material project or programme]		
85		[Description of material project or programme]		
86		[Description of material project or programme]		
87		[Description of material project or programme]		
88		[Description of material project or programme]		
89		** include additional rows if needed*		
90		All other projects or programmes - legislative and regulatory		
91		**Legislative and regulatory expenditure**		–
92	*less*	Capital contributions funding legislative and regulatory		
93		**Legislative and regulatory less capital contributions**		–
94	**6a(viii): Other Reliability, Safety and Environment**			
95		*Project or programme**	($000)	($000)
96		Reinforcement - Zone substations	26	
		Reinforcement - Distribution and LV lines	209	
		Reinforcement - Other	0	
97		Major Projects - Zone substations	860	
98		Major Projects - Distribution and LV lines	–	
99		Major Projects - Other	–	
100		[Description of material project or programme]	–	
101		** include additional rows if needed*		
102		All other projects or programmes - other reliability, safety and environment		
103		**Other reliability, safety and environment expenditure**		1,095
104	*less*	Capital contributions funding other reliability, safety and environment		
105		**Other reliability, safety and environment less capital contributions**		1,095
106				
107	**6a(ix): Non-Network Assets**			
108	**Routine expenditure**			
109		*Project or programme**	($000)	($000)
110		Freehold Land	6	
111		Buildings	100	
111		Motor Vehicles	36	
111		Office Furniture & Fittings	130	
112		Plant & Equipment	477	
113		Computer Hardware	306	
114		Computer Software	973	
115		** include additional rows if needed*		
116		All other projects or programmes - routine expenditure		
117		**Routine expenditure**		2,028
118	**Atypical expenditure**			
119		*Project or programme**	($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]		

	Company Name	MainPower New Zealand
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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			
125	** include additional rows if needed*		
126	All other projects or programmes - atypical expenditure		
127	**Atypical expenditure**		–
128			
129	**Expenditure on non-network assets**		2,028

Company Name	**MainPower New Zealand**
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SCHEDULE 6b: REPORT ON OPERATIONAL EXPENDITURE FOR THE DISCLOSURE YEAR

This schedule requires a breakdown of operational expenditure incurred in the disclosure year.

EDBs must provide explanatory comment on their operational expenditure in Schedule 14 (Explanatory notes to templates). This includes explanatory comment on any atypical operational expenditure and assets replaced or renewed as part of asset replacement and renewal operational expenditure, and additional information on insurance.

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

sch ref			
7	**6b(i): Operational Expenditure** *Not Required before DY2026*	**($000)**	**($000)**
8	Service interruptions and emergencies:		
9	Vegetation-related	302	
10	Other	1,932	
11	**Total service interruptions and emergencies**	2,233	
12	Vegetation management:		
13	Assessment and notification costs	277	
14	Felling or trimming vegetation - in-zone	549	
15	Felling or trimming vegetation - out-of-zone	495	
16	Other	462	
17	**Total vegetation management**	1,784	
18			
19	Routine and corrective maintenance and inspection:	5,454	
20	Asset replacement and renewal	–	
21	**Network opex**		9,472
22	Non-network solutions provided by a related party or third party	–	
23	System operations and network support	12,217	
24	Business support	5,012	
25	**Non-network opex**		17,229
26			
27	**Operational expenditure**		26,701
28	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
29	Energy efficiency and demand side management, reduction of energy losses		–
30	Direct billing*		–
31	Research and development		–
32	Insurance		960
33	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

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Company Name	**MainPower New Zealand**
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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

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For Year Ended	31 March 2026

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		Target ($000) [1]	Actual ($000)	% variance
7	**7(i): Revenue**			
8	Line charge revenue	81,190	77,898	(4%)

sch ref		Forecast ($000) [2]	Actual ($000)	% variance
9	**7(ii): Expenditure on Assets**			
10	Consumer connection	6,000	9,706	62%
11	System growth	16,330	15,289	(6%)
12	Asset replacement and renewal	13,085	13,010	(1%)
13	Asset relocations	–	–	–
14	Reliability, safety and environment:			
15	Quality of supply	58	350	509%
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	300	1,095	265%
18	**Total reliability, safety and environment**	358	1,445	304%
19	**Expenditure on network assets**	35,772	39,449	10%
20	Expenditure on non-network assets	1,705	2,028	19%
21	Expenditure on assets	37,477	41,476	11%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,200	2,233	86%
24	Vegetation management	1,800	1,784	(1%)
25	Routine and corrective maintenance and inspection	6,692	5,454	(18%)
26	Asset replacement and renewal	–	–	–
27	**Network opex**	9,692	9,472	(2%)
28	Non-network solutions provided by a related party or third party	–	–	–
29	System operations and network support	15,181	12,217	(20%)
30	Business support	8,183	5,012	(39%)
31	**Non-network opex**	23,364	17,229	(26%)
32	**Operational expenditure**	33,056	26,701	(19%)
33	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
34	Energy efficiency and demand side management, reduction of energy losses	–	–	–
35	Overhead to underground conversion	–	–	–
36	Research and development	–	–	–
37				
38	**7(v): Subcomponents of Operational Expenditure (where known)**			
39	Energy efficiency and demand side management, reduction of energy losses	–	–	–
40	Direct billing	–	–	–
41	Research and development	–	–	–
42	Insurance	1,065	960	(10%)
43				

44 *1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of this determination*

45 *2 From the CY+1 nominal dollar expenditure forecasts disclosed in accordance with clause 2.6.6 for the forecast period starting at the beginning of the disclosure year (the second to last disclosure of Schedules 11a and 11b)*

Company Name	MainPower New Zealand
For Year Ended	31 March 2026
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

sch ref

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

sch ref	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)
15	MPCOUNPUMP	Community	Standard	210	13,242
16	MPAILU	Residential	Standard	2,667	14,814
17	MPAISTD	Residential	Standard	3,683	37,680
18	Irrigation MPIRR	Commercial	Standard	1,456	70,814
19	MPLGEUSER	Commercial	Standard	44	58,747
20	Non-Residential MPNONRES	Commercial	Standard	5,892	133,192
21	Residential Low User MPRLU	Residential	Standard	13,939	78,829
22	MPRSTD	Residential	Standard	18,098	178,869
23	Streetlighting MPSTLGT	Commercial	Standard	101	3,443
24	Temporary Supply MPTEMP	Commercial	Standard	293	633
25		[Select one]	[Select one]		
26	at 12/06/2026	Commercial	Standard	–	481
27		[Select one]	[Select one]		
28	ICP's Direct Supply	Commercial	Non-standard	1	32,560
29		[Select one]	[Select one]		
30	Transmission SRAM	All Customers	Standard		
31		[Select one]	[Select one]		
32		[Select one]	[Select one]		
33		[Select one]	[Select one]		
34	*Add extra rows for additional consumer groups or price category codes as necessary*				
35			**Standard consumer totals**	46,383	590,744
36			**Non-standard consumer totals**	1	32,560
37			**Total for all consumers**	46,384	623,304

Billed quantities by price component

sch ref	Consumer group name or price category code	Daily fixed charge - $/day: Distribution billed quantity	Daily fixed charge - $/day: Transmission billed quantity	Other charge [see EDB defined price component below] — Default variable charge - $/kWh: Distribution billed quantity	Default variable charge - $/kWh: Transmission billed quantity	Other charge [see EDB defined price component below] — Hot Water variable charge - $/kWh: Distribution billed quantity	Hot Water variable charge - $/kWh: Transmission billed quantity
15	MPCOUNPUMP	75,127	75,127	13,241,811	13,241,811	–	–
16	MPAILU	973,903	973,903	14,813,649	14,813,649	–	–
17	MPAISTD	1,329,079	1,329,079	37,679,973	37,679,973	–	–
18	Irrigation MPIRR	498,722	498,722	70,813,695	70,813,695	–	–
19	MPLGEUSER	16,060	16,060	58,747,171	58,747,171	–	–
20	Non-Residential MPNONRES	1,933,589	1,933,589	133,184,087	133,184,087	8,297,394	8,297,394
21	Residential Low User MPRLU	5,045,199	5,045,199	78,827,605	78,827,605	65,885,250	65,885,250
22	MPRSTD	6,528,081	6,528,081	178,867,180	178,867,180	141,138,284	141,138,284
23	Streetlighting MPSTLGT	36,564	36,564	3,442,757	3,442,757	–	–
24	Temporary Supply MPTEMP	81,081	81,081	632,764	632,764	–	–
25							
26	at 12/06/2026			481,173	481,173		
27							
28	ICP's Direct Supply						
29							
30	Transmission SRAM						
31							
32							
33							
35	Standard consumer totals	16,517,405	16,517,405	590,731,866	590,731,866	215,320,928	215,320,928
36	Non-standard consumer totals	–	–	–	–	–	–
37	Total for all consumers	16,517,405	16,517,405	590,731,866	590,731,866	215,320,928	215,320,928

sch ref	Consumer group name or price category code	Other charge [see EDB defined price component below] — Night Only variable charge - $/kWh: Distribution billed quantity	Night Only variable charge - $/kWh: Transmission billed quantity	Other charge [see EDB defined price component below] — Miscelleaneous Unmetered non-TOU variable charge - $/kWh: Distribution billed quantity	Miscelleaneous Unmetered non-TOU variable charge - $/kWh: Transmission billed quantity	Other charge [see EDB defined price component below] — Individual contract Total Annual - $/year: Distribution billed quantity	Individual contract Total Annual - $/year: Transmission billed quantity	Other charge [see EDB defined price component below] — Transmission SRAM Pass-Through - $/month by retailer or customer: Distribution billed quantity	Transmission SRAM Pass-Through - $/month by retailer or customer: Transmission billed quantity
15	MPCOUNPUMP	–	–	–	–				
16	MPAILU	–	–	204	204				
17	MPAISTD	–	–	321	321				
18	Irrigation MPIRR	–	–	–	–				
19	MPLGEUSER	–	–	–	–				
20	Non-Residential MPNONRES	–	–	7,847	7,847				
21	Residential Low User MPRLU	661,794	661,794	1,590	1,590				
22	MPRSTD	1,599,273	1,599,273	2,101	2,101				
23	Streetlighting MPSTLGT	–	–	–	–				
24	Temporary Supply MPTEMP	–	–	–	–				
25									
26	at 12/06/2026								
27									
28	ICP's Direct Supply					341,989	1,659,507		
29									
30	Transmission SRAM								–
31									
32									
33									
35	Standard consumer totals	2,261,067	2,261,067	12,063	12,063	–	–	–	–
36	Non-standard consumer totals	–	–	–	–	341,989	1,659,507	–	–
37	Total for all consumers	2,261,067	2,261,067	12,063	12,063	341,989	1,659,507	–	–

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

Company Name	MainPower New Zealand
For Year Ended	31 March 2026
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

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

				Consumer discounts ($000)				
			Standardised price component	Consumer discount - $/day				
			EDB defined price component	Consumer discount - $/day				
Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Total distribution line charge revenue	Total transmission line charge revenue
MPCOUNPUMP	Community	Standard	$966	($0)	–	($0)	$772	$194
MPAILU	Residential	Standard	$2,640	($193)	–	($193)	$2,467	$173
MPAISTD	Residential	Standard	$5,043	($1,237)	–	($1,237)	$4,208	$835
Irrigation MPIRR	Commercial	Standard	$8.997	($285)	–	($285)	$6.350	$2.647
MPLGEUSER	Commercial	Standard	$3,665	($75)	–	($75)	$2,836	$829
Non-Residential MPNONRES	Commercial	Standard	$15.484	($1.137)	–	($1.137)	$13.359	$2.124
Residential Low User MPRLU	Residential	Standard	$14.408	($1.000)	–	($1.000)	$13.486	$922
MPRSTD	Residential	Standard	$25,928	($6,077)	–	($6,077)	$21,826	$4,102
Streetlighting MPSTLGT	Commercial	Standard	$483	($0)	–	($0)	$386	$96
Temporary Supply MPTEMP	Commercial	Standard	$432	$0	–	$0	$345	$87
	[Select one]	[Select one]	–			–	–	–
at 12/06/2026	Commercial	Standard	$21			–	$21	–
	[Select one]	[Select one]	–			–	–	–
ICP's Direct Supply	Commercial	Non-standard	$2.001			–	$342	$1.660
	[Select one]	[Select one]	–			–	–	–
Transmission SRAM	All Customers	Standard	($2.170)			–	–	($2.170)
	[Select one]	[Select one]	–			–	–	–
	[Select one]	[Select one]	–			–	–	–
	[Select one]	[Select one]	–			–	–	–
Add extra rows for additional consumer groups or price category codes as necessary								
		Standard consumer totals	$75,896	($10,005)	–	($10,005)	$66,056	$9,840
		Non-standard consumer totals	$2,001	–	–	–	$342	$1,660
		Total for all consumers	$77,898	($10,005)	–	($10,005)	$66,398	$11,500

Line charge revenues ($000) by price component

Standardised price component	Daily fixed charge - $/day			Other charge [see EDB defined price component below]			Other charge [see EDB defined price component below]		
EDB defined price component				Default variable charge - $/kWh			Hot Water variable charge - $/kWh		
Consumer group name or price category code	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)
MPCOUNPUMP	$492	$194	$686	$280	–	$280	–	–	–
MPAILU	$537	–	$537	$1,930	$173	$2,103	–	–	–
MPAISTD	$3,447	$835	$4,282	$762	–	$762	–	–	–
Irrigation MPIRR	$4.160	$2.647	$6.807	$2.190	–	$2.190	–	–	–
MPLGEUSER	$1,231	$829	$2,059	$1,606	–	$1,606	–	–	–
Non-Residential MPNONRES	$7.724	$2.124	$9.848	$5.936	–	$5.936	($302)	–	($302)
Residential Low User MPRLU	$2.784	–	$2.784	$13.134	$922	$14.057	($2.396)	–	($2.396)
MPRSTD	$16,929	$4,102	$21,031	$10,119	–	$10,119	($5,132)	–	($5,132)
Streetlighting MPSTLGT	$386	$96	$483	–	–	–	–	–	–
Temporary Supply MPTEMP	$345	$87	$432	–	–	–	–	–	–
			–			–			–
at 12/06/2026			–	$21	–	$21			–
			–			–			–
ICP's Direct Supply			–			–			–
			–			–			–
Transmission SRAM			–			–			–
			–			–			–
			–			–			–
			–			–			–
Standard consumer totals	$38,035	$10,915	$48,949	$35,977	$1,096	$37,073	($7,829)	–	($7,829)
Non-standard consumer totals	–	–	–	–	–	–	–	–	–
Total for all consumers	$38,035	$10,915	$48,949	$35,977	$1,096	$37,073	($7,829)	–	($7,829)

Standardised price component	Other charge [see EDB defined price component below]			Other charge [see EDB defined price component below]			Other charge [see EDB defined price component below]			Other charge [see EDB defined price component below]		
EDB defined price component	Night Only variable charge - $/kWh			Miscelleaneous Unmetered non-TOU variable charge - $/kWh			Individual contract Total Annual - $/year			Transmission SRAM Pass-Through - $/month by retailer or customer		
Consumer group name or price category code	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)
MPCOUNPUMP	–	–	–	–	–	–			–			–
MPAILU	–	–	–	$0	–	$0			–			–
MPAISTD	–	–	–	$0	–	$0			–			–
Irrigation MPIRR	–	–	–	–	–	–			–			–
MPLGEUSER	–	–	–	–	–	–			–			–
Non-Residential MPNONRES	–	–	–	$1	–	$1			–			–
Residential Low User MPRLU	($37)	–	($37)	$0	–	$0			–			–
MPRSTD	($90)	–	($90)	$0	–	$0			–			–
Streetlighting MPSTLGT	–	–	–	–	–	–			–			–
Temporary Supply MPTEMP	–	–	–	–	–	–			–			–
			–			–			–			–
at 12/06/2026			–			–			–			–
			–			–			–			–
ICP's Direct Supply			–			–	$342	$1.660	$2.001			–
			–			–			–			–
Transmission SRAM			–			–			–		($2.170)	($2.170)
			–			–			–			–
			–			–			–			–
			–			–			–			–
Standard consumer totals	($128)	–	($128)	$1	–	$1	–	–	–	–	($2,170)	($2,170)
Non-standard consumer totals	–	–	–	–	–	–	$342	$1,660	$2,001	–	–	–
Total for all consumers	($128)	–	($128)	$1	–	$1	$342	$1,660	$2,001	–	($2,170)	($2,170)

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

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	1

Company Name	**MainPower New Zealand**
For Year Ended	**31 March 2026**
Network / Sub-network Name	

SCHEDULE 9a: ASSET REGISTER

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

sch ref

9a: Asset Register

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	10,369	10,578	209	3
10	All	Overhead Line	Wood poles	No.	46,090	45,702	(388)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	380	380	0	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	5	5	0	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	15	18	3	3
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	13	10	(3)	3
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	4	4	3
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	41	40	(1)	3
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	1	11	10	3
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	17	19	2	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	54	48	(6)	2
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	26	22	(4)	2
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	25	25	–	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3,303	3,314	12	2
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	117	117	0	2
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	341	351	11	2
39	HV	Distribution Cable	Distribution UG PILC	km	53	54	1	2
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	140	141	1	2
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	38	63	25	3
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	9,969	10,005	36	2
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	1	1	N/A
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	436	450	14	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	7,603	7,667	64	2
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	891	896	5	2
48	HV	Distribution Transformer	Voltage regulators	No.	28	27	(1)	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	946	953	7	2
50	LV	LV Line	LV OH Conductor	km	236	240	4	2
51	LV	LV Cable	LV UG Cable	km	823	828	6	2
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	563	608	45	2
53	LV	Connections	OH/UG consumer service connections	No.	46,011	46,751	740	2
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	302	287	(15)	2
55	All	SCADA and communications	SCADA and communications equipment operating as a single syste	Lot	140	150	10	2
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	7	7	–	3
58	All	Load Control	Relays	No	11,170	11,125	(45)	1
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	**MainPower New Zealand**
For Year Ended	**31 March 2026**
Network / Sub-network Name	

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

9b: Asset Age Profile

8 **Disclosure Year (year ended)**

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006
10	All	Overhead Line	Concrete poles / steel structure	No.	–	31	330	293	842	1,598	454	24	45	67	306	127	116	85
11	All	Overhead Line	Wood poles	No.	424	866	1,253	2,150	4,545	8,657	8,533	533	699	586	441	771	1,227	814
12	All	Overhead Line	Other pole types	No.														
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	0	27	45	119	40	2	1	13	18	–	–	0
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km														
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	0	2	0	0	–	–	–	–	–	–
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km														
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km														
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km														
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km														
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km														
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km														
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km														
23	HV	Subtransmission Cable	Subtransmission submarine cable	km														
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	–	1	9	2	–	–	–	2	–	–	–	–
25	HV	Zone substation Buildings	Zone substations 110kV+	No.														
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.														
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	1	–	–	–	–	–	–	–
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	2	10	9	–	–	–	–	–	–	–	–
30	HV	Zone substation switchgear	33kV RMU	No.														
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	–	5	–	2	–	–	–	–	1	–	–
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	1	2	2	–	–	4	–	–	–	–
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	1	–	–	–	–	1	–	–	1
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	–	3	2	1	3	–	–	–	2	–	–	–
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	23	6	31	149	496	1,073	802	37	27	39	45	33	54	40
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km														
38	HV	Distribution Line	SWER conductor	km	–	–	–	16	25	65	3	–	2	–	0	–	–	2
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	0	–	–	4	5	28	14	10	9	2	13	9	10
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	2	22	15	13	1	–	–	–	–	–	–
41	HV	Distribution Cable	Distribution Submarine Cable	km														
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser	No.	–	–	–	–	–	1	8	–	–	–	–	–	1	2
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	9	1	–	–	–	–	–	–	–	1
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	12	2	3	1,379	192	1,522	925	1,009	130	121	160	141	191	192
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	7	27	35	16	5	2	6	9	6	12
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	1	1	7	348	1,069	790	1,004	209	198	201	192	227	280	222
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	1	16	64	72	56	20	10	21	17	16	24	42
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	1	–	–	–	–	–	2	4	4	–
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	1	127	18	81	94	76	16	20	21	28	23	26
51	LV	LV Line	LV OH Conductor	km	0	1	2	10	106	54	34	6	2	1	1	1	1	1
52	LV	LV Cable	LV UG Cable	km	–	–	–	–	78	69	108	26	12	9	10	22	23	23
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	0	0	1	2	243	29	15	7	9	2	3	8	10	8
54	LV	Connections	OH/UG consumer service connections	No.	12	127	1,813	2,036	3,206	3,326	2,964	471	570	567	624	787	1,024	909
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	3	40	15	10	3	–	10	–	3	18	1
56	All	SCADA and communications	SCADA and communications equipment operating as a single syst	Lot	–	–	–	–	–	4	28	6	–	6	1	1	4	2
57	All	Capacitor Banks	Capacitors including controls	No														
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	3	–	–	–	–	–	–	–
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–
60	All	Civils	Cable Tunnels	km														

sch ref	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	68	105	88	254	173	267	386	492	508	699	414	287	191	431	425	293	362	287	230	293	–	–	7	10,578		3
11	802	979	1,439	1,126	759	842	657	736	860	817	709	313	476	750	583	440	491	451	278	625	–	–	70	45,702		3
12																								–		N/A
13	1	0	–	1	–	83	3	4	10	5	–	–	–	–	1	–	–	–	2	2	–	–	3	380.5		3
14																								–		N/A
15	–	–	–	1	1	–	–	–	–	–	–	1	–	0	0	0	0	–	–	–	–	–	0	5.06		3
16																								–		N/A
17																								–		N/A
18																								–		N/A
19																								–		N/A
20																								–		N/A
21																								–		N/A
22																								–		N/A
23																								–		N/A
24	–	–	1	–	–	–	–	–	2	–	–	–	–	–	–	1	–	–	–	–	–	–	–	18.0		3
25																								–		N/A
26																								–		N/A
27	–	4	3	–	–	–	1	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	10.0		3
28	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4	–	–	–	4.0		3
29	5	–	6	–	2	–	1	1	2	–	–	–	–	–	2	–	–	–	–	–	–	–	–	40.0		3
30																								–		N/A
31	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	10	–	–	–	11.0		3
32	1	–	1	–	2	–	–	–	2	–	–	–	–	1	–	–	–	–	–	4	–	–	–	19.0		3
33	–	–	8	–	–	–	1	–	12	–	–	–	–	–	18	–	–	–	–	–	–	–	–	48.0		2
34	4	9	3	–	–	2	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	22.0		2
35	2	5	–	–	–	–	–	4	–	–	–	–	–	–	–	3	–	–	–	–	–	–		25.0		3
36	40	38	69	37	30	22	50	32	46	22	15	14	5	7	5	2	3	6	4	13	–	–	1	3,314.31		2
37																								–		N/A
38	2	0	–	–	–	–	–	–	–	–	–	–	–	0	–	–	0	0	–	0	–	–		116.8		2
39	12	19	20	9	19	12	16	14	16	22	11	10	6	7	7	8	8	14	9	9	–	–		351.5		2
40	–	0	–	0	1	–	–	–	–	0	–	0	–	0	0	0	–	0	1	1	–	–	–	54.2		2
41																								–		N/A
42	4	–	–	3	3	1	2	20	20	33	1	–	–	8	8	15	1	3	2	2	–	–	3	141.0		2
43	–	–	–	18	1	9	–	–	–	–	2	–	–	–	–	–	–	–	–	22	–	–	–	63.0		3
44	140	158	138	124	134	224	472	480	393	403	326	175	97	4	–	11	127	214	167	238	–	–	1	10,005.0		2
45	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	1.0		N/A
46	10	9	12	11	21	13	23	20	17	11	9	5	5	54	12	21	32	12	11	13	–	–	4	450.0		3
47	121	218	181	133	161	84	427	263	107	280	53	63	45	131	106	125	110	25	8	16	–	–	261	7,667.0		2
48	36	51	42	16	22	18	42	42	32	37	15	12	13	19	14	25	40	7	–	5	–	–	49	896.0		2
49	–	1	–	–	–	–	–	–	–	–	–	–	–	9	–	–	4	2	–	–	–	–	–	27.0		3
50	20	22	19	18	20	21	26	31	38	40	28	21	14	–	–	–	18	36	23	27	–	–	–	953.0		2
51	1	1	1	2	1	2	0	0	0	–	0	0	0	0	0	–	0	1	0	1	–	–	6	239.5		2
52	26	35	19	24	14	20	42	29	27	24	24	17	15	15	20	25	22	21	15	12	–	–	(3)	828.4		2
53	13	12	5	14	10	11	5	8	20	17	14	11	16	11	15	13	9	13	7	7	–	–	39	608.4		2
54	755	903	698	628	660	812	1,325	1,454	1,332	980	1,033	864	969	898	849	1,113	968	883	826	815	–	–	9,550	46,751.0		2
55	9	24	21	30	4	12	12	15	27	12	4	–	–	–	–	–	–	1	–	13	–	–	–	287		2
56	1	25	15	18	5	–	12	1	2	3	–	–	–	–	–	–	1	1	6	8	–	–	–	150		2
57																								–		N/A
58	–	1	–	–	–	–	–	–	3	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7		3
59	–	–	–	–	–	–	–	25	61	418	324	1,517	695	437	2,757	341	807	627	1,533	1,583	–	–		11,125		1
60																								–		N/A

Company Name	**MainPower New Zealand**
For Year Ended	**31 March 2026**
Network / Sub-network Name	

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

9 9c: Overhead Lines and Underground Cables

sch ref		Overhead (km)	Underground (km)	Total circuit length (km)
10				
11	**Circuit length by operating voltage (at year end)**			
12	> 66kV			–
13	50kV & 66kV	222.3	0.6	223
14	33kV	158.2	4.5	163
15	SWER (all SWER voltages)	117.0	3.5	120
16	22kV (other than SWER)	962.1	70.7	1,033
17	6.6kV to 11kV (inclusive—other than SWER)	2,352.2	336.0	2,688
18	Low voltage (< 1kV)	239.5	828.4	1,068
19	**Total circuit length (for supply)**	4,051	1,244	5,295
20				
21	Dedicated street lighting circuit length (km)	63	546	608
22	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			
23				

sch ref		Circuit length (km)	(% of total overhead length)
24	**Overhead circuit length by terrain (at year end)**		
25	Urban	139	3%
26	Rural	3,911	97%
27	Remote only		–
28	Rugged only	0	0%
29	Remote and rugged		–
30	Unallocated overhead lines		–
31	**Total overhead length**	4,051	100%
32			

sch ref		Circuit length (km)	(% of total circuit length)
33			
34	Length of circuit within 10km of coastline or geothermal areas (where known)	1,972	37%
35			

sch ref		Total newly identified throughout the disclosure year	Total remaining at high risk at the disclosure year-end	
36				
37	Number of overhead circuit sites at high risk from vegetation damage	–	17,289	*Not required before DY2026*
38				

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

sch ref	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	
40				
41	Single tree - urban	1,878	108	*Not required before DY2026*
42	Single tree - rural	10,961	1,104	*Not required before DY2026*
43	Group of trees - urban	693	30	*Not required before DY2026*
44	Group of trees - rural	3,757	255	*Not required before DY2026*
45				*Not required before DY2026*
46				*Not required before DY2026*
47	**Total number of sites**	17,289	1,497	*Not required before DY2026*

48 ** Insert new rows in table above Total line as necessary*

Company Name: MainPower New Zealand
For Year Ended: 31 March 2026

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)
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			

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

Company Name	MainPower New Zealand
For Year Ended	31 March 2026
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**		**Number of connections (ICPs)**	
11		Residential	441	
12		General	110	
13		Irrigation	6	
14		Council pumping	3	
15		Other	256	
16		**Connections total**	816	
17		** include additional rows if needed*		
18				
19	*Number of ICPs decommissioned during year by consumer type*			
20	*Consumer types defined by EDB**		**Number of decommissionings**	
21		Residential	28	
22		General	46	
23		Irrigation	1	
24		Council pumping	2	
25		Other	7	
26		**Decommissionings total**	84	
27		** include additional rows if needed*		
28				
29	**Distributed generation**			
30		Number of connections made in year	571	**connections**
31		Capacity of distributed generation installed in year	6.03	**MVA**
32				
33	**9e(ii): System Demand**			
34				
35				
36	**Maximum coincident system demand**		**Demand at time of maximum coincident demand (MW)**	
37		GXP demand	114	
38	*plus*	Distributed generation output at HV and above	2	
39		**Maximum coincident system demand**	116	
40	*less*	Net transfers to (from) other EDBs at HV and above		
41		**Demand on system for supply to consumers' connection points**	116	
42	**Electricity volumes carried**		**Energy (GWh)**	
43		Electricity supplied from GXPs	627	
44	*less*	Electricity exports to GXPs		
45	*plus*	Electricity supplied from distributed generation	32	
46	*less*	Net electricity supplied to (from) other EDBs		
47		**Electricity entering system for supply to consumers' connection points**	660	
48	*less*	Total energy delivered to ICPs	623	
49		**Electricity losses (loss ratio)**	37	5.5%
50				
51		**Load factor**	0.65	
52	**9e(iii): Transformer Capacity**			
53			**(MVA)**	
54		Distribution transformer capacity (EDB owned)	633	
55		Distribution transformer capacity (Non-EDB owned)	19	
56		**Total distribution transformer capacity**	652	
57				
58			**(MVA)**	
59		Zone substation transformer capacity (EDB owned)	154	
60		Zone substation transformer capacity (Non-EDB owned)		
61		**Total zone substation transformer capacity**	154	

Company Name	MainPower New Zealand
For Year Ended	31 March 2026
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)		
11	Class B (planned interruptions on the network)	537	
12	Class C (unplanned interruptions on the network)	950	
13	Class D (unplanned interruptions by Transpower)	19	
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**	1,506	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	575	375
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)		
26	Class B (planned interruptions on the network)	0.46	143.3
27	Class C (unplanned interruptions on the network)	1.80	527.9
28	Class D (unplanned interruptions by Transpower)	0.15	5.0
29	Class E (unplanned interruptions of EDB owned generation)		
30	Class F (unplanned interruptions of generation owned by others)		
31	Class G (unplanned interruptions caused by another disclosing entity)		
32	Class H (planned interruptions caused by another disclosing entity)		
33	Class I (interruptions caused by parties not included above)		
34	**Total**	2.42	676.2
35			
36	**Transitional SAIFI and SAIDI (previous method)**	**SAIFI**	**SAIDI**
37	Class B (planned interruptions on the network)		
38	Class C (unplanned interruptions on the network)		
39			
40	*Where EDBs do not currently record their SAIFI and SAIDI values using the 'multi-count' approach, they shall continue to record their SAIFI and SAIDI values on the same basis that they employed as at 31 March 2023 as 'Transitional SAIFI' and 'Transitional SAIDI' values, in addition to their SAIFI and SAIDI values (Classes B & C) using the 'multi-count approach'.* ***This is a transitional reporting requirement that shall be in place for the 2024, 2025, and 2026 disclosure years.***		

Company Name	**MainPower New Zealand**
For Year Ended	**31 March 2026**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

Cause	SAIFI	SAIDI
Lightning	0.01	0.7
Vegetation	0.36	112.2
Adverse weather	0.45	322.5
Adverse environment	0.00	0.5
Third party interference	0.28	30.3
Wildlife	0.08	7.7
Human error	0.01	0.1
Defective equipment	0.46	32.2
Other cause		–
Unknown	0.15	21.7

Breakdown of third party interference	SAIFI	SAIDI
Dig-in	–	0.0
Overhead contact	0.05	4.1
Vandalism		
Vehicle damage	0.18	20.3
Other	0.05	6.0

Breakdown of vegetation interruptions (vegetation cause)	SAIFI	SAIDI	
In-zone	0.03	4.0	*Not required before DY2026*
Out-of-zone	0.33	108.2	*Not required before DY2026*

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.00	0.7
Subtransmission cables		
Subtransmission other		
Distribution lines (excluding LV)	0.38	113.3
Distribution cables (excluding LV)	0.08	29.3
Distribution other (excluding LV)		

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.53	36.8
Subtransmission cables		
Subtransmission other		
Distribution lines (excluding LV)	1.15	482.7
Distribution cables (excluding LV)	0.12	8.4
Distribution other (excluding LV)		

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	17	381	4.47
Subtransmission cables		5	–
Subtransmission other			
Distribution lines (excluding LV)	913	3,431	26.61
Distribution cables (excluding LV)	20	410	4.88
Distribution other (excluding LV)			
Total	950		

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Identification

Company Name	MainPower New Zealand
For Year Ended	31 March 2026
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 **10(vi): Worst-performing feeders (unplanned)**

9

10 **SAIDI**

sch ref	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)
12	1	P55	53.7	70	Adverse Weather	90.5	216	
	2	P45	51.6	84	Adverse Weather	203.9	896	
	3	N34	39.0	12	Adverse Weather	32.6	1048	
	4	N44	35.4	22	Adverse Weather	32.3	640	
	5	P25	31.2	53	Adverse Weather	139.3	381	
	6	H31	31.2	40	Adverse Weather	186.2	560	
	7	T43	23.1	19	Adverse Weather	79.3	228	
13	8	U42	23.0	30	Adverse Weather	114.6	670	
14	9	P35	22.4	35	Wildlife	101.9	562	
15	10	X54	17.5	36	Adverse Weather	180.6	1739	

16 [1] *Extend table as necessary to disclose all worst-performing feeders*

17

18 **SAIFI**

sch ref	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)
20	1	CUL_142	0.194	3	Defective Equipment	117.23	3054	
	2	SBK_152	0.116	2	Vegetation	39	2844	
	3	P45	0.101	84	Adverse Weather	203.91	896	
	4	SBK_202	0.069	1	Vegetation	43.47	3258	
	5	WPR_82	0.069	1	Cause Unknown	86.29	2659	
	6	X54	0.058	36	Adverse Weather	180.55	1739	
	7	N44	0.058	22	Adverse Weather	32.34	640	
21	8	K35	0.058	11	Third party interference	16.36	984	
22	9	KAI_5	0.052	19	Vegetation	49.31	776	
23	10	KAI_4	0.048	3	Defective Equipment	14.28	1123	

24 [1] *Extend table as necessary to disclose all worst-performing feeders*

25

26 **Customer Impact**

sch ref	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)
28	1	P55	11,539	70	Adverse Weather	90.51	216	
	2	L52	6,123	12	Adverse Weather	35.95	79	
	3	E80	5,335	4	Wildlife	47.8	64	
	4	T43	4,693	19	Adverse Weather	79.28	228	
	5	P25	3,801	53	Adverse Weather	139.28	381	
	6	X57	3,369	30	Adverse Weather	63.37	164	
29	7	H41	3,127	17	Adverse Weather	82.51	191	
30	8	P45	2,669	84	Adverse Weather	203.91	896	
31	9	H31	2,585	40	Adverse Weather	186.17	560	

32 [1] *Extend table as necessary to disclose all worst-performing feeders*

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for Identification

COMMERCE COMMISSION NEW ZEALAND

EDB Information Disclosure Requirements
Information Templates

Schedule 10a

Company Name	MainPower New Zealand
Disclosure Date	31 August 2026
Disclosure Year (year ended)	31 March 2026

Template for Schedule 10a
Prepared 2 June 2026.

Table of Contents

Disclosure Template Instructions

This document forms Schedule 10a to the Electricity Distribution Information Disclosure (Non-material) Amendment Determination 2026 [2026] NZCC 21.

The Schedules take the form of templates for use by EDBs when making disclosures under subclause 2.5.1 of the Electricity Distribution Information Disclosure Determination 2012, as amended.

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.

Inserting Additional Rows and Columns

The schedule 10a template 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 10a template 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.

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.

Company Name MainPower New Zealand

For Year Ended 31 March 2026

SCHEDULE 10a: REPORT ON INTERRUPTIONS

This schedule requires raw interruption data for the disclosure year. SAIDI and SAIFI is to be recorded using the multi-count approach. Where multiple feeders are affected, the interruption record is to be split into multiple interruptions, ie, one interruption record per feeder. 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.

10a(i): Raw interruption data

	Sub-network											Planned or unplanned interruption		Any explanation to help clarify the context of the interruption, including what

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for Identification

Company Name: MainPower New Zealand
For Year Ended: 31 March 2026

SCHEDULE 10a: REPORT ON INTERRUPTIONS

This schedule requires raw interruption data for the disclosure year. SAIDI and SAIFI is to be recorded using the multi-count approach. Where multiple feeders are affected, the interruption record is to be split into multiple interruptions, ie, one interruption record per feeder. 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.

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for
Identification

Company Name: MainPower New Zealand
For Year Ended: 31 March 2026

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for Identification

Company Name: MainPower New Zealand
For Year Ended: 31 March 2026

SCHEDULE 10a: REPORT ON INTERRUPTIONS

This schedule requires raw interruption data for the disclosure year. SAIDI and SAIFI is to be recorded using the multi-count approach. Where multiple feeders are affected, the interruption record is to be split into multiple interruptions, ie, one interruption record per feeder. 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.

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for
Identification

Company Name MainPower New Zealand
For Year Ended 31 March 2026

SCHEDULE 10a: REPORT ON INTERRUPTIONS

This schedule requires raw interruption data for the disclosure year. SAIDI and SAIFI is to be recorded using the multi-count approach.Where multiple feeders are affected, the interruption record is to be split into multiple interruptions, ie, one interruption record per feeder. 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

* Extend table as necessary to disclose information for all individual interruptions

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for Identification

Company Name	MainPower New Zealand Limited
For Year Ended	31 March 2026

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

MainPower's Post Tax ROI of 7.48% is higher than both the 5.90% mid-point and 6.62% 75th percentile estimates provided by the Commerce Commission..

Line charge revenue was less than forecasted due to lower transmission costs and revenue, and lower irrigation consumption. This was partially offset by other regulated revenue. Expenses were less than forecast both in the network and non-network categories, due to the lower transmission costs and timing delays related to software development.

Expenditure on assets was higher than forecast with customer connections driving systems growth.

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

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

Box 2: Explanatory comment on regulatory profit
Regulatory profit before tax is $34.5m compared to $18.5m in FY2025. The main area of fluctuation year-on year was increased lines revenue of $10m (15%) and an increase in revaluations of $2.5m (28%). Lines revenue increased due to network growth and an increase in customer connections. Other regulated income (other than gains/losses on asset disposals) is comprised of interest revenue on MainPower's self-insurance fund and revenue relating to sundry network charges for capacity upgrades and connection fees. This also includes revenue from vegetation management and faults that was previously offset against expenditure.

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
N/A

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).

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

Comments on Schedule 4

The closing RAB value is $387m. Capital expenditure (net of capital contributions) on the RAB was $36.1m, $11.2m remains in works under construction at the end of the period. Additions to the RAB totalled $34.7m ($10m of which was in opening works under construction).

Depreciation and disposals for the year totalled $17.0m (FY2025: $17.8m) and revaluations were $11.0m (FY2025: $8.5m).

Adjustments resulting from asset allocation were $67k (FY2025: $105k).

The value of the unallocated RAB increased by $29.2m to $393.9m (FY2025: $364.6m), whereas due to the reduction from the asset allocation the allocated RAB increased by $28.9m to $387.4m (FY2025: $358.6m).

There were no items reclassified or any changes in the accounting treatment of expenditure from those adopted last year.

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 are no permanent differences in the tax calculation.

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)
Temporary differences of $(45k) related to $(51k) for movements in Employee Entitlement Provisions, $8k for movements in ROU assets and associated lease liabilities, and $15k for movements in Other Provisions.

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
Operating costs were allocated using the Accounting based allocation approach (ABAA). Costs of $2,847have been allocated to Non-electricity distribution services in FY2026 ($427k FY25). There were not any items reclassified or any changes in the accounting treatment of expenditure from those adopted last year.

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
Asset costs were allocated using the Accounting based allocation approach (ABAA). Asset costs of $34.6m have been allocated to Non-electricity distribution services in FY2026 ($36.1m FY25). There were not any items reclassified or any changes in the accounting treatment of expenditure from those adopted last year.

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

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

Box 9: Explanation of capital expenditure for the disclosure year
Capital expenditure of $36.1m net of capital contributions was made up of $34.0m on Network assets and $2.0m on Non-network assets. With regard to 12.1 above, the materiality threshold MainPower has applied is identified projects that form part of the AMP forecasts, where the expenditure reclassification is greater than $50k. No items were reclassified nor have there been any changes in the accounting treatment of expenditure from that adopted last 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
There was no Operational Expenditure on asset replacement and renewals. Operating expenditure of $26.7m was made up of $9.5m directly on the network, $12.2m on System operating and network support, and $5.0m on Business support. No items were reclassified nor have there been any changes in the accounting treatment of expenditure from that adopted last year.

Variance between forecast and actual expenditure (Schedule 7)

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

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

Capital expenditure on Network assets of $39.4m was 10% below forecast ($3.3m), which is explained as follows:

- System growth expenditure was 6% less than forecast ($1m)
- Consumer connection spend was 62% above forecast ($3.7m) due to an increase in new connections. The spend varies depending on the demand and type of connections and there is a corresponding uplift in the contributions from customers included in other revenue.
- Asset replacement and renewal was 1% below forecast ($0.1m).

Network and non-network capital expenditure combined was greater than the FY2026 AMP forecast by 11%.

Network operational expenditure of $9.4m was 2% below forecast.

Non-network operating expenditure of $17.2m was $6.1m lower than forecast (26%). Savings were achieved on IT and other support spend.

No items were reclassified nor have there been any changes in the accounting treatment of expenditure from that adopted last year.

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Information relating to revenues and quantities for the disclosure year

15. In the box below provide-

15.1 a comparison of the target revenue disclosed before the start of the disclosure year, in accordance with clause 2.4.1 and subclause 2.4.3(3) to total billed line charge revenue for the disclosure year, as disclosed in Schedule 8; and

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

Box 12: Explanatory comment relating to revenue for the disclosure year

Lines revenue for the year of $77.9m was below the target of $81.1m due to lower than expected irrigation revenues due to a wetter than normal summer.

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

Network reliability measurements for FY2026 were calculated using ADMS system reports and the Tableau BI tool to develop the reporting. Successive interruptions for FY2026 have been treated in the same way as they were for FY2025.

10(i): The number, duration and frequency of unplanned interruptions in FY2026 was higher than the five-year average, primarily due to a major weather event in October 2025 that interrupted the service to around 16,000 ICPs.

Excluding major events, both unplanned SAIDI and unplanned SAIFI were on par with the five-year average FY22-FY26, but above the SAIDI/SAIFI values recorded in FY2025, which was a year unaffected by any major events.

Class B planned SAIFI and SAIDI was at the five-year average and in accordance with the delivery of the asset management program.

A number of Class D, unplanned Transpower interruptions, were recorded during FY2026. These Class D unplanned interruptions accounted for 7.9% of the total unplanned SAIFI and 0.9% of the total unplanned SAIDI in FY2026.

10(ii): Class C SAIDI was above normal, primarily due to a major weather event in October 2025 that accounted for 59% of unplanned SAIDI and 21% of unplanned SAIFI. In that event, 44% of unplanned SAIDI was related to adverse weather, and 14% of unplanned SAIDI related to out-of-zone vegetation.

Class C SAIFI was affected to a lesser degree in the October weather event, with 13% of unplanned SAIFI being attributed to adverse weather and 8% of unplanned SAIFI being attributed to out-of-zone vegetation. SAIFI was also impacted by an unrelated interruption attributed to equipment failure that occurred in August 2025, which accounted for 6% of unplanned SAIFI and interrupted over 3000 ICPs.

10(iii): The main equipment involved in planned Class B interruptions were the overhead distribution lines. This was a result of the delivery of our work program that was focussed on improving the condition of overhead assets, and configuring the network for planned system growth.

10(iv) and 10(v): The main equipment involved in Class C unplanned interruptions were overhead distribution lines, which were severely affected by the events as explained in section 10(ii). 64% of unplanned SAIFI and 91% of unplanned SAIDI is attributed to the distribution lines category, while 29% of unplanned SAIFI and 7% of unplanned SAIDI is attributed to interruptions of overhead subtransmission circuits.

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
MainPower has extensive insurance cover for structures such as zone substations and plant, however it is uneconomic to insure the distribution network E.g. poles and conductors. As disclosed in 3(v) MainPower maintains a separate self-insurance fund to cover damage caused to uninsured parts of the Network caused by catastrophic events (such as earthquakes and storms). This fund is currently $3.4m and is invested in bank term deposits.

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

Company Name	MainPower New Zealand
For Year Ended	31-03-2026

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

This commentary relates to the disclosure schedule 9c, Overhead Lines and Underground Cables.

Schedule 9c sub-section: Breakdown of overhead circuit sites at high risk from vegetation damage at disclosure year-end:-

> The information in this sub-section is provided on a best-endeavours basis as the assessment relies on limited Lidar data. Approximately 90% of network circuits are covered by the Lidar data, but the lack of Lidar data covering remote areas and the age the Lidar data means that the assessment for this element of schedule 9c is of poor quality.
>
> Areas that have not been assessed due to unavailability of Lidar data include some remote and difficult-to-access overhead lines. These overhead lines are not included in the totals provided in this sub-section.
>
> MainPower is currently in the process of developing tools to better manage the assessment and reporting of vegetation in proximity to overhead lines.

MainPower New Zealand Limited
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PO Box 346, Rangiora 7440
T. 0800 30 90 80

Schedule 18 Certification for Year-end Disclosures

Clause 2.9.2

We, Jan Fraser Jonker and Janice Evelyn Fredric, being directors of MainPower New Zealand Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) the information prepared for the purposes of clauses 2.3.1, 2.3.2, 2.3.8 - 2.3.12,2.4.21, 2.4.22, 2.5.1(1)(a)-(f), 2.5.2, 2.5.2A, 2.6.1B and 2.7.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination; and

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

c) In respect of information concerning assets, costs and revenues valued or disclosed in accordance with clause 2.3.6 of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012, we are satisfied that

   i. the costs and values of assets or goods or services acquired from a related party comply, in all material respects, with clauses 2.3.6(1) and 2.3.6(3) of the Electricity Distribution Information Disclosure Determination 2012 and clauses2.2.11(1)(g) and 2.2.11(5)(a)-2.2.11(5)(b) of the Electricity Distribution Services Input Methodologies Determination 2012; and

   ii. the value of assets or goods or services sold or supplied to a related party comply, in all material respects, with clause 2.3.6(2) of the Electricity Distribution Information Disclosure Determination 2012.

JAN FRASER JONKER **JANICE EVELYN FREDRIC**

26 August 2026
August 2026

Deloitte.

INDEPENDENT ASSURANCE REPORT
TO THE DIRECTORS OF MAINPOWER NEW ZEALAND LIMITED AND THE COMMERCE COMMISSION

Report on the Disclosure Information prepared in accordance with the Electricity Distribution Information Disclosure Determination 2012 (and subsequent amendments)

We have undertaken a reasonable assurance engagement in respect of the compliance of MainPower New Zealand Limited (the '**Company**') and its subsidiaries (the '**Group**') with the Electricity Distribution Information Disclosure Determination 2012 (and subsequent amendments) (the '**Information Disclosure Determination**') for the disclosure year ended 31 March 2026, where we are required to opine on:

- whether the Group has complied, in all material respects, in accordance with the Information Disclosure Determination, in preparing the information disclosed in Schedules 1 to 4, 5a to 5h, 6a and 6b, 7, the system average interruption duration index ('**SAIDI**') and system average interruption frequency index ('**SAIFI**') information disclosed in Schedules 10 and 10a and the explanatory notes in boxes 1 to 11 of Schedule 14 (the '**Disclosure Information**'); and
- whether the Group's basis for valuation of related party transactions (the '**Related Party Transaction Information**') has complied, in all material respects, in accordance with clauses 2.3.6, 2.3.8, 2.3.10, 2.3.11 and 2.3.12 of the Information Disclosure Determination, and clauses 2.2.11(1)(g), 2.2.11(5) and 2.2.11(6) of the Electricity Distribution Services Input Methodologies Determination 2012 (and subsequent amendments) (the '**Input Methodologies Determinatio**n').

Opinion

In our opinion, in all material respects:

- as far as appears from an examination, the information used in the preparation of the Disclosure Information and the Related Party Transaction Information has been properly extracted from the Group's accounting and other records, sourced from the Group's financial and non-financial systems;
- as far as appears from an examination, proper records to enable the complete and accurate compilation of the Disclosure Information and the Related Party Transaction information have been kept by the Group;
- the Group has complied with the Information Disclosure Determination in preparing the Disclosure Information; and
- the Group's basis for the valuation of related party transactions complies with the Information Disclosure Determination and the Input Methodologies Determination.

Basis of Opinion

We have conducted our engagement in accordance with International Standard on Assurance Engagements (New Zealand) 3000 (Revised): *Assurance Engagements Other Than Audits or Reviews of Historical Financial Information* ('**ISAE (NZ) 3000**') and the Standard on Assurance Engagements 3100 (Revised): *Compliance Engagements* ('**SAE 3100**'), issued by the New Zealand Auditing and Assurance Standards Board ('**NZAuASB**').

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

Key Assurance Matters

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

Key assurance matter	How our procedures addressed the key assurance matter
Accuracy and completeness of the number and duration of electricity outages	
The Information Disclosure Determination defines certain quality measures in relation to the number and duration of interruptions, faults, and causes of faults. These quality measures are expressed in the form of SAIDI and SAIFI values as disclosed in Schedule 10. This is a key assurance matter because information on the frequency and duration of outages is an important measure about the reliability of electricity supply. The accuracy completeness of the data is a key assurance matter because although the faults database is automated, the details of some faults are entered manually onto a portable device which then flows into the Advanced Distribution Management System (‘**ADMS**’) which automatically logs all outages into the faults database.	We have: • Obtained an understanding of the Group’s methods by which electricity outages and their duration are recorded; • Assessed the design and implementation of key controls related to the recording, reconciliation and review of outage data obtained from ADMS; • For a sample of outage events from the Raw Data Outage Report (list of all events recorded in the system) used to prepare the schedules, traced the start time, number of customers affected and end time to the fault log sheet and responding technicians records; • For a sample of events captured by the system management software used to monitor the network, traced the start time, number of customers affected and the end time to information recorded in the Raw Data Outage Report; • For a sample of manual outage sheets, traced the start time, number of customers affected and the end time to the information recorded in the Raw Data Outage Report.

Directors’ Responsibilities

The Directors are responsible on behalf of the Group for the preparation of the Disclosure Information and Related Party Transaction Information in accordance with the Information Disclosure Determination and the Input Methodologies Determinations.

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

Our Independence and Quality Management

We have complied with the independence and other ethical requirements of the Professional and Ethical Standard 1: *International Code of Ethics for Assurance Practitioners (including International Independence Standards) (New Zealand)* issued by the NZAuASB, which is founded on fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behaviour.

Other than in our capacity as statutory auditor of the financial statements, and the provision of other assurance services including the audit of regulatory disclosure statement, we have no relationship with or interests in the Group. These services have not impaired our independence as auditor.

Our firm applies 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 us to design, implement and operate a system of quality management including policies and procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

Assurance Practitioner's Responsibility

Our responsibility in terms of clauses 2.8.1(1)(b)(vi) and (vii), 2.8.1(1)(c) and 2.8.1(1)(d) of the Information Disclosure Determination is to express an opinion on whether:

- as far as appears from an examination, the information used in the preparation of the Disclosure Information and the Related Party Transaction Information has been properly extracted from the Group's accounting and other records, sourced from the Group's financial and non-financial systems;
- as far as appears from an examination, proper records to enable the complete and accurate compilation of the Disclosure Information and the Related Party Transaction information have been kept by the Group and if not, the records not so kept;
- the Group has complied, in all material respects, with the Information Disclosure Determination in preparing the Disclosure Information; and
- the Group's basis for valuation of related party transactions in the disclosure year has complied, in all material respects, with clause 2.3.6 of the Information Disclosure Determination and clauses 2.2.11(1)(g) 2.2.11(5) and 2.2.11(6) of the Input Methodologies Determination.

ISAE (NZ) 3000 and SAE 3100 requires that we plan and perform our procedures to obtain reasonable assurance that the Group has complied, in all material aspects, with the Information Disclosure Determination and the Input Methodologies Determination in relation to the preparation of the Disclosure Information and the Related Party Transaction Information.

An assurance engagement to report on the Group's compliance of the Disclosure Information and the Related Party Transaction Information in accordance with the Information Disclosure Determination and the Input Methodologies Determination involves performing procedures to obtain evidence about the compliance activity and control implemented to meet the requirements of the Information Disclosure Determination and the Input Methodologies Determination. The procedures selected depend on our judgement, including the identification and assessment of risk of material non-compliance with the Information Disclosure Determination and the Input Methodologies Determination.

Inherent Limitations

Because of the inherent limitations of an assurance engagement together with the inherent limitations of any system of internal control, it is possible that fraud, error or non-compliance may occur and not be detected. As the procedures performed for this engagement are not performed continuously throughout the current disclosure year, and the procedures performed in respect of the Group's compliance with the Information Disclosure Determination and the Input Methodologies Determination are undertaken on a test basis, our assurance engagement cannot be relied on to detect all instances where the Group may not have complied with the Information Disclosure Determination and the Input Methodologies Determination.

Further, a reasonable assurance engagement for the current disclosure year does not provide assurance on whether the Group's compliance with the Information Disclosure Determination and the Input Methodologies Determination will continue in the future.

Use of Report

Our assurance report ('**our Report**') has been prepared solely for the Directors of the Company and the Commerce Commission in accordance with clause 2.8.1(1)(a) of the Information Disclosure Determination, for the purpose of establishing whether the compliance requirements have been met. We accept or assume no duty, responsibility or liability to any party, other than you, in connection with our Report or this engagement, including without limitation, liability for negligence in relation to the opinion expressed in our Report.

Deloitte Limited

Christchurch, New Zealand
26 August 2026