COMMERCE COMMISSION
NEW ZEALAND

Electricity Distribution Information Disclosure Determination 2012
Consolidated determination as of 18 May 2023

Schedules 1–10
excluding 5f–5g

Company Name	Northpower
Disclosure Date	31 August 2023
Disclosure Year (year ended)	31 March 2023

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Disclosure Template Instructions

This document forms Schedules 1–10 to the Electricity Distribution Information Disclosure Determination 2012 (Consolidated detemination as of 18 May 2023)

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

Company Name and Dates

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

The cell C12 entry (current year) is used to calculate disclosure years in the column headings that show above some of the tables and in labels adjacent to some entry cells. It is also used to calculate the 'For year ended' date in the template title blocks (the title blocks are the light green shaded areas at the top of each template).
The cell C8 entry (company name) is used in the template title blocks.
Dates should be entered in day/month/year order (Example -"1 April 2013").

Data Entry Cells and Calculated Cells

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

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

Validation Settings on Data Entry Cells

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

Conditional Formatting Settings on Data Entry Cells

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

Inserting Additional Rows and Columns

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

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

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

Changes Since Previous Version
Refer to the Targeted Information Disclosure Review - Electricity Distribution Businesses Final reasons paper - Tranche 1, for the details of changes made. A summary is provided in Chapter 2.

Company Name	**Northpower**
For Year Ended	**31 March 2023**

SCHEDULE 1: ANALYTICAL RATIOS

This schedule calculates expenditure, revenue and service ratios from the information disclosed. The disclosed ratios may vary for reasons that are company specific and, as a result, must be interpreted with care. The Commerce Commission will publish a summary and analysis of information disclosed in accordance with 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**					
8		**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)**
9	**Operational expenditure**	46,125	580	231,939	5,901	60,925
10	Network	24,179	304	121,583	3,093	31,937
11	Non-network	21,946	276	110,356	2,808	28,988
12						
13	**Expenditure on assets**	36,917	464	185,637	4,723	48,763
14	Network	35,892	451	180,482	4,592	47,408
15	Non-network	1,025	13	5,155	131	1,354
16						

17	**1(ii): Revenue metrics**		
18		**Revenue per GWh energy delivered to ICPs ($/GWh)**	**Revenue per average no. of ICPs ($/ICP)**
19	**Total consumer line charge revenue**	83,042	1,044
20	Standard consumer line charge revenue	95,717	881
21	Non-standard consumer line charge revenue	48,400	1,283,451
22			

23	**1(iii): Service intensity measures**		
24			
25	Demand density	25	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	128	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
27	Connection point density	10	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
28	Energy intensity	12,570	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*
29			

30	**1(iv): Composition of regulatory income**		
31		**($000)**	**% of revenue**
32	Operational expenditure	36,529	54.95%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	18,819	28.31%
34	Total depreciation	12,204	18.36%
35	Total revaluations	21,787	32.77%
36	Regulatory tax allowance	35	0.05%
37	Regulatory profit/(loss) including financial incentives and wash-ups	20,680	31.11%
38	**Total regulatory income**	66,479	
39			

40	**1(v): Reliability**		
41			
42	Interruption rate	21.18	*Interruptions per 100 circuit km*

Company Name	**Northpower**
For Year Ended	**31 March 2023**

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		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
9	**ROI – comparable to a post tax WACC**	%	%	%
10	Reflecting all revenue earned	2.96%	8.46%	5.91%
11	Excluding revenue earned from financial incentives	2.96%	8.46%	5.91%
12	Excluding revenue earned from financial incentives and wash-ups	2.96%	8.46%	5.91%
14	**Mid-point estimate of post tax WACC**	3.72%	3.52%	4.88%
15	25th percentile estimate	3.04%	2.84%	4.20%
16	75th percentile estimate	4.40%	4.20%	5.56%
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	3.29%	8.76%	6.43%
21	Excluding revenue earned from financial incentives	3.29%	8.76%	6.43%
22	Excluding revenue earned from financial incentives and wash-ups	3.29%	8.76%	6.43%
24	**WACC rate used to set regulatory price path**			
26	**Mid-point estimate of vanilla WACC**	4.05%	3.82%	5.39%
27	25th percentile estimate	3.37%	3.14%	4.71%
28	75th percentile estimate	4.73%	4.50%	6.07%

sch ref				($000)	
30	**2(ii): Information Supporting the ROI**				
32		Total opening RAB value	328,448		
33	*plus*	Opening deferred tax	(14,210)		
34	**Opening RIV**			314,238	
36	**Line charge revenue**			65,767	
38		Expenses cash outflow	55,348		
39	*add*	Assets commissioned	15,667		
40	*less*	Asset disposals	151		
41	*add*	Tax payments	(1,709)		
42	*less*	Other regulated income	713		
43	**Mid-year net cash outflows**			68,443	
45	**Term credit spread differential allowance**			–	
47		Total closing RAB value	353,169		
48	*less*	Adjustment resulting from asset allocation	(379)		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(15,954)		
51	**Closing RIV**			337,594	
53	**ROI – comparable to a vanilla WACC**				6.43%
55		Leverage (%)			42%
56		Cost of debt assumption (%)			4.38%
57		Corporate tax rate (%)			28%
59	**ROI – comparable to a post tax WACC**				5.91%

Company Name	**Northpower**
For Year Ended	**31 March 2023**

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(iii): Information Supporting the Monthly ROI

Opening RIV	N/A

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

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

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

Year-end ROI – comparable to a vanilla WACC	6.42%
Year-end ROI – comparable to a post tax WACC	5.91%

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

2(v): Financial Incentives and Wash-Ups

Net recoverable costs allowed under incremental rolling incentive scheme	–	
Purchased assets – avoided transmission charge		
Energy efficiency and demand incentive allowance		
Quality incentive adjustment		
Other financial incentives		
Financial incentives		–
Impact of financial incentives on ROI		–
Input methodology claw-back		
CPP application recoverable costs		
Catastrophic event allowance		
Capex wash-up adjustment		
Transmission asset wash-up adjustment		
2013–15 NPV wash-up allowance		
Reconsideration event allowance		
Other wash-ups		
Wash-up costs		–
Impact of wash-up costs on ROI		–

Company Name	**Northpower**
For Year Ended	**31 March 2023**

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	65,767
10	*plus*	Gains / (losses) on asset disposals	
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	713
12			
13		**Total regulatory income**	66,479
14		**Expenses**	
15	*less*	Operational expenditure	36,529
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	18,819
18			
19		**Operating surplus / (deficit)**	11,131
20			
21	*less*	Total depreciation	12,204
22			
23	*plus*	Total revaluations	21,787
24			
25		**Regulatory profit / (loss) before tax**	20,714
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	35
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	20,680
32			

33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34	**Pass through costs**		
35	Rates	111	
36	Commerce Act levies	164	
37	Industry levies	202	
38	CPP specified pass through costs		
39	**Recoverable costs excluding financial incentives and wash-ups**		
40	Electricity lines service charge payable to Transpower	17,929	
41	Transpower new investment contract charges		
42	System operator services		
43	Distributed generation allowance	413	
44	Extended reserves allowance		
45	Other recoverable costs excluding financial incentives and wash-ups		
46	**Pass-through and recoverable costs excluding financial incentives and wash-ups**		18,819
47			

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

65	**3(iv): Merger and Acquisition Expenditure**	
70		**($000)**
66	Merger and acquisition expenditure	
67		
68	*Provide commentary on the benefits of merger and acquisition expenditure to the electricity distribution business, including required disclosures in accordance with section 2.7, in Schedule 14 (Mandatory Explanatory Notes)*	
69	**3(v): Other Disclosures**	
70		**($000)**
71	Self-insurance allowance	

Company Name	**Northpower**
For Year Ended	**31 March 2023**

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

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)
Total opening RAB value	262,813	267,167	279,361	298,438	328,448
less **Total depreciation**	10,169	9,962	10,574	11,454	12,204
plus **Total revaluations**	3,897	6,765	4,241	20,647	21,787
plus **Assets commissioned**	12,121	16,089	24,903	20,879	15,667
less **Asset disposals**	42	57	29	453	151
plus **Lost and found assets adjustment**	–	–	–	–	–
plus **Adjustment resulting from asset allocation**	(1,453)	(642)	536	392	(379)
Total closing RAB value	267,167	279,361	298,438	328,448	353,169

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
Total opening RAB value		330,768		328,448
less				
Total depreciation		12,320		12,204
plus				
Total revaluations		21,941		21,787
plus				
Assets commissioned (other than below)	2,295		2,295	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	13,372		13,372	
Assets commissioned		15,667		15,667
less				
Asset disposals (other than below)	151		151	
Asset disposals to a regulated supplier				
Asset disposals to a related party				
Asset disposals		151		151
plus **Lost and found assets adjustment**				
plus **Adjustment resulting from asset allocation**				(379)
Total closing RAB value		355,905		353,169

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

Company Name	**Northpower**
For Year Ended	**31 March 2023**

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

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

sch ref			Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
54		CPI_4				1,218
55		CPI_4^{-4}				1,142
56		Revaluation rate (%)				6.65%
60		Total opening RAB value	330,768		328,448	
61	*less*	Opening value of fully depreciated, disposed and lost assets	1,069		1,069	
63		Total opening RAB value subject to revaluation	329,698		327,379	
64		**Total revaluations**		21,941		21,787

4(iv): Roll Forward of Works Under Construction

sch ref			Unallocated works under construction		Allocated works under construction	
68		**Works under construction—preceding disclosure year**		8,297		8,375
69	*plus*	Capital expenditure	25,141		22,478	
70	*less*	Assets commissioned	15,667		15,667	
71	*plus*	Adjustment resulting from asset allocation				
72		**Works under construction - current disclosure year**		17,771		15,186
74		Highest rate of capitalised finance applied				6.21%

4(v): Regulatory Depreciation

sch ref		Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
79	Depreciation - standard	11,695		11,584	
80	Depreciation - no standard life assets	625		620	
81	Depreciation - modified life assets				
82	Depreciation - alternative depreciation in accordance with CPP				
83	**Total depreciation**		12,320		12,204

4(vi): Disclosure of Changes to Depreciation Profiles

($000 unless otherwise specified)

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

95 ** include additional rows if needed*

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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

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

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

sch ref			Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
98												
99		**Total opening RAB value**	7,944	10,366	34,749	132,617	52,542	53,819	8,911	8,019	19,483	328,448
100	*less*	Total depreciation	375	310	1,416	4,467	1,908	1,866	395	847	620	12,204
101	*plus*	Total revaluations	528	690	2,309	8,828	3,494	3,576	593	483	1,286	21,787
102	*plus*	Assets commissioned	360	–	4,513	6,541	(364)	1,906	1,163	–	1,549	15,667
103	*less*	Asset disposals	8	–	–	68	–	74	–	–	–	151
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	10	–	–	(256)	(45)	–	–	–	(87)	(379)
106	*plus*	Asset category transfers	–	–	–	–	–	–	–	–	–	–
107		**Total closing RAB value**	8,458	10,745	40,155	143,194	53,718	57,361	10,272	7,655	21,611	353,169
108												
109		**Asset Life**										
110		Weighted average remaining asset life	33.2	38.2	32.0	41.7	32.1	35.2	27.0	16.1	28.9	(years)
111		Weighted average expected total asset life	54.9	57.6	43.4	59.6	47.6	45.0	38.0	22.2	34.2	(years)

Company Name	Northpower
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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

sch ref					
7	**5a(i): Regulatory Tax Allowance**				**($000)**
8		**Regulatory profit / (loss) before tax**			20,714
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	22	*	
12		Amortisation of initial differences in asset values	4,532		
13		Amortisation of revaluations	2,302		
14					6,856
15					
16	*less*	Total revaluations	21,787		
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	5,658		
21					27,445
22					
23		**Regulatory taxable income**			125
24					
25	*less*	Utilised tax losses			
26		Regulatory net taxable income			125
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			35
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	91,999		
37	*less*	Amortisation of initial differences in asset values	4,532		
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			87,467
41					
42		Opening weighted average remaining useful life of relevant assets (years)			20.3
43					
44	**5a(iv): Amortisation of Revaluations**				**($000)**
45					
46		Opening sum of RAB values without revaluations	274,300		
47					
48		Adjusted depreciation	9,902		
49		Total depreciation	12,204		
50		Amortisation of revaluations			2,302
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**			–

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For Year Ended	31 March 2023

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

sch ref

sch ref		5a(vi): Calculation of Deferred Tax Balance		($000)
60		**Opening deferred tax**	(14,210)	
62	*plus*	Tax effect of adjusted depreciation	2,773	
64	*less*	Tax effect of tax depreciation	3,450	
66	*plus*	Tax effect of other temporary differences*	(21)	
68	*less*	Tax effect of amortisation of initial differences in asset values	1,269	
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year		
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year	(41)	
74	*plus*	Deferred tax cost allocation adjustment	183	
76		**Closing deferred tax**		(15,954)

5a(vii): Disclosure of Temporary Differences

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).

5a(viii): Regulatory Tax Asset Base Roll-Forward

sch ref				($000)
83		**Opening sum of regulatory tax asset values**	132,516	
84	*less*	Tax depreciation	12,321	
85	*plus*	Regulatory tax asset value of assets commissioned	15,512	
86	*less*	Regulatory tax asset value of asset disposals	6	
87	*plus*	Lost and found assets adjustment		
88	*plus*	Adjustment resulting from asset allocation	273	
89	*plus*	Other adjustments to the RAB tax value	–	
90		**Closing sum of regulatory tax asset values**		135,974

Company Name **Northpower**
For Year Ended **31 March 2023**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

This schedule provides information on the valuation of related party transactions, in accordance with clause 2.3.6 of 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			
7	**5b(i): Summary—Related Party Transactions**	**($000)**	**($000)**
8	**Total regulatory income**		
9			
10	**Market value of asset disposals**		
11			
12	Service interruptions and emergencies	6,848	
13	Vegetation management	2,738	
14	Routine and corrective maintenance and inspection	3,902	
15	Asset replacement and renewal (opex)	5,060	
16	**Network opex**		18,549
17	Business support	19	
18	System operations and network support	256	
19	**Operational expenditure**		18,824
20	Consumer connection	130	
21	System growth	920	
22	Asset replacement and renewal (capex)	14,752	
23	Asset relocations	8	
24	Quality of supply	1	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	530	
27	**Expenditure on non-network assets**		16
28	**Expenditure on assets**		16,356
29	Cost of financing		
30	Value of capital contributions		
31	Value of vested assets		
32	**Capital Expenditure**		16,356
33	**Total expenditure**		35,180
34			
35	**Other related party transactions**		

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

	Name of related party	**Nature of opex or capex service provided**	**Total value of transactions ($000)**
37			
38	Northpower Contracting Division	Service interruptions and emergencies	6,848
39	Northpower Contracting Division	Vegetation management	2,738
40	Northpower Contracting Division	Routine and corrective maintenance and inspection	3,902
41	Northpower Contracting Division	Asset replacement and renewal (opex)	5,041
42	Northpower Contracting Division	System operations and network support	198
43	Northpower Fibre Ltd	System operations and network support	58
44	Electricity Engineers' Association	Business support	19
45	Busck Prestressed Concrete	Asset replacement and renewal (opex)	19
46	Northpower Contracting Division	Asset relocations	8
47	Northpower Contracting Division	Consumer connection	130
48	Northpower Contracting Division	Asset replacement and renewal (capex)	14,749
49	Northpower Contracting Division	Quality of supply	1
50	Northpower Contracting Division	Other reliability, safety and environment	530
51	Northpower Contracting Division	System growth	920
52	Northpower Contracting Division	Expenditure on non-network assets	16
53	**Total value of related party transactions**		35,180

54 ** include additional rows if needed*
55

Company Name	**Northpower**
For Year Ended	**31 March 2023**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

7

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

9

sch ref	Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
10									
11									
12									
13									
14									
15									
16	** include additional rows if needed*						–	–	–

17

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

sch ref			
19			
20	**Gross term credit spread differential**		–
21			
22	Total book value of interest bearing debt		
23	Leverage	42%	
24	Average opening and closing RAB values		
25	**Attribution Rate (%)**		–
26			
27	**Term credit spread differential allowance**		–

Company Name	**Northpower**
For Year Ended	**31 March 2023**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

This schedule provides information on the allocation of operational costs. EDBs must provide explanatory comment on their cost allocation in Schedule 14 (Mandatory Explanatory Notes), including on the impact of any reclassifications.
This information is part of audited disclosure information (as defined in section 1.4 of 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		6,971			
12	Not directly attributable				–	
13	**Total attributable to regulated service**		6,971			
14	**Vegetation management**					
15	Directly attributable		2,874			
16	Not directly attributable				–	
17	**Total attributable to regulated service**		2,874			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		4,001			
20	Not directly attributable				–	
21	**Total attributable to regulated service**		4,001			
22	**Asset replacement and renewal**					
23	Directly attributable		5,303			
24	Not directly attributable				–	
25	**Total attributable to regulated service**		5,303			
26	**System operations and network support**					
27	Directly attributable		4,398			
28	Not directly attributable				–	
29	**Total attributable to regulated service**		4,398			
30	**Business support**					
31	Directly attributable		7,890			
32	Not directly attributable		5,093	13,645	18,738	
33	**Total attributable to regulated service**		12,983			
34						
35	**Operating costs directly attributable**		31,436			
36	**Operating costs not directly attributable**	–	5,093	13,645	18,738	–
37	**Operational expenditure**		36,529			
38						

Company Name	**Northpower**
For Year Ended	**31 March 2023**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(ii): Other Cost Allocations

Pass through and recoverable costs	($000)
Pass through costs	
Directly attributable	477
Not directly attributable	
Total attributable to regulated service	477
Recoverable costs	
Directly attributable	18,342
Not directly attributable	
Total attributable to regulated service	18,342

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

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

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

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

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

Company Name	**Northpower**
For Year Ended	**31 March 2023**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	8,183
Not directly attributable	276
Total attributable to regulated service	8,459
Subtransmission cables	
Directly attributable	10,745
Not directly attributable	
Total attributable to regulated service	10,745
Zone substations	
Directly attributable	40,155
Not directly attributable	
Total attributable to regulated service	40,155
Distribution and LV lines	
Directly attributable	135,641
Not directly attributable	7,553
Total attributable to regulated service	143,194
Distribution and LV cables	
Directly attributable	53,231
Not directly attributable	487
Total attributable to regulated service	53,718
Distribution substations and transformers	
Directly attributable	57,360
Not directly attributable	
Total attributable to regulated service	57,360
Distribution switchgear	
Directly attributable	10,272
Not directly attributable	
Total attributable to regulated service	10,272
Other network assets	
Directly attributable	6,446
Not directly attributable	1,209
Total attributable to regulated service	7,655
Non-network assets	
Directly attributable	18,066
Not directly attributable	3,545
Total attributable to regulated service	21,611
Regulated service asset value directly attributable	340,099
Regulated service asset value not directly attributable	13,070
Total closing RAB value	353,169

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

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

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

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

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

Company Name	**Northpower**
For Year Ended	**31 March 2023**

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

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

sch ref			($000)	($000)
7		**6a(i): Expenditure on Assets**	($000)	($000)
8		Consumer connection		5,821
9		System growth		2,670
10		Asset replacement and renewal		17,501
11		Asset relocations		514
12		Reliability, safety and environment:		
13		Quality of supply	358	
14		Legislative and regulatory	60	
15		Other reliability, safety and environment	1,500	
16		**Total reliability, safety and environment**		1,918
17		**Expenditure on network assets**		28,425
18		Expenditure on non-network assets		812
19				
20		**Expenditure on assets**		29,237
21	*plus*	Cost of financing		633
22	*less*	Value of capital contributions		7,392
23	*plus*	Value of vested assets		
24				
25		**Capital expenditure**		22,478

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	
	Cybersecurity (Commission only)	

30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	($000)	($000)
32		All customer types	5,821	
33				
34				
35				
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		5,821
39				
40	*less*	Capital contributions funding consumer connection expenditure	7,392	
41		**Consumer connection less capital contributions**		(1,571)

42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement and**
43			**System Growth**	**Renewal**
44			**($000)**	**($000)**
45		Subtransmission	–	23
46		Zone substations	1,761	5,964
47		Distribution and LV lines	2	8,006
48		Distribution and LV cables	15	451
49		Distribution substations and transformers	893	1,801
50		Distribution switchgear	–	2
51		Other network assets	–	1,254
52		**System growth and asset replacement and renewal expenditure**	2,670	17,501
53	*less*	Capital contributions funding system growth and asset replacement and renewal		
54		**System growth and asset replacement and renewal less capital contributions**	2,670	17,501
55				

56		**6a(v): Asset Relocations**		
57		*Project or programme**	($000)	($000)
58		Manuka Place	33	
59		Ground Mounted Sub	370	
60		Minor Relocation	95	
61		Overhead to Underground	17	
62				
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations		
65		**Asset relocations expenditure**		514
66	*less*	Capital contributions funding asset relocations		
67		**Asset relocations less capital contributions**		514

Company Name	**Northpower**
For Year Ended	**31 March 2023**

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

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

sch ref				
68				
69	**6a(vi): Quality of Supply**			
70		*Project or programme**	**($000)**	**($000)**
71		Communications for remote control	1	
72		Maungaturoto to Mangawhai 33kV	93	
73		System Growth	264	
74				
75				
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply		
78		**Quality of supply expenditure**		358
79	*less*	Capital contributions funding quality of supply		
80		**Quality of supply less capital contributions**		358
81	**6a(vii): Legislative and Regulatory**			
82		*Project or programme**	**($000)**	**($000)**
83		Zone substation risk mitigation	60	
84				
85				
86				
87				
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory		
90		**Legislative and regulatory expenditure**		60
91	*less*	Capital contributions funding legislative and regulatory		
92		**Legislative and regulatory less capital contributions**		60
93	**6a(viii): Other Reliability, Safety and Environment**			
94		*Project or programme**	**($000)**	**($000)**
95		Dsub MDI Meters	1	
		Long & Crawford GMS replacement	289	
		Minor capital expenditure R,S&E improvement	266	
		Research & Development	6	
96		Ring main units	76	
97		SCADA & communications improvements	1	
98		Zone substation security improvements	5	
99		Zone substation Transformer upgrade	856	
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment		
102		**Other reliability, safety and environment expenditure**		1,500
103	*less*	Capital contributions funding other reliability, safety and environment		
104		**Other reliability, safety and environment less capital contributions**		1,500
105				
106	**6a(ix): Non-Network Assets**			
107		**Routine expenditure**		
108		*Project or programme**	**($000)**	**($000)**
109		Hiko	98	
110		Lease vehicles	75	
111				
112				
113				
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure		
116		**Routine expenditure**		174
117		**Atypical expenditure**		
118		*Project or programme**	**($000)**	**($000)**
119		Asset Data Management System (ADMS)	384	
120		Faults Management System	253	
121		G Tech Upgrade	2	
122				
123				
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure		
126		**Atypical expenditure**		638
127				
128		**Expenditure on non-network assets**		812

Company Name	Northpower
For Year Ended	31 March 2023

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

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

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	6,971	
9	Vegetation management	2,874	
10	Routine and corrective maintenance and inspection	4,001	
11	Asset replacement and renewal	5,303	
12	**Network opex**		19,149
13	System operations and network support	4,398	
14	Business support	12,983	
15	**Non-network opex**		17,381
16			
17	**Operational expenditure**		36,529
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	*EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*		
20	Energy efficiency and demand side management, reduction of energy losses		
21	Direct billing*		
22	Research and development		
23	Insurance		
24	Cybersecurity (Commission only)		
25	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Northpower**
For Year Ended	**31 March 2023**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

EDBs must provide explanatory comment on the variance between actual and target revenue and forecast expenditure in Schedule 14 (Mandatory Explanatory Notes). This information is part of the audited disclosure information (as defined in section 1.4 of 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

sch ref		Target ($000) [1]	Actual ($000)	% variance
7	**7(i): Revenue**			
8	Line charge revenue	66,600	65,767	(1%)

sch ref		Forecast ($000) [2]	Actual ($000)	% variance
9	**7(ii): Expenditure on Assets**			
10	Consumer connection	4,238	5,821	37%
11	System growth	10,535	2,670	(75%)
12	Asset replacement and renewal	23,055	17,501	(24%)
13	Asset relocations	109	514	372%
14	Reliability, safety and environment:			
15	Quality of supply	3,624	358	(90%)
16	Legislative and regulatory	–	60	–
17	Other reliability, safety and environment	921	1,500	63%
18	**Total reliability, safety and environment**	4,545	1,918	(58%)
19	**Expenditure on network assets**	42,482	28,425	(33%)
20	Expenditure on non-network assets	2,780	812	(71%)
21	Expenditure on assets	45,261	29,237	(35%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	2,799	6,971	149%
24	Vegetation management	2,902	2,874	(1%)
25	Routine and corrective maintenance and inspection	3,724	4,001	7%
26	Asset replacement and renewal	2,642	5,303	101%
27	**Network opex**	12,066	19,149	59%
28	System operations and network support	3,673	4,398	20%
29	Business support	14,796	12,983	(12%)
30	**Non-network opex**	18,469	17,381	(6%)
31	**Operational expenditure**	30,535	36,529	20%
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses		–	–
34	Overhead to underground conversion		–	–
35	Research and development		–	–
36				
37	**7(v): Subcomponents of Operational Expenditure (where known)**			
38	Energy efficiency and demand side management, reduction of energy losses		–	–
39	Direct billing		–	–
40	Research and development		–	–
41	Insurance		–	–
42				

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

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

Company Name	Northpower
For Year Ended	31 March 2023
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

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

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
15	DM1 - Principal Res - Low User	Residential	Standard	4,548	21,338
16	DM1-TOU - Principal Res - Low User	Residential	Standard	25,699	137,502
17	DM3 - Non-Principal Residence	Residential	Standard	1,099	3,231
18	DM3-TOU - Non-Principal Residence	Residential	Standard	4,264	15,663
19	DM7 - Principal Res - Standard	Residential	Standard	2,657	21,323
20	DM7-TOU - Principal Res - Standard	Residential	Standard	13,401	126,227
21	ND1 - Up to 70kVA (100A or less)	General	Standard	3,452	37,364
22	ND1-TOU - Up to 70kVA (100A or less)	General	Standard	6,420	77,497
23	ND2 - Above 70kVA (CT Metering)	General	Standard	113	8,921
24	ND2-TOU - Above 70kVA (CT Metering)	General	Standard	315	30,595
25	ND5 - Irrigation and Pumps	General	Standard	70	2,140
26	ND6 - Unmetered 24 Hour	General	Standard	193	283
27	ND7 - Unmetered Public Lighting	General	Standard	17	2,382
28	ND12 - Builders Supply	General	Standard	578	641
29	LC1 - Low Voltage Volume Based ToU	Large Commercial	Standard	48	8,259
30	LC2 - Low Voltage Capacity Based	Large Commercial	Standard	30	20,742
31	LC3 - Dedicated Transformer Capacity	Large Commercial	Standard	88	64,226
32	LC4 - High Voltage Capacity Based	Large Commercial	Standard	2	1,494
33	IND - Individual Pricing	Asset Based	Non-standard	8	212,139
34	Discount (1 to 1,999 kWh)	All Consumers	Standard		
35	Discount (2,000+ kWh)	All Consumers	Standard		
36					
37			Standard consumer totals	62,994	579,827
38			Non-standard consumer totals	8	212,139
39			Total for all consumers	63,002	791,966

Billed quantities by price component

sch ref	Price component	Daily Fixed Charge	Daily Fixed Charge	Consumption	Injection	Demand (incl Excess Demand)	Capacity	Excess Reactive Power	Excess Reactive Power	Asset Utilisation	Transmission Pass Through	Eligible Discount
13	Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	ICP Day	Fixture Day	kWh	kWh	kVA	kVA	kVArh	kVAr	Per ICP	Per ICP	Per ICP
15	DM1 - Principal Res - Low User	1,449,267		21,137,197	699,695							
16	DM1-TOU - Principal Res - Low User	9,421,494		138,287,506	1,917,087							
17	DM3 - Non-Principal Residence	368,954		3,174,613	86,370							
18	DM3-TOU - Non-Principal Residence	1,583,928		15,785,363	83,753							
19	DM7 - Principal Res - Standard	897,420		21,319,538	477,167							
20	DM7-TOU - Principal Res - Standard	4,987,759		126,118,044	1,070,019							
21	ND1 - Up to 70kVA (100A or less)	1,009,312		37,068,601	48,849							
22	ND1-TOU - Up to 70kVA (100A or less)	213,645		77,469,168	428,763							
23	ND2 - Above 70kVA (CT Metering)	35,407		8,854,920	(5,715)							
24	ND2-TOU - Above 70kVA (CT Metering)	119,543		30,604,040	756,152							
25	ND5 - Irrigation and Pumps	24,203		2,196,222								
26	ND6 - Unmetered 24 Hour	72,261		288,393								
27	ND7 - Unmetered Public Lighting	110,895		2,382,234								
28	ND12 - Builders Supply	213,645		526,009								
29	LC1 - Low Voltage Volume Based ToU	17,338		8,299,713	76,102			3,427				
30	LC2 - Low Voltage Capacity Based	10,178			–	50,381	72,880	4,890				
31	LC3 - Dedicated Transformer Capacity	33,108			642	201,783	604,846	26,774				
32	LC4 - High Voltage Capacity Based	730				4,497	18,600	1,920				
33	IND - Individual Pricing			212,138,633				4,632	49,787	8	8	
34	Discount (1 to 1,999 kWh)											8,522
35	Discount (2,000+ kWh)											52,559
36												
37	Standard consumer totals	20,569,087	–	493,511,561	5,638,884	256,661	696,326	37,011	–	–	–	61,081
38	Non-standard consumer totals	–	–	212,138,633	–	–	–	4,632	49,787	8	8	–
39	Total for all consumers	20,569,087	–	705,650,194	5,638,884	256,661	696,326	41,643	49,787	8	8	61,081

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

42 ### 8(ii): Line Charge Revenues ($000) by Price Component

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)
48	DM1 - Principal Res - Low User	Residential	Standard	$2,641		$2,641	
49	DM1-TOU - Principal Res - Low User	Residential	Standard	$16,669		$16,669	
50	DM3 - Non-Principal Residence	Residential	Standard	$720		$720	
51	DM3-TOU - Non-Principal Residence	Residential	Standard	$3,147		$3,147	
52	DM7 - Principal Res - Standard	Residential	Standard	$2,461		$2,461	
53	DM7-TOU - Principal Res - Standard	Residential	Standard	$13,474		$13,474	
54	ND1 - Up to 70kVA (100A or less)	General	Standard	$5,000		$5,000	
55	ND1-TOU - Up to 70kVA (100A or less)	General	Standard	$10,646		$10,646	
56	ND2 - Above 70kVA (CT Metering)	General	Standard	$1,088		$1,088	
57	ND2-TOU - Above 70kVA (CT Metering)	General	Standard	$3,625		$3,625	
58	ND5 - Irrigation and Pumps	General	Standard	$215		$215	
59	ND6 - Unmetered 24 Hour	General	Standard	$272		$272	
60	ND7 - Unmetered Public Lighting	General	Standard	$768		$768	
61	ND12 - Builders Supply	General	Standard	$323		$323	
62	LC1 - Low Voltage Volume Based ToU	Large Commercial	Standard	$1,100		$1,100	
63	LC2 - Low Voltage Capacity Based	Large Commercial	Standard	$626		$626	
64	LC3 - Dedicated Transformer Capacity	Large Commercial	Standard	$4,900		$4,900	
65	LC4 - High Voltage Capacity Based	Large Commercial	Standard	$142		$142	
66	IND - Individual Pricing	Asset Based	Non-standard	$10,268		$10,268	
67	Discount (1 to 1,999 kWh)	All Consumers	Standard	($703)		($703)	
68	Discount (2,000+ kWh)	All Consumers	Standard	($11,616)		($11,616)	
69				–			
71			Standard consumer totals	$55,499	–	$55,499	–
72			Non-standard consumer totals	$10,268	–	$10,268	–
73			Total for all consumers	$65,767	–	$65,767	–

70 *Add extra rows for additional consumer groups or price category codes as necessary*

Line charge revenues ($000) by price component

sch ref	Price component											
46	Rate (eg, $ per day, $ per kWh, etc.)											
48	DM1 - Principal Res - Low User	$435		$2,200	$7							
49	DM1-TOU - Principal Res - Low User	$2,826		$13,824	$19							
50	DM3 - Non-Principal Residence	$553		$166	$1							
51	DM3-TOU - Non-Principal Residence	$2,376		$771	$1							
52	DM7 - Principal Res - Standard	$1,346		$1,110	$5							
53	DM7-TOU - Principal Res - Standard	$7,482		$5,982	$10							
54	ND1 - Up to 70kVA (100A or less)	$2,120		$2,880	$1							
55	ND1-TOU - Up to 70kVA (100A or less)	$4,872		$5,770	$4							
56	ND2 - Above 70kVA (CT Metering)	$159		$928	$0							
57	ND2-TOU - Above 70kVA (CT Metering)	$538		$3,080	$7							
58	ND5 - Irrigation and Pumps	$51		$165								
59	ND6 - Unmetered 24 Hour	$249		$23								
60	ND7 - Unmetered Public Lighting	$579		$188								
61	ND12 - Builders Supply	$299		$24								
62	LC1 - Low Voltage Volume Based ToU	$78		$1,015	$1			$6				
63	LC2 - Low Voltage Capacity Based	$46			–	$1	$570	$8				
64	LC3 - Dedicated Transformer Capacity	$149			$0	$21	$4,686	$44				
65	LC4 - High Voltage Capacity Based	$3			–	($0)	$135	$3				
66	IND - Individual Pricing			$41					$88	$3,445	$6,693	
67	Discount (1 to 1,999 kWh)											($703)
68	Discount (2,000+ kWh)											($11,616)
69												
71	Standard consumer totals	$24,162	–	$38,125	$56	$22	$5,392	$61	–	–	–	($12,319)
72	Non-standard consumer totals	–	–	$41	–	–	–	–	$88	$3,445	$6,693	–
73	Total for all consumers	$24,162	–	$38,167	$56	$22	$5,392	$61	$88	$3,445	$6,693	($12,319)

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

75 ### 8(iii): Number of ICPs directly billed

Check: OK

76 Number of directly billed ICPs at year end: 1

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

SCHEDULE 9a: ASSET REGISTER

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

sch ref

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	53,560	53,759	199	2
10	All	Overhead Line	Wood poles	No.	1,167	1,137	(30)	2
11	All	Overhead Line	Other pole types	No.	49	48	(1)	2
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	296	296	(1)	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	28	28	–	3
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	12	13	1	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	8	8	–	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km			–	4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	3	3	–	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	0	0	–	4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km			–	4
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km			–	4
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km			–	4
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	1	1	–	4
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	21	21	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	1	1	–	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.			–	4
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	19	19	–	2
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	29	36	7	2
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	175	175	–	2
29	HV	Zone substation switchgear	33kV RMU	No.	4	4	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	37	38	1	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	59	59	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	157	158	1	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.			–	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	43	41	(2)	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3,506	3,507	2	2
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km			–	4
37	HV	Distribution Line	SWER conductor	km			–	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	263	272	9	3
39	HV	Distribution Cable	Distribution UG PILC	km	39	38	(0)	2
40	HV	Distribution Cable	Distribution Submarine Cable	km	2	2	–	1
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	33	33	–	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.			–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	8,555	8,605	50	2
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	16	16	–	2
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	232	234	2	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	6,011	6,039	28	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,517	1,552	35	3
48	HV	Distribution Transformer	Voltage regulators	No.	12	12	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	119	116	(3)	4
50	LV	LV Line	LV OH Conductor	km	1,182	1,185	2	2
51	LV	LV Cable	LV UG Cable	km	812	837	26	2
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	410	418	9	2
53	LV	Connections	OH/UG consumer service connections	No.	62,537	63,445	908	2
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	359	381	22	2
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	23	23	–	4
57	All	Load Control	Centralised plant	Lot	6	6	–	4
58	All	Load Control	Relays	No	39,227	39,561	334	2
59	All	Civils	Cable Tunnels	km	–		–	N/A

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

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 Disclosure Year (year ended)

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940–1949	1950–1959	1960–1969	1970–1979	1980–1989	1990–1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
9																																									
10	All	Overhead Line	Concrete poles / steel structure	No.	144	152	1,524	7,959	13,147	9,584	7,779	626	504	680	679	836	793	665	576	610	722	720	662	703	591	601	579	522	389	324	354	380	376	407	171				53,759	4,454	2
11	All	Overhead Line	Wood poles	No.	1		10	56	136	433	255	17	20	24	40	53	33	23	5	8	3	3	4		3	2	2	2		2	2								1,137	209	2
12	All	Overhead Line	Other pole types	No.			2	5	13	19	4			2		2			1																				48	2	2
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km			70	104	28	38	46	4	0	0	1	0			0	0	0	0		1	0						1	2		0	0				296	2	3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km					28																														28		3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km						1	0	1	3	0	0		0	0	0		3	0		0		2	0				0	0	1	1	0				13	0	3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km				5	3	0																													8		4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km																																			–		4
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km						3																													3		4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km							0																0												0		4
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km																																			–		4
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km																																			–		4
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km																																			–		4
23	HV	Subtransmission Cable	Subtransmission submarine cable	km							1																												1		4
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	1		3	7	1	4	1	1							1	1													1						21	2	4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.						1																													1		4
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.																																			–		4
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	1	2	6	2			3	3		2																									19	2	2
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.														4		31	1																		36	23	2
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			14	66	10	11	2	2		4	5	1	25	3	1	8	5		1	2	2				5	1	6	1							175	5	2
30	HV	Zone substation switchgear	33kV RMU	No.								2	2																										4		4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.						18	1		1	1				1		3	2				1	1					5	3	1						38		4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.						5	22	6				5	1	3	1		2			2			5	1	4				2						59		4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.				5	13	20	1		5		4			9	31		17	12			1						17	11	12						158		4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.																																			–		4
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.			1	10	7	4			1	2	1		2				2					2			1	2	2	2	2						41		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	9	19	83	548	694	674	577	72	35	47	31	66	33	21	21	19	18	23	39	67	78	26	42	34	36	38	61	35	31	23	5				3,507	53	2
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																			–		4
38	HV	Distribution Line	SWER conductor	km																																			–		4
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km				1	0	10	29	7	7	12	9	15	24	27	20	8	12	4	3	4	9	5	6	6	6	7	10	9	11	9	1				272	4	3
40	HV	Distribution Cable	Distribution UG PILC	km				5	9	14	6	2	1		0	0	1	0		0		0	0	0															38	4	2
41	HV	Distribution Cable	Distribution Submarine Cable	km					2																														2		1
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.								2	1			1	8		1	2	2	1	1	1	2	1	2			1	1	2	1	2	1				33		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.																																			–		4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	5	8	8	130	228	521	1,031	135	124	147	151	197	212	218	198	351	523	340	488	383	397	363	398	292	307	261	278	254	290	337	30				8,605		2
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.					4	8																				2	1	1							16	1	2
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.					3	7	14	2	4	2	2	2	29	25	6	9	19	4	5	5	6	7	8	8	11	8	11	11	17	6	3				234		4
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	69	115	106	500	417	405	1,081	164	128	152	130	167	158	157	201	120	143	47	135	91	138	225	147	114	167	153	196	154	132	127					6,039	15	3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	3	3	12	148	158	153	138	34	34	41	28	57	80	86	69	25	37	49	6	1	14	34	47	36	43	33	44	41	73	25					1,552	2	3
49	HV	Distribution Transformer	Voltage regulators	No.					2		2					3											3				2								12		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.				12	21	22	31	5	1	7	1	1			1	4	2	1	1	2	1					2	1								116		4
51	LV	LV Line	LV OH Conductor	km	1	1	20	149	170	493	170	10	8	10	22	22	19	14	6	5	6	5	5	3	3	3	4	3	3	4	5	8	4	5	1				1,185	273	2
52	LV	LV Cable	LV UG Cable	km	0		0	24	52	77	85	19	20	28	35	49	52	49	47	25	29	16	7	6	17	8	15	24	26	29	25	21	21	29	2				837	23	2
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km			2	47	148	40	52	2	4	3	4	8	10	12	11	6	12	1	3	1	3	6	4	3	6	7	4	4	5	9	0				418	99	2
54	LV	Connections	OH/UG consumer service connections	No.	1	15	70	1,682	4,105	19,184	15,824	2,145	815	894	1,104	1,126	1,175	1,111	1,055	853	776	744	593	632	646	630	854	1,089	1,116	1,058	945	916	1,119	1,052	116				63,445	12,421	2
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.					7	19	54	6	5	4	1	5	20	13	28	48	16	31	3	5	1	4	2	22		18	27	20	18	2	2				381	10	2
56	All	SCADA and communications	SCADA and communications equipment operating as a single syste	Lot																												1							1		4
57	All	Capacitor Banks	Capacitors including controls	No							5						2			1	5	5		3				1						1					23		4
58	All	Load Control	Centralised plant	Lot						2					2				1			1																	6		4
59	All	Load Control	Relays	No											144	244	69	16	19	26	20	24	20	21	16	12	20	11	13	14	5	1,381	405	505	5			36,571	39,561	297	2
60	All	Civils	Cable Tunnels	km																																			–		N/A

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

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	28	0	28
12	50kV & 66kV	75		75
13	33kV	221	25	246
14	SWER (all SWER voltages)			–
15	22kV (other than SWER)			–
16	6.6kV to 11kV (inclusive—other than SWER)	3,507	312	3,819
17	Low voltage (< 1kV)	1,185	837	2,022
18	**Total circuit length (for supply)**	5,016	1,175	6,190
19				
20	Dedicated street lighting circuit length (km)			–
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	570	11%	
25	Rural	4,446	89%	
26	Remote only		–	
27	Rugged only		–	
28	Remote and rugged		–	
29	Unallocated overhead lines		–	
30	**Total overhead length**	5,016	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	3,417	55%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	5,016	100%	

Company Name	**Northpower**
For Year Ended	**31 March 2023**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref

8	**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	**Northpower**
For Year Ended	**31 March 2023**
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref				
8		**9e(i): Consumer Connections and Decommissionings**		
9		*Number of ICPs connected during year by consumer type*		
10		*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11		Mass Market New ICPs	779	
12		Large Customer and industrial (ND9) New ICPs	2	
13		Very Large industrial New ICPs	–	
14				
15				
16		** include additional rows if needed*		
17		**Connections total**	781	
18				
19		*Number of ICPs decommissioned during year by consumer type*		
20		*Consumer types defined by EDB**	**Number of decommissionings**	
21		Mass Market ICPs	1,422	
22		Large Customer and industrial (ND9) ICPs	–	
23		Very Large industrial ICPs	–	
24				
25				
26		** include additional rows if needed*		
27		**Decommissionings total**	1,422	
28				
29		**Distributed generation**		
30		Number of connections made in year	414	**connections**
32		Capacity of distributed generation installed in year	2.62	**MVA**
33				
34		**9e(ii): System Demand**		
35				
36				
37		**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
38		GXP demand	153	
39	*plus*	Distributed generation output at HV and above	5	
40		**Maximum coincident system demand**	157	
41	*less*	Net transfers to (from) other EDBs at HV and above		
42		**Demand on system for supply to consumers' connection points**	157	
43		**Electricity volumes carried**	**Energy (GWh)**	
44		Electricity supplied from GXPs	816	
45	*less*	Electricity exports to GXPs	–	
46	*plus*	Electricity supplied from distributed generation	21	
47	*less*	Net electricity supplied to (from) other EDBs	–	
48		**Electricity entering system for supply to consumers' connection points**	837	
49	*less*	Total energy delivered to ICPs	792	
51		**Electricity losses (loss ratio)**	46	5.4%
52				
53		**Load factor**	0.61	
54		**9e(iii): Transformer Capacity**		
55			**(MVA)**	
56		Distribution transformer capacity (EDB owned)	600	
57		Distribution transformer capacity (Non-EDB owned, estimated)	5	
58		**Total distribution transformer capacity**	605	
59				
60		**Zone substation transformer capacity**	354	
61				

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

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 10(i): Interruptions

sch ref		Number of interruptions
9	**Interruptions by class**	
10	Class A (planned interruptions by Transpower)	
11	Class B (planned interruptions on the network)	379
12	Class C (unplanned interruptions on the network)	932
13	Class D (unplanned interruptions by Transpower)	–
14	Class E (unplanned interruptions of EDB owned generation)	
15	Class F (unplanned interruptions of generation owned by others)	
16	Class G (unplanned interruptions caused by another disclosing entity)	
17	Class H (planned interruptions caused by another disclosing entity)	
18	Class I (interruptions caused by parties not included above)	
19	**Total**	1,311
20		

sch ref		≤3Hrs	>3hrs
21	**Interruption restoration**		
22	Class C interruptions restored within	674	258
23			

sch ref		SAIFI	SAIDI
24	**SAIFI and SAIDI by class**		
25	Class A (planned interruptions by Transpower)		
26	Class B (planned interruptions on the network)	0.44	115.6
27	Class C (unplanned interruptions on the network)	7.35	1,099.4
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)		
30	Class F (unplanned interruptions of generation owned by others)		
31	Class G (unplanned interruptions caused by another disclosing entity)		
32	Class H (planned interruptions caused by another disclosing entity)		
33	Class I (interruptions caused by parties not included above)		
34	**Total**	7.79	1,215.0
35			

sch ref		Normalised SAIFI	Normalised SAIDI
36	**Normalised SAIFI and SAIDI**		
37	Classes B & C (interruptions on the network)	5.35	334.8
38			

sch ref		SAIFI	SAIDI
39	**Transitional SAIDI and SAIDI (previous method)**		
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.***		
41	Class B (planned interruptions on the network)		
42	Class C (unplanned interruptions on the network)		
43			

44 10(ii): Class C Interruptions and Duration by Cause

sch ref		SAIFI	SAIDI
45			
46	**Cause**		
47	Lightning	0.03	0.5
48	Vegetation	0.41	21.9
49	Adverse weather	4.70	992.5
50	Adverse environment	0.00	0.0
51	Third party interference	0.37	29.9
52	Wildlife	0.17	7.4
53	Human error	0.02	0.3
54	Defective equipment	0.59	27.0
55	Cause unknown	1.05	19.9
56			

sch ref		SAIFI	SAIDI
57	**Breakdown of third party interference**		
58	Dig-in		
59	Overhead contact		
60	Vandalism		
61	Vehicle damage		
62	Other		
63			

64 10(iii): Class B Interruptions and Duration by Main Equipment Involved

sch ref		SAIFI	SAIDI
65			
66	**Main equipment involved**		
67	Subtransmission lines	0.01	3.4
68	Subtransmission cables	0.00	0.0
69	Subtransmission other		
70	Distribution lines (excluding LV)	0.38	103.0
71	Distribution cables (excluding LV)	0.04	9.2
72	Distribution other (excluding LV)		

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

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

73 **10(iv): Class C Interruptions and Duration by Main Equipment Involved**

74

Row	Main equipment involved	SAIFI	SAIDI
76	Subtransmission lines	0.91	149.1
77	Subtransmission cables		
78	Subtransmission other		
79	Distribution lines (excluding LV)	6.35	943.8
80	Distribution cables (excluding LV)	0.10	6.5
81	Distribution other (excluding LV)		

82 **10(v): Fault Rate**

Row	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
84	Subtransmission lines	37	324	11.42
85	Subtransmission cables		25	–
86	Subtransmission other			
87	Distribution lines (excluding LV)	884	3,508	25.20
88	Distribution cables (excluding LV)	23	313	7.34
89	Distribution other (excluding LV)			
90	**Total**	944		

Company Name	Northpower Limited
For Year Ended	31 March 2023

Schedule 14 Mandatory Explanatory Notes

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

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

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

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

Return on Investment (Schedule 2)

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

Box 1: Explanatory comment on return on investment

The calculated post tax ROI and vanilla ROI for disclosure year were 5.91% and 6.43% respectively. This compares to 8.46% and 8.76% for the previous year.

The reduction in the ROI is a result of increased costs relating to the impact Cyclone Gabrielle had on the Network combined with some significant temporary bypass works required to address geotechnical risks on a key transmission line.

Regulatory Profit (Schedule 3)

5. In the box below, comment on regulatory profit for the disclosure year as disclosed in Schedule 3. This comment must include-

    5.1 a description of material items included in other regulated income (other than gains / (losses) on asset disposals), as disclosed in 3(i) of Schedule 3

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

Box 2: Explanatory comment on regulatory profit

Other regulatory income of $713k relates to value added work on charged to customers.

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

Not applicable – there were no incurred merger and acquisition expenditure during the disclosure year.

Value of the Regulatory Asset Base (Schedule 4)

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

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

- The RAB roll-forward in Schedule 4 is determined in accordance with the IM requirements and is consistent with prior year.
- There were no reclassifications made.
- Disposed assets of $151k were mainly distribution assets impacted by Cyclone Gabrielle.
- Shared assets in the RAB have been allocated with the application of the ABAA approach for this disclosure year. Refer box 8 for details.

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

$22k expenditure or loss in regulatory profit before tax but not tax deductible relates to non deductible entertainment expenditure.

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

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

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

The tax effect of other temporary differences of $21k represents tax on the movement between FY22 and FY23 in the following provisions:

- Holiday leave provisions;
- Long service leave provisions;
- Bonus accrual;
- Doubtful debt provision;
- Cost of financing

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

Cost allocations were calculated using the ABAA methodology as per Part 2.1 of the IM determination for business support.

Business support costs not directly attributable has decreased by $2,817k from FY22. This was largely driven by:

- The realignment of costs from central allocations to business direct costs for specific costs that are now directly managed by the Electricity business.

There has been a change to the Digital allocation category compared with the prior year, but the other categories remain consistent:

- People and capability costs allocated using headcount as causal allocator consistent with prior year.
- Digital costs allocated using either headcount, licence numbers or time as causal allocators. This is a change from FY23 when all costs were allocated based on a weight average of the number of devices.
- Finance costs allocated using gross margin as a proxy allocator consistent with prior year.
- Facilities costs allocated using floor space as a causal allocator consistent with prior year.
- Corporate costs allocated using non-current assets as a proxy allocator consistent with prior 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 allocations were calculated using the ABAA methodology as per Part 2.1 of the IM determination. A summary of RAB assets that were allocated are as follows:

- Sub transmission line, distribution and LV line assets – Shared pole assets used for fibre and network assets (proxy allocator).
- Distribution and LV cables – 100% of CBD ducts and civils exclusively used for the Fibre business.
- Other network assets – Backhaul fibre assets shared between the Fibre and Network business (causal allocator).
- Land and buildings – Estimated area shared between regulated network and non-network businesses (proxy allocator).

The method of asset allocations is consistent with the prior year. No items were reclassified.

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

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

Box 9: Explanation of capital expenditure for the disclosure year
The largest component of capex in FY23 was asset replacement and renewal, followed by consumer connections. This trend is consistent with FY20, FY21 and FY22. All capex projects or programmes above a $50k threshold have been described in schedule 6a, and where possible, we have aggregated projects below this threshold. No items were reclassified.

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

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

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

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

Box 10: Explanation of operational expenditure for the disclosure year
Asset replacement and renewal operating expenditure relates to work done to make good on defects identified during scheduled preventative maintenance inspections. • There are no reclassified items to report. • There is no material atypical expenditure included in the operational expenditure. • Operational expenditure has increased across all categories, in response to asset condition and risk monitoring as well as the impact of storms and Cyclone Gabrielle. The largest increase in expenditure were: ▪ Service interruptions and emergencies ▪ Asset replacement and renewal • Business support – please refer Box 7

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
Asset expenditure was overall 35% lower than the target expenditure. The main underspends were in system growth and asset replacement and renewal which were both impacted by equipment supply delays as well as design resource constraints. • Network Opex was 59% higher than target mainly as a result of the impact Cyclone Gabrielle had on the Network combined with some significant temporary work required to address geotechnical risks on a key transmission line. • Non-network Opex was 6% lower than target.

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
Target revenue disclosed before the start of the year was 1% higher than the total billed line charge revenue for the disclosure year. This was due to slightly lower consumption per ICP and the impact of outages caused by Cyclone Gabrielle.

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

The results for FY23 network reliability and performance results were severely impacted by higher than average adverse weather events during FY23, including Cyclone Gabrielle in February. There were six multi-day summer storms in FY23, compared to two in FY22, with these years showing higher than average SAIDI due to vegetation contact.

Targets for unplanned SAIDI, unplanned SAIFI and faults per 100km were not met in FY23 due to these adverse weather events , with vegetation being the major cause of faults during these events. These events included Cyclone Gabrielle in February which was the most severe weather event seen for 20+ years on the network.

Cyclone Gabrielle's impact on network performance was extensive, with raw SAIDI of 934*, with over 90% of network impacts due to vegetation damage.

However, underlying network performance remains stable, with defective equipment SAIDI remaining reasonably static year on year (when excluding the one-off impacts of Cyclone Gabrielle, and Kensington regional substation outage the prior year).

Our 2023 AMP included another lift in forecast renewal capital expenditure to continue to lift focus on renewing end of life distribution assets, and we have recently introduced a refreshed risk based vegetation programme – which will help to make the network more resilient to adverse weather events, as these are expected to become more common.

Planned SAIDI remain at similar levels to FY22 with the continuing focus on asset renewal across the network to ensure resilience and reliability. Wet weather events have also affected planned work as access into paddocks have been limited over summer, reflecting the lower than forecast planned SAIDI.

*Cyclone Gabrielle impacted normal SAIDI/SAIFI data recording processes between the period 12 February and 19 February 2023 (eight days). Northpower applied to the Commerce Commission and have been granted an exemption to provide estimated data this period. Unplanned normalised SAIDI and SAIFI was estimated during these eight days using operations captured automatically in SCADA from circuit breakers and reclosers. The normalised SAIDI/SAIFI data for the year remains materially accurate and enables comparison with prior years.

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

Significant assets located in one place (e.g. zone substations, control room, other buildings) are insured under a comprehensive replacement insurance policy. Assets that are spread over a large area (e.g. lines, cables and distribution transformers) are uninsured.

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

No amendments to previously disclosed information.

Company Name Northpower Limited

For Year Ended 31 March 2022

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.

Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

S8. Billed Quantities + Revenues – price components

Volume information for price category codes disclosed in schedule 8 is received from retailers at the more detailed price component code level. Some price component codes are used across multiple price category codes and in these instances it is not possible to determine the volume and revenues for each price category code. The volumes and revenue for the price component codes that are shared across multiple price category codes have been treated as being derived from the price category code which is likely to consume the largest proportion.

S8. Billed Quantities + Revenues – ND7 consumption

Excludes consumption by private streetlights as we do not hold this information because we invoice on a wattage basis rather than consumption. Consumers provide voluntary consumption data for public streetlights only. This is consistent with prior years and does not have a significant impact on the disclosures in schedule 8.

S9b. Asset Age Profile

The asset age profile data has been presented by calendar year, which is consistent with prior years. This treatment has been adopted because we do not hold information on the month of installation for historic assets and therefore are not able to align the data to 31 March year ends.

S10. Report on Network Reliability

Reliability measures have been calculated on a consistent basis with previous years, including the treatment of successive interruptions. During the interruption to supply, some customers may be temporarily resorted for a short period due to switching operations carried out in the course of locating a fault (e.g. opening a switch, reclosing a circuit breaker to identify which section has the fault, and repeating this along the circuit until the fault is identified). Northpower treats this activity as one interruption. This is because, until the fault has been located and addressed, supply has not properly been restored along the HV.

This approach has been updated from 1 April 2024 in line with the Commerce Commission requirements outlined Tranche 1 of the Targeted Information Disclosure Review (TIDR) project.

NORTHPOWER NETWORK YEAR TO 31 MARCH 2023 ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE (EDID) FOR RELATED PARTY TRANSACTIONS

Table of Contents

Northpower

Summary of Northpower Network's Related Party Transactions

(Clause 2.3.8 of EDID requirements)

Related Party	Nature of Relationship	Principal Activity of Related Party	FY23 Expenditure with Related Party
Northpower Contracting Division	Both Northpower Network and Contracting division are part of Northpower Limited	The Contracting division provides maintenance and construction services for the electricity network.	Capital expenditure $16.4m Operating expenditure (maintenance) $18.7m
Northpower Fibre Limited	Northpower Limited is a shareholder of Northpower Fibre Limited	Northpower Fibre Limited owns and operates an ultra-fast broadband network in the Whangarei area.	Operating expenditure (leased fibre scada circuit for communications) $58k
Busck Prestressed Concrete Limited	Mr Paul Yovich is a Trustee of Northpower Electric Power Trust, the Shareholder of Northpower Limited. Mr Yovich is also a Trustee of a Shareholder of Busck Prestressed Concrete Limited.	Supplier of concrete products to the network, mainly poles (Note: the majority of purchases from this supplier are made by Northpower Contracting division. This related party disclosure is for purchases made directly by Northpower Network.)	Capital expenditure $3k Operating expenditure $19k
Electricity Engineers' Association (EEA)	Ms Josie Boyd is the COO Network and an Executive Committee Member of the Electricity Engineers' Association.	Professional engineers employed by Northpower Network are members of the EEA and purchase products from EEA.	Operating expenditure $19k

Northpower

Summary of Northpower Network's Policy in Respect of Procurement of Assets or Goods or Services from any Related Party

(Clause 2.3.10 of EDID requirements)

Purpose

This is a summary of the policy that outlines Northpower Network's approach to purchasing goods, services or assets from its related parties, including how those assets are valued.

Introduction

This document outlines Northpower Network's approach to purchasing goods, services or assets from its related parties, including how those assets are valued.

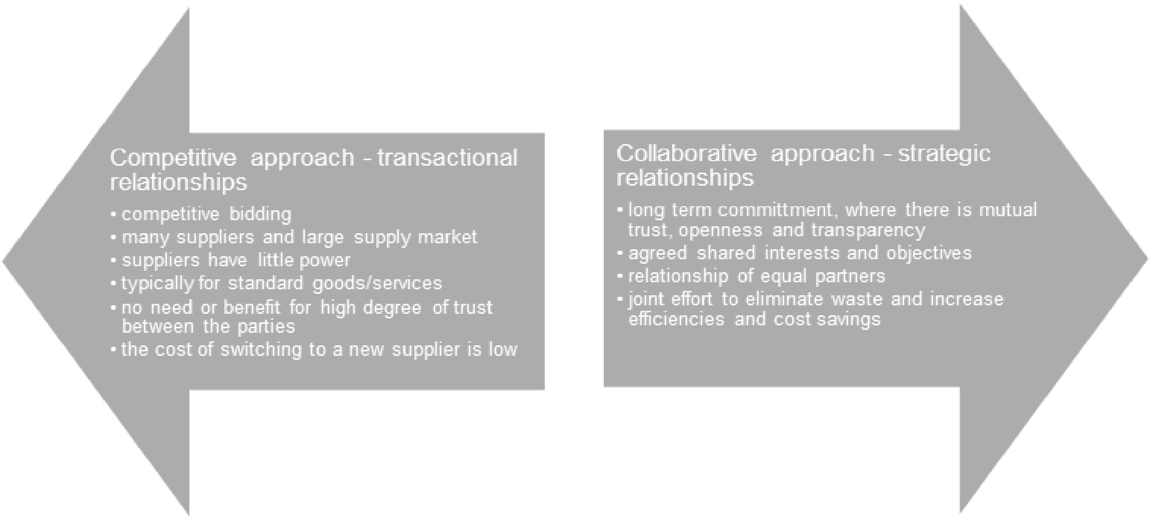
Procurement Objectives

The following objectives will inform Network's decision around the procurement of goods and services:

1. Ensuring that the services delivered meet the requirements and expectations of the consumers of Whangarei and Kaipara.
2. A delivery model that is cost effective and delivers efficiencies for the long-term benefit of consumers.
3. Achieving a high performing HSQE culture across all areas of its business, including staff and contractors.
4. The delivery of works programmes in accordance with Northpower's asset management strategies, including the ability to access resources to meet peak workloads.
5. Achieving innovation and continuous improvement in the areas identified above.

The choice around suppliers and procurement models, including transactions with related parties, will depend on the existing market for the specific goods or services, the strategic importance of the services, and the long-term needs of Network and its consumers.

Goods or services with characteristics that support a transactional relationship are likely to be subject to market contestability. In contrast, strategic supplier relationships are more likely to be based on a collaborative approach, underpinned by long-term relationships.



Where goods or services are not acquired through market contestability, Northpower will ensure that transactions are valued as if they were an arm's-length transaction.

Valuation of Transactions

Transactions between Network and its related parties will be conducted and valued as if it were an arm's-length transaction.

To meet these requirements, the following principles will be applied to all transactions with a related party who is providing goods or services to Network:

1. The value of a good or service acquired by Network must be given a value not greater than if that transaction had the terms of an arm's-length transaction;
2. The value of an asset or good or service sold or supplied to Network must be given a value not less than if that transaction had the terms of an arm's-length transaction;
3. Network will use an objective and independent measure in determining the terms of an arm's-length transaction for the purpose of principles 1 and 2 above.

For the purpose of principle 1, where a good or service is acquired from a third party and then on-sold to a related entity, the value of the subsequent transfer between related entities must reflect the amount charged by the third party.

Objective & Independent Measures of Value

Northpower will ensure that transactions with its related parties are valued on arm's-length terms by utilising independent and objective measures to establish that a related party transaction value is consistent with the value that would have otherwise been charged by an unrelated party commissioned to do the same work.

Methods used may include any or all of the following depending on the nature of the proposed transaction, the information reasonably available and what is practicable in the circumstances given the market for the relevant services.

- Conducting a tendering process for the goods or services.
- Undertaking internal benchmarking of the related party transactions against substantially same goods or services provided by the related party to its other customers.
- Undertaking internal benchmarking of the related party transactions against substantially same goods or services provided by similar external providers.
- Commissioning a third party to undertake market benchmarking of the prices of substantially similar goods or services.
- Engaging an expert to undertake an independent valuation to determine market value of the goods or service.

Procurement processes

External procurement processes will follow the Northpower Group Procurement Policy. Subject to Appendix 2 – Delegated Authority for Related Parties, all transactions, including those with related parties, must follow the Northpower Group Delegated Authorities Policy.

Confidentiality

The Northpower Group will adopt appropriate processes to protect the confidential and commercially sensitive information of its customers, its related parties and suppliers. These provisions include:

- The company will comply with the protocols outlined in Appendix 1 – Tendering involving Related Parties, where a tendering process is used.
- Appropriate protocols include information barriers, confidentiality undertakings and anonymisation of data.

Contractual Arrangements

Contractual arrangements with related parties will replicate good industry practice, be subject to regular review against market benchmarks, and may include an independent review.

Independent Representation

In some circumstances, it may be necessary for Network and its related parties to engage separate legal representation to provide sign off on the respective commercial terms.

Success Measures (Outcomes)

Successful implementation of this Network Policy will achieve the following outcomes:

- The Network Policy principles and objectives are met.
- Related party transactions are valued based on objective customer transactions.
- Network procurement processes are followed.

Tendering Involving Related Parties

The protocols set out below will be implemented by Northpower Network in order to receive and evaluate bids from related parties alongside third party contractors on a fair and compliant basis. These will also enable Northpower to mitigate process risks and enhance the attractiveness of the project for tenderers considering whether or not to submit a response.

- Disclosure that a related party has the capability to perform the project and will be invited to submit a bid.
- Disclosure of Evaluation Criteria in tender documents.
- Information barriers between Network and its related parties.
- Confidentiality undertakings required from Tenderers.
- Undertaking that pre-existing Intellectual Property is retained by Tenderers.
- Documentation of the Procurement Process to demonstrate probity.
- Briefings and de-briefings with successful and unsuccessful Tenderers.

The following two protocols may also be considered for sensitive RFPs

- Paying a stipend to Tenderers
- Appointing a Probity Adviser

A description of how Northpower Network's related party policy is applied in practice

(Clause 2.3.12.1 of EDID requirements)

Large capital projects (typically a defined set of works with a value of over $1 million) conducted by Northpower Network are generally based on fixed price contracts. EDB management will determine whether these projects should be subject to a competitive tender process or negotiated directly with Northpower Network's contracting partner, Northpower Contracting Division. In assessing whether these projects should be subject to tender, the EDB considers:

- The urgency of the project in terms of network function and safety
- Contractor availability and capability
- Whether the project will be seen as attractive to external contractors. This review involves factors such as the size of the project, the number of crews required, the type of work being undertaken, travel and mobilisation costs.

Competitive tender processes follow established tender processes that are based on industry recognised tendering and contracting frameworks (generally Standard NZS3910). Northpower Contracting Division is given the option to participate in the competitive tender process.

The specialised nature of construction and maintenance services for the EDB, including management of safety risks, dynamic workflow requirements and short response times along with the value of the work offered and efficiency benefits, lends itself to Northpower EDB establishing a preferred supplier relationship for the procurement of these services. Northpower EDB has this relationship with Northpower Contracting, which means that they complete the majority of the EDB's capital (other than tendered) and maintenance work. The Northpower Contracting Division is an established provider of construction and maintenance services for electrical networks for a number of EDB's. This provides the capability and scale to ensure the division is well placed to provide high quality and efficient services.

Work negotiated directly with the Northpower Contracting Division's Northland region is based on negotiated labour, plant and unit rates. With the exception of tendered projects, all work completed by Northpower Contracting's Northland region is governed by a field services agreement (referred to as the Service Level Agreement (SLA)). The SLA outlines how Northpower Network and Contracting's Northland region will work together, specifies the scope of services provided by the Contracting's Northland region, details rates, and includes a set of KPI's. The agreement is negotiated between representatives of the two Northpower divisions and approved by the respective Executives. Work completed by Northpower Contracting's other regions is priced at the project rates offered to their local Network customers.

A description of any Northpower Network policies or procedures that require or have the effect of requiring the consumer to purchase assets or goods or services from a related party

(Clause 2.3.12.2 of EDID requirements)

To work on or near Northpower's electricity distribution network, a contractor must be deemed competent and authorised to complete the work undertaken to satisfactorily meet Network standards.

Network extensions or customer initiated works must be undertaken by a Network approved contractor.

No external contractor is authorised for the following customer chargeable work:

a) HV network enhancements.

b) Third party network damage.

Due to risk to people and property and with any delay, no external contractor is authorised to remediate third party network damage. For completeness, the cost of remedying third party network damage, which is generally recovered from the responsible party, remains part of the services provided under the SLA.

Representative examples of how Northpower Network's Related Party Policy has been applied for the procurement of assets or goods or services and how arm's length terms were tested

(Clauses 2.3.12.3 – 2.3.12.5 of EDID requirements)

Capex Projects: Competitive Tender

There were no competitive tenders that involved Northpower Contracting Division and external parties in the 2023 financial year.

Directly negotiated work with Northpower Contracting Division

Work completed by Northpower Contracting Division under direct negotiation is governed by a SLA and negotiated rates. Both the rates and SLA are negotiated between the divisional management teams and final approval is required from the Executive Managers of the respective divisions.

Northpower's Corporate Finance Division has completed industry benchmarking of the related party transactions between Northpower Network and Northpower Contracting Division for the year ended 31 March 2023. The Finance Division operates independently from Northpower Network and Contracting divisions and provides an impartial view. This arm's-length assessment focused on:

- Assessing how the Northpower Contracting Division sets rates charged to Northpower Network, compared to other customers;
- Comparing rates between a selection of customers;
- Comparing margins earned by the Northpower Contracting Division for a selection of customers;
- Comparing year-on year movements in rates by customer, labour type and unit cost type;
- Reviewing the management of the supplier relationship;
- Confirming the approval process of the SLA and agreed rates.

This assessment concluded that the related party transactions between Northpower Network and Northpower Contracting Division meet the valuation requirements outlined in disclosure determination paragraph 2.3.6.

Opex Programme: Vegetation

Vegetation control for Northpower's EDB has been completed by Northpower Contracting Division and a third party. An RFP was undertaken in June 2022 and rates from Northern Contracting and two other external parties from the RFP were compared by Northpower's Corporate Finance Division. This comparison concluded that the vegetation control rates between Northpower Network and Northpower Contracting Division meet the valuation requirements outlined in disclosure determination paragraph 2.3.6.

Procurement Examples

The following provide examples of the procurement process for work completed by Northpower Contracting under the SLA.

Faults Services

On 12th June 2022 at 00.14, the dispatcher received a call from New Zealand Police reporting an incident where a vehicle had hit a pole on State Highway 14, between Snooks Rd and Tatton Rd (Pole no 59775) and requested Northpower's attendance. The Dispatcher recorded this job in the faults management system under reference number 356092 and dispatched a contracting fault crew to the site. Traffic management was also required while the pole was replaced.

Northpower Contracting recorded the labour, plant, equipment and materials used in replacing the pole as detailed on the service request. An invoice was issued to Network (Journal Batch #1170878) along with a copy of the unit rate billing sheet. This was approved for payment by Network.

Planned Maintenance

Northpower Network's maintenance is split between distribution and sub-stations. Each has an annual schedule of maintenance required. The maintenance tasks are created in our maintenance system, and are packaged into a work pack and issued to Northpower Contracting. The current process is that a purchase order (PO) is automatically created in the ERP system (JDE) when the work pack is issued. Work is completed by Northpower Contracting and any defects that require further follow up are recorded. Northpower Contracting raise an invoice, which is matched to the PO in the ERP system. The invoice is automatically approved if it matches the purchase order; otherwise, the invoices are manually reviewed and approved if the charges are appropriate. Invoices that require approval are highlighted in an exceptions report.

Defects identified when Northpower Contracting are completing the preventative maintenance tasks are recorded on a data sheet and Northpower Contracting create 'tasks' in Wasp (the asset maintenance system). These are then planned and packaged into work packs by Northpower Contracting and sent to the Network team for approval before being sent back to Northpower Contracting to carry out the work.

Vegetation

A prioritised annual vegetation maintenance programme is established using a risk-based approach. Specialist inspectors carry out risk-based assessments on sites where vegetation poses a risk to the Network. They prepare a plan to mitigate the risk including an estimate of resource required. Details of any cutting work required is recorded in the maintenance system in a work pack. There is a built-in mechanism to approve and track works variations when there is a change in scope between the assessment and cutting stages. The work is then assigned to vegetation contractors (Northern Contracting or an external contractor) for clearance based on risk and available resource. If Northpower Contracting are carrying out the work they invoice the Network once the work is complete. If the invoice is in line with the purchase orders, they are automatically approved. If there are variances Network management review and once the variance is understood and accepted the invoices are approved.

Capital Project

There are routine sample tests carried out to identify conductors that are end of life. Conductors to include in conductor replacement projects are identified by the condition of the conductors and age. Network issue contracting a Project Job Sheet detailing works required. Northpower Contracting prepare a Project Work Proposal detailing the methodology, timeline and pricing to carry out the works. The Project Work Proposal is reviewed by Network, ensuring the proposal satisfies the requirements of the Project Job Sheet. If accepted, Network issues a purchase order accepting Northpower Contracting Project Work Proposal. Invoicing is done on a monthly basis as works are completed. Network approves the invoice if it is in line with the purchase order.

CAPEX and OPEX in AMP Planning Period

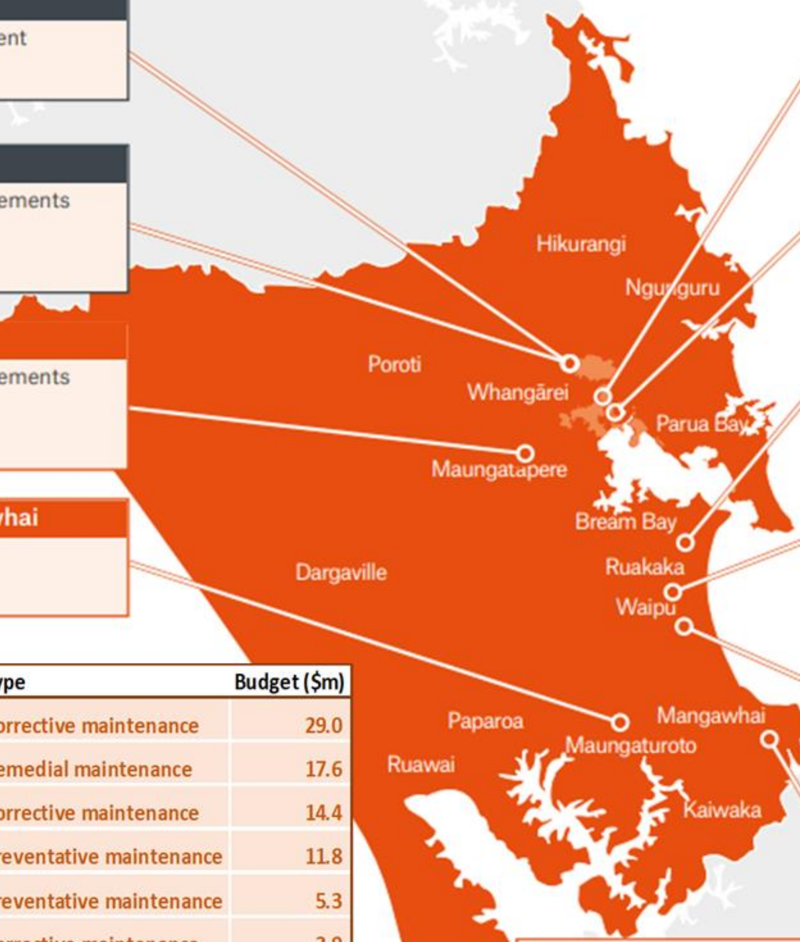
Northpower

Kensington
33kV Switchboard Replacement
Renewal $5.2m 1-2 Years

Kensington
110/33kV Transformer Replacements (70-100MVAx2)
Growth $7.5m 1-2 Years

Maungatapere
110/33kV Transformer Replacements (50-70MVAx2)
Renewal $7.3m 1-3 Years

Maungaturoto to Mangawhai
34km 33kV Line
Growth $7.2m 1-2 Years



Whangarei South
33kV Outdoor-to-Indoor Conversion
Renewal $5.4m 9-10 Years

Whangarei South
Transformer Replacements (15MVAx2)
Renewal $5m 3-5 Years

Bream Bay
T2 and 11kV Switchgear Installation
Growth $6m 1-3 Years

Waipu to Ruakaka
10km 33kV Line & Easements
Growth $7.2m 6-8 Years

Waipu Zone Substation (New)
(5MVAx1)
Growth $6.9m 8-10 Years

Mangawhai Central
Zone Substation
Growth $4.5m 1 Year

Opex Programme	Type	Budget ($m)
Vegetation	Corrective maintenance	29.0
Overhead lines	Remedial maintenance	17.6
Overhead lines	Corrective maintenance	14.4
Overhead lines	Preventative maintenance	11.8
Distribution earthing	Preventative maintenance	5.3
Ground mounted substations	Corrective maintenance	3.9
Ground mounted substations	Preventative maintenance	3.8
Underground cables	Preventative maintenance	3.5
Unplanned inspections	Remedial maintenance	2.8
Pillars	Preventative maintenance	2.5

Capital Project
Currently not indicated for supply by a related party

Capital Project
To be supplied by a related party

Operating Program
With the exception of a small amount of vegetation management, this program is forcast to require the supply of assets or goods or services by a related party

The project will install a new 15/23 MVA substation to support the emerging load growth. Growth in the Mangawhai area has accelerated since 2020, and now requires an upgrade in network capacity to support further development and security of supply. The design is complete, and project is underway. The $4.5m is the forward looking AMP budget for FY24. The total budget is $10.1m.

Northpower

DIRECTORS' CERTIFICATE

We, Mark Trigg and Kerry Friend, being Directors of Northpower Limited, certify that, having made all reasonable enquiry, to the best of our knowledge –

a) The information prepared for the purposes of clauses 2.3.1, 2.3.2, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.7.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination; and

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

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

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

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

Director	Director
Mark Trigg	Kerry Friend
Date 30 August 2023	Date 30 August 2023

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Independent Assurance Report to the Directors of Northpower Limited and to the Commerce Commission on the Disclosure Information for the Disclosure Year Ended 31 March 2023 as required by the Electricity Distribution Information Disclosure Determination 2012 (Consolidated 6 July 2023)

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

The Auditor-General is the auditor of the company.

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

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

- Schedules 1 to 4, 5a to 5g, 6a and 6b, 7, 10 and 14 (limited to the explanatory notes in boxes 1 to 11) of the Determination.

- Clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 20 May 2020) (the IM Determination), in respect of the basis for valuation of related party transactions (the Related Party Transaction Information).

This assurance report should be read in conjunction with the following Commerce Commission's Information Disclosure exemption:

- Issued to all electricity distribution businesses on 26 May 2023 under clause 2.11.1 of the Determination. The Commerce Commission granted an exemption from the requirement that the assurance report, in respect of the information in Schedule 10 of the Determination, must take into account any issues arising out of the company's recording of SAIDI, SAIFI, and number of interruptions due to successive interruptions.

- Issued to Northpower Limited on 24 July 2023, in respect of the information in Schedule 10 of the ID Determination, from providing complete SAIDI and SAIFI data for the period covering 12 to 19 February 2023, due to the impact of Cyclone Gabrielle. Specifically, the exemption applies to:
    - Schedule 10 (i): Interruptions for Class C (unplanned interruptions on the network) and Normalised SAIFI and SAIDI Classes B & C (interruptions on the network); and
    - Schedule 10 (ii): Class C Interruptions and Duration by Cause for Adverse weather.

Opinion

In our opinion, in all material respects:

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

- as far as appears from an examination, the information used in the preparation of the Disclosure Information has been properly extracted from the company's accounting and other records, sourced from the company's financial and non-financial systems;

- the Disclosure Information complies, in all material respects, with the Determination; and

- the basis for valuation of related party transactions complies with the Determination and the IM Determination.

Basis for opinion

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

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

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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 quantity and duration of electricity outages and ICP numbers The Information Disclosure Determination defines certain quality measures in relation to the number and duration of interruptions, faults, and causes of faults. These quality measures are expressed in the form of SAIDI and SAIFI values. The accuracy of the data is a key audit matter because information on the frequency and duration of outages is an important measure about the reliability of electricity supply. The completeness of the data is a key audit matter because the details of the faults are entered manually into the fault outage report, which is used to calculate the SAIDI/ SAIFI. The feeder maps capture the Individual Connection Point data that is used in the calculation of the SAIDI and SAIFI values. These Feeder Maps are updated only once every 2 years.	We have: • Obtained an understanding of the company'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 the outage data obtained from the outage report; • For a sample of outages, observed the number of consumers affected from the feeder maps on the date of testing and assessed the reasonability of this number against impacted consumers recorded in the data; • Reviewed the recorded detail for a sample of outages and ensured that the appropriate dates and times were used and the outage was started and ended by an appropriate individual; and • Recalculated the normalised SAIDI and SAIFI using the predetermined boundary limits.
Valuation and identification of related party transactions The valuation of transactions with related parties ($11.3 million of purchases from related parties included in operating expenditures, and $17.0 million of assets acquired from related parties included into capital expenditure in the period) is a key assurance matter due to: - the significant judgement in forming a view of related party pricing in the absence, or insufficiency, of publicly available information about pricing and terms of certain transactions. The identification of transactions with related parties is a key assurance matter because Northpower Limited operate in a number of business areas and holds certain investments which may give rise to related party transactions with the electricity distribution business.	To evaluate valuation of related party transactions, we have: • Obtained management's methodology of how they determined the transactions were related party transactions and their assessment of these transactions at arm's length; • Re-performed the calculations and agreed the disclosures within Schedule 5(b) to the accounting records, investigating any differences and determining whether such differences are justified; and • Made a selection of related party transaction samples and where benchmarking or other market information was used as independent and objective measures, we agreed key inputs and assumptions to supporting documentation. To evaluate completeness of related party transactions, we have: • Assessed whether all related party transactions had been included by comparing to our understanding of Northpower Limited's operating model; and

	• Assessed whether all related party transactions recorded for financial reporting purposes had been correctly identified and disclosed.

Directors' responsibilities

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

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

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

Auditor's responsibilities

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

- as far as appears from an examination, the information used in the preparation of the audited Disclosure Information has been properly extracted from the company's accounting and other records, sourced from its financial and non-financial systems;

- as far as appears from an examination, proper records to enable the complete and accurate compilation of the audited Disclosure Information required by the Determination have been kept by the company and, if not, the records not so kept;

- the company complied, in all material respects, with the Determination in preparing the audited Disclosure Information; and

- the company's basis for valuation of related party transactions in the disclosure year has complied, in all material respects, with clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the IM Determination.

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

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

Inherent limitations

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

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

Restricted use

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

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Independence and quality control

We complied with the Auditor-General's:

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

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

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

Silvio Bruinsma
Deloitte Limited
On behalf of the Auditor-General
Auckland, New Zealand
30 August 2023