EDB Information Disclosure Requirements
Information Templates
for
Schedules 1–10

Company Name	Northpower Limited
Disclosure Date	31 August 2020
Disclosure Year (year ended)	31 March 2020

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

Template Version 4.1. Prepared 21 December 2017

Table of Contents

Disclosure Template Instructions

These templates have been prepared 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 templates for schedules 4, 5b, 5c, 5d, 5e, 6a, 8, 9d, and 9e 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 schedules 5c, 6a, and 9e 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.

Schedules 5d and 5e 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.

Schedule References
The references labelled 'sch ref' in the leftmost column of each template are consistent with the row references in the Electricity Distribution ID Determination 2012 (as issued on 21 December 2017). They provide a common reference between the rows in the determination and the template.

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

Company Name	**Northpower Limited**
For Year Ended	**31 March 2020**

SCHEDULE 1: ANALYTICAL RATIOS

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

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

sch ref

1(i): Expenditure metrics

	Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
Operational expenditure	24,786	449	156,339	4,444	47,701
Network	10,732	194	67,689	1,924	20,653
Non-network	14,055	254	88,650	2,520	27,048
Expenditure on assets	22,422	406	141,427	4,020	43,151
Network	20,261	367	127,793	3,633	38,992
Non-network	2,162	39	13,634	388	4,160

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	56,965	1,031
Standard consumer line charge revenue	93,312	884
Non-standard consumer line charge revenue	17,044	1,477,212

1(iii): Service intensity measures

Demand density	28	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	179	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	10	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	18,106	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	27,047	43.26%
Pass-through and recoverable costs excluding financial incentives and wash-ups	20,342	32.54%
Total depreciation	9,962	15.93%
Total revaluations	6,765	10.82%
Regulatory tax allowance	1,955	3.13%
Regulatory profit/(loss) including financial incentives and wash-ups	9,983	15.97%
Total regulatory income	62,523	

1(v): Reliability

Interruption rate	15.40	*Interruptions per 100 circuit km*

Company Name **Northpower Limited**

For Year Ended **31 March 2020**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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

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

sch ref		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
8		31 Mar 18	31 Mar 19	31 Mar 20
9	**ROI – comparable to a post tax WACC**	%	%	%
10	Reflecting all revenue earned	5.89%	5.66%	3.35%
11	Excluding revenue earned from financial incentives	5.89%	5.66%	3.35%
12	Excluding revenue earned from financial incentives and wash-ups	5.89%	5.66%	3.35%
13				
14	**Mid-point estimate of post tax WACC**	5.04%	4.75%	4.27%
15	25th percentile estimate	4.36%	4.07%	3.59%
16	75th percentile estimate	5.72%	5.43%	4.95%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	6.48%	6.17%	3.77%
21	Excluding revenue earned from financial incentives	6.48%	6.17%	3.77%
22	Excluding revenue earned from financial incentives and wash-ups	6.48%	6.17%	3.77%
23				
24	**WACC rate used to set regulatory price path**			
25				
26	**Mid-point estimate of vanilla WACC**	5.60%	5.26%	4.69%
27	25th percentile estimate	4.92%	4.58%	4.01%
28	75th percentile estimate	6.29%	5.94%	5.37%
29				

sch ref					
30	**2(ii): Information Supporting the ROI**			($000)	
31					
32		Total opening RAB value	267,167		
33	*plus*	Opening deferred tax	(9,010)		
34	**Opening RIV**			258,157	
35					
36	**Line charge revenue**			62,160	
37					
38		Expenses cash outflow	47,389		
39	*add*	Assets commissioned	16,089		
40	*less*	Asset disposals	57		
41	*add*	Tax payments	478		
42	*less*	Other regulated income	363		
43	**Mid-year net cash outflows**			63,536	
44					
45	**Term credit spread differential allowance**			–	
46					
47		Total closing RAB value	279,361		
48	*less*	Adjustment resulting from asset allocation	(642)		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(10,486)		
51	**Closing RIV**			269,516	
52					
53	**ROI – comparable to a vanilla WACC**				3.77%
54					
55		Leverage (%)			42%
56		Cost of debt assumption (%)			3.61%
57		Corporate tax rate (%)			28%
58					
59	**ROI – comparable to a post tax WACC**				3.35%
60					

Company Name	**Northpower Limited**
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EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).

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

sch ref

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	3.75%
Year-end ROI – comparable to a post tax WACC	3.33%

** 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 Limited**
For Year Ended	**31 March 2020**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

sch ref				
7		**3(i): Regulatory Profit**		**($000)**
8		**Income**		
9		Line charge revenue		62,160
10	*plus*	Gains / (losses) on asset disposals		15
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		347
12				
13		**Total regulatory income**		62,523
14		**Expenses**		
15	*less*	Operational expenditure		27,047
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		20,342
18				
19		**Operating surplus / (deficit)**		15,134
20				
21	*less*	Total depreciation		9,962
22				
23	*plus*	Total revaluations		6,765
24				
25		**Regulatory profit / (loss) before tax**		11,937
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		1,955
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		9,983
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	106	
36		Commerce Act levies	34	
37		Industry levies	219	
38		CPP specified pass through costs		
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	18,639	
41		Transpower new investment contract charges		
42		System operator services		
43		Distributed generation allowance	1,343	
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**		20,342
47				

Company Name	**Northpower Limited**
For Year Ended	**31 March 2020**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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sch ref

48	**3(iii): Incremental Rolling Incentive Scheme**			**($000)**
49			**CY-1**	**CY**
50			**31 Mar 19**	**31 Mar 20**
51	Allowed controllable opex			
52	Actual controllable opex			
53				
54	Incremental change in year			
55				
56			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
57	CY-5	31 Mar 15		
58	CY-4	31 Mar 16		
59	CY-3	31 Mar 17		
60	CY-2	31 Mar 18		
61	CY-1	31 Mar 19		
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 Limited**
For Year Ended	**31 March 2020**

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

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

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

sch ref								
7		**4(i): Regulatory Asset Base Value (Rolled Forward)**		**RAB**	**RAB**	**RAB**	**RAB**	**RAB**
8			for year ended	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
9				**($000)**	**($000)**	**($000)**	**($000)**	**($000)**
10		**Total opening RAB value**		242,199	253,531	258,435	262,813	267,167
11								
12	*less*	**Total depreciation**		9,439	9,805	10,016	10,169	9,962
13								
14	*plus*	**Total revaluations**		1,421	5,491	2,840	3,897	6,765
15								
16	*plus*	**Assets commissioned**		19,351	9,218	11,619	12,121	16,089
17								
18	*less*	**Asset disposals**		–	–	65	42	57
19								
20	*plus*	**Lost and found assets adjustment**		–	–	–	–	–
21								
22	*plus*	**Adjustment resulting from asset allocation**		–	–	–	(1,453)	(642)
23								
24		**Total closing RAB value**		253,531	258,435	262,813	267,167	279,361
25								

26		**4(ii): Unallocated Regulatory Asset Base**				
27			**Unallocated RAB ***		**RAB**	
28			**($000)**	**($000)**	**($000)**	**($000)**
29		**Total opening RAB value**		268,621		267,167
30	*less*					
31		**Total depreciation**		10,007		9,962
32	*plus*					
33		**Total revaluations**		6,802		6,765
34	*plus*					
35		Assets commissioned (other than below)	3,403		3,131	
36		Assets acquired from a regulated supplier	–		–	
37		Assets acquired from a related party	13,259		12,958	
38		**Assets commissioned**		16,662		16,089
39	*less*					
40		Asset disposals (other than below)	57		57	
41		Asset disposals to a regulated supplier	–		–	
42		Asset disposals to a related party	–		–	
43		**Asset disposals**		57		57
44						

	Company Name	Northpower Limited
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SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

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sch ref				
45	*plus*	**Lost and found assets adjustment**		
46				
47	*plus*	**Adjustment resulting from asset allocation**		(642)
48				
49		**Total closing RAB value**	282,020	279,361
50		** 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 Limited
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SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

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

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sch ref						
51						
52		**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**				
53						
54		CPI_4				1,052
55		CPI_4^{-4}				1,026
56		Revaluation rate (%)				2.53%
57						
58			**Unallocated RAB ***		**RAB**	
59			**($000)**	**($000)**	**($000)**	**($000)**
60		Total opening RAB value	268,621		267,167	
61	*less*	Opening value of fully depreciated, disposed and lost assets	201		201	
62						
63		Total opening RAB value subject to revaluation	268,419		266,966	
64		**Total revaluations**		6,802		6,765
65						
66		**4(iv): Roll Forward of Works Under Construction**				
67			**Unallocated works under construction**		**Allocated works under construction**	
68		**Works under construction—preceding disclosure year**		6,115		6,115
69	*plus*	Capital expenditure	20,660		20,660	
70	*less*	Assets commissioned	16,662		16,089	
71	*plus*	Adjustment resulting from asset allocation			(603)	
72		**Works under construction - current disclosure year**		10,113		10,083
73						
74		Highest rate of capitalised finance applied				2.63%
75						

Company Name	**Northpower Limited**
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SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

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

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

sch ref

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

sch ref		Unallocated RAB *		RAB	
78		($000)	($000)	($000)	($000)
79	Depreciation - standard	9,828		9,792	
80	Depreciation - no standard life assets	179		171	
81	Depreciation - modified life assets				
82	Depreciation - alternative depreciation in accordance with CPP				
83	**Total depreciation**		10,007		9,962
84					

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

($000 unless otherwise specified)

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

95 ** include additional rows if needed*

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

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

sch ref			Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
99		**Total opening RAB value**	7,176	9,644	33,171	111,184	48,417	33,372	7,252	7,064	9,888	267,167
100	*less*	Total depreciation	367	269	1,273	3,750	1,666	1,373	309	784	171	9,962
101	*plus*	Total revaluations	182	244	840	2,817	1,227	844	184	178	250	6,765
102	*plus*	Assets commissioned	342	1	279	6,733	735	5,272	456	1,683	589	16,089
103	*less*	Asset disposals	–	–	–	31	–	26	–	–	–	57
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	(3)	–	–	(87)	9	–	–	(560)	–	(642)
106	*plus*	Asset category transfers	–	–	–	–	–	–	–	–	–	–
107		**Total closing RAB value**	7,329	9,620	33,017	116,865	48,721	38,088	7,583	7,580	10,557	279,361

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

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

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

sch ref											
108											
109	**Asset Life**										
110	Weighted average remaining asset life	30.8	40.1	33.4	40.2	32.9	31.9	26.8	12.5	22.0	(years)
111	Weighted average expected total asset life	51.1	56.4	39.1	56.1	43.8	39.7	35.0	16.1	28.6	(years)

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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref				
7	**5a(i): Regulatory Tax Allowance**			**($000)**
8		**Regulatory profit / (loss) before tax**		11,937
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	10	*
12		Amortisation of initial differences in asset values	4,536	
13		Amortisation of revaluations	1,108	
14				5,654
15				
16	*less*	Total revaluations	6,765	
17		Income included in regulatory profit / (loss) before tax but not taxable		*
18		Discretionary discounts and customer rebates		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax		*
20		Notional deductible interest	3,845	
21				10,611
22				
23		**Regulatory taxable income**		6,981
24				
25	*less*	Utilised tax losses		
26		Regulatory net taxable income		6,981
27				
28		Corporate tax rate (%)	28%	
29		**Regulatory tax allowance**		1,955
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	105,607	
37	*less*	Amortisation of initial differences in asset values	4,536	
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		101,071
41				
42		Opening weighted average remaining useful life of relevant assets (years)		23
43				

Company Name	**Northpower Limited**
For Year Ended	**31 March 2020**

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref				
44	**5a(iv): Amortisation of Revaluations**			**($000)**
45				
46		Opening sum of RAB values without revaluations	240,819	
47				
48		Adjusted depreciation	8,854	
49		Total depreciation	9,962	
50		Amortisation of revaluations		1,108
51				
52	**5a(v): Reconciliation of Tax Losses**			**($000)**
53				
54		**Opening tax losses**		
55	*plus*	Current period tax losses		
56	*less*	Utilised tax losses		
57		**Closing tax losses**		–
58	**5a(vi): Calculation of Deferred Tax Balance**			**($000)**
59				
60		**Opening deferred tax**	(9,010)	
61				
62	*plus*	Tax effect of adjusted depreciation	2,479	
63				
64	*less*	Tax effect of tax depreciation	2,616	
65				
66	*plus*	Tax effect of other temporary differences*	(90)	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	1,270	
69				
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year		
71				
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year	0	
73				
74	*plus*	Deferred tax cost allocation adjustment	20	
75				
76		**Closing deferred tax**		(10,486)
77				
78	**5a(vii): Disclosure of Temporary Differences**			
79		*In Schedule 14, Box 6, provide descriptions and workings of items recorded in the asterisked category in Schedule 5a(vi) (Tax effect of other temporary differences).*		
80				
81	**5a(viii): Regulatory Tax Asset Base Roll-Forward**			
82				**($000)**
83		**Opening sum of regulatory tax asset values**	104,314	
84	*less*	Tax depreciation	9,342	
85	*plus*	Regulatory tax asset value of assets commissioned	15,914	
86	*less*	Regulatory tax asset value of asset disposals	57	
87	*plus*	Lost and found assets adjustment		
88	*plus*	Adjustment resulting from asset allocation	(569)	
89	*plus*	Other adjustments to the RAB tax value	–	
90		**Closing sum of regulatory tax asset values**		110,260

Company Name	**Northpower Limited**
For Year Ended	**31 March 2020**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

sch ref

sch ref	5b(i): Summary—Related Party Transactions	($000)	($000)
8	**Total regulatory income**		
9			
10	**Market value of asset disposals**		
11			
12	Service interruptions and emergencies	3,116	
13	Vegetation management	3,019	
14	Routine and corrective maintenance and inspection	3,075	
15	Asset replacement and renewal (opex)	2,014	
16	**Network opex**		11,224
17	Business support	120	
18	System operations and network support	131	
19	**Operational expenditure**		11,475
20	Consumer connection	925	
21	System growth	759	
22	Asset replacement and renewal (capex)	8,711	
23	Asset relocations	480	
24	Quality of supply	605	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	413	
27	**Expenditure on non-network assets**		–
28	**Expenditure on assets**		11,892
29	Cost of financing		
30	Value of capital contributions		
31	Value of vested assets		
32	**Capital Expenditure**		11,892
33	**Total expenditure**		23,367
34			
35	**Other related party transactions**		91

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

37	**Name of related party**	**Nature of opex or capex service provided**	**Total value of transactions ($000)**
38	Northpower Contracting Division	Service interruptions and emergencies	3,116
39	Northpower Contracting Division	Vegetation management	3,019
40	Northpower Contracting Division	Routine and corrective maintenance and inspection	3,075
41	Northpower Contracting Division	System operations and network support	122
42	Northpower Contracting Division	Asset replacement and renewal (opex)	2,014
43	Northpower Fibre Ltd	System operations and network support	9
44	Northpower Corporate Division	Business support	120
45	Northpower Fibre Division	Other reliability, safety and environment	220
46	Northpower Contracting Division	System growth	759
47	Northpower Contracting Division	Asset replacement and renewal (capex)	8,711
48	Northpower Contracting Division	Asset relocations	480
49	Northpower Contracting Division	Quality of supply	605
50	Northpower Contracting Division	Other reliability, safety and environment	192
51	Northpower Contracting Division	Consumer connection	925
52			
53	**Total value of related party transactions**		23,367

54 ** include additional rows if needed*

55

								Company Name	**Northpower Limited**
								For Year Ended	**31 March 2020**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref									
7									
8	**5c(i): Qualifying Debt (may be Commission only)**								
9									
10	**Issuing party**	**Issue date**	**Pricing date**	**Original tenor (in years)**	**Coupon rate (%)**	**Book value at issue date (NZD)**	**Book value at date of financial statements (NZD)**	**Term Credit Spread Difference**	**Debt issue cost readjustment**
11									
12									
13									
14									
15									
16	** include additional rows if needed*						–	–	–
17									
18	**5c(ii): Attribution of Term Credit Spread Differential**								
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 Limited**
For Year Ended	**31 March 2020**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref						
7	**5d(i): Operating Cost Allocations**					
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		3,126			
12	Not directly attributable				–	
13	**Total attributable to regulated service**		3,126			
14	**Vegetation management**					
15	Directly attributable		3,241			
16	Not directly attributable				–	
17	**Total attributable to regulated service**		3,241			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		3,267			
20	Not directly attributable				–	
21	**Total attributable to regulated service**		3,267			
22	**Asset replacement and renewal**					
23	Directly attributable		2,076			
24	Not directly attributable				–	
25	**Total attributable to regulated service**		2,076			
26	**System operations and network support**					
27	Directly attributable		2,712			
28	Not directly attributable				–	
29	**Total attributable to regulated service**		2,712			
30	**Business support**					
31	Directly attributable		5,686			
32	Not directly attributable		6,938	17,687	24,625	
33	**Total attributable to regulated service**		12,624			
34						
35	**Operating costs directly attributable**		20,109			
36	**Operating costs not directly attributable**	–	6,938	17,687	24,625	–
37	**Operational expenditure**		27,047			
38						

Company Name	**Northpower Limited**
For Year Ended	**31 March 2020**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

sch ref		($000)
39	**5d(ii): Other Cost Allocations**	
40	**Pass through and recoverable costs**	($000)
41	**Pass through costs**	
42	Directly attributable	359
43	Not directly attributable	–
44	**Total attributable to regulated service**	359
45	**Recoverable costs**	
46	Directly attributable	19,983
47	Not directly attributable	
48	**Total attributable to regulated service**	19,983
49		

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

sch ref				($000) CY-1	Current Year (CY)
51				($000)	
52	**Change in cost allocation 1**			CY-1	Current Year (CY)
53	Cost category		Original allocation		
54	Original allocator or line items		New allocation		
55	New allocator or line items		Difference	–	–
56					
57	Rationale for change				
58					
59					
60				($000)	
61	**Change in cost allocation 2**			CY-1	Current Year (CY)
62	Cost category		Original allocation		
63	Original allocator or line items		New allocation		
64	New allocator or line items		Difference	–	–
65					
66	Rationale for change				
67					
68					
69				($000)	
70	**Change in cost allocation 3**			CY-1	Current Year (CY)
71	Cost category		Original allocation		
72	Original allocator or line items		New allocation		
73	New allocator or line items		Difference	–	–
74					
75	Rationale for change				
76					
77					

78 ** 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.*
79 *† include additional rows if needed*

Company Name	**Northpower Limited**
For Year Ended	**31 March 2020**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

7 5e(i): Regulated Service Asset Values

sch ref		Value allocated ($000s) Electricity distribution services
8		
9		
10	**Subtransmission lines**	
11	Directly attributable	6,995
12	Not directly attributable	334
13	**Total attributable to regulated service**	7,329
14	**Subtransmission cables**	
15	Directly attributable	9,620
16	Not directly attributable	–
17	**Total attributable to regulated service**	9,620
18	**Zone substations**	
19	Directly attributable	33,017
20	Not directly attributable	–
21	**Total attributable to regulated service**	33,017
22	**Distribution and LV lines**	
23	Directly attributable	112,308
24	Not directly attributable	4,557
25	**Total attributable to regulated service**	116,865
26	**Distribution and LV cables**	
27	Directly attributable	48,721
28	Not directly attributable	–
29	**Total attributable to regulated service**	48,721
30	**Distribution substations and transformers**	
31	Directly attributable	38,088
32	Not directly attributable	–
33	**Total attributable to regulated service**	38,088
34	**Distribution switchgear**	
35	Directly attributable	7,583
36	Not directly attributable	–
37	**Total attributable to regulated service**	7,583
38	**Other network assets**	
39	Directly attributable	6,347
40	Not directly attributable	1,232
41	**Total attributable to regulated service**	7,580
42	**Non-network assets**	
43	Directly attributable	8,686
44	Not directly attributable	1,871
45	**Total attributable to regulated service**	10,557
46		
47	**Regulated service asset value directly attributable**	271,365
48	**Regulated service asset value not directly attributable**	7,995
49	**Total closing RAB value**	279,361
50		

51 5e(ii): Changes in Asset Allocations* †

sch ref				($000) CY-1	($000) Current Year (CY)
52					
53	**Change in asset value allocation 1**				
54	Asset category		Original allocation		
55	Original allocator or line items		New allocation		
56	New allocator or line items		Difference	–	–
57					
58	Rationale for change				
59					
60					
61					
62	**Change in asset value allocation 2**				
63	Asset category		Original allocation		
64	Original allocator or line items		New allocation		
65	New allocator or line items		Difference	–	–
66					
67	Rationale for change				
68					
69					
70					
71	**Change in asset value allocation 3**				
72	Asset category		Original allocation		
73	Original allocator or line items		New allocation		
74	New allocator or line items		Difference	–	–
75					
76	Rationale for change				
77					
69					
70					
71	**Change in asset value allocation 4**				
72	Asset category		Original allocation		
73	Original allocator or line items		New allocation		
74	New allocator or line items		Difference	–	–
75					
76	Rationale for change				
77					
69					
70					
71	**Change in asset value allocation 5**				
72	Asset category		Original allocation		
73	Original allocator or line items		New allocation		
74	New allocator or line items		Difference	–	–
75					
76	Rationale for change				
77					
69					
70					
71	**Change in asset value allocation 6**				
72	Asset category		Original allocation		
73	Original allocator or line items		New allocation		
74	New allocator or line items		Difference	–	–
75					
76	Rationale for change				
77					
78					

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

Company Name	Northpower Limited
For Year Ended	31 March 2020

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

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

sch ref

6a(i): Expenditure on Assets

		($000)	($000)
	Consumer connection		4,919
	System growth		3,662
	Asset replacement and renewal		11,098
	Asset relocations		515
	Reliability, safety and environment:		
	Quality of supply	675	
	Legislative and regulatory	1	
	Other reliability, safety and environment	1,238	
	Total reliability, safety and environment		1,914
	Expenditure on network assets		22,108
	Expenditure on non-network assets		2,359
	Expenditure on assets		24,467
plus	Cost of financing		184
less	Value of capital contributions		3,991
plus	Value of vested assets		
	Capital expenditure		20,660

6a(ii): Subcomponents of Expenditure on Assets (where known)

	($000)
Energy efficiency and demand side management, reduction of energy losses	–
Overhead to underground conversion	–
Research and development	–

6a(iii): Consumer Connection

		($000)	($000)
	*Consumer types defined by EDB**		
	All Customer Types	4,919	
		–	
		–	
		–	
		–	
	** include additional rows if needed*		
	Consumer connection expenditure		4,919
less	Capital contributions funding consumer connection expenditure	3,991	
	Consumer connection less capital contributions		927

6a(iv): System Growth and Asset Replacement and Renewal

		System Growth ($000)	Asset Replacement and Renewal ($000)
	Subtransmission	–	2
	Zone substations	3,387	2,307
	Distribution and LV lines	5	6,341
	Distribution and LV cables	17	309
	Distribution substations and transformers	254	563
	Distribution switchgear	–	1
	Other network assets	1	1,576
	System growth and asset replacement and renewal expenditure	3,662	11,098
less	Capital contributions funding system growth and asset replacement and renewal		
	System growth and asset replacement and renewal less capital contributions	3,662	11,098

6a(v): Asset Relocations

		($000)	($000)
	*Project or programme**		
	Ground mounted substations	257	
	Minor Expenditure relocation	86	
	Roading works asset relocation	160	
	Asset relocation Manuka Place	12	
		–	
	** include additional rows if needed*		
	All other projects or programmes - asset relocations		
	Asset relocations expenditure		515
less	Capital contributions funding asset relocations		
	Asset relocations less capital contributions		515

Company Name	**Northpower Limited**
For Year Ended	**31 March 2020**

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

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

sch ref				
68				
69	**6a(vi): Quality of Supply**			
70		*Project or programme**	**($000)**	**($000)**
71		Whangarei South 33kV	675	
72				
73				
74				
75				
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply		
78		**Quality of supply expenditure**		675
79	*less*	Capital contributions funding quality of supply		
80		**Quality of supply less capital contributions**		675
81	**6a(vii): Legislative and Regulatory**			
82		*Project or programme**	**($000)**	**($000)**
83		Zone substation risk mitigation	1	
84				
85				
86				
87				
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory		
90		**Legislative and regulatory expenditure**		1
91	*less*	Capital contributions funding legislative and regulatory		
92		**Legislative and regulatory less capital contributions**		1
93	**6a(viii): Other Reliability, Safety and Environment**			
94		*Project or programme**	**($000)**	**($000)**
95		Minor capital expenditure r,s&e improvement	275	
96		Fibre provision	628	
97				
98				
99				
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment	335	
102		**Other reliability, safety and environment expenditure**		1,238
103	*less*	Capital contributions funding other reliability, safety and environment		
104		**Other reliability, safety and environment less capital contributions**		1,238
105				
106	**6a(ix): Non-Network Assets**			
107	**Routine expenditure**			
108		*Project or programme**	**($000)**	**($000)**
109				
110				
111				
112				
113				
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure		
116		**Routine expenditure**		–
117	**Atypical expenditure**			
118		*Project or programme**	**($000)**	**($000)**
119		Asset Data Management System (ADMS)	1,540	
120		CRM Salesforce	224	
121		Leased Assets - Vehicles	451	
122				
123				
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure	144	
126		**Atypical expenditure**		2,359
127				
128		**Expenditure on non-network assets**		2,359

Company Name	**Northpower Limited**
For Year Ended	**31 March 2020**

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

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

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

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

sch ref		($000)	($000)
7	**6b(i): Operational Expenditure**		
8	Service interruptions and emergencies	3,126	
9	Vegetation management	3,241	
10	Routine and corrective maintenance and inspection	3,267	
11	Asset replacement and renewal	2,076	
12	**Network opex**		11,710
13	System operations and network support	2,712	
14	Business support	12,624	
15	**Non-network opex**		15,336
16			
17	**Operational expenditure**		27,047
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		
20	Direct billing*		
21	Research and development		
22	Insurance		
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Northpower Limited**
For Year Ended	**31 March 2020**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

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

sch ref				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	72,000	62,160	(14%)
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	4,395	4,919	12%
11	System growth	3,625	3,662	1%
12	Asset replacement and renewal	10,136	11,098	9%
13	Asset relocations	255	515	102%
14	Reliability, safety and environment:			
15	Quality of supply	800	675	(16%)
16	Legislative and regulatory	–	1	–
17	Other reliability, safety and environment	309	1,238	301%
18	**Total reliability, safety and environment**	1,109	1,914	73%
19	**Expenditure on network assets**	19,520	22,108	13%
20	Expenditure on non-network assets	2,411	2,359	(2%)
21	Expenditure on assets	21,931	24,467	12%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	2,066	3,126	51%
24	Vegetation management	2,369	3,241	37%
25	Routine and corrective maintenance and inspection	2,864	3,267	14%
26	Asset replacement and renewal	2,661	2,076	(22%)
27	**Network opex**	9,960	11,710	18%
28	System operations and network support	3,071	2,712	(12%)
29	Business support	12,293	12,624	3%
30	**Non-network opex**	15,364	15,336	(0%)
31	**Operational expenditure**	25,324	27,047	7%
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 Limited
For Year Ended	31 March 2020
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 Residence	Residential	Standard	46,046	299,531
16	DM3 - Non-Principal Residence	Residential	Standard	3,227	6,668
17	DM4 - Inclusive (Obsolete)	Residential	Standard	66	426
18	DM6 - ToU Principal Residence	Residential	Standard	53	516
19	ND1 - Up to 70kVA (100A or less)	General	Standard	9,601	117,555
20	Metering)	General	Standard	384	35,412
21	ND5 - Irrigation and Pumps	General	Standard	79	3,021
	ND6 - Unmetered 24 Hour	General	Standard	196	196
	ND7 - Unmetered Public Lighting	General	Standard	12	2,811
22	ND12 - Builders Supply	General	Standard	433	507
23	ND10 - Volume Based ToU	Large Commercial	Standard	86	18,797
	ND9 - Demand Based ToU	Large Commercial	Standard	78	85,727
	IND - Individual Pricing	Asset Based	Non-standard	6	520,028
	Discount (1 to 1,999 kWh)	All Consumers	Standard		
24	Discount (2,000+ kWh)	All Consumers	Standard		
25	*Add extra rows for additional consumer groups or price category codes as necessary*				
26			**Standard consumer totals**	60,261	571,167
27			**Non-standard consumer totals**	6	520,028
28			**Total for all consumers**	60,267	1,091,195

Billed quantities by price component

sch ref		Daily Fixed Charge	Daily Fixed Charge	Consumption	Monthly Fixed Charge	Demand	Excess Reactive Power	Excess Reactive Power	Asset Utilisation	Transmission Pass Through	Eligible Discount
12	**Price component**	Daily Fixed Charge	Daily Fixed Charge	Consumption	Monthly Fixed Charge	Demand	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	ICP Month	kVA Demand	kVArh	kVAr	Per ICP	Per ICP	Per ICP
15	DM1 - Principal Residence	16,728,696		301,889,106							
16	DM3 - Non-Principal Residence	1,165,745		6,667,522							
17	DM4 - Inclusive (Obsolete)	25,889		425,876							
18	DM6 - ToU Principal Residence	28,587		516,181							
19	ND1 - Up to 70kVA (100A or less)	3,286,359		117,888,075							
20	Metering)	139,017		35,412,064							
21	ND5 - Irrigation and Pumps	29,609		3,020,841							
	ND6 - Unmetered 24 Hour	70,278		195,839							
	ND7 - Unmetered Public Lighting	–	2,834,380	–							
22	ND12 - Builders Supply	156,971		506,620							
23	ND10 - Volume Based ToU	31,481		18,796,558			2,007,857				
	ND9 - Demand Based ToU	–		–	768	530,484		14,688			
	IND - Individual Pricing	–		520,027,927				37,051	6	6	
	Discount (1 to 1,999 kWh)										8,054
24	Discount (2,000+ kWh)										50,212
26	**Standard consumer totals**	21,662,632	2,834,380	485,318,682	768	530,484	2,007,857	14,688	–	–	58,266
27	**Non-standard consumer totals**	–	–	520,027,927	–	–	–	37,051	6	6	–
28	**Total for all consumers**	21,662,632	2,834,380	1,005,346,609	768	530,484	2,007,857	51,739	6	6	58,266

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

29

30

Company Name	Northpower Limited
For Year Ended	31 March 2020
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.

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

Row	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	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)
37	DM1 - Principal Residence	Residential	Standard	$34,267		$34,267	
38	DM3 - Non-Principal Residence	Residential	Standard	$1,801		$1,801	
39	DM4 - Inclusive (Obsolete)	Residential	Standard	$46		$46	
40	DM6 - ToU Principal Residence	Residential	Standard	$62		$62	
41	ND1 - Up to 70kVA (100A or less)	General	Standard	$15,363		$15,363	
	Metering)	General	Standard	$4,102		$4,102	
	ND5 - Irrigation and Pumps	General	Standard	$197		$197	
42	ND6 - Unmetered 24 Hour	General	Standard	$105		$105	
43	ND7 - Unmetered Public Lighting	General	Standard	$649		$649	
44	ND12 - Builders Supply	General	Standard	$277		$277	
45	ND10 - Volume Based ToU	Large Commercial	Standard	$2,265		$2,265	
	ND9 - Demand Based ToU	Large Commercial	Standard	$4,244		$4,244	
	IND - Individual Pricing	Asset Based	Non-standard	$8,863		$8,863	
	Discount (1 to 1,999 kWh)		Standard	($443)		($443)	
46	Discount (2,000+ kWh)		Standard	($9,641)		($9,641)	
47	*Add extra rows for additional consumer groups or price category codes as necessary*						
48			**Standard consumer totals**	$53,297	–	$53,297	–
49			**Non-standard consumer totals**	$8,863	–	$8,863	–
50			**Total for all consumers**	$62,160	–	$62,160	–

Line charge revenues ($000) by price component

Row	Price component	Daily Fixed Charge	Daily Fixed Charge	Consumption	Monthly Fixed Charge	Demand	Excess Reactive Power	Excess Reactive Power	Asset Utilisation	Transmission Pass Through	Eligible Discount
35	Rate (eg, $ per day, $ per kWh, etc.)	$ per ICP per Day	$ Fixture per Day	$ per kWh	ICP Month	kVA Demand	$ per Excess kVArh	kVAr	Asset Value	Coincident kW Demand	$ per Eligibility
37	DM1 - Principal Residence	$2,509	–	$31,757	–	–	–	–	–	–	–
38	DM3 - Non-Principal Residence	$1,166	–	$636	–	–	–	–	–	–	–
39	DM4 - Inclusive (Obsolete)	$4	–	$43	–	–	–	–	–	–	–
40	DM6 - ToU Principal Residence	$4	–	$58	–	–	–	–	–	–	–
41	ND1 - Up to 70kVA (100A or less)	$3,944	–	$11,420	–	–	–	–	–	–	–
	Metering)	$264	–	$3,838	–	–	–	–	–	–	–
	ND5 - Irrigation and Pumps	$36	–	$162	–	–	–	–	–	–	–
42	ND6 - Unmetered 24 Hour	$84	–	$21	–	–	–	–	–	–	–
43	ND7 - Unmetered Public Lighting	–	$649	–	–	–	–	–	–	–	–
44	ND12 - Builders Supply	$220	–	$57	–	–	–	–	–	–	–
45	ND10 - Volume Based ToU	$81	–	$2,124	–	–	$60	–	–	–	–
	ND9 - Demand Based ToU	–	–	–	$92	$4,128	–	$24	–	–	–
	IND - Individual Pricing	–	–	$66	–	–	–	$60	$1,870	$6,868	–
	Discount (1 to 1,999 kWh)	–	–	–	–	–	–	–	–	–	($443)
46	Discount (2,000+ kWh)	–	–	–	–	–	–	–	–	–	($9,641)
48	Standard consumer totals	$8,312	$649	$50,115	$92	$4,128	$60	$24	–	–	($10,084)
49	Non-standard consumer totals	–	–	$66	–	–	–	$60	$1,870	$6,868	–
50	Total for all consumers	$8,312	$649	$50,181	$92	$4,128	$60	$84	$1,870	$6,868	($10,084)

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

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

Check OK

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

Company Name	**Northpower Limited**
For Year Ended	**31 March 2020**
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.	53,164	53,318	154	2
10	All	Overhead Line	Wood poles	No.	1,342	1,255	(87)	2
11	All	Overhead Line	Other pole types	No.	52	49	(3)	2
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	293	295	2	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	28	28	–	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	11	11	0	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	0	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.	20	20	–	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.	20	20	–	2
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	11	29	18	2
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	174	174	–	2
29	HV	Zone substation switchgear	33kV RMU	No.	4	4	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	30	30	–	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.	146	146	–	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.	39	40	1	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3,498	3,502	4	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	238	247	9	3
39	HV	Distribution Cable	Distribution UG PILC	km	39	39	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.	31	31	–	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.	8,412	8,449	37	2
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	21	21	–	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	207	212	5	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	5,930	5,949	19	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,420	1,453	33	3
48	HV	Distribution Transformer	Voltage regulators	No.	10	10	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	118	120	2	4
50	LV	LV Line	LV OH Conductor	km	1,189	1,182	(7)	2
51	LV	LV Cable	LV UG Cable	km	743	767	24	2
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	411	410	(0)	2
53	LV	Connections	OH/UG consumer service connections	No.	59,852	60,680	828	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	333	334	1	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	27	27	–	4
57	All	Load Control	Centralised plant	Lot	6	6	–	4
58	All	Load Control	Relays	No	36,562	38,439	1,877	3
59	All	Civils	Cable Tunnels	km		–	–	N/A

Company Name	Northpower Limited
For Year Ended	31 March 2020
Network / Sub-network Name	

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 Disclosure Year (year ended) 31 March 2020

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	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	153	160	1,677	8,170	12,453	9,908	7,792	612	580	495	747	792	738	726	603	609	744	742	741	806	746	652	665	580	453	390	470	114							53,318	3,596	2
11	All	Overhead Line	Wood poles	No.	1		11	77	165	452	267	14	24	24	39	55	34	23	12	11	5	5	9	3	2	3	2	4	2	4	6	1							1,255	222	2
12	All	Overhead Line	Other pole types	No.			2	5	12	21	3			2		2			1										1										49	1	2
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km			72	104	26	38	46	4	0	0	1	0			0	0	0	0		1	0	0					1	2							295	0	3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km					28	0																													28		4
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								11	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																			20		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.	2	2	8				3	3		2																									20	2	2
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.														4		24	1																		29	16	2
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			18	51	10	19	2	2		5	5	1	29	4	1	8	5	2	1	4	2				5										174	2	2
30	HV	Zone substation switchgear	33kV RMU	No.								2	2																										4		4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.						19	1		1	1				1		3	2				1	1													30		4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.						6	24	6				5	1	3	1		2			2			4	1	4										59		4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.			1	16	29	20	1		5		4			9	31		17	12			1														146		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.			4	13	6	4			1	2	1		2				2					2			1	2									40		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	13	21	93	584	705	712	506	51	29	48	33	68	36	23	26	25	24	28	46	72	85	34	47	37	41	41	65	8							3,502	7	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	11	27	7	8	12	9	16	24	27	21	8	12	4	3	4	9	5	6	7	6	7	10	1							247	2	3
40	HV	Distribution Cable	Distribution UG PILC	km				5	10	13	6	0	1	0	0	0	1	0	1	0		0	0	0	1		0		0	0									39	3	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	3	2	3	2		1	1									31		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.	8	8	12	158	280	650	1,207	144	136	161	158	219	236	228	217	381	549	371	500	401	406	379	410	298	317	266	290	59							8,449	386	2
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.					12	8																				1									21	1	3
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.					3	9	15	2	4	2	2	5	33	26	6	10	23	5	5	5	6	7	9	8	10	8	9								212		4
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	83	130	128	573	503	428	1,148	171	136	155	131	179	156	163	210	123	144	48	141	93	142	228	152	115	170	143	154	2							5,949	16	3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	3	3	16	173	173	162	141	35	35	41	29	57	82	86	71	25	37	49	6	1	14	34	46	34	43	31	26								1,453	3	3
49	HV	Distribution Transformer	Voltage regulators	No.					2		2					3											3												10		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.			1	14	21	23	31	5	1	7	1	1			1	4	2	2	1	2						2	1								120		4
51	LV	LV Line	LV OH Conductor	km	2	2	27	178	194	319	178	12	10	12	25	23	22	17	14	13	18	16	17	13	11	10	11	9	7	8	9	4							1,182	101	2
52	LV	LV Cable	LV UG Cable	km	0		0	25	51	69	86	20	20	27	35	48	52	49	49	26	29	16	7	6	18	8	16	23	26	30	25	5							767	13	2
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km			2	47	153	42	53	2	4	3	4	8	11	13	11	6	14	1	4	1	3	6	4	3	6	7	4	0							410	103	2
54	LV	Connections	OH/UG consumer service connections	No.				3	7	11,854	27,622	3,905	827	887	1,117	1,114	1,174	1,100	1,055	849	769	739	587	629	629	616	830	1,052	1,132	1,039	976	168							60,680	2,925	3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.					8	27	75	13	3	3	1	7	20	15	29	36	22	30	2	7	1	4	2	24	1	4									334		4
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot																1																			1		4
57	All	Capacitor Banks	Capacitors including controls	No							5		1				3			1	5	8		3				1											27		4
58	All	Load Control	Centralised plant	Lot						2					2				1			1																	6		4
59	All	Load Control	Relays	No						5,184	8,161	1,104	841	856	3,309	5,392	1,176	853	1,021	1,221	741	905	606	517	1,005	964	1,404	830	858	869	618	4							38,439	1,279	3
60	All	Civils	Cable Tunnels	km																																			–		N/A

Company Name	**Northpower Limited**
For Year Ended	**31 March 2020**
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	220	23	243
14	SWER (all SWER voltages)			–
15	22kV (other than SWER)			–
16	6.6kV to 11kV (inclusive—other than SWER)	3,502	288	3,790
17	Low voltage (< 1kV)	1,182	767	1,949
18	**Total circuit length (for supply)**	5,007	1,078	6,086
19				
20	Dedicated street lighting circuit length (km)	174	236	410
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			119
22				

23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**
24	Urban	570	11%
25	Rural	4,438	89%
26	Remote only		–
27	Rugged only		–
28	Remote and rugged		–
29	Unallocated overhead lines		–
30	**Total overhead length**	5,007	100%
31			
32		**Circuit length (km)**	**(% of total circuit length)**
33	Length of circuit within 10km of coastline or geothermal areas (where known)	4,409	72%
34		**Circuit length (km)**	**(% of total overhead length)**
35	Overhead circuit requiring vegetation management	5,007	100%

Company Name	**Northpower Limited**
For Year Ended	**31 March 2020**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref

	Location *	Number of ICPs served	Line charge revenue ($000)
9			
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 Limited**
For Year Ended	**31 March 2020**
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

8	**9e(i): Consumer Connections**			
9	*Number of ICPs connected in year by consumer type*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11	Mass Market New ICPs		920	
12	Large Commercial and Industrial (ND9) New ICPs		–	
13	Very Large Industrial New ICPs		–	
14				
15				
16	** include additional rows if needed*			
17	**Connections total**		920	
18				
19	**Distributed generation**			
20	Number of connections made in year		162	**connections**
21	Capacity of distributed generation installed in year		0.89	**MVA**
22	**9e(ii): System Demand**			
23				
24			**Demand at time of maximum coincident demand (MW)**	
25	**Maximum coincident system demand**			
26		GXP demand	162	
27	*plus*	Distributed generation output at HV and above	11	
28	**Maximum coincident system demand**		173	
29	*less*	Net transfers to (from) other EDBs at HV and above		
30	**Demand on system for supply to consumers' connection points**		173	
31	**Electricity volumes carried**		**Energy (GWh)**	
32		Electricity supplied from GXPs	1,101	
33	*less*	Electricity exports to GXPs	–	
34	*plus*	Electricity supplied from distributed generation	18	
35	*less*	Net electricity supplied to (from) other EDBs	–	
36	**Electricity entering system for supply to consumers' connection points**		1,119	
37	*less*	Total energy delivered to ICPs	1,091	
38	**Electricity losses (loss ratio)**		28	2.5%
39				
40	**Load factor**		0.74	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43		Distribution transformer capacity (EDB owned)	567	
44		Distribution transformer capacity (Non-EDB owned, estimated)	5	
45	**Total distribution transformer capacity**		572	
46				
47	**Zone substation transformer capacity**		331	

Company Name	**Northpower Limited**
For Year Ended	**31 March 2020**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

10(i): Interruptions

Interruptions by class	**Number of interruptions**
Class A (planned interruptions by Transpower)	
Class B (planned interruptions on the network)	439
Class C (unplanned interruptions on the network)	494
Class D (unplanned interruptions by Transpower)	4
Class E (unplanned interruptions of EDB owned generation)	
Class F (unplanned interruptions of generation owned by others)	
Class G (unplanned interruptions caused by another disclosing entity)	
Class H (planned interruptions caused by another disclosing entity)	
Class I (interruptions caused by parties not included above)	
Total	937

Interruption restoration	**≤3Hrs**	**>3hrs**
Class C interruptions restored within	375	119

SAIFI and SAIDI by class	**SAIFI**	**SAIDI**
Class A (planned interruptions by Transpower)		
Class B (planned interruptions on the network)	0.41	105.0
Class C (unplanned interruptions on the network)	3.13	145.2
Class D (unplanned interruptions by Transpower)	1.17	124.8
Class E (unplanned interruptions of EDB owned generation)		
Class F (unplanned interruptions of generation owned by others)		
Class G (unplanned interruptions caused by another disclosing entity)		
Class H (planned interruptions caused by another disclosing entity)		
Class I (interruptions caused by parties not included above)		
Total	4.71	375.0

Normalised SAIFI and SAIDI	**Normalised SAIFI**	**Normalised SAIDI**
Classes B & C (interruptions on the network)	3.54	238.4

Company Name	**Northpower Limited**
For Year Ended	**31 March 2020**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

Cause	SAIFI	SAIDI
Lightning	0.31	7.8
Vegetation	0.38	31.5
Adverse weather	0.31	29.5
Adverse environment	0.01	0.7
Third party interference	0.21	17.9
Wildlife	0.29	5.7
Human error	0.01	0.1
Defective equipment	0.92	43.4
Cause unknown	0.69	8.6

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.0	0.0
Subtransmission cables		
Subtransmission other		
Distribution lines (excluding LV)	0.37	93.3
Distribution cables (excluding LV)	0.05	11.7
Distribution other (excluding LV)		

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	1.06	41.6
Subtransmission cables		
Subtransmission other		
Distribution lines (excluding LV)	1.97	97.1
Distribution cables (excluding LV)	0.10	6.5
Distribution other (excluding LV)		

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	36	323	11.15
Subtransmission cables			–
Subtransmission other			
Distribution lines (excluding LV)	449	3,502	12.82
Distribution cables (excluding LV)	19	288	6.60
Distribution other (excluding LV)			
Total	504		

Company Name	Northpower Limited
For Year Ended	31 March 2020

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 sub clauses 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 sub clause 2.7.1(2).

Box 1: Explanatory comment on return on investment

The calculated post tax ROI and vanilla ROI for the disclosure year was 3.35% and 3.77% respectively. The reduction in ROI relative to FY19 reflects:

- Inclusion of a consumer discount ($10.1m)
- Increased opex (see box 10).

These changes are partly offset by:

- Lower pass-through and recoverable costs ($20.3 vs $22.1)
- Higher revaluations ($6.8k vs $3.9k). These are based on the closing CPI which for FY20 was 2.53% and for FY19 was 1.48%.

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 sub clause 2.7.1(2).

Box 2: Explanatory comment on regulatory profit
Other regulatory income of $347k relates mostly to value added work on charged to customers (93%).
Lease income on fibre assets has been excluded in this disclosure year as the shared portion of the asset has been allocated out of the RAB value. This is consistent with last year.

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 sub clause 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 sub clause 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.
- There were no reclassifications made.
- Disposed assets of $57k were related to conductors, transformers and substations.
- 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
There are no material permanent differences included in schedule 5a.

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 temporary differences of $90k represents tax on the movement between FY19 and FY20 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 sub clause 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 increased by $200k from FY19. This was largely driven by:

- An increase in Finance support costs due to increased resources in this area to better support the business.
- An allocation of HSQE costs in FY20. These costs have previously been incurred directly by the Distribution Business. Partway through the 2020 disclosure year, costs and management of these activities have been centralised. A share of the centralised costs have been allocated to the Distribution business.
- These increases have been partly offset by a decrease in corporate support costs due to a reduction in the allocator portion attributable to the Distribution Business associated with a revaluation of the distribution system.

Allocation categories are consistent with the prior year for existing categories but include a new HSQE category for FY20. Allocators are outlined below:

- Human resources costs allocated using headcount as a casual allocator.
- Information technology costs allocated using the weighted average of devices as a casual allocator.
- Finance costs allocated using gross margin as a proxy allocator.
- Rent costs allocated using floor space as a casual allocator.
- Corporate costs allocated using non-current assets as a proxy allocator.
- HSQE is a newly centralised category which is allocated using headcount as a casual allocator.

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 sub clause 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 (casual 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 and resulted in a further $603k being allocated out of the regulatory asset base.

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 sub clause 2.7.1(2).

Box 9: Explanation of capital expenditure for the disclosure year

The largest component of capex in FY20 was asset replacement, followed by consumer connections. This trend is consistent with FY19 and FY18.

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 sub clause 2.7.1(2);

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

Box 10: Explanation of operational expenditure for the disclosure year

- 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, excluding asset replacement and renewal, in response to asset condition and risk monitoring. The largest increases in expenditure were:
  - Service interruptions and emergencies – increased impact from weather events
  - Business support – 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 sub clause 2.7.1(2).

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

- Asset expenditure was overall 8% higher than the target expenditure due to higher new subdivisions than expected leading to consumer connections expenditure higher than forecast. Asset replacement and renewal and reliability, safety and environment were higher than forecast due to increases in labour and material costs and higher replacement costs associated with more frequent weather events.
- Network Opex was 18% higher than target mainly from service interruptions and emergencies and vegetation management. These were due to increased labour and material costs and higher repair costs from weather events.
- Non-network Opex was 0.2% 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 sub clause 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 14% higher than the total billed line charge revenue for the disclosure year. The material movement came from a $10.1m discount paid to consumers.

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 unplanned SAIDI target of less than 90 minutes was not achieved, largely due to the extent of weather related events causing both vegetation related outages and stressing end of life assets resulting in higher than average SAIDI from defective equipment. This included a total of 22 SAIDI minutes on the 33kV line to Mangawhai caused by two vegetation related outages. These factors also contributed to the negative variance in faults per 100km of line and SAIFI targets.

Reliability measures have been calculated on a consistent basis with previous years. During the interruption to supply, some customers may be temporarily restored 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.

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 Ltd
For Year Ended	31 March 2020

Schedule 15 Voluntary Explanatory Notes

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

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

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

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

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

3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

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.

NORTHPOWER NETWORK YEAR TO 31 MARCH 2020 ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE (EDID) FOR RELATED PARTY TRANSACTIONS

Table of Contents

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	FY20 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 $11,672k Operating expenditure (maintenance) $11,345k
Northpower Corporate Division	Both Northpower Network and Corporate division are part of Northpower Limited	Northpower Corporate owns land and buildings office space. Northpower Network rents office space from the Corporate division.	Operating expenditure (rental) $120k
Northpower Fibre Division	Both Northpower Network and Fibre division are part of Northpower Limited	Northpower Fibre division has constructed network fibre lines used for communications systems by Northpower Network.	Capital expenditure $220k
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) $9k
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.)	Capex $70k
Electricity Engineers' Association (EEA)	Ms Josie Boyd is the GM of Northpower Network and a Board Member of the Electricity Engineers' Association.	Professional engineers employed by Northpower Network are members of the EEA and purchase products from EEA.	Operating expenditure $21k

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.

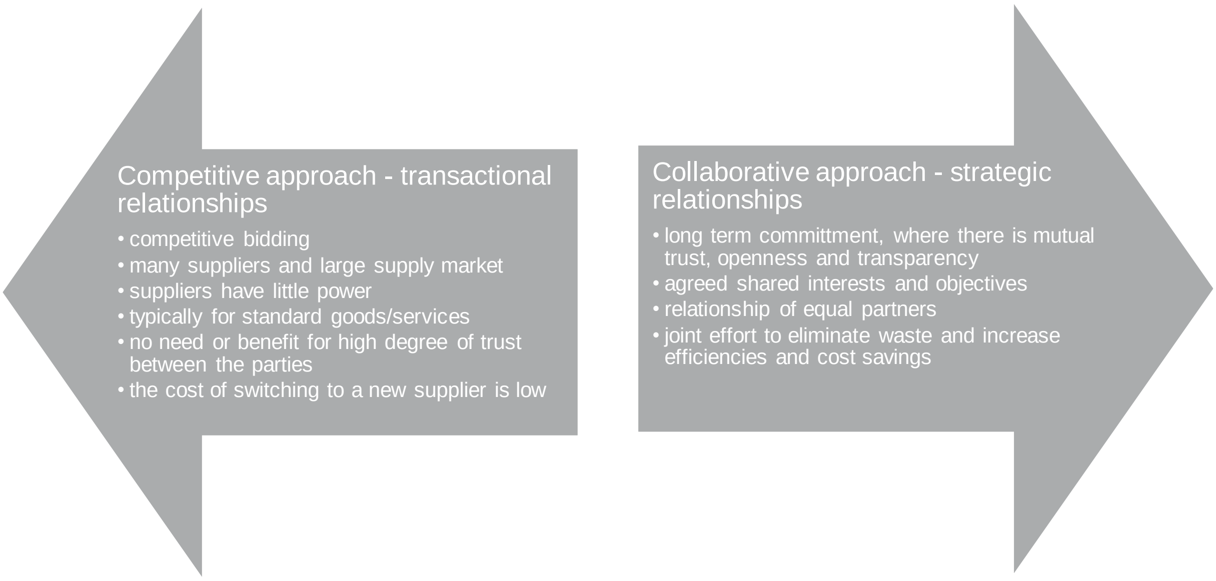
Procurement Objectives

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.

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 expected 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 is based on negotiated labour, plant and unit rates. All work completed by the Northpower Contracting Division is governed by a field services agreement (referred to as the Service Level Agreement (SLA)) that outlines how Northpower Network and Contracting Division will work together, specifies the scope of services provided by the Contracting Division and rates, and includes a set of KPI's. The agreement is negotiated between representatives of the two Northpower divisions and approved by the respective General Managers.

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.

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 – Maunu Substation

Construction of the Maunu Substation was awarded under competitive tender using NZS3910 based tender process. The tender was offered to four established electrical contractors and released to three who elected to participate in the tender, including Northpower Contracting Division. Northpower Contracting withdrew during the tender process. The award decision was based on weighted and objective criteria disclosed to the respondents in the tender documentation. Electrix Ltd was awarded this contract, based on the results of the tender process. The nature of the tender process provided an arms-length assessment for this contract. Construction for this project has commenced and is expected to be complete during FY21.

Capex Projects: Competitive Tender - Whangarei South Switchboard

Construction of the Whangarei South Switchboard was awarded under competitive tender using NZS3910 based tender process. The tender was offered to five established electrical contractors and released to three who elected to participate in the tender, including Northpower Contracting Division. Two of the contractors withdrew during the tender process and Northpower Contracting Division was awarded this contract. The nature of the tender process provided an arms-length assessment for this contract.

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 General 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 2020. 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 is completed by Northpower Contracting Division and a third party. Northpower's Corporate Finance Division has compared the rates charged by each of these parties during the 31 March 2020 year. 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.

Land and Building Rental

Northpower Network operates from a property owned by the Northpower Corporate Division. As noted in the schedule of related parties, Northpower Network pays rental for this property. The rental has been compared to similar local commercial office advertised rates. This assessment indicates that the rental paid by Northpower Network meets the arms-length requirements. The rental is a standing monthly charge that is reviewed during the annual budget process.

Fibre Backhaul

Northpower Fibre and Contracting divisions completed the build of a fibre line for communications purposes between Mangawhai and Kaiwaka in the year ending 31 March 2020. The Contracting division portion was charged in line with the SLA rates and the Fibre division portion was at cost.

Procurement Examples

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

Faults Services

On 15 March 2020 at 10.14am the Control Room received a call for an incident where a vehicle collided with a pole (Pole no 30017). The fault was recorded in the faults management system with ref: 330078 and a faultman was dispatched to attend the site. The faultman made the site safe and a standby crew was called in to replace the pole. Northpower Contracting recorded the labour, plant and materials used to replace the pole for the work detailed on the service request. An invoice was issued to Network along with a copy of the service request sheet. This was approved for payment by the Network.

Planned Maintenance

Northpower Network's Maintenance Manager schedules bi-monthly substation maintenance. The maintenance task is created in our maintenance system, which is 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 PO, otherwise Network Management review the invoice and approve if the charges are appropriate. Invoices that require approval are highlighted by an exceptions report.

Defects identified when Northpower Contracting are completing the original work are recorded on a defect sheet and Northpower Contracting create 'tasks' in Wasp (the asset maintenance system). If approved, the Network Maintenance Team then package those defects into a work pack and send back to Contracting for any remedial work.

Vegetation

A prioritised annual vegetation maintenance programme is established for the year and non-urban work is distributed to Northpower Contracting for implementation. The programme is split into Feeder Lines and each is inspected in the order of Network's priority. Following inspection, details of any cutting work required is recorded in the maintenance system in a work pack. Once this work is completed, Northpower Contracting invoice Network. Network management review and approve the invoice for payment.

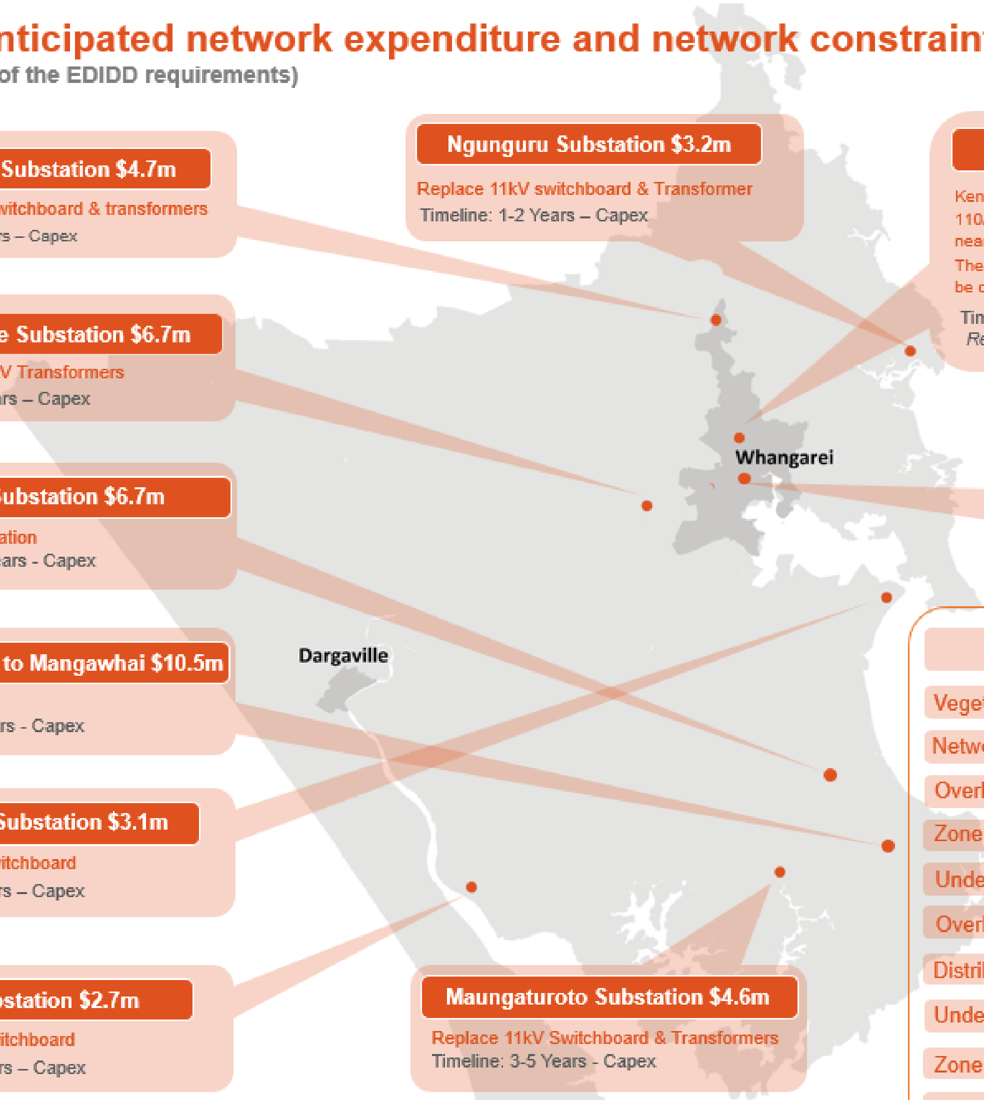
Capital Project

A distribution line conductor was due for EOL (End of Life) replacement. Conductor replacement projects are identified by conditions 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.

Map of anticipated network expenditure and network constraints

(Clause 2.3.13 of the EDIDD requirements)

Northpower



Hikurangi Substation $4.7m

Replace 11kV Switchboard & transformers

Timeline: 1-2 Years – Capex

Ngunguru Substation $3.2m

Replace 11kV switchboard & Transformer

Timeline: 1-2 Years – Capex

Kensington Substation Upgrade $9m

Kensington Substation upgrade includes replacement of two 110/33kV transformers due to the existing 110/33kV transformers nearing end of life and reaching their capacity at peak.

They will be replaced with two modern transformers each of which will be capable of carrying the full substation load

Timeline: 4-6 Years – Capex

Representative example of a project in response to a constraint in the network

Maungatapere Substation $6.7m

Replace 110/33kV Transformers

Timeline: 3-5 Years – Capex

Waipu Substation $6.7m

New Zone Substation

Timeline: 7-10 Years - Capex

Whangarei South Substation $4.7m

Replace 33/11kV Transformers

Timeline: 6-8 Years - Capex

Maungaturoto to Mangawhai $10.5m

New 33kV Line

Timeline: 1-5 Years - Capex

Bream Bay Substation $3.1m

Replace 33kV Switchboard

Timeline: 1-3 Years – Capex

Ruawai Substation $2.7m

Replace 11kV Switchboard

Timeline: 1-5 Years – Capex

Maungaturoto Substation $4.6m

Replace 11kV Switchboard & Transformers

Timeline: 3-5 Years - Capex

OPEX Programme

- Vegetation management $28.0m
- Network reactive maintenance (Faults) $18.2m
- Overhead network corrective maintenance $10.0m
- Zone substation preventative maintenance $6.7m
- Underground network preventive maintenance $5.1m
- Overhead network preventive maintenance $4.3m
- Distribution earth maintenance $3.9m
- Underground network corrective maintenance $3.5m
- Zone substation corrective maintenance $3.4m
- Overhead 11kV switch refurbishment $2.9m

Note:The OPEX Programme is not location based or in response to a constraint on the network

Capital Project

currently not indicated for supply by a related party, but the related party will be invited to participate in a tender or pricing process

Operating Program

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

Appendix II – Directors' Certification

DIRECTORS' CERTIFICATE

We, Mark Trigg and Michael James, 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 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	Michael James
Date: 26 August 2020	Date: 26 August 2020

Audit New Zealand
Mana Arotake Aotearoa

Independent Assurance Report

To the directors of Northpower Limited and the Commerce Commission

The Auditor-General is the auditor of Northpower Limited (the Company). The Auditor-General has appointed me, Clarence Susan, using the staff and resources of Audit New Zealand, to provide an opinion, on his behalf, on:

- whether the information ("the Disclosure Information") required to be disclosed in accordance with the Electricity Distribution Information Disclosure Determination 2012, as amended by the Information Disclosure exemption: Disclosure and auditing of reliability information within schedule 10, issued by the Commerce Commission on 9 April 2020 ("the Information Disclosure Determination, as amended") for the disclosure year ended 31 March 2020, has been prepared, in all material respects, in accordance with the Information Disclosure Determination, as amended.
- The Disclosure Information required to be reported by the Company, and audited by the Auditor-General, under the Information Disclosure Determination, as amended, is in schedules 1 to 4, 5a to 5g, 6a and 6b, 7, the disclosure that shows the connection between the Electricity Distribution Business (EDB) and the related parties with which it has had related party transactions in the disclosure year, the disclosure of the EDB's related party procurement policy, the disclosures about related party transactions required under clause 2.3.12 of the Information Disclosure Determination, the system average interruption duration index ("SAIDI") and system average interruption frequency index ("SAIFI") information disclosed in Schedule 10 and the explanatory notes in boxes 1 to 11, in Schedule 14.
- whether the Company's basis for valuation of related party transactions ("the Related Party Transaction Information") for the disclosure year ended 31 March 2020, has been prepared, in all material respects, in accordance with clause 2.3.6 of the Information Disclosure Determination, as amended, and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 ("the Input Methodologies Determination").

Opinion

In our opinion:

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

- the Related Party Transaction Information complies, in all material respects, with the Information Disclosure Determination, as amended, and the Input Methodologies Determination.

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

Basis of opinion

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

These standards require that we comply with ethical requirements and plan and perform our assurance engagement to provide reasonable assurance about whether the Disclosure Information has been prepared, in all material respects, with the Information Disclosure Determination, as amended, and about whether the Related Party Transaction Information has been prepared, in all material respects, with the Information Disclosure Determination, as amended, and the Input Methodologies Determination. Reasonable assurance is a high level of assurance.

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

Scope and inherent limitations

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

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

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

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 audit, and in forming our opinion. We do not provide a separate opinion on these matters.

<table>
<tr><th>Key audit matter</th><th>How our procedures addressed the key audit matter</th></tr>
<tr><td colspan="2">Cost and Asset Allocations</td></tr>
<tr><td>The Information Disclosure Determination, as amended and the Input Methodologies Determination require the disclosure of information concerning the supply of electricity distribution services (regulated services). The Company also supplies customers with unregulated services such as contracting and metering services.

Costs and asset values that relate to electricity distribution services regulated under the Information Disclosure Determination and the Input Methodologies Determination should comprise:
• all of the costs and assets directly attributable to the supply of electricity distribution services; and
• an allocated portion of the costs and assets that are not directly attributable.

The Input Methodologies Determination sets out the rules and processes for allocating non-directly attributable costs and assets.

This is a key audit matter because of the professional judgement involved in determining and applying the method to allocate non-directly attributable costs and assets to the Company’s regulated services.</td><td>We have obtained an understanding of the Company’s approach to allocating costs and assets to the regulated and non-regulated business. We confirmed the approach used is in accordance with the Information Disclosure Determination, as amended and the Input Methodologies Determination

The procedures we carried out, to satisfy ourselves that cost and assets were correctly allocated, included:
• reconciling the regulated and non-regulated financial information to the audited financial statements for the year ended 31 March 2020;
• reviewing of the costs by business unit, based on their nature and on our understanding of the business, to determine the reasonableness of the directly attributable costs by business unit;
• testing a sample of invoices to ensure their classification as either directly attributable or non-directly attributable costs are appropriate and in compliance with the Information Disclosure Determination, as amended and the Input Methodologies Determination;
• reviewing the fixed asset register to identify any asset classes which, based on their nature and our understanding of the business, could be considered assets directly attributable to the supply of electricity distribution services; and
• testing a sample of cost allocation calculations.</td></tr>
</table>

Key audit matter	How our procedures addressed the key audit matter
Accuracy of the number and duration of electricity outages	
The Company has a combination of manual and automated systems to identify outages and to record the duration of outages. This outage information is used to report the Company's Report on Network Reliability in Schedule 10. If this information is inaccurate then the measures of the reliability of the network could be materially misstated. This is a key audit matter because information on the frequency and duration of outages is an important measure of the reliability of electricity supply. Relatively small inaccuracies can have a significant impact on the reliability thresholds against which Company performance is assessed. There can also be significant consequences if the Company breaches the reliability thresholds. The Commission has issued an Exemption notice which, if it applies excludes the assurance report from coverage of the information, in Schedule 10 of the ID determination, for any issues arising out of the EDB's recording of SAIDI, SAIFI and number of interruptions due to successive interruptions. We need to ensure that the Company meets the criteria for the Exemption to apply, including that it makes the necessary disclosures so the exclusion to the assurance opinion applies.	We have obtained an understanding of the Company's system to record electricity outages, and their duration. This included review of the Company's definition of interruptions, planned interruptions and major event days. Our procedures to assess the adequacy of the Company's methods to identify and record electricity outages and their duration included: • performing an assessment of the reliability of the manual and automated processes to record the details of interruptions to supply; • obtaining internal and external information on interruptions to supply to gain assurance that interruptions to supply were recorded. Internal and external information sources included works orders for contractors, media reports, and Board minutes; • testing a sample of interruptions to supply to source records to conclude on their accuracy of calculation, and the appropriateness of the categorisation of the cause of the interruption and whether it was planned or unplanned, and that the cause of the interruptions is correctly categorised; • checked the SAIDI and SAIFI ratios were correctly calculated in accordance with the Information Disclosure Determination, as amended, and the Input Methodologies Determination; • obtained explanations for all significant variances to forecast; and • testing the accuracy of the number of connections to the Electricity Authority's register. With respect to the Exemption, we: • obtained and documented our understanding of the Company's methods by which electricity outages and their duration are recorded where an outage event results in successive interruptions of supply.

<table>
<tr><th>Key audit matter</th><th>How our procedures addressed the key audit matter</th></tr>
<tr><td></td><td>compared this to the documented process that the Company followed in the previous year.
identified potential incidences of successive interruptions of supply to ensure that the Company’s methods, by which electricity outages and their duration are recorded where an outage event results in successive interruptions of supply, was the same for both years.
Having carried out these procedures, and in assessing the likelihood of reported electricity outages and their duration being materially misstated in the Disclosure Information, we have no matters to report.</td></tr>
<tr><td colspan="2">Valuation of related-party transactions at arms-length</td></tr>
<tr><td>The Information Disclosure Determination, as amended and the Input Methodologies Determination place a requirement on the Company to value related-party procurement transactions at a value not greater than arms-length. In other words, the value at which a transaction, with the same terms and conditions, would be entered into between a willing seller and a willing buyer who are unrelated and who are acting independently of each other and pursuing their own best interests.

In the absence of an active market for related-party transactions, assigning an objective arms-length value to a related-party transaction is difficult.

This is a key audit matter because it is a new requirement that involves considerable judgement by company personnel. In turn, verification of the appropriate assignment of an objective arms-length valuation to related-party transactions requires the exercise of significant professional judgement by the auditor.</td><td>We have obtained an understanding of the Company’s approach to identifying and valuing related-party transactions at arm’s-length in accordance with the Information Disclosure Determination, as amended and the Input Methodologies Determination.

The procedures we undertook to satisfy ourselves that related-party transactions are appropriately identified and valued at a value not greater than arm’s-length, included:
testing the completeness of the related-parties identified through review of Board minutes, review of Companies Office records, and related-parties identified through detailed testing of transactions and balances in our audit of the annual financial statements audit;
comparing the prices charged to the Company by related parties with the unit prices charged to other electricity distribution companies;
comparing the prices charged to the Company by related parties to unit prices charged to the Company by other suppliers;
comparing the prices for the actual tenders, awarded to related parties, to normal unit prices charged on non-tendered contracts;</td></tr>
</table>

Key audit matter	How our procedures addressed the key audit matter
	• testing samples of transactions, with related parties for the different categories of procurement for compliance with policies. This included reviewing tender evaluations, and quotes obtained to ensure transactions are at arm’s length; and • confirming the material accuracy of related party values disclosed, and compliance of their calculation with the Information Disclosure Determination, as amended and the Input Methodologies Determination.

Directors’ responsibility for the preparation of the Disclosure Information and Related Party Transaction Information

The directors of the Company are responsible for:

- the preparation of the Disclosure Information in accordance with the Information Disclosure Determination, as amended; and
- the Related Party Transaction Information in accordance with the Information Disclosure Determination, as amended, and the Input Methodologies Determination.

The directors are responsible for such internal control as the directors determine is necessary to enable the preparation of the Disclosure Information and the Related Party Transaction Information that are free from material misstatement.

Our responsibility for the audit of the Disclosure Information and the Related Party Transaction Information

Our responsibility is to express an opinion on whether:

- the Disclosure Information has been prepared, in all material respects, in accordance with the Information Disclosure Determination, as amended; and
- the Related Party Transaction Information has been prepared, in all material respects, in accordance with the Information Disclosure Determination, as amended, and the Input Methodologies Determination.

Independence and quality control

When carrying out the engagement, we complied with:

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

- the independence requirements specified in the Information Disclosure Determination, as amended; and

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

- The Auditor-General, and his 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 business, 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.

Use of this report

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

Clarence Susan
Audit New Zealand
On behalf of the Auditor-General
Tauranga, New Zealand
26 August 2020