COMMERCE COMMISSION
NEW ZEALAND

EDB Information Disclosure Requirements
Information Templates
for
Schedules 1–10

Company Name	Northpower Limited
Disclosure Date	31 August 2019
Disclosure Year (year ended)	31 March 2019

Templates for Schedules 1–10 excluding 5f–5g
Template Version 4.1. Prepared 21 December 2017

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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 2019**

SCHEDULE 1: ANALYTICAL RATIOS

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

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

sch ref

7 **1(i): Expenditure metrics**

sch ref		Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
8						
9	**Operational expenditure**	23,331	415	140,095	4,073	44,042
10	Network	9,977	178	59,906	1,742	18,833
11	Non-network	13,354	238	80,188	2,332	25,209
12						
13	**Expenditure on assets**	20,105	358	120,727	3,510	37,953
14	Network	19,868	354	119,301	3,469	37,505
15	Non-network	238	4	1,426	41	448
16						

17 **1(ii): Revenue metrics**

sch ref		Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
18			
19	**Total consumer line charge revenue**	69,513	1,237
20	Standard consumer line charge revenue	112,649	1,065
21	Non-standard consumer line charge revenue	20,607	1,701,108
22			

23 **1(iii): Service intensity measures**

sch ref			
24			
25	Demand density	29	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	175	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
27	Connection point density	10	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
28	Energy intensity	17,798	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*
29			

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

sch ref		($000)	% of revenue
31			
32	Operational expenditure	24,657	33.37%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	22,108	29.92%
34	Total depreciation	10,169	13.76%
35	Total revaluations	3,897	5.27%
36	Regulatory tax allowance	5,041	6.82%
37	Regulatory profit/(loss) including financial incentives and wash-ups	15,807	21.39%
38	**Total regulatory income**	73,884	
39			

40 **1(v): Reliability**

sch ref			
41			
42	Interruption rate	12.11	*Interruptions per 100 circuit km*

Company Name	**Northpower Limited**
For Year Ended	**31 March 2019**

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				
7	**2(i): Return on Investment**	**CY-2**	**CY-1**	**Current Year CY**
8		**31 Mar 17**	**31 Mar 18**	**31 Mar 19**
9	**ROI – comparable to a post tax WACC**	**%**	**%**	**%**
10	Reflecting all revenue earned	7.58%	5.89%	5.66%
11	Excluding revenue earned from financial incentives	7.58%	5.89%	5.66%
12	Excluding revenue earned from financial incentives and wash-ups	7.58%	5.89%	5.66%
13				
14	**Mid-point estimate of post tax WACC**	4.77%	5.04%	4.75%
15	25th percentile estimate	4.05%	4.36%	4.07%
16	75th percentile estimate	5.48%	5.72%	5.43%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	8.13%	6.48%	6.17%
21	Excluding revenue earned from financial incentives	8.13%	6.48%	6.17%
22	Excluding revenue earned from financial incentives and wash-ups	8.13%	6.48%	6.17%
23				
24	**WACC rate used to set regulatory price path**			
25				
26	**Mid-point estimate of vanilla WACC**	5.31%	5.60%	5.26%
27	25th percentile estimate	4.59%	4.92%	4.58%
28	75th percentile estimate	6.03%	6.29%	5.94%
29				
30	**2(ii): Information Supporting the ROI**		**($000)**	
31				
32	Total opening RAB value	262,813		
33	*plus* Opening deferred tax	(8,096)		
34	**Opening RIV**		254,717	
35				
36	**Line charge revenue**		73,463	
37				
38	Expenses cash outflow	46,764		
39	*add* Assets commissioned	12,121		
40	*less* Asset disposals	42		
41	*add* Tax payments	4,127		
42	*less* Other regulated income	421		
43	**Mid-year net cash outflows**		62,550	
44				
45	**Term credit spread differential allowance**		–	
46				
47	Total closing RAB value	267,167		
48	*less* Adjustment resulting from asset allocation	(1,453)		
49	*less* Lost and found assets adjustment	–		
50	*plus* Closing deferred tax	(9,010)		
51	**Closing RIV**		259,611	
52				
53	**ROI – comparable to a vanilla WACC**			6.17%
54				
55	Leverage (%)			42%
56	Cost of debt assumption (%)			4.33%
57	Corporate tax rate (%)			28%
58				
59	**ROI – comparable to a post tax WACC**			5.66%
60				

Company Name	**Northpower Limited**
For Year Ended	**31 March 2019**

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

2(iii): Information Supporting the Monthly ROI

Opening RIV	N/A

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

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

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

Year-end ROI – comparable to a vanilla WACC	6.06%
Year-end ROI – comparable to a post tax WACC	5.55%

** 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 2019**

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				($000)
7		**3(i): Regulatory Profit**		**($000)**
8		**Income**		
9		Line charge revenue		73,463
10	*plus*	Gains / (losses) on asset disposals		(18)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		439
12				
13		**Total regulatory income**		73,884
14		**Expenses**		
15	*less*	Operational expenditure		24,657
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		22,108
18				
19		**Operating surplus / (deficit)**		27,119
20				
21	*less*	Total depreciation		10,169
22				
23	*plus*	Total revaluations		3,897
24				
25		**Regulatory profit / (loss) before tax**		20,848
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		5,041
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		15,807
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	90	
36		Commerce Act levies	61	
37		Industry levies	222	
38		CPP specified pass through costs		
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	20,422	
41		Transpower new investment contract charges		
42		System operator services		
43		Distributed generation allowance	1,312	
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**		22,108
47				

Company Name	**Northpower Limited**
For Year Ended	**31 March 2019**

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				
48	**3(iii): Incremental Rolling Incentive Scheme**		**($000)**	
49			**CY-1**	**CY**
50			**31 Mar 18**	**31 Mar 19**
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 14		
58	CY-4	31 Mar 15		
59	CY-3	31 Mar 16		
60	CY-2	31 Mar 17		
61	CY-1	31 Mar 18		
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**
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SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

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

sch ref

4(i): Regulatory Asset Base Value (Rolled Forward)

	RAB	**RAB**	**RAB**	**RAB**	**RAB**
for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**
	($000)	**($000)**	**($000)**	**($000)**	**($000)**
Total opening RAB value	241,237	242,199	253,531	258,435	262,813
less **Total depreciation**	9,821	9,439	9,805	10,016	10,169
plus **Total revaluations**	202	1,421	5,491	2,840	3,897
plus **Assets commissioned**	10,580	19,351	9,218	11,619	12,121
less **Asset disposals**	–	–	–	65	42
plus **Lost and found assets adjustment**	–	–	–	–	–
plus **Adjustment resulting from asset allocation**	–	–	–	–	(1,453)
Total closing RAB value	242,199	253,531	258,435	262,813	267,167

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB *		**RAB**	
	($000)	**($000)**	**($000)**	**($000)**
Total opening RAB value		262,813		262,813
less				
Total depreciation		10,169		10,169
plus				
Total revaluations		3,897		3,897
plus				
Assets commissioned (other than below)	1,083		1,083	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	11,038		11,038	
Assets commissioned		12,121		12,121
less				
Asset disposals (other than below)	–		–	
Asset disposals to a regulated supplier	–		–	
Asset disposals to a related party	42		42	
Asset disposals		42		42
plus **Lost and found assets adjustment**				
plus **Adjustment resulting from asset allocation**				(1,453)
Total closing RAB value		268,621		267,167

** 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**
For Year Ended	**31 March 2019**

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						
51						
52	**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**					
53						
54		CPI_4				1,026
55		CPI_4^{-4}				1,011
56		Revaluation rate (%)				1.48%
57						
58			**Unallocated RAB ***		**RAB**	
59			**($000)**	**($000)**	**($000)**	**($000)**
60		Total opening RAB value	262,813		262,813	
61	*less*	Opening value of fully depreciated, disposed and lost assets	167		167	
62						
63		Total opening RAB value subject to revaluation	262,646		262,646	
64		**Total revaluations**		3,897		3,897
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**		1,147		1,147
69	*plus*	Capital expenditure	17,088		17,088	
70	*less*	Assets commissioned	12,121		12,121	
71	*plus*	Adjustment resulting from asset allocation				
72		**Works under construction - current disclosure year**		6,115		6,115
73						
74		Highest rate of capitalised finance applied				2.70%
75						

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

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

sch ref

76 ## 4(v): Regulatory Depreciation

sch ref		Unallocated RAB *		RAB	
77					
78		($000)	($000)	($000)	($000)
79	Depreciation - standard	9,943		9,943	
80	Depreciation - no standard life assets	225		225	
81	Depreciation - modified life assets				
82	Depreciation - alternative depreciation in accordance with CPP				
83	**Total depreciation**		10,169		10,169
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
86					
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
98												
99		**Total opening RAB value**	7,336	9,763	33,722	108,430	48,814	29,904	7,317	6,904	10,622	262,813
100	*less*	Total depreciation	368	265	1,298	3,652	1,698	1,489	301	872	225	10,169
101	*plus*	Total revaluations	109	145	500	1,609	723	444	109	102	157	3,897
102	*plus*	Assets commissioned	133	0	289	5,216	758	4,514	128	1,027	56	12,121
103	*less*	Asset disposals	–	–	42	–	–	–	–	–	–	42
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	(34)	–	–	(420)	(180)	–	–	(98)	(723)	(1,453)
106	*plus*	Asset category transfers	–	–	–	–	–	–	–	–	–	–
107		**Total closing RAB value**	7,176	9,644	33,171	111,184	48,417	33,372	7,252	7,064	9,888	267,167
108												
109		**Asset Life**										
110		Weighted average remaining asset life	30.6	41.0	33.8	39.9	33.4	30.5	27.5	11.8	22.4	(years)
111		Weighted average expected total asset life	54.1	57.8	46.4	59.2	46.6	45.0	37.7	18.9	28.9	(years)

Company Name	**Northpower Limited**
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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**		20,848	
9					
10	*plus*	Income not included in regulatory profit / (loss) before tax but taxable			*
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible	22		*
12		Amortisation of initial differences in asset values	4,536		
13		Amortisation of revaluations	1,031		
14				5,589	
15					
16	*less*	Total revaluations	3,897		
17		Income included in regulatory profit / (loss) before tax but not taxable			*
18		Discretionary discounts and customer rebates	–		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax			*
20		Notional deductible interest	4,535		
21				8,432	
22					
23		**Regulatory taxable income**		18,004	
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income		18,004	
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		5,041	
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	110,143		
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		105,607	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		24	
43					

Company Name	**Northpower Limited**
For Year Ended	**31 March 2019**

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	239,174	
47				
48		Adjusted depreciation	9,138	
49		Total depreciation	10,169	
50		Amortisation of revaluations		1,031
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**	(8,096)	
61				
62	*plus*	Tax effect of adjusted depreciation	2,559	
63				
64	*less*	Tax effect of tax depreciation	2,629	
65				
66	*plus*	Tax effect of other temporary differences*	20	
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	407	
75				
76		**Closing deferred tax**		(9,010)
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**	101,484	
84	*less*	Tax depreciation	9,390	
85	*plus*	Regulatory tax asset value of assets commissioned	12,262	
86	*less*	Regulatory tax asset value of asset disposals	42	
87	*plus*	Lost and found assets adjustment	–	
88	*plus*	Adjustment resulting from asset allocation	0	
89	*plus*	Other adjustments to the RAB tax value	–	
90		**Closing sum of regulatory tax asset values**		104,314

Company Name	Northpower Limited
For Year Ended	31 March 2019

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			
7	**5b(i): Summary—Related Party Transactions**	**($000)**	**($000)**
8	**Total regulatory income**		–
9			
10	**Market value of asset disposals**		–
11			
12	Service interruptions and emergencies	2,246	
13	Vegetation management	2,413	
14	Routine and corrective maintenance and inspection	3,123	
15	Asset replacement and renewal (opex)	2,426	
16	**Network opex**		10,208
17	Business support	120	
18	System operations and network support	226	
19	**Operational expenditure**		10,554
20	Consumer connection	1,039	
21	System growth	1,440	
22	Asset replacement and renewal (capex)	6,877	
23	Asset relocations	299	
24	Quality of supply	927	
25	Legislative and regulatory	3	
26	Other reliability, safety and environment	775	
27	**Expenditure on non-network assets**		–
28	**Expenditure on assets**		11,360
29	Cost of financing		
30	Value of capital contributions		
31	Value of vested assets		
32	**Capital Expenditure**		11,360
33	**Total expenditure**		21,914
34			
35	**Other related party transactions**		71

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

	Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
37			
38	Northpower Contracting Division	Service interruptions and emergencies	2,246
39	Northpower Contracting Division	Vegetation management	2,413
40	Northpower Contracting Division	Routine and corrective maintenance and inspection	3,123
41	Northpower Contracting Division	System operations and network support	212
42	Northpower Contracting Division	Asset replacement and renewal (opex)	2,426
43	Northpower Fibre Ltd	System operations and network support	14
44	Northpower Corporate Division	Business support	120
45	Northpower Fibre Division	Other reliability, safety and environment	222
46	Northpower Contracting Division	System growth	1,440
47	Northpower Contracting Division	Asset replacement and renewal (capex)	6,877
48	Northpower Contracting Division	Asset relocations	299
49	Northpower Contracting Division	Quality of supply	927
50	Northpower Contracting Division	Legislative and regulatory	3
51	Northpower Contracting Division	Other reliability, safety and environment	553
52	Northpower Contracting Division	Consumer connection	1,039
53	**Total value of related party transactions**		21,914

54 ** include additional rows if needed*
55

Company Name	**Northpower Limited**
For Year Ended	**31 March 2019**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

7
8 ### 5c(i): Qualifying Debt (may be Commission only)
9

sch ref	Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	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

sch ref			
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 2019**

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		2,248			
12	Not directly attributable				–	
13	**Total attributable to regulated service**		2,248			
14	**Vegetation management**					
15	Directly attributable		2,681			
16	Not directly attributable				–	
17	**Total attributable to regulated service**		2,681			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		3,122			
20	Not directly attributable				–	
21	**Total attributable to regulated service**		3,122			
22	**Asset replacement and renewal**					
23	Directly attributable		2,493			
24	Not directly attributable				–	
25	**Total attributable to regulated service**		2,493			
26	**System operations and network support**					
27	Directly attributable		2,606			
28	Not directly attributable				–	
29	**Total attributable to regulated service**		2,606			
30	**Business support**					
31	Directly attributable		4,774			
32	Not directly attributable		6,734	10,811	17,544	
33	**Total attributable to regulated service**		11,507			
34						
35	**Operating costs directly attributable**		17,923			
36	**Operating costs not directly attributable**	–	6,734	10,811	17,544	–
37	**Operational expenditure**		24,657			
38						

Company Name	**Northpower Limited**
For Year Ended	**31 March 2019**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	373
Not directly attributable	
Total attributable to regulated service	373
Recoverable costs	
Directly attributable	21,734
Not directly attributable	
Total attributable to regulated service	21,734

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

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

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

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

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

† include additional rows if needed

Company Name	**Northpower Limited**
For Year Ended	**31 March 2019**

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	6,872
12	Not directly attributable	304
13	**Total attributable to regulated service**	7,176
14	**Subtransmission cables**	
15	Directly attributable	9,644
16	Not directly attributable	–
17	**Total attributable to regulated service**	9,644
18	**Zone substations**	
19	Directly attributable	33,171
20	Not directly attributable	–
21	**Total attributable to regulated service**	33,171
22	**Distribution and LV lines**	
23	Directly attributable	107,407
24	Not directly attributable	3,777
25	**Total attributable to regulated service**	111,184
26	**Distribution and LV cables**	
27	Directly attributable	48,417
28	Not directly attributable	–
29	**Total attributable to regulated service**	48,417
30	**Distribution substations and transformers**	
31	Directly attributable	33,372
32	Not directly attributable	–
33	**Total attributable to regulated service**	33,372
34	**Distribution switchgear**	
35	Directly attributable	7,252
36	Not directly attributable	–
37	**Total attributable to regulated service**	7,252
38	**Other network assets**	
39	Directly attributable	6,015
40	Not directly attributable	1,049
41	**Total attributable to regulated service**	7,064
42	**Non-network assets**	
43	Directly attributable	8,017
44	Not directly attributable	1,871
45	**Total attributable to regulated service**	9,888
46		
47	**Regulated service asset value directly attributable**	260,166
48	**Regulated service asset value not directly attributable**	7,001
49	**Total closing RAB value**	267,167
50		

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

sch ref				CY-1 ($000)	Current Year (CY) ($000)
52					
53	**Change in asset value allocation 1**				
54	Asset category	Subtransmission lines	Original allocation		338
55	Original allocator or line items	ACAM	New allocation		304
56	New allocator or line items	ABAA - Pole area attributable to Non regulated business	Difference	–	34
57					
58	Rationale for change	Changed from ACAM to ABAA per the new cost allocation input methodologies			
59					
60					
61					
62	**Change in asset value allocation 2**				
63	Asset category	Distribution and LV Lines	Original allocation		4,197
64	Original allocator or line items	ACAM - Fully allocated to regulated service	New allocation		3,777
65	New allocator or line items	ABAA - Pole area attributable to Non regulated business	Difference	–	420
66					
67	Rationale for change	Changed from ACAM to ABAA per the new cost allocation input methodologies			
68					
69					
70					
71	**Change in asset value allocation 3**				
72	Asset category	Other Network Assets	Original allocation		1,147
73	Original allocator or line items	ACAM	New allocation		1,049
74	New allocator or line items	ABAA - Number of fibres used by fibre business	Difference	–	98
75					
76	Rationale for change	Changed from ACAM to ABAA per the new cost allocation input methodologies			
77					
69					
71	**Change in asset value allocation 3**			CY-1	Current Year (CY)
72	Asset category	Distribution and LV Cables	Original allocation		180
73	Original allocator or line items	ACAM - Fully allocated to regulated service	New allocation		–
74	New allocator or line items	ABAA - Pole area attributable to Non regulated business	Difference	–	180
75					
76	Rationale for change	Changed from ACAM to ABAA per the new cost allocation input methodologies			
77					
70					($000)
71	**Change in asset value allocation 4**			CY-1	Current Year (CY)
72	Asset category	Non-network Assets - Land	Original allocation		1,410
73	Original allocator or line items	ACAM - Fully allocated to regulated service	New allocation		1,059
74	New allocator or line items	ABAA - Land area estimated to be not attributable to regulated business (m2)	Difference	–	351
75					
76	Rationale for change	Changed from ACAM to ABAA per the new cost allocation input methodologies			
77					
69					
70					($000)
71	**Change in asset value allocation 5**			CY-1	Current Year (CY)
72	Asset category	Non-network Assets - Buildings	Original allocation		1,183
73	Original allocator or line items	ACAM - Fully allocated to regulated service	New allocation		812
74	New allocator or line items	ABAA - Floor area estimated to be not attributable to regulated business (m2)	Difference	–	371
75					
76	Rationale for change	Changed from ACAM to ABAA per the new cost allocation input methodologies			
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 2019**

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				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		5,496
9		System growth		3,961
10		Asset replacement and renewal		8,401
11		Asset relocations		298
12		Reliability, safety and environment:		
13		Quality of supply	1,455	
14		Legislative and regulatory	14	
15		Other reliability, safety and environment	1,373	
16		**Total reliability, safety and environment**		2,841
17		**Expenditure on network assets**		20,997
18		Expenditure on non-network assets		251
19				
20		**Expenditure on assets**		21,248
21	*plus*	Cost of financing		122
22	*less*	Value of capital contributions		4,281
23	*plus*	Value of vested assets		
24				
25		**Capital expenditure**		17,088

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

30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		All Customer Types	5,496	
33			–	
34			–	
35			–	
36			–	
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		5,496
39				
40	*less*	Capital contributions funding consumer connection expenditure	4,281	
41		**Consumer connection less capital contributions**		1,215

42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement and**
43			**System Growth**	**Renewal**
44			**($000)**	**($000)**
45		Subtransmission	–	–
46		Zone substations	3,557	1,402
47		Distribution and LV lines	4	5,174
48		Distribution and LV cables	255	240
49		Distribution substations and transformers	146	536
50		Distribution switchgear	–	338
51		Other network assets	–	710
52		**System growth and asset replacement and renewal expenditure**	3,961	8,401
53	*less*	Capital contributions funding system growth and asset replacement and renewal		
54		**System growth and asset replacement and renewal less capital contributions**	3,961	8,401
55				

56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		Ground mounted substations	124	
59		Minor Expenditure relocation	118	
60		Roading works asset relocation	56	
61			–	
62			–	
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations		
65		**Asset relocations expenditure**		298
66	*less*	Capital contributions funding asset relocations		
67		**Asset relocations less capital contributions**		298

Company Name	**Northpower Limited**
For Year Ended	**31 March 2019**

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(vi): Quality of Supply

	Project or programme*	($000)	($000)
	33kV air break switch upgrades	8	
	Mareretu suibstation 33kV switch upgrade	83	
	Maungaturoto 33kV circuit separation	161	
	New reclosers	46	
	Whangarei South 33kV	1,158	
	* include additional rows if needed		
	All other projects programmes - quality of supply		
Quality of supply expenditure			1,455
less	Capital contributions funding quality of supply		
Quality of supply less capital contributions			1,455

6a(vii): Legislative and Regulatory

	Project or programme*	($000)	($000)
	Zone substation risk mitigation	14	
	* include additional rows if needed		
	All other projects or programmes - legislative and regulatory		
Legislative and regulatory expenditure			14
less	Capital contributions funding legislative and regulatory		
Legislative and regulatory less capital contributions			14

6a(viii): Other Reliability, Safety and Environment

	Project or programme*	($000)	($000)
	Minor capital expenditure r,s&e improvement	348	
	SCADA & communications improvements	224	
	Zone substation security improvements	164	
	* include additional rows if needed		
	All other projects or programmes - other reliability, safety and environment	638	
Other reliability, safety and environment expenditure			1,373
less	Capital contributions funding other reliability, safety and environment		
Other reliability, safety and environment less capital contributions			1,373

6a(ix): Non-Network Assets

Routine expenditure

	Project or programme*	($000)	($000)
	* include additional rows if needed		
	All other projects or programmes - routine expenditure		
Routine expenditure			–

Atypical expenditure

	Project or programme*	($000)	($000)
	Asset Data Management Systems (ADMS)	251	
	* include additional rows if needed		
	All other projects or programmes - atypical expenditure		
Atypical expenditure			251
Expenditure on non-network assets			251

Company Name	**Northpower Limited**
For Year Ended	**31 March 2019**

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

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

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

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

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	2,248	
9	Vegetation management	2,681	
10	Routine and corrective maintenance and inspection	3,122	
11	Asset replacement and renewal	2,493	
12	**Network opex**		10,543
13	System operations and network support	2,606	
14	Business support	11,507	
15	**Non-network opex**		14,113
16			
17	**Operational expenditure**		24,657
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 2019**

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	72,389	73,463	1%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	3,795	5,496	45%
11	System growth	3,613	3,961	10%
12	Asset replacement and renewal	8,400	8,401	0%
13	Asset relocations	205	298	45%
14	Reliability, safety and environment:			
15	Quality of supply	1,320	1,455	10%
16	Legislative and regulatory	–	14	–
17	Other reliability, safety and environment	873	1,373	57%
18	**Total reliability, safety and environment**	2,193	2,841	30%
19	**Expenditure on network assets**	18,206	20,997	15%
20	Expenditure on non-network assets	601	251	(58%)
21	Expenditure on assets	18,807	21,248	13%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,777	2,248	26%
24	Vegetation management	2,300	2,681	17%
25	Routine and corrective maintenance and inspection	2,740	3,122	14%
26	Asset replacement and renewal	2,306	2,493	8%
27	**Network opex**	9,123	10,543	16%
28	System operations and network support	3,145	2,606	(17%)
29	Business support	10,836	11,507	6%
30	**Non-network opex**	13,981	14,113	1%
31	**Operational expenditure**	23,104	24,657	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	80	–	(100%)
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 2019**
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)	Billed quantities by price component								
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
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
15	DM1 - Principal Residence	Residential	Standard	45,309	290,251	16,364,605		292,054,244						
16	DM3 - Non-Principal Residence	Residential	Standard	3,117	6,953	1,190,801		6,953,370						
17	DM4 - Inclusive (Obsolete)	Residential	Standard	116	592	38,507		592,082						
18	ND1 - up to 70kVA (100A or less)	General	Standard	9,552	116,164	3,281,924		116,325,879						
19	Metering)	General	Standard	371	34,874	134,712		34,873,978						
20	ND5 - Irrigation and Pumps	General	Standard	86	2,287	31,217		2,286,709						
21	ND6 - Unmetered 24 Hour	General	Standard	199	202	72,792		202,025						
	Lighting	General	Standard	13	3,261		2,806,790							
	ND12 - Builders Supply	General	Standard	447	850	162,029		850,333						
22	ND10 - Volume Based ToU	Large Commercial	Standard	86	18,636	31,664		18,635,577			2,423,350			
23	ND9 - Demand Based ToU	Large Commercial	Standard	78	87,462				768	532,781		15,215		
24	IND - Individual Pricing	Asset Based	Non-standard	6	495,296			495,295,666				30,221	6	6
25	*Add extra rows for additional consumer groups or price category codes as necessary*													
26			**Standard consumer totals**	59,374	561,532	21,308,251	2,806,790	472,774,197	768	532,781	2,423,350	15,215	–	–
27			**Non-standard consumer totals**	6	495,296	–	–	495,295,666	–	–	–	30,221	6	6
28			**Total for all consumers**	59,380	1,056,828	21,308,251	2,806,790	968,069,863	768	532,781	2,423,350	45,436	6	6

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

Company Name	**Northpower Limited**
For Year Ended	**31 March 2019**
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.

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)
Residence	Residential	Standard	$34,087		$34,087	
DM3 - Non-Principal Residence	Residential	Standard	$1,865		$1,865	
DM4 - Inclusive (Obsolete)	Residential	Standard	$65		$65	
less)	General	Standard	$15,419		$15,419	
Metering)	General	Standard	$4,022		$4,022	
ND5 - Irrigation and Pumps	General	Standard	$165		$165	
ND6 - Unmetered 24 Hour	General	Standard	$95		$95	
Lighting	General	Standard	$686		$686	
ND12 - Builders Supply	General	Standard	$323		$323	
ND10 - Volume Based ToU	Large Commercial	Standard	$2,261		$2,261	
ND9 - Demand Based ToU	Large Commercial	Standard	$4,268		$4,268	
IND - Individual Pricing	Asset Based	Non-standard	$10,207		$10,207	
Add extra rows for additional consumer groups or price category codes as necessary						
		Standard consumer totals	$63,256	–	$63,256	–
		Non-standard consumer totals	$10,207	–	$10,207	–
		Total for all consumers	$73,463	–	$73,463	–

Line charge revenues ($000) by price component

Price component	Daily Fixed Charge	Daily Fixed Charge	Consumption	Monthly Fixed Charge	Demand	Excess Reactive Power	Excess Reactive Power	Asset Utilisation	Transmission Pass Through
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
Residence	2,455	–	31,633	–	–	–	–	–	–
DM3 - Non-Principal Residence	1,191	–	674	–	–	–	–	–	–
DM4 - Inclusive (Obsolete)	6	–	59	–	–	–	–	–	–
less)	3,279	–	12,139	–	–	–	–	–	–
Metering)	256	–	3,766	–	–	–	–	–	–
ND5 - Irrigation and Pumps	31	–	134	–	–	–	–	–	–
ND6 - Unmetered 24 Hour	72	–	23	–	–	–	–	–	–
Lighting	–	686	–	–	–	–	–	–	–
ND12 - Builders Supply	227	–	96	–	–	–	–	–	–
ND10 - Volume Based ToU	82	–	2,106	–	–	73	–	–	–
ND9 - Demand Based ToU	–	–	–	92	4,151	–	25	–	–
IND - Individual Pricing	–	–	70	–	–	–	49	1,869	8,218
Standard consumer totals	$7,599	$686	$50,630	$92	$4,151	$73	$25	–	–
Non-standard consumer totals	–	–	$70	–	–	–	$49	$1,869	$8,218
Total for all consumers	$7,599	$686	$50,700	$92	$4,151	$73	$74	$1,869	$8,218

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

Check OK

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end

Company Name	Northpower Limited
For Year Ended	31 March 2019
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

	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	52,990	53,164	174	2
10	All	Overhead Line	Wood poles	No.	1,407	1,342	(65)	2
11	All	Overhead Line	Other pole types	No.	52	52	–	2
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	293	293	0	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	28	28	(0)	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	(0)	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km			–	4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	3	3	–	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	0	0	–	4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km			–	4
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km			–	4
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km			–	4
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	1	1	–	4
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	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	–	3
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	11	11	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	169	174	5	3
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	–	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	146	146	–	3
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	39	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3,500	3,498	(1)	3
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	231	238	7	3
39	HV	Distribution Cable	Distribution UG PILC	km	39	39	0	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	2	2	–	3
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	30	31	1	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.			–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	8,350	8,412	62	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	29	21	(8)	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	198	207	9	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	5,895	5,930	35	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,398	1,420	22	3
48	HV	Distribution Transformer	Voltage regulators	No.	10	10	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	118	118	–	3
50	LV	LV Line	LV OH Conductor	km	1,191	1,189	(2)	3
51	LV	LV Cable	LV UG Cable	km	711	743	33	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	405	411	5	2
53	LV	Connections	OH/UG consumer service connections	No.	58,910	59,852	942	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	332	333	1	3
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	35,747	36,562	815	3
59	All	Civils	Cable Tunnels	km			–	[Select one]

Company Name	**Northpower Limited**
For Year Ended	**31 March 2019**
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 2019

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
10	All	Overhead Line	Concrete poles / steel structure	No.	153	170	1,701	8,220	12,628	9,912	7,773	612	581	503	748	797	737	732	604
11	All	Overhead Line	Wood poles	No.	1		11	122	171	474	277	14	24	26	40	56	34	23	14
12	All	Overhead Line	Other pole types	No.			4	5	13	21	4			1		2			1
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km			72	104	26	38	46	4	0	0	1	0			0
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km					28	0									
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km					0	1	0	1	3	0	0		0	0	0
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km				5	3	0									
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km															
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km						3									
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km							0								
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km															
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km															
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km															
23	HV	Subtransmission Cable	Subtransmission submarine cable	km							1								
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	1		3	7	1	4	1	1							1
25	HV	Zone substation Buildings	Zone substations 110kV+	No.						1									
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.															
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	2	2	8				3	3		2					
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.														2	
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			18	49	10	19	2	2		5	5	1	29	6	1
30	HV	Zone substation switchgear	33kV RMU	No.								2	2						
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.						19	1		1	1				1	
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.						6	24	6				5	1	3	1
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.			1	16	29	20	1		5		4			9	31
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.															
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.			4	13	6	5			1	2	1		2		
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	13	21	104	590	727	732	497	51	29	48	33	68	37	24	26
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km															
38	HV	Distribution Line	SWER conductor	km															
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km				1	0	10	29	7	7	13	9	16	24	27	21
40	HV	Distribution Cable	Distribution UG PILC	km				5	10	13	6	0	1	0	0	0	1	0	0
41	HV	Distribution Cable	Distribution Submarine Cable	km					2										
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.									1				9		2
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.															
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	9	8	13	174	305	703	1,271	148	145	164	164	227	246	231	220
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.					12	8									
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.					3	10	15	2	4	2	2	5	33	26	6
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	95	135	138	608	535	443	1,176	172	137	156	133	181	161	166	211
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	3	3	16	175	174	162	142	35	33	41	29	57	84	87	70
49	HV	Distribution Transformer	Voltage regulators	No.					2		2					3			
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.			1	14	20	22	32	5	1	6	1	1			1
51	LV	LV Line	LV OH Conductor	km	2	3	30	180	303	220	178	12	10	12	25	23	22	17	14
52	LV	LV Cable	LV UG Cable	km	0		0	25	52	68	87	19	19	27	35	49	51	49	50
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km			2	47	155	42	53	2	4	3	4	8	11	13	11
54	LV	Connections	OH/UG consumer service connections	No.				3	7	11,878	27,534	3,918	834	894	1,125	1,122	1,181	1,107	1,062
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.					8	27	75	13	3	3	1	7	20	15	29
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot															
57	All	Capacitor Banks	Capacitors including controls	No							5		1				3		
58	All	Load Control	Centralised plant	Lot						2					2				1
59	All	Load Control	Relays	No						5,177	7,808	1,103	841	856	3,158	5,143	1,105	835	1,001
60	All	Civils	Cable Tunnels	km															

sch ref	Asset class	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	Concrete poles / steel structure	607	746	749	740	811	747	651	669	580	454	397	142							–	53,164	3,710	2
11	Wood poles	12	6	4	9	3	2	3	2	4	2	3	5							–	1,342	245	2
12	Other pole types										1									–	52	2	2
13	Subtransmission OH up to 66kV conductor	0	0	0		1	0	0					1							–	293	0	4
14	Subtransmission OH 110kV+ conductor																			–	28		3
15	Subtransmission UG up to 66kV (XLPE)		3	0		0		2	0											–	11	0	3
16	Subtransmission UG up to 66kV (Oil pressurised)																			–	8		4
17	Subtransmission UG up to 66kV (Gas pressurised)																			–	–		4
18	Subtransmission UG up to 66kV (PILC)																			–	3		4
19	Subtransmission UG 110kV+ (XLPE)								0											–	0		4
20	Subtransmission UG 110kV+ (Oil pressurised)																			–	–		4
21	Subtransmission UG 110kV+ (Gas Pressurised)																			–	–		4
22	Subtransmission UG 110kV+ (PILC)																			–	–		4
23	Subtransmission submarine cable																			–	1		4
24	Zone substations up to 66kV	1																		–	20		4
25	Zone substations 110kV+																			–	1		4
26	50/66/110kV CB (Indoor)																			–	–		4
27	50/66/110kV CB (Outdoor)																			–	20	2	3
28	33kV Switch (Ground Mounted)	8	1																	–	11		4
29	33kV Switch (Pole Mounted)	8	5	2	1	4	2				5									–	174		3
30	33kV RMU																			–	4		4
31	22/33kV CB (Indoor)	3	2				1	1												–	30		4
32	22/33kV CB (Outdoor)		2			2			4	1	4									–	59		3
33	3.3/6.6/11/22kV CB (ground mounted)		17	12			1													–	146		3
34	3.3/6.6/11/22kV CB (pole mounted)																			–	–		4
35	Zone Substation Transformers		2					2				1								–	39		4
36	Distribution OH Open Wire Conductor	26	24	29	45	72	85	34	47	37	41	41	19							–	3,498	11	3
37	Distribution OH Aerial Cable Conductor																			–	–		4
38	SWER conductor																			–	–		4
39	Distribution UG XLPE or PVC	8	12	4	3	4	9	5	6	7	6	7	3							–	238	2	3
40	Distribution UG PILC	0		0	0	0	1		0		0	0								–	39	3	3
41	Distribution Submarine Cable																			–	2		3
42	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	3	2	1	1	3	2	3	1		2	1								–	31		4
43	3.3/6.6/11/22kV CB (Indoor)																			–	–		4
44	3.3/6.6/11/22kV Switches and fuses (pole mounted)	390	555	384	505	405	407	383	413	301	324	257	60							–	8,412	415	3
45	3.3/6.6/11/22kV Switch (ground mounted) - except RMU											1								–	21	1	3
46	3.3/6.6/11/22kV RMU	10	24	5	4	6	7	7	9	8	11	7	1							–	207		4
47	Pole Mounted Transformer	125	143	48	141	94	141	227	154	114	166	119	11							–	5,930	16	3
48	Ground Mounted Transformer	26	37	48	5	1	14	34	43	33	39	28	1							–	1,420	3	3
49	Voltage regulators								3											–	10		4
50	Ground Mounted Substation Housing	3	2	2	2	2						2	1							–	118		3
51	LV OH Conductor	13	18	17	16	14	11	10	11	9	8	9	2							–	1,189	107	3
52	LV UG Cable	26	29	16	7	6	18	8	16	23	26	29	7							–	743	13	3
53	LV OH/UG Streetlight circuit	6	14	1	4	1	3	6	4	3	6	7	1							–	411	106	2
54	OH/UG consumer service connections	856	778	746	594	635	635	622	836	1,058	1,139	1,050	238							–	59,852	2,962	3
55	Protection relays (electromechanical, solid state and numeric)	36	22	30	2	7	1	4	2	24	1	3								–	333		3
56	SCADA and communications equipment operating as a single sys	1																		–	1		4
57	Capacitors including controls	1	5	8		3				1										–	27		4
58	Centralised plant			1																–	6		4
59	Relays	1,195	720	878	585	496	984	943	1,368	782	791	741	52							–	36,562	986	3
60	Cable Tunnels																				–		[Select one]

Company Name	**Northpower Limited**
For Year Ended	**31 March 2019**
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	218	22	241
14	SWER (all SWER voltages)			–
15	22kV (other than SWER)			–
16	6.6kV to 11kV (inclusive—other than SWER)	3,498	279	3,777
17	Low voltage (< 1kV)	1,189	743	1,932
18	**Total circuit length (for supply)**	5,009	1,045	6,053
19				
20	Dedicated street lighting circuit length (km)	175	235	411
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			120
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	572	11%	
25	Rural	4,436	89%	
26	Remote only		–	
27	Rugged only		–	
28	Remote and rugged		–	
29	Unallocated overhead lines		–	
30	**Total overhead length**	5,009	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	4,379	72%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	5,009	100%	

Company Name	**Northpower Limited**
For Year Ended	**31 March 2019**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref	**Location ***	**Number of ICPs served**	**Line charge revenue ($000)**
8			
9			
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 2019**
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	1,068	
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**	1,068	
18				
19	**Distributed generation**			
20		Number of connections made in year	145	**connections**
21		Capacity of distributed generation installed in year	0.53	**MVA**
22	**9e(ii): System Demand**			
23				
24			**Demand at time of maximum coincident demand (MW)**	
25	**Maximum coincident system demand**			
26		GXP demand	163	
27	*plus*	Distributed generation output at HV and above	13	
28		**Maximum coincident system demand**	176	
29	*less*	Net transfers to (from) other EDBs at HV and above	–	
30		**Demand on system for supply to consumers' connection points**	176	
31	**Electricity volumes carried**		**Energy (GWh)**	
32		Electricity supplied from GXPs	1,068	
33	*less*	Electricity exports to GXPs	–	
34	*plus*	Electricity supplied from distributed generation	29	
35	*less*	Net electricity supplied to (from) other EDBs	–	
36		**Electricity entering system for supply to consumers' connection points**	1,097	
37	*less*	Total energy delivered to ICPs	1,057	
38		**Electricity losses (loss ratio)**	40	3.7%
39				
40		**Load factor**	0.71	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43		Distribution transformer capacity (EDB owned)	560	
44		Distribution transformer capacity (Non-EDB owned, estimated)	5	
45		**Total distribution transformer capacity**	565	
46				
47		**Zone substation transformer capacity**	316	

Company Name	**Northpower Limited**
For Year Ended	**31 March 2019**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)		
11	Class B (planned interruptions on the network)	359	
12	Class C (unplanned interruptions on the network)	372	
13	Class D (unplanned interruptions by Transpower)	2	
14	Class E (unplanned interruptions of EDB owned generation)		
15	Class F (unplanned interruptions of generation owned by others)		
16	Class G (unplanned interruptions caused by another disclosing entity)		
17	Class H (planned interruptions caused by another disclosing entity)		
18	Class I (interruptions caused by parties not included above)		
19	**Total**	733	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	293	79
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)		
26	Class B (planned interruptions on the network)	0.28	71.6
27	Class C (unplanned interruptions on the network)	2.90	110.6
28	Class D (unplanned interruptions by Transpower)	0.22	4.9
29	Class E (unplanned interruptions of EDB owned generation)		
30	Class F (unplanned interruptions of generation owned by others)		
31	Class G (unplanned interruptions caused by another disclosing entity)		
32	Class H (planned interruptions caused by another disclosing entity)		
33	Class I (interruptions caused by parties not included above)		
34	**Total**	3.40	187.1
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	3.18	181.4
38			

Company Name	Northpower Limited
For Year Ended	31 March 2019
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	0.21	2.5
Vegetation	0.44	16.5
Adverse weather	0.07	4.0
Adverse environment	0.00	0.2
Third party interference	0.40	27.2
Wildlife	0.31	20.6
Human error	0.22	5.7
Defective equipment	0.46	24.7
Cause unknown	0.78	9.3

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.00	0.0
Subtransmission cables		
Subtransmission other		
Distribution lines (excluding LV)	0.26	66.9
Distribution cables (excluding LV)	0.02	4.7
Distribution other (excluding LV)		

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	1.00	26.0
Subtransmission cables		
Subtransmission other		
Distribution lines (excluding LV)	1.82	79.8
Distribution cables (excluding LV)	0.08	4.8
Distribution other (excluding LV)		

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	34	321	10.59
Subtransmission cables	–	22	–
Subtransmission other	–		
Distribution lines (excluding LV)	342	3,498	9.78
Distribution cables (excluding LV)	12	275	4.36
Distribution other (excluding LV)			
Total	388		

Company Name	Northpower Limited
For Year Ended	31 March 2019

Schedule 14 Mandatory Explanatory Notes

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

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

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

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

Return on Investment (Schedule 2)

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

Box 1: Explanatory comment on return on investment

The calculated post tax ROI and vanilla ROI for the disclosure year was 5.94% and 6.17% respectively. The reduction in ROI relative to FY18 reflects:

- Increased opex (see box 10)
- Changes in opex cost allocators to accurately reflect resources used (see box 7)
- Change to the asset allocation method to ABAA from ACAM (see box 8).

Regulatory Profit (Schedule 3)

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

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

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

Box 2: Explanatory comment on regulatory profit

Other regulatory income of $439k relates to value added work on charged to customers.

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.

Merger and acquisition expenses (3(iv) of Schedule 3)

6. If the EDB incurred merger and acquisitions expenditure during the disclosure year, provide the following information in the box below:

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

    6.2 Any other commentary on the benefits of the merger and acquisition expenditure to the EDB.

Box 3: Explanatory comment on merger and acquisition expenditure

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

Value of the Regulatory Asset Base (Schedule 4)

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

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

- The RAB roll-forward in Schedule 4 is determined in accordance with the IM requirements.
- There were no reclassifications made.
- Disposed assets of $42k were related to zone substation assets.
- 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

Permanent differences are made up of the following expenditure items that are not deductible for tax purposes:

- $16k entertainment;
- $6k professional fees.

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 $20k represents tax on the movement between FY18 and FY19 in the following provisions:

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

Cost allocation (Schedule 5d)

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

Box 7: Cost allocation

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

Business support costs not directly attributable has increased by $700k from FY18. This was largely driven by:

- An increase in allocated IT support costs due to increased focus on, and resources associated with, supporting the electricity business. This has allowed us to develop and refine our core capabilities, systems and processes.
- A decrease from the addition of a further allocation step in the cost allocation model implemented in FY18. This involved conducting an internal survey of network staff and identifying a proportion of time spent on non-regulatory activities (e.g. metering and generation activities).

Allocation categories are consistent with the prior year as outlined below:

- Human resources costs allocated using headcount as a causal allocator.
- Information technology costs allocated using the weighted average of devices as a causal allocator.
- Finance costs allocated using gross margin as a proxy allocator.
- Rent costs allocated using floor space as a causal allocator.
- Corporate costs allocated using non-current assets as a proxy 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 subclause 2.7.1(2).

Box 8: Commentary on asset allocation

The asset allocation methodology has changed from the avoided cost allocation method (ACAM) to the accounting based allocation approach (ABAA), as prescribed in Part 2.1 of the IM determination.

Our process included consulting head engineers from each of our business divisions and firstly identifying the RAB asset categories shared between the regulated and non-regulated businesses, and secondly developing allocators that appropriately and materially reflect the drivers of cost associated with the use of each asset.

The summary of RAB assets that were allocated are as follows:

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

The net effect of this allocation exercise resulted in approximately $1.4m being allocated out of the regulatory asset base.

No additional items were reclassified.

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

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

Box 9: Explanation of capital expenditure for the disclosure year

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

All capex projects above a $50k threshold have been described in schedule 6a, and where possible, we have aggregated projects below this threshold.

No items were reclassified.

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

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

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

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

Box 10: Explanation of operational expenditure for the disclosure year

- Asset replacement and renewal operating expenditure relates to work done to make good on defects identified during scheduled preventative maintenance inspections.
- There are no reclassified items to report.
- There is no material atypical expenditure included in the operational expenditure.
- Operational expenditure has increased across all categories in response to asset condition and risk monitoring. The largest increases in expenditure were:
    - Vegetation control – increased resources to accelerate the cyclical program.
    - 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 subclause 2.7.1(2).

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

- Asset expenditure was overall 13% higher than the target expenditure mainly due to higher new subdivisions than expected leading to consumer connections expenditure higher than forecast. Reliability, safety and environment costs were higher than forecast due to increases in labour and material costs. The non-network asset expenditure on the Asset Management Data System is lower than forecast, due to timing.

- Network Opex was 16% higher than target. This was due to higher than expected spend across service interruptions and emergencies, routine and corrective maintenance and inspections, and asset replacement and renewals. The vegetation management increased spend was due to a focus on accelerating the cyclical vegetation program during the disclosure year.

- Non-network Opex was 1% higher than target.

Information relating to revenues and quantities for the disclosure year

15. In the box below provide:

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

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

Box 12: Explanatory comment relating to revenue for the disclosure year
Target revenue disclosed before the start of the year was 1% higher than the total billed line charge revenue for the disclosure year. There was no material movement between target revenue and total billed line charge revenue.

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
N/A - exemption notice issued 22 August 2019

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
9c – refer to schedule 15, voluntary explanatory notes

Company Name Northpower Limited

For Year Ended 31 March 2019

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

9c: Length of circuit within 10km of coastline or geothermal areas (where known)

Historically, this metric has been calculated including only the length of overhead circuit within 10km of the coastline, on the basis that the question was intended to identify the length of circuit which is at risk of corrosion from salt spray. We have amended our calculation methodology this year to include both overhead and underground circuit length.

9e(iii): Transformer capacity

Our standard sub-transmission voltage is 33kV (which is the voltage we are generally supplied by Transpower at), and this is reduced to 11KV at our zone substations.

However, in years 2013 and 2015, we purchased various assets from Transpower including the connection assets at the Dargaville and Kensington GXPs, the lines back to Maungatapere GXP, and various transformers.

This means that we now own:

- 2 x 110/50KV transformers at Maungatapere which feed Dargaville substation;
- 2 x 110/33KV transformers at Maungatapere which feed Maungatapere and other Northpower substations;
- 2 x 110/33KV transformers at Kensington, which feed various Northpower substations.

As these transformers reduce the incoming voltage to the sub-transmission voltage, we have not included them in our zone sub-station capacity. This is because including them in that metric could overstate the capacity of our zone-substations to feed our distribution network at 11KV.

Related party disclosure requirements

Section 2.3 of the Determination requires certain information in respect of related party transactions to be publically disclosed. Northpower's disclosures in respect of these matters can be found on Northpower's website at https://northpower.com/company/disclosures.

Reliability Measures

SAIFI for the disclosure year was measured at 3.18 interruptions per customer, and SAIDI at 181.4 minutes.

Both reliability statistics were slightly higher than in FY18. The increase in the SAIDI measure was due to more occurrences of third party interference (car v poles) and a substation outage caused by wildlife.

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.

Northpower

NORTHPOWER NETWORK YEAR TO MARCH 2019 ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE (EDID) FOR RELATED PARTY TRANSACTIONS

Table of Contents

Northpower

Summary of Northpower Network's Related Party transactions

(Clause 2.3.8 of EDID requirements)

Related Party	Nature of Relationship	Principal Activity of Related Party	FY19 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 $11,138k Operating expenditure (maintenance) $10,420k
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 $222k
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) $14k
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 $33k
Electricity Engineers' Association (EEA)	Ms Josie Boyd is the GM of of Northpower Network and a Board member of the Electricity Engineers' Association.	Professional engineers employed by Northpower Network are members of the EEA.	Operating expenditure $38k

Northpower

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

(Clause 2.3.10 of EDID requirements)

Purpose

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

Introduction

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

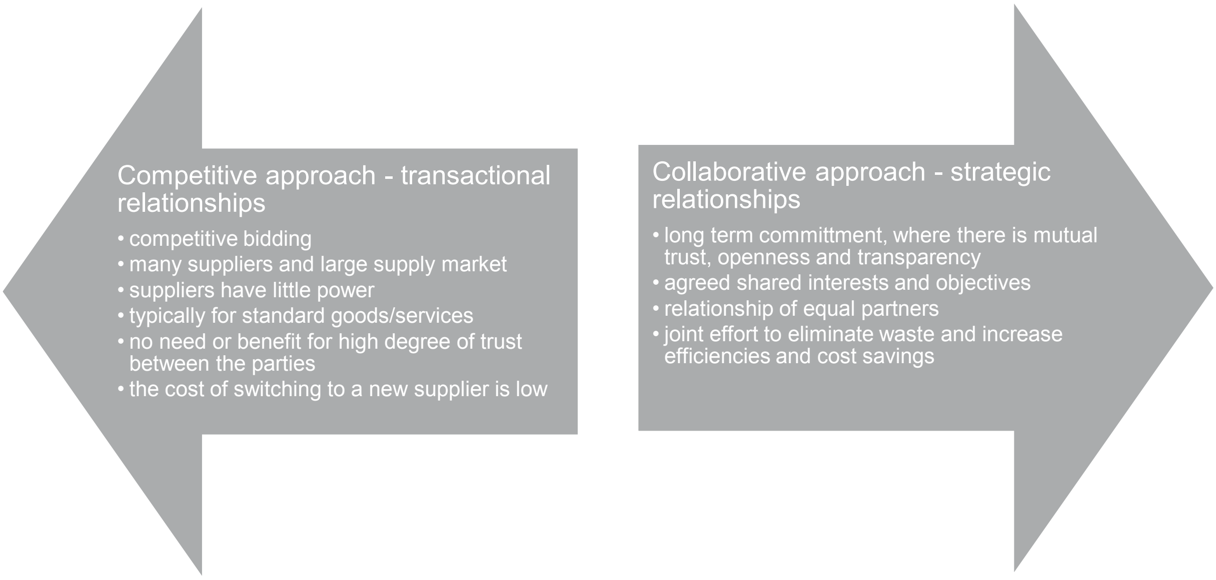
Procurement Objectives

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

1. Ensuring that the services delivered meet the requirements and expectations of the consumers of Whangarei and Kaipara.
2. A delivery model that is cost effective and delivers efficiencies for the long-term benefit of consumers.
3. Achieving a high performing HSQE culture across all areas of it 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 un-related 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.

- Commissioning a third party to undertake market benchmarking of the prices of substantially similar goods or 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.
- 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/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)

Significant capital projects conducted by Northpower Network are 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.

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

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) that outlines how Northpower Network and Contracting Division will work together, specifies the scope of services provided by the Contracting Division and includes a set of KPI's.

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. In the disclosure year to March 2019, no external contractor was authorised for the following customer chargeable work:

a) Livening to the Network
b) Minor Network Enhancements such as fuse carrier fit out
c) Third party network damage.

Post March 2019, external contractors have been authorised to carry out livening and minor network enhancement.

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 Service Level Agreement. The rates are determined as part of the annual SLA review and also subject to periodic benchmarking.

Northpower

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 – Whangarei South T

Construction of the Whangarei South T was awarded under competitive tender using NZS3910 based tender process. The tender was released to four established electrical contractors, including Northpower Contracting Division. The award decision was based on weighted and objective criteria disclosed to the respondents in the tender documentation. Northpower Contracting Division 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.

Directly negotiated work with Northpower Contracting Division

Work completed by Northpower Contracting division under direct negotiation is governed by a Service Level Agreement (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 2019. 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;
- Confirming that information is not shared between the divisions, other than information that would normally be expected to be shared between a supplier and customer;
- 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 2019 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.

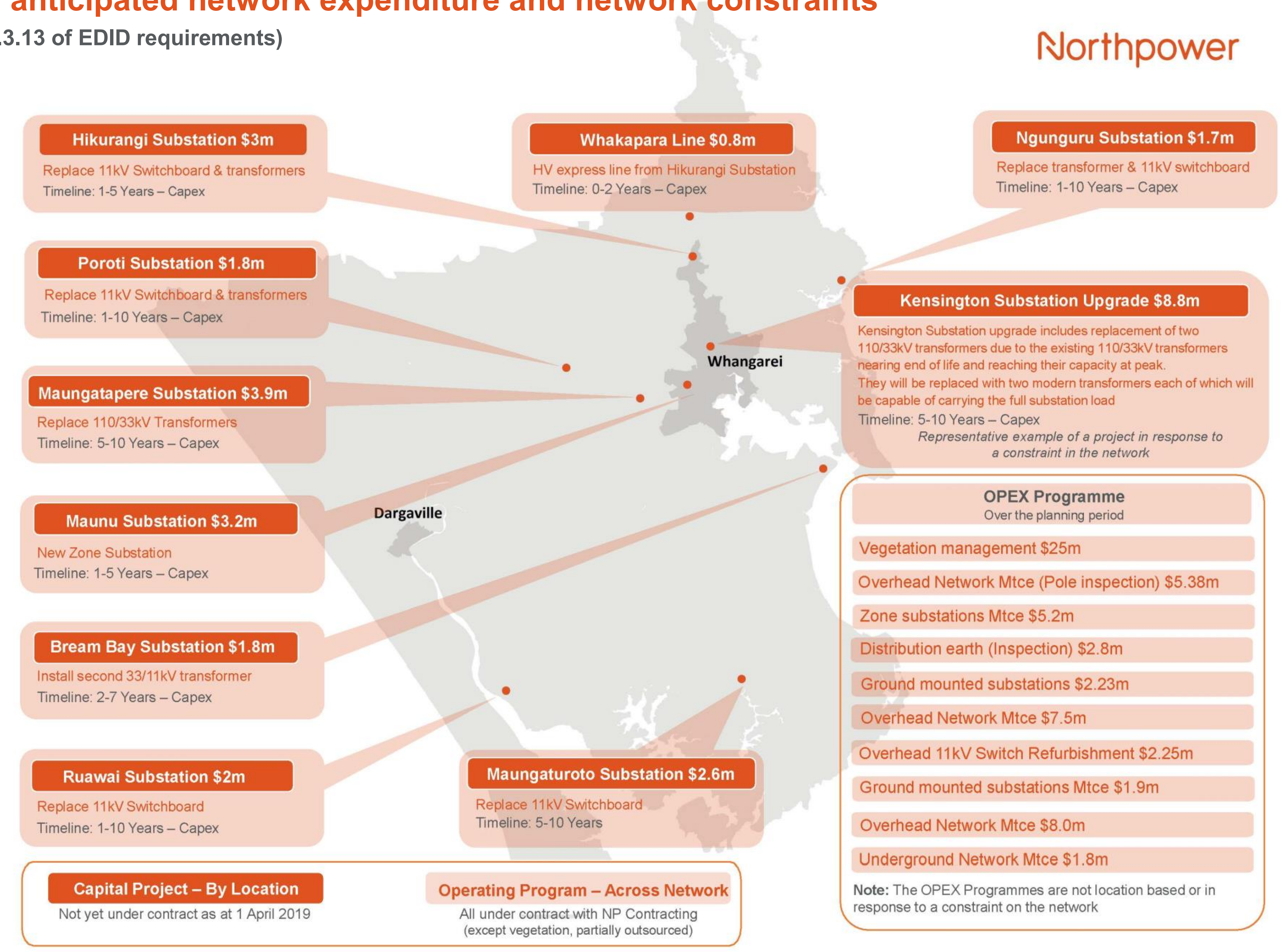
Land and Building Rental

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.

Map of anticipated network expenditure and network constraints

(Clause 2.3.13 of EDID requirements)

Northpower



SCHEDULE 18 CERTIFICATION FOR YEAR END DISCLOSURES

We, Nicole Davies-Colley 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 the Northpower Limited's accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained.

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

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

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

Director	Director
Nicole Davies-Colley	Michael James
Date 28 August 2019	Date 28 August 2019

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 ('the Information Disclosure Determination') for the disclosure year ended 31 March 2019, has been prepared, in all material respects, in accordance with the Information Disclosure Determination.

  The Disclosure Information required to be reported by the Company, and audited by the Auditor-General, under the Information Disclosure Determination 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, 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 2019, has been prepared, in all material respects, in accordance with clause 2.3.6 of the Information Disclosure Determination, 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; and

- the Related Party Transaction Information complies, in all material respects, with the Information Disclosure Determination 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 for 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, and about whether the Related Party Transaction Information has been prepared, in all material respects, with the Information Disclosure Determination 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 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 Audit Matters

Key audit 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.

Key audit matter	How our procedures addressed the key audit matter
Cost and Asset Allocations The Information Disclosure Determination 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 noting the allocation rules were modified for this year.	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 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 2019; • 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 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;

Key audit matter	How our procedures addressed the key audit matter
	• testing a sample of assets to ensure their classification as either directly attributable or non-directly attributable is appropriate and in compliance with the Information Disclosure Determination and the Input Methodologies Determination; • reviewing the Company's judgements in determining and applying appropriate methods to allocate non-directly attributable costs and assets and assessing if the method complies with the Information Disclosure Determination and the Input Methodologies Determination; and • testing a sample of cost allocation calculations
Valuation of related-party transactions at arms-length The Information Disclosure Determination 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.	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 and the Input Methodologies Determination. Due to the value of related party transactions that occurred during the year, the Company was required to engage an Independent Appraiser under the regulations. We were appointed as the Independent Appraisers. The procedures we undertook as the Independent Appraisers 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;

Key audit matter	How our procedures addressed the key audit matter
	• 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; • 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 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; and
- the Related Party Transaction Information in accordance with the Information Disclosure Determination 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 that provides reasonable assurance on whether:

- the Disclosure Information has been prepared, in all material respects, in accordance with the Information Disclosure Determination; and

- the Related Party Transaction Information has been prepared, in all material respects, in accordance with the Information Disclosure Determination 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; 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, and Audit New Zealand and its employees may deal with the Company and its subsidiaries on normal terms within the ordinary course of trading activities of the Company and its subsidiaries. Other than any dealings on normal terms within the ordinary course of business, this engagement, the independent appraiser report engagement, and the annual audit of the Company's and its subsidiaries financial statements, we have no relationship with or interests in the Company and its subsidiaries.

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 and whether the Related Party Transaction Information has been prepared, in all material respects, in accordance with the Information Disclosure Determination 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
28 August 2019

Report of the Independent Appraiser

To the directors of Northpower Limited and the Commerce Commission

The Auditor-General is the independent appraiser of Northpower Limited (the Company). The Auditor-General has appointed me, Clarence Susan, using the staff and resources of Audit New Zealand to provide a report, on behalf of the Auditor-General, on:

- whether the Company's related party transactions for the disclosure year ended 31 March 2019, comply, in all material respects, with clauses 2.3.6 and 2.3.7 of the Electricity Distribution Information Disclosure Determination 2012 (the Information Disclosure Determination) and clauses 2.2.11(1)(g), 2.2.11(5) and 2.2.11(6) of the Electricity Distribution Services Input Methodologies Determination 2012 (the Input Methodologies Determination); and

- whether the steps taken by the Company, as specified under the "*Description of steps and analysis undertaken by the Company*" are considered to be, in all material respects, reasonable in the circumstances.

Opinion

In our opinion:

- based on the information we have obtained, the related party transactions we have sampled and the analysis we have undertaken, the Company's related party transactions for the disclosure year ended 31 March 2019, comply, in all material respects, with clauses 2.3.6 and 2.3.7 of the Information Disclosure Determination and clauses 2.2.11(1)(g), 2.2.11(5) and 2.2.11(6) of the Input Methodologies Determination; and

- the steps taken by the Company, as specified under the "*Description of steps and analysis undertaken by the Company*" are considered to be, in all material respects, reasonable in the circumstances.

In forming our opinion we confirm we have obtained all the recorded information and explanations we have required.

Basis for 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 Company's related party transactions for the disclosure year ended 31 March 2019, comply, in all material respects, with clauses 2.3.6 and 2.3.7 of the Information Disclosure Determination and clauses 2.2.11(1)(g), 2.2.11(5) and 2.2.11(6) of the Input Methodologies Determination; and

- the steps taken by the Company, as specified under the "*Description of steps and analysis undertaken by the Company*" are considered to be, in all material respects, reasonable in the circumstances.

We have complied with the fundamental principle of *professional competence and due care* in the Auditor-General's Auditing Standards that is based on Professional and Ethical Standard 1 (Revised) issued by the New Zealand Auditing and Assurance Standards Board. Clarence Susan is a member of Chartered Accountants Australia and New Zealand who has 26 years of audit experience, including in the identification and disclosure of related party transactions. Clarence is supported by Audit New Zealand staff who possess a range of experience and disciplines in relevant areas such as assessing the probity of procurement processes.

Reasonable assurance is a high level of assurance.

We have performed procedures to obtain evidence about the Company's valuation of goods and services acquired from or supplied to a related party. The procedures selected depend on our judgement, including the assessment of the risks of material misstatement of the valuation, whether due to fraud, error, or non-compliance with the Information Disclosure Determination or the Input Methodologies Determination. In making those risk assessments, we considered internal control relevant to the Company's valuation of goods and services acquired from or supplied to a related party 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.

The key assumptions we made in carrying out our work

In carrying out our work we have assumed that the Company's internal controls that we tested, and placed reliance on, during our audit of the financial statements for the year ended 31 March 2019 also applied in relation to our work as the independent appraiser for the disclosure year ended 31 March 2019.

In building on this assumption we have carried out specific tests to assess if the Company has identified related parties and related party transactions during the disclosure year ended 31 March 2019.

How we sampled the Company's related party transactions

For each of the related-parties who provided, or acquired, a material value of goods and services to or from the Company, respectively, we selected a small sample of related-party transactions to assess if they had been valued in accordance with the requirements of the Information Disclosure Determination and the Input Methodologies Determination.

Description of steps and analysis undertaken by the Company

The process to ensure transactions were on an arm's length basis are set out in Northpower Limited's Network Procurement policy for Related Parties.

Methods available to be used 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:

- Commissioning a third party to undertake market benchmarking of the prices of substantially similar goods or services (not utilised during the 31 March 2019 disclosure year);
- Conducting a tendering process for the goods or services (utilised once during the 31 March 2019 disclosure year);
- Undertaking internal benchmarking of the related party transactions against substantially the same goods or services provided by the related party to its other customers (utilised for the majority of transactions during 31 March 2019 disclosure year); and
- Engaging an expert to undertake an independent valuation to determine the market value of the goods or service (not utilised during the 31 March 2019 disclosure year).

During the 2019 financial year, there was only one contract for contracting work that went through a competitive tender process. This contract was won by the related party. Management compared the prices quoted by the related party to the service level agreement with Northpower Limited to ensure that the same prices (or higher) were used in the tender process.

To further assess whether the Service level agreement, and other related party transactions, were at arm's length, an internal benchmarking review was completed. The rates applied, in the Service Level Agreement with Northpower Contracting Limited, were compared to rates agreed in third party service level agreements for similar work.

Scope and inherent limitations

Due to 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 related party transaction, nor do we guarantee complete accuracy of the related-party disclosures.

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

Directors' responsibilities

The directors of the Company are responsible for:

- the identification of related-parties and related-party transactions during the disclosure year ended 31 March 2019; and
- the valuation of goods and services acquired from or supplied to a related party, in accordance with the requirements of the Information Disclosure Determination and the Input Methodologies Determination.

Our responsibility for the independent report

Our responsibility is to prepare a report that provides reasonable assurance on whether:

- the Company's related party transactions for the disclosure year ended 31 March 2019, comply, in all material respects, with clauses 2.3.6 and 2.3.7 of the Information Disclosure Determination and clauses 2.2.11(1)(g), 2.2.11(5) and 2.2.11(6) of the Input Methodologies Determination; and
- the steps taken by the Company, as specified under the "*Description of steps and analysis undertaken by the Company*" are considered to be, in all material respects, reasonable in the circumstances.

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; 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, *and Audit New Zealand and its employees* may deal with the Company 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.

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 on whether:

- the Company's related party transactions for the disclosure year ended 31 March 2019, comply, in all material respects, with clauses 2.3.6 and 2.3.7 of the Information Disclosure Determination and clauses 2.2.11(1)(g), 2.2.11(5) and 2.2.11(6) of the Input Methodologies Determination; and
- the steps taken by the Company, as specified under the "*Description of steps and analysis undertaken by the Company*" are considered to be, in all material respects, reasonable in the circumstances.

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
28 August 2019