INFORMATION DISCLOSURE PREPARED IN ACCORDANCE WITH ELECTRICITY INFORMATION DISCLOSURE DETERMINATION UNDER PART 4 OF THE COMMERCE ACT 1986

FOR THE YEAR ENDED 31 MARCH 2021

CONTENTS

1. INTRODUCTION

These Information Disclosure documents are submitted by The Power Company Limited pursuant to Part 4 of the Commerce Act 1986 in accordance with:

- The Electricity Information Disclosure Determination 2012, (Consolidated in 2018), issued 3 April 2018.
- The Electricity Distribution Services Input Methodologies Determination 2012, (Consolidated in 2014), issued 30 March 2015.

2. INFORMATION DISCLOSURE DISCLAIMER

The information disclosed in this Information Disclosure package issued by The Power Company Limited has been prepared in accordance with the Determination listed above.

The Determination requires the information to be disclosed in the manner it is presented.

The information should not be used for any other purposes than that intended under the Determination.

The financial information presented is for the electricity distribution business as described within the Determination.

Due to rounding and automatic calculations in the spreadsheets there may be minor summing variances.

3. SCHEDULES

Company Name	The Power Company Limited
For Year Ended	31 March 2021

SCHEDULE 1: ANALYTICAL RATIOS

This schedule calculates expenditure, revenue and service ratios from the information disclosed. The disclosed ratios may vary for reasons that are company specific and, as a result, must be interpreted with care. The Commerce Commission will publish a summary and analysis of information disclosed in accordance with the ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of the determination.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

1(i): Expenditure metrics

	Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
Operational expenditure	21,097	458	103,732	1,892	36,176
Network	12,678	275	62,336	1,137	21,739
Non-network	8,419	183	41,396	755	14,437
Expenditure on assets	31,664	687	155,687	2,840	54,294
Network	31,664	687	155,687	2,840	54,294
Non-network	–	–	–	–	–

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	71,213	1,545
Standard consumer line charge revenue	83,816	1,408
Non-standard consumer line charge revenue	28,075	839,741

1(iii): Service intensity measures

Demand density	18	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	90	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	4	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	21,696	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	16,746	29.63%
Pass-through and recoverable costs excluding financial incentives and wash-ups	12,329	21.81%
Total depreciation	15,236	26.95%
Total revaluations	6,184	10.94%
Regulatory tax allowance	4,486	7.94%
Regulatory profit/(loss) including financial incentives and wash-ups	13,684	24.21%
Total regulatory income	56,526	

1(v): Reliability

Interruption rate	16.86	*Interruptions per 100 circuit km*

Company Name	The Power Company Limited
For Year Ended	31 March 2021

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(i): Return on Investment

	CY-2 31 Mar 19 %	CY-1 31 Mar 20 %	Current Year CY 31 Mar 21 %
ROI – comparable to a post tax WACC			
Reflecting all revenue earned	4.98%	6.04%	3.17%
Excluding revenue earned from financial incentives	4.98%	6.04%	3.17%
Excluding revenue earned from financial incentives and wash-ups	4.98%	6.04%	3.17%
Mid-point estimate of post tax WACC	4.75%	4.27%	3.72%
25th percentile estimate	4.07%	3.59%	3.04%
75th percentile estimate	5.43%	4.95%	4.40%
ROI – comparable to a vanilla WACC			
Reflecting all revenue earned	5.49%	6.47%	3.50%
Excluding revenue earned from financial incentives	5.49%	6.47%	3.50%
Excluding revenue earned from financial incentives and wash-ups	5.49%	6.47%	3.50%
WACC rate used to set regulatory price path	NA	NA	NA
Mid-point estimate of vanilla WACC	5.26%	4.69%	4.05%
25th percentile estimate	4.58%	4.01%	3.37%
75th percentile estimate	5.94%	5.37%	4.73%

2(ii): Information Supporting the ROI

		($000)		
	Total opening RAB value	407,982		
plus	Opening deferred tax	(20,753)		
Opening RIV			387,229	
Line charge revenue			56,526	
	Expenses cash outflow	29,075		
add	Assets commissioned	22,706		
less	Asset disposals	818		
add	Tax payments	2,266		
less	Other regulated income	(0)		
Mid-year net cash outflows			53,230	
Term credit spread differential allowance			229	
	Total closing RAB value	420,819		
less	Adjustment resulting from asset allocation	(0)		
less	Lost and found assets adjustment	–		
plus	Closing deferred tax	(22,973)		
Closing RIV			397,846	
ROI – comparable to a vanilla WACC				3.50%
	Leverage (%)			42%
	Cost of debt assumption (%)			2.82%
	Corporate tax rate (%)			28%
ROI – comparable to a post tax WACC				3.17%

2(iii): Information Supporting the Monthly ROI

Opening RIV	N/A

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

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

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

Year-end ROI – comparable to a vanilla WACC	3.43%
Year-end ROI – comparable to a post tax WACC	3.10%

** 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	The Power Company Limited
For Year Ended	31 March 2021

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**		
8		**Income**	
9		Line charge revenue	56,526
10	*plus*	Gains / (losses) on asset disposals	(783)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	782
12			
13		**Total regulatory income**	56,526
14		**Expenses**	
15	*less*	Operational expenditure	16,746
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	12,329
18			
19		**Operating surplus / (deficit)**	27,451
20			
21	*less*	Total depreciation	15,236
22			
23	*plus*	Total revaluations	6,184
24			
25		**Regulatory profit / (loss) before tax**	18,400
26			
27	*less*	Term credit spread differential allowance	229
28			
29	*less*	Regulatory tax allowance	4,486
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	13,684
32			

			($000)	
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**			
34		**Pass through costs**		
35		Rates	231	
36		Commerce Act levies	64	
37		Industry levies	157	
38		CPP specified pass through costs	–	
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	11,653	
41		Transpower new investment contract charges	224	
42		System operator services	–	
43		Distributed generation allowance	–	
44		Extended reserves allowance	–	
45		Other recoverable costs excluding financial incentives and wash-ups	–	
46		**Pass-through and recoverable costs excluding financial incentives and wash-ups**		12,329
47				

			($000)	
48	**3(iii): Incremental Rolling Incentive Scheme**			
49			**CY-1**	**CY**
50			**31 Mar 20**	**31 Mar 21**
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 16	–	–
58	CY-4	31 Mar 17	–	–
59	CY-3	31 Mar 18	–	–
60	CY-2	31 Mar 19	–	–
61	CY-1	31 Mar 20	–	–
62		**Net incremental rolling incentive scheme**		–
63				
64		**Net recoverable costs allowed under incremental rolling incentive scheme**		–

		($000)
65	**3(iv): Merger and Acquisition Expenditure**	
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)*	

		($000)
69	**3(v): Other Disclosures**	
70		
71	Self-insurance allowance	–

Company Name	The Power Company Limited
For Year Ended	31 March 2021

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)

		for year ended	RAB 31 Mar 17 ($000)	RAB 31 Mar 18 ($000)	RAB 31 Mar 19 ($000)	RAB 31 Mar 20 ($000)	RAB 31 Mar 21 ($000)
	Total opening RAB value		339,946	355,086	373,678	385,009	407,982
less	Total depreciation		12,755	12,615	13,762	14,313	15,236
plus	Total revaluations		7,349	3,886	5,526	9,710	6,184
plus	Assets commissioned		20,976	25,100	20,360	28,192	22,706
less	Asset disposals		429	744	792	616	818
plus	Lost and found assets adjustment		–	2,964	–	–	–
plus	Adjustment resulting from asset allocation						(0)
	Total closing RAB value		355,086	373,678	385,009	407,982	420,819

4(ii): Unallocated Regulatory Asset Base

		Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
	Total opening RAB value		407,982		407,982
less					
	Total depreciation		15,236		15,236
plus					
	Total revaluations		6,184		6,184
plus					
	Assets commissioned (other than below)	–		–	
	Assets acquired from a regulated supplier	–		–	
	Assets acquired from a related party	22,706		22,706	
	Assets commissioned		22,706		22,706
less					
	Asset disposals (other than below)	810		810	
	Asset disposals to a regulated supplier	–		–	
	Asset disposals to a related party	7		7	
	Asset disposals		818		818
plus	Lost and found assets adjustment		–		–
plus	Adjustment resulting from asset allocation				(0)
	Total closing RAB value		420,819		420,819

** 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.*

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

	CPI_4	1,068
	CPI_4[-4]	1,052
	Revaluation rate (%)	1.52%

		Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
	Total opening RAB value	407,982		407,982	
less	Opening value of fully depreciated, disposed and lost assets	1,358		1,358	
	Total opening RAB value subject to revaluation	406,624		406,625	
	Total revaluations		6,184		6,184

4(iv): Roll Forward of Works Under Construction

		Unallocated works under construction	Allocated works under construction
	Works under construction—preceding disclosure year	10,148	10,148
plus	Capital expenditure	23,068	23,068
less	Assets commissioned	22,706	22,706
plus	Adjustment resulting from asset allocation		
	Works under construction - current disclosure year	10,510	10,510
	Highest rate of capitalised finance applied		

4(v): Regulatory Depreciation

		Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
	Depreciation - standard	15,236		15,236	
	Depreciation - no standard life assets	–		–	
	Depreciation - modified life assets	–		–	
	Depreciation - alternative depreciation in accordance with CPP	–		–	
	Total depreciation		15,236		15,236

4(vi): Disclosure of Changes to Depreciation Profiles

($000 unless otherwise specified)

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

** include additional rows if needed*

4(vii): Disclosure by Asset Category

($000 unless otherwise specified)

		Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
	Total opening RAB value	60,803	4,321	105,438	139,369	20,007	55,796	14,879	7,363	7	407,982
less	Total depreciation	1,881	107	3,809	6,134	683	1,729	639	253		15,236
plus	Total revaluations	927	66	1,612	2,101	304	833	228	112		6,184
plus	Assets commissioned	483	91	8,351	8,153	303	1,658	3,311	356		22,706
less	Asset disposals			130			600	88			818
plus	Lost and found assets adjustment										–
plus	Adjustment resulting from asset allocation										–
plus	Asset category transfers										–
	Total closing RAB value	60,332	4,372	111,463	143,489	19,930	55,958	17,692	7,578	7	420,819
	Asset Life										
	Weighted average remaining asset life	37.7	40.3	33.6	24.7	43.2	33.5	25.0	16.5	–	(years)
	Weighted average expected total asset life	57.3	45.5	45.6	58.3	61.7	47.2	39.2	32.4	–	(years)

Company Name	The Power Company Limited
For Year Ended	31 March 2021

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**			18,400
9					
10	*plus*	Income not included in regulatory profit / (loss) before tax but taxable	–	*	
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible	–	*	
12		Amortisation of initial differences in asset values	6,968		
13		Amortisation of revaluations	1,736		
14					8,704
15					
16	*less*	Total revaluations	6,184		
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	148	*	
20		Notional deductible interest	4,749		
21					11,081
22					
23		**Regulatory taxable income**			16,022
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			16,022
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			4,486
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	118,454		
37	*less*	Amortisation of initial differences in asset values	6,968		
38	*plus*	Adjustment for unamortised initial differences in assets acquired			
39	*less*	Adjustment for unamortised initial differences in assets disposed	432		
40		Closing unamortised initial differences in asset values			111,054
41					
42		Opening weighted average remaining useful life of relevant assets (years)			17
43					

5a(iv): Amortisation of Revaluations

		($000)
Opening sum of RAB values without revaluations	363,769	
Adjusted depreciation	13,500	
Total depreciation	15,236	
Amortisation of revaluations		1,736

5a(v): Reconciliation of Tax Losses

		($000)
Opening tax losses	–	
plus Current period tax losses	–	
less Utilised tax losses	–	
Closing tax losses		–

5a(vi): Calculation of Deferred Tax Balance

		($000)
Opening deferred tax	(20,753)	
plus Tax effect of adjusted depreciation	3,780	
less Tax effect of tax depreciation	4,756	
plus Tax effect of other temporary differences*	629	
less Tax effect of amortisation of initial differences in asset values	1,951	
plus Deferred tax balance relating to assets acquired in the disclosure year	–	
less Deferred tax balance relating to assets disposed in the disclosure year	(78)	
plus Deferred tax cost allocation adjustment	0	
Closing deferred tax		(22,973)

5a(vii): Disclosure of Temporary Differences

In Schedule 14, Box 6, provide descriptions and workings of items recorded in the asterisked category in Schedule 5a(vi) (Tax effect of other temporary differences).

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

		($000)
Opening sum of regulatory tax asset values	182,315	
less Tax depreciation	16,986	
plus Regulatory tax asset value of assets commissioned	25,241	
less Regulatory tax asset value of asset disposals	322	
plus Lost and found assets adjustment	–	
plus Adjustment resulting from asset allocation	–	
plus Other adjustments to the RAB tax value	–	
Closing sum of regulatory tax asset values		190,248

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2021**

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

5b(i): Summary—Related Party Transactions

		($000)	($000)
8	**Total regulatory income**		170
9			
10	**Market value of asset disposals**		7
11			
12	Service interruptions and emergencies	3,587	
13	Vegetation management	1,564	
14	Routine and corrective maintenance and inspection	4,251	
15	Asset replacement and renewal (opex)	662	
16	**Network opex**		10,064
17	Business support	3,053	
18	System operations and network support	2,030	
19	**Operational expenditure**		15,147
20	Consumer connection	2,829	
21	System growth	4,012	
22	Asset replacement and renewal (capex)	13,644	
23	Asset relocations	118	
24	Quality of supply	356	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	4,174	
27	**Expenditure on non-network assets**		–
28	**Expenditure on assets**		25,133
29	Cost of financing		–
30	Value of capital contributions		–
31	Value of vested assets		–
32	**Capital Expenditure**		25,133
33	**Total expenditure**		40,280
34			
35	**Other related party transactions**		–

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

37	Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
38	PowerNet Limited	Service interruptions and emergencies	3,587
39	PowerNet Limited	Vegetation management	1,564
40	PowerNet Limited	Routine and corrective maintenance and inspection	4,251
41	PowerNet Limited	Asset replacement and renewal (opex)	662
42	PowerNet Limited	System operations and network support	2,030
43	PowerNet Limited	Business support	3,053
44	PowerNet Limited	Consumer connection	2,829
45	PowerNet Limited	System growth	4,012
46	PowerNet Limited	Asset replacement and renewal (capex)	13,644
47	PowerNet Limited	Asset relocations	118
48	PowerNet Limited	Quality of supply	356
49	PowerNet Limited	Other reliability, safety and environment	4,174
50			
51			
52			
53	**Total value of related party transactions**		40,280
54	** include additional rows if needed*		
55			

Company Name	The Power Company Limited
For Year Ended	31 March 2021

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

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

Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
US Private Placement (USPP) US $40M	4/2/2020	7/11/2019	10.0	BKBM plus margin	62,794	58,137	235	(63)
US Private Placement (USPP) US $25M	4/2/2020	7/11/2019	11.0	BKBM plus margin	39,246	36,336	177	(43)
** include additional rows if needed*						94,473	412	(106)

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

Gross term credit spread differential		306
Total book value of interest bearing debt	232,490	
Leverage	42%	
Average opening and closing RAB values	414,401	
Attribution Rate (%)		75%
Term credit spread differential allowance		229

Company Name	The Power Company Limited
For Year Ended	31 March 2021

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(i): Operating Cost Allocations

	Value allocated ($000s)				
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
Service interruptions and emergencies					
Directly attributable		3,587			
Not directly attributable				–	
Total attributable to regulated service		3,587			
Vegetation management					
Directly attributable		1,564			
Not directly attributable				–	
Total attributable to regulated service		1,564			
Routine and corrective maintenance and inspection					
Directly attributable		4,251			
Not directly attributable				–	
Total attributable to regulated service		4,251			
Asset replacement and renewal					
Directly attributable		662			
Not directly attributable				–	
Total attributable to regulated service		662			
System operations and network support					
Directly attributable		2,871			
Not directly attributable				–	
Total attributable to regulated service		2,871			
Business support					
Directly attributable		3,332			
Not directly attributable		481	27	507	
Total attributable to regulated service		3,812			
Operating costs directly attributable		16,266			
Operating costs not directly attributable	–	481	27	507	–
Operational expenditure		16,746			

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	452
Not directly attributable	–
Total attributable to regulated service	452
Recoverable costs	
Directly attributable	11,877
Not directly attributable	–
Total attributable to regulated service	11,877

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

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

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

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

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

Company Name	The Power Company Limited
For Year Ended	31 March 2021

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

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	60,332
Not directly attributable	–
Total attributable to regulated service	60,332
Subtransmission cables	
Directly attributable	4,372
Not directly attributable	–
Total attributable to regulated service	4,372
Zone substations	
Directly attributable	111,463
Not directly attributable	–
Total attributable to regulated service	111,463
Distribution and LV lines	
Directly attributable	143,489
Not directly attributable	–
Total attributable to regulated service	143,489
Distribution and LV cables	
Directly attributable	19,930
Not directly attributable	–
Total attributable to regulated service	19,930
Distribution substations and transformers	
Directly attributable	55,958
Not directly attributable	–
Total attributable to regulated service	55,958
Distribution switchgear	
Directly attributable	17,692
Not directly attributable	–
Total attributable to regulated service	17,692
Other network assets	
Directly attributable	7,578
Not directly attributable	–
Total attributable to regulated service	7,578
Non-network assets	
Directly attributable	7
Not directly attributable	–
Total attributable to regulated service	7
Regulated service asset value directly attributable	420,819
Regulated service asset value not directly attributable	–
Total closing RAB value	420,819

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

Change in asset value allocation 1

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

Change in asset value allocation 2

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

Change in asset value allocation 3

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

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

Company Name	The Power Company Limited
For Year Ended	31 March 2021

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5d (Cost allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.
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	Line Item*	Allocation methodology type	Cost allocator	Allocator type	Allocator Metric (%)		Value allocated ($000)				OVABAA allocation increase ($000)
					Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	
	Service interruptions and emergencies										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Vegetation management										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Routine and corrective maintenance and inspection										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Asset replacement and renewal										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	System operations and network support										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Business support										
	Administration expenses	ABAA	Revenue	Proxy	94.75%	5.25%		481	27	507	
										-	
										-	
										-	
	Not directly attributable						-	481	27	507	-
	Operating costs not directly attributable						-	481	27	507	-
	Pass through and recoverable costs										
	Pass through costs										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Recoverable costs										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	** include additional rows if needed*										

											Company Name	The Power Company Limited
											For Year Ended	31 March 2021

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5e (Report on Asset Allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.

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	Line Item*	Allocation methodology type	Allocator	Allocator type	Allocator Metric (%)		Value allocated ($000)				OVABAA allocation increase ($000)
					Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	
	Subtransmission lines										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Subtransmission cables										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Zone substations										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Distribution and LV lines										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Distribution and LV cables										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Distribution substations and transformers										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Distribution switchgear										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Other network assets										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Non-network assets										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Regulated service asset value not directly attributable						-	-	-	-	-
	** include additional rows if needed*										

Company Name	The Power Company Limited
For Year Ended	31 March 2021

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

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

sch ref

6a(i): Expenditure on Assets

			($000)	($000)
8		Consumer connection		2,829
9		System growth		4,012
10		Asset replacement and renewal		13,644
11		Asset relocations		118
12		Reliability, safety and environment:		
13		Quality of supply	356	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	4,174	
16		**Total reliability, safety and environment**		4,530
17		**Expenditure on network assets**		25,133
18		Expenditure on non-network assets		–
19				
20		**Expenditure on assets**		25,133
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		2,066
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		23,068

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	–

6a(iii): Consumer Connection

		*Consumer types defined by EDB**	($000)	($000)
32		Non Half Hour Individuals	1,114	
33		Non- Domestic	481	
34		Domestic	1,235	
35				
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		2,829
39				
40	*less*	Capital contributions funding consumer connection expenditure	1,690	
41		**Consumer connection less capital contributions**		1,139

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

			System Growth ($000)	Asset Replacement and Renewal ($000)
45		Subtransmission	772	236
46		Zone substations	1,210	1,076
47		Distribution and LV lines	738	6,027
48		Distribution and LV cables	905	–
49		Distribution substations and transformers	270	3,650
50		Distribution switchgear	108	2,202
51		Other network assets	9	451
52		**System growth and asset replacement and renewal expenditure**	4,012	13,644
53	*less*	Capital contributions funding system growth and asset replacement and renewal	258	101
54		**System growth and asset replacement and renewal less capital contributions**	3,754	13,543

6a(v): Asset Relocations

		*Project or programme**	($000)	($000)
58		Line relocation	118	
59				
60				
61				
62				
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations		
65		**Asset relocations expenditure**		118
66	*less*	Capital contributions funding asset relocations	17	
67		**Asset relocations less capital contributions**		102

6a(vi): Quality of Supply

	Project or programme*	($000)	($000)
	Mobile Substation Site Made Ready	232	
	* include additional rows if needed		
	All other projects programmes - quality of supply	124	
	Quality of supply expenditure		356
less	Capital contributions funding quality of supply		
	Quality of supply less capital contributions		356

6a(vii): Legislative and Regulatory

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

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

	Project or programme*	($000)	($000)
	Earth Upgrades	2,312	
	Substation Safety	432	
	11kV Indoor Switchgear	609	
	Microwave Ring Network	551	
	* include additional rows if needed		
	All other projects or programmes - other reliability, safety and environment	270	
	Other reliability, safety and environment expenditure		4,174
less	Capital contributions funding other reliability, safety and environment		
	Other reliability, safety and environment less capital contributions		4,174

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)
	* include additional rows if needed		
	All other projects or programmes - atypical expenditure		
	Atypical expenditure		–
	Expenditure on non-network assets		–

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2021**

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

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

sch ref		($000)	($000)
7	**6b(i): Operational Expenditure**		
8	Service interruptions and emergencies	3,587	
9	Vegetation management	1,564	
10	Routine and corrective maintenance and inspection	4,251	
11	Asset replacement and renewal	662	
12	**Network opex**		10,063
13	System operations and network support	2,871	
14	Business support	3,812	
15	**Non-network opex**		6,683
16			
17	**Operational expenditure**		16,746
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		211
20	Direct billing*		–
21	Research and development		–
22	Insurance		335
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2021**

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

		Target ($000) [1]	Actual ($000)	% variance
7	**7(i): Revenue**			
8	Line charge revenue	56,506	56,526	0%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	2,692	2,829	5%
11	System growth	3,602	4,012	11%
12	Asset replacement and renewal	13,617	13,644	0%
13	Asset relocations	433	118	(73%)
14	Reliability, safety and environment:			
15	Quality of supply	478	356	(26%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	3,181	4,174	31%
18	**Total reliability, safety and environment**	3,659	4,530	24%
19	**Expenditure on network assets**	24,003	25,133	5%
20	Expenditure on non-network assets	100	–	(100%)
21	Expenditure on assets	24,103	25,133	4%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	3,385	3,587	6%
24	Vegetation management	1,535	1,564	2%
25	Routine and corrective maintenance and inspection	4,547	4,251	(7%)
26	Asset replacement and renewal	798	662	(17%)
27	**Network opex**	10,265	10,063	(2%)
28	System operations and network support	4,506	2,871	(36%)
29	Business support	3,621	3,812	5%
30	**Non-network opex**	8,127	6,683	(18%)
31	**Operational expenditure**	18,392	16,746	(9%)
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses	–	–	–
34	Overhead to underground conversion	–	–	–
35	Research and development	–	–	–
36				
37	**7(v): Subcomponents of Operational Expenditure (where known)**			
38	Energy efficiency and demand side management, reduction of energy losses	425	211	(50%)
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	996	335	(66%)
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	The Power Company Limited
For Year Ended	31 March 2021
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(i): Billed Quantities 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)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
Low user	Residential	Standard	10,301	65,200
Domestic	Residential	Standard	16,756	159,162
Non-Domestic	Commerical	Standard	9,255	206,673
Individual non half hour	Commerical	Standard	68	7,953
Individual half hour	Commerical	Standard	199	175,303
Non-Standard	Commerical	Non-standard	4	179,112
Generation	Commerical	Non-standard	2	354

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

Standard consumer totals	36,579	614,291
Non-standard consumer totals	6	179,467
Total for all consumers	36,585	793,758

Billed quantities by price component

Price component	Variable day energy sales	Variable day energy purchases				
Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	KWh				
	–	53,798,179				
	–	126,792,547				
	–	163,463,134				
		6,298,539				
	124,165,754	–				
	118,911,582	–				
	236,509	–				
	124,165,754	350,352,400	–	–	–	–
	119,148,091	–	–	–	–	–
	243,313,845	350,352,400	–	–	–	–

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

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)	Line charge revenues ($000) by price component						
							Price component	Fixed	Variable	Variable			
							Rate (eg, $ per day, $ per kWh, etc.)	$/Day	$/kwh	NIGHT $/kWh [Volume Not Charged]			
Low user	Residential	Standard	$7,058	$1,151	$5,937	$1,121		$425	$6,955	($322)			
Domestic	Residential	Standard	$17,263	$2,877	$14,514	$2,749		$8,727	$9,341	($806)			
Non-Domestic	Commerical	Standard	$21,228	$3,250	$17,843	$3,385		$8,716	$13,090	($578)			
Individual non half hour	Commerical	Standard	$536	$84	$316	$219		$11	$525				
Individual half hour	Commerical	Standard	$5,404	$526	$2,549	$2,855		$3,103	$2,301				
Non-Standard	Commerical	Non-standard	$3,591	$241	$2,258	$1,333		$3,591					
Generation	Commerical	Non-standard	$1,447	$49	$1,232	$215		$1,447					
			–										
			–										
			–										
Add extra rows for additional consumer groups or price category codes as necessary													
		Standard consumer totals	$51,488	$7,888	$41,159	$10,329		$20,981	$32,213	($1,706)	–	–	–
		Non-standard consumer totals	$5,038	$291	$3,490	$1,548		$5,038	–	–	–	–	–
		Total for all consumers	$56,526	$8,179	$44,649	$11,877		$26,019	$32,213	($1,706)	–	–	–

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

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	6	**Check** OK

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	

SCHEDULE 9a: ASSET REGISTER

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

sch ref

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	90,759	91,507	748	3
10	All	Overhead Line	Wood poles	No.	18,588	18,236	(352)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	907	891	(16)	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	11	13	1	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	1	1	–	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	58	58	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	58	59	1	3
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	8	9	1	3
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	294	294	–	3
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	20	21	1	3
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	30	32	2	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	150	163	13	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	47	45	(2)	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	62	61	(1)	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	6,808	6,717	(92)	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	8	9	0	3
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	116	118	2	3
39	HV	Distribution Cable	Distribution UG PILC	km	37	37	(0)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	32	30	(2)	3
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	15	20	5	3
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	13,798	13,858	60	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	N/A
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	102	111	9	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	10,543	10,575	32	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	674	689	15	3
48	HV	Distribution Transformer	Voltage regulators	No.	72	72	–	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	7	7	–	3
50	LV	LV Line	LV OH Conductor	km	846	848	3	3
51	LV	LV Cable	LV UG Cable	km	213	216	2	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	354	355	2	3
53	LV	Connections	OH/UG consumer service connections	No.	38,039	38,361	322	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	593	603	10	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	6	6	–	4
57	All	Load Control	Centralised plant	Lot	5	5	–	4
58	All	Load Control	Relays	No	–	–	–	N/A
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	The Power Company Limited
For Year Ended	31 March 2021
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 2021		Number of assets at disclosure year end by installation date																																		
9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	–	–	2,202	36,199	12,033	21,044	2,988	199	787	989	609	175	50	137	330	320	858	1,214	786	919	986	1,179	1,202	1,316	1,451	1,184	1,142	600	69	–	–	–	–	499	91,507	–	3
11	All	Overhead Line	Wood poles	No.	–	–	498	1,299	4,550	636	3,548	731	780	728	733	728	458	864	792	1,042	120	7	2	16	13	164	2	18	14	17	4	5	–	–	–	–	–	447	18,236	–	3
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	129	125	126	139	135	59	35	8	26	–	–	0	29	21	1	–	0	–	–	36	13	–	12	1	–	0	–	–	–	–	–	2	891	–	3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	–	1	–	0	1	0	0	1	–	2	0	–	–	–	–	–	–	2	–	0	–	0	4	0	–	–	–	–	1	13	–	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	1	–	4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	2	7	10	6	6	–	2	1	–	–	–	–	1	–	–	–	–	1	1	1	1	1	8	3	3	–	–	–	–	–	4	58	–	4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	11	6	1	–	–	2	2	2	13	–	5	–	–	3	1	1	–	–	6	4	–	–	2	–	–	–	–	59	–	3
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	8	–	–	1	–	–	–	–	–	–	–	9	–	3
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	18	11	14	28	61	3	35	2	2	11	7	10	23	2	8	1	1	7	4	5	4	–	5	7	10	6	1	–	–	–	–	8	294	–	3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	7	–	–	–	–	5	–	–	–	–	–	–	–	–	7	1	–	–	–	1	–	–	–	–	–	21	–	3
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	2	1	3	6	2	–	–	–	–	3	2	5	2	–	1	1	–	–	–	–	–	1	–	1	3	1	–	–	–	–	–	32	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	–	14	49	–	–	1	–	–	–	–	6	–	2	–	–	20	8	13	14	9	6	8	5	5	3	–	–	–	–	–	163	–	3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	3	18	6	–	–	1	3	1	–	–	2	–	1	–	–	5	1	–	–	2	–	–	2	–	–	–	–	–	–	45	–	3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	–	6	8	8	2	1	3	2	1	3	–	2	–	2	1	–	2	1	6	1	2	2	4	3	–	1	–	–	–	–	–	–	61	–	3
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3	0	192	721	3,255	1,075	310	47	98	101	71	61	58	54	72	103	76	49	51	55	37	75	34	36	11	20	10	15	0	–	–	–	–	27	6,717	–	3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
38	HV	Distribution Line	SWER conductor	km	–	–	–	4	1	–	–	–	–	–	–	–	–	–	–	4	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–	9	–	3
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	–	0	16	4	5	2	4	3	5	8	4	5	8	4	2	2	1	4	1	3	6	3	1	15	1	3	0	–	–	–	–	8	118	–	3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	0	13	5	8	1	–	1	0	–	1	1	3	1	1	0	1	0	–	0	–	–	0	–	–	–	–	–	–	–	–	2	37	–	3
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	1	1	3	–	–	–	–	1	2	1	–	–	1	–	–	–	2	3	–	4	3	5	3	–	–	–	–	–	–	30	–	3
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	1	–	1	5	8	2	1	–	–	–	–	–	20	–	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	9	1	182	348	1,275	2,032	1,413	110	329	398	297	327	260	352	422	498	539	516	450	405	336	421	337	259	289	305	313	317	49	–	–	–	–	1,071	13,858	–	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	1	2	8	–	–	–	9	1	2	3	7	13	7	2	1	2	1	2	3	–	4	23	5	14	1	–	–	–	–	–	111	–	3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	8	1	160	69	1,231	1,899	1,339	95	307	371	255	246	228	310	369	402	401	382	339	321	254	322	242	175	206	184	194	200	31	–	–	–	–	34	10,575	–	3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	3	7	82	84	38	5	18	23	19	31	20	36	32	27	24	21	13	18	21	29	16	17	37	22	16	23	4	–	–	–	–	3	689	–	3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	4	–	1	6	5	5	16	13	3	–	–	–	2	8	2	–	5	–	1	1	–	–	–	–	–	–	72	–	3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	–	1	–	1	–	–	–	–	–	1	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	3
51	LV	LV Line	LV OH Conductor	km	–	–	19	72	488	104	41	3	9	11	7	5	4	6	5	6	6	5	5	4	5	5	4	5	6	5	8	4	0	–	–	–	–	6	848	–	3
52	LV	LV Cable	LV UG Cable	km	–	–	0	2	80	20	11	1	1	4	4	7	2	14	15	6	7	5	4	4	3	2	3	1	2	3	3	2	0	–	–	–	–	4	216	–	3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	0	14	237	41	17	1	3	2	1	3	2	3	7	13	7	2	1	3	2	1	2	0	0	0	2	1	0	2	–	–	–	–	12	355	–	3
54	LV	Connections	OH/UG consumer service connections	No.	–	206	2,125	5,262	7,021	7,886	6,971	245	343	438	432	414	467	512	568	681	522	420	476	358	397	326	299	276	330	329	398	75	–	–	–	–	584	38,361	–	3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	3	7	82	84	38	5	18	23	19	31	20	36	32	27	24	21	13	18	21	29	16	17	37	22	16	23	4	–	–	–	–	3	689	–	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	4
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	6	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	6	–	4
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	2	3	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5	–	4
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A

Company Name	The Power Company Limited
For Year Ended	31 March 2021
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	–	–	–
12	50kV & 66kV	525	–	525
13	33kV	366	14	380
14	SWER (all SWER voltages)	5	4	9
15	22kV (other than SWER)	0	1	1
16	6.6kV to 11kV (inclusive—other than SWER)	6,717	154	6,871
17	Low voltage (< 1kV)	848	216	1,064
18	**Total circuit length (for supply)**	8,462	388	8,850
19				
20	Dedicated street lighting circuit length (km)	270	85	355
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	474	6%	
25	Rural	4,557	54%	
26	Remote only	803	9%	
27	Rugged only	2,016	24%	
28	Remote and rugged	612	7%	
29	Unallocated overhead lines	0	0%	
30	**Total overhead length**	8,462	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,542	17%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	1,528	18%	

Company Name	The Power Company Limited
For Year Ended	31 March 2021

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	**The Power Company Limited**
For Year Ended	**31 March 2021**
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

9e(i): Consumer Connections

Number of ICPs connected in year by consumer type

	*Consumer types defined by EDB**	Number of connections (ICPs)
	Domestic	321
	Half Hour Individual	1
	Non Domestic	98

** include additional rows if needed*

Connections total	420	

Distributed generation

	Number of connections made in year	36	connections
	Capacity of distributed generation installed in year	0.22	MVA

9e(ii): System Demand

		Demand at time of maximum coincident demand (MW)	
	Maximum coincident system demand		
	GXP demand	154	
plus	Distributed generation output at HV and above	9	
	Maximum coincident system demand	163	
less	Net transfers to (from) other EDBs at HV and above	1	
	Demand on system for supply to consumers' connection points	161	

		Energy (GWh)	
	Electricity volumes carried		
	Electricity supplied from GXPs	670	
less	Electricity exports to GXPs	145	
plus	Electricity supplied from distributed generation	325	
less	Net electricity supplied to (from) other EDBs	14	
	Electricity entering system for supply to consumers' connection points	836	
less	Total energy delivered to ICPs	794	
	Electricity losses (loss ratio)	42	5.0%
	Load factor	0.59	

9e(iii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	463
Distribution transformer capacity (Non-EDB owned, estimated)	46
Total distribution transformer capacity	509
Zone substation transformer capacity	461

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2021**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

10(i): Interruptions

	Interruptions by class	Number of interruptions
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	679
12	Class C (unplanned interruptions on the network)	812
13	Class D (unplanned interruptions by Transpower)	–
14	Class E (unplanned interruptions of EDB owned generation)	–
15	Class F (unplanned interruptions of generation owned by others)	–
16	Class G (unplanned interruptions caused by another disclosing entity)	1
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	–
19	**Total**	1,492

	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	606	206

	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.65	143.31
27	Class C (unplanned interruptions on the network)	2.88	170.73
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	0.00	0.02
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	3.53	314.1

	Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
37	Classes B & C (interruptions on the network)	3.53	314.1

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

	Cause	SAIFI	SAIDI
42	Lightning	0.01	0.45
43	Vegetation	0.29	26.74
44	Adverse weather	0.29	25.29
45	Adverse environment	0.00	0.02
46	Third party interference	0.53	34.82
47	Wildlife	0.12	6.18
48	Human error	0.07	0.72
49	Defective equipment	1.04	52.13
50	Cause unknown	0.54	24.38

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

	Main equipment involved	SAIFI	SAIDI
55	Subtransmission lines	0.00	0.86
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	0.61	139.19
69	Distribution cables (excluding LV)	0.01	0.87
60	Distribution other (excluding LV)	0.02	2.39

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

	Main equipment involved	SAIFI	SAIDI
64	Subtransmission lines	0.26	5.27
65	Subtransmission cables	0.01	0.19
66	Subtransmission other	0.08	1.21
67	Distribution lines (excluding LV)	2.01	142.28
68	Distribution cables (excluding LV)	0.04	1.04
69	Distribution other (excluding LV)	0.48	20.75

10(v): Fault Rate

	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
72	Subtransmission lines	13	891	1.46
73	Subtransmission cables	2	14	14.29
74	Subtransmission other	2		
75	Distribution lines (excluding LV)	645	6,722	9.60
76	Distribution cables (excluding LV)	7	159	4.40
77	Distribution other (excluding LV)	143		
78	**Total**	812		

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 Power Company Limited achieved a post-tax ROI of 3.17%, which is 1.23% below the 75th percentile estimate of post-tax WACC of 4.40% and a 3.50% vanilla ROI, which is 1.23% below the 75th percentile estimate of vanilla WACC of 4.73%.

No items were reclassified in the disclosure year.

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

Included in other regulated income is income related to the Mobile Substation and the Seaward Bush to Bluff 33kv distribution lines.

No items were reclassified in the disclosure year.

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

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

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

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

Box 3: Explanatory comment on merger and acquisition expenditure

There were no merger or acquisition expenses incurred in 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 calculation of the Regulatory Asset Base used the 31 March 2020 figure of $407,982k as the starting point with inflationary indexing over the year to 31 March 2021 plus additions less disposals, totalling $420,819k at 31 March 2021.

No items were reclassified.

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

The expenditure deductible but not in regulatory profit is the $148k cost of easements which is a tax deductible expense.

Income included in regulatory profit / (loss) before tax but not taxable is $6,184k of revaluations for the year.

There are no other permanent differences.

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

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

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

Temporary differences are the tax effect of the difference between the tax and disclosure treatment of capital contribution income.

Taxable Capital Contributions:	$	2,245
	$	2,245
Tax Rate:		28%
Temporary Differences	$	629

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

With the exception of some Business Support costs (which have been apportioned using the ABAA method vis a revenue proxy cost allocator), all other costs are directly attributable as they were either passed through by PowerNet Ltd as agents or were invoiced to The Power Company Ltd.

A proxy cost allocator is used as there is no direct relationship between not directly attributable business support costs and how they have been incurred.

No items were reclassifie

Asset allocation (Schedule 5e)

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

Box 8: Commentary on asset allocation

All network assets are directly attributable.

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 2.7.1(2).

Box 9: Explanation of capital expenditure for the disclosure year

The materiality threshold of programmes or projects identified during the disclosure year was set at $500k. Lower value projects with defined scope were included in the list for specific identification within categories.

No items were reclassified during the disclosure year.

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

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

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

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

Box 10: Explanation of capital expenditure for the disclosure year

Reactive and minor maintenance is performed on The Power Company Limited's transformers and lines and this is classified as refurbishment and renewal maintenance when the work performed is not material in relation to the overall value of the asset.

No items were reclassified during the disclosure year.

There was no material atypical expenditure disclosed in Schedule 6b.

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

No items were reclassified during the disclosure year. Refer to each classification under point 13 and 14 above.

The overall actual capex expenditure on network assets was 4% over budget.

System Growth:

- Overall spend was 11% over budget.
- Additional cost attributed to scope variation for Kennington Substation 2nd 33kV feeder project.
- Additional cost attributed to the installation of the mobile substation to limit outages during construction of the Gorge Substation upgrade project.
- The relocation costs of two 66kV ABS units on the Centre Bush to Mossburn line.

Asset Relocations:

- Overall spend was 73% under budget.
- Associated cost of the Fairlight regulator reallocation project transferred to the 22kV upgrade Athol to Kingston project.

Supply Quality:

- Overall spend was 26% under budget.
- Reduced Quality of supply events requiring capital related projects.

Reliability, Safety and Environment:

- 31% over budget.
- Increased emphasis on earth upgrades to improve network safety.
- Additional cost due to construction difficulties at Edendale substation for the internal arc protection upgrade project.

Operational Expenditure:
Total operational expenditure was 9% under budget.

Routine and corrective maintenance and inspection:

- 7% under budget.
- Lower defects identified during routine inspections.
- Technical and Distribution reactive maintenance are below budget as they are reactive in nature.
- Due to increase in capital earth upgrading there was a reduction in budget for earth testing

Asset replacement and renewal:

- 17% under budget
- Lower defects identified requiring replacement or refurbishment**.**

System Operations and Network support 36% under budget

- This is due an input error in the AMP. The actual budget was $2,659 giving an 8% variance which was mainly due to higher than budget customer compensation claims which are subject to an insurance claim.

Energy efficiency and demand management, reduction of energy losses

- EECA increased the funding of the Warm Homes project to 90% which resulted in less need for 3rd party funding.

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

Revenue of $56,526k is within budget with a 0% variance.

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

Due to its consumer ownership, The Power Company Ltd (TPCL) is not subject to Default Price-Quality Path (DPP) regulation. Nonetheless TPCL calculated SAIDI and SAIFI limits and targets to allow for the assessment of performance on a consistent basis with other non-exempt networks.

In accordance with the Issues Register for Electricity and Gas Information Disclosure (ID), issues 447 and 458, TPCL has calculated and disclosed normalised SAIDI and SAIFI consistent with the 2012 Electricity Distribution Business (EDB) ID Determination.

TPCL has disclosed a normalised SAIDI at 314.05 and normalised SAIFI at 3.53 for 2020/21. This compares with the 2019/20 year TPCL published ID Determination values for normalised SAIDI of 351.76 and normalised SAIFI of 4.09 for the 2019/20 year – meaning an improvement in performance compared with last year.

The total number of power interruptions on TPCL's network increased in 2020/21 in comparison to 2019/20. There was a significant increase in unplanned Class C interruptions, increasing from 629 to 812, with a number of the additional unplanned power interruptions taking more than three hours to be restored. Nonetheless the average duration of unplanned interruptions decreased across the year, and Class C SAIDI has decreased significantly.
The cause of Class C interruptions was relatively evenly spread across main causes, with only third party interference showing a relatively significant increase from the previous year.

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

The Power Company Limited insures its substations, network equipment and buildings.

- Substations and network equipment are insured for $182.36 million.

Lines and cables are not insured.

The Power Company Limited therefore "self-insures" but does not recognise the cost of self-insurance.

Amendments to previously disclosed information

18. In the box below, provide information about amendments to previously disclosed information disclosed in accordance with clause 2.12.1 in the last 7 years, including:

    18.1 a description of each error; and

    18.2 for each error, reference to the web address where the disclosure made in accordance with clause 2.12.1 is publicly disclosed.

Box 15: Disclosure of amendment to previously disclosed information

No amendments were disclosed.

SCHEDULE 14A MANDATORY EXPLANATORY NOTES ON FORECAST INFORMATION

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

1. This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

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

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

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

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

Inflationary assumptions were used to calculate the nominal prices in the forecast.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

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

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

Nominal Prices are based on publicly available New Zealand Treasury's economic forecast indicated in the Half Year Economic and Fiscal Update (HYEFU) report released in December 2019:

	2021	2022	2023	2024	2024
Inflator (CAPEX & OPEX)	2.0%	2.0%	2.0%	2.2%	2.2%

Forecasts are in line with the business plan projections and explanations outlined in the Asset Management Plan.

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

SADI/SAFI : The information has been prepared on a basis consistent with the previous year's disclosure and TPCL has recorded successive interruptions, originating from the same cause, as single interruptions.

Network reliability is compliant with quality requirements under DPP3, however there are inherent limitations in the ability of TPCL to collect and record the network reliability information required to be disclosed in Schedule 10 (i) to 10 (iv).

Network Discount: The Power Company Ltd now posts its annual discounts. This year is the first year the revenue has been shown net of the posted discount ($8,197). It has resulted in a reduction in the ROI measure from previous years.

APPENDICES

APPENDIX A:

Related Party Transactions:

Additional Information Disclosures

1. INTRODUCTION

For the purpose of meeting the 2021 Related Party Transaction reporting requirements, in accordance with section 2.3.6 of the Electricity Information Disclosure Determination 2012, (Consolidated in 2018), issued 3 April 2018.

The following information is provided in reference to and support of:

- **The Power Company Limited's Information Disclosure**, for the year ended 31 March 2021 - Schedule 5(b) Related party Transactions

2. INFORMATION DISCLOSURE REQUIREMENTS

The Related Party Transaction information disclosed on the following pages has been prepared in accordance with **Full Disclosure** requirements, due to the level of expenditure incurred by a related party on the The Power Company Limited (TPCL) network assets, being greater than $20 million for the year ending 31 March 2021.

Full Disclosure requires additional information be provided associated with related party transactions, including related party relationships, procurement policies & processes, application of these policies & processes and examples of market testing of transaction terms. The IM Determination require all related party transactions be valued at an 'arm's length' basis. Under Full Disclosure, an independent appraiser is required to assess whether the related party transactions comply with an 'arm's length' valuation criteria.

This information is also subject to the Information Disclosure assurance opinion and Director Certification.

3. RELATED PARTY RELATIONSHIPS

In accordance with Input Methodology rules, a Related Party Transaction occurs when a regulated supplier transacts with an entity which is related to it by common shareholding or other common control.

The Power Company Limited has an interest in the PowerNet Limited Joint Venture, the OtagoNet Joint Venture, Electricity Southland Limited, and the Southern Generation Limited Partnership through their wholly owned subsidiary company Last Tango Limited.

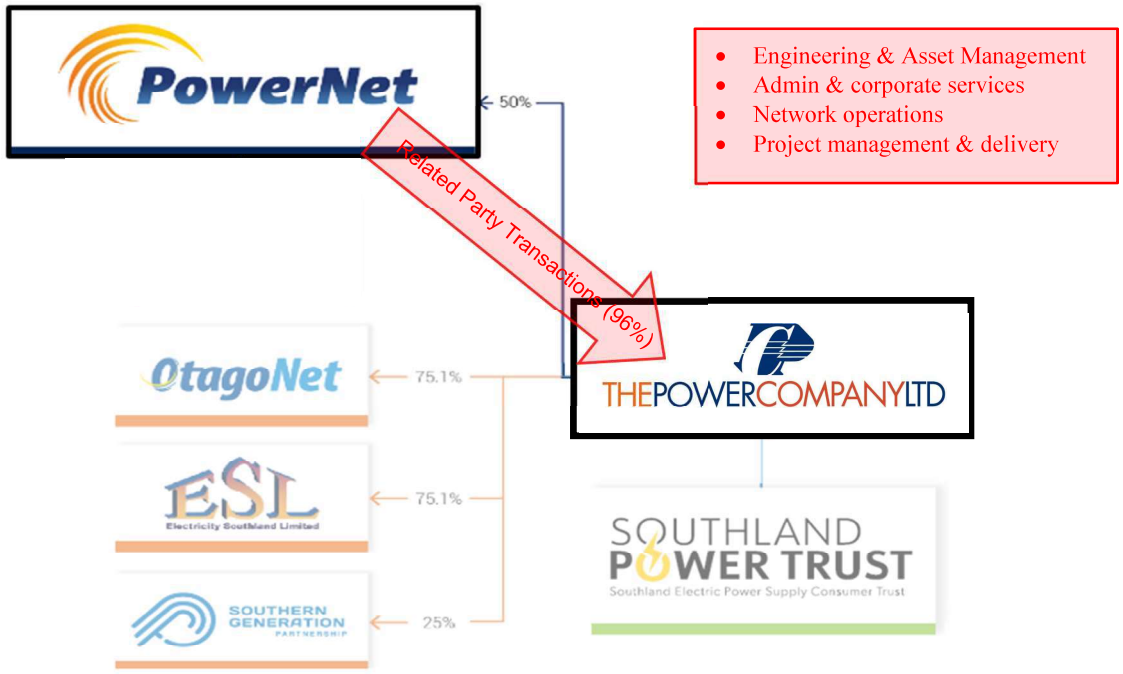
During the year ending 31 March 2021, TPCL had related party transactions with the following entities:

- Goods and services provided by – PowerNet Limited, OtagoNet Joint Venture;
- Goods and services provided to – PowerNet Limited, OtagoNet Joint Venture.

Company Structure

The Power Company Limited (TPCL) is wholly-owned by the Southland Electric Power Supply Consumer Trust ("Southland Power Trust"). The following diagrams illustrate TPCL's ownership interests in PowerNet and other related entities, and the nature of related party transaction work undertaken.

ID Determination reference: 2.3.8



a. **PowerNet Limited**

TPCL holds a 50% shareholding in electricity network management company PowerNet Limited. PowerNet provides a range of field contracting, asset management, system control and business services to TPCL. The value of regulatory related goods and services provided to TPCL by PowerNet, for the year ended 31 March 2021, is categorised as follows:

		($000)
Operating Expenditure:		
i.	Service interruptions and emergencies	3,587
ii.	Vegetation management	1,564
iii.	Routine and corrective maintenance and inspection	4,251
iv.	Asset replacement and renewal (Opex)	662
v.	System operations and network support	2,030
vi.	Business support	3,053
Capital Expenditure:		
vii.	Consumer connection	2,829
viii.	System growth	4,012
ix.	Asset replacement and renewal (Capex)	13,644
x.	Asset relocations	118
xi.	Quality of supply	356
xii.	Other reliability, safety and environment	4,174
	Total PowerNet Related Party expenditure	**40,280**

In the year to 31 March 2021, PowerNet provided 100% of the TPCL Lines Business Capital Expenditure, and 90% of all Operating Expenditure. The high percentage of related party transactions relative to total expenditure is due to PowerNet operating under a Network Management Agreement (NMA) with TPCL, in the form of an "agency agreement".

Services provided under the agreement include:

- Electricity distribution field services
- System control services
- Project management of capital and maintenance work
- Faults restoration and stand by (on call) arrangements
- Asset management for TPCL and metering,
- Heath, Safety and Environment management
- Business support, IT support and human resources
- Corporate, finance and commercial services

b. **OtagoNet Joint Venture**

TPCL has a 75.1% ownership interest in the OtagoNet Joint Venture electricity distribution network (OJV), based in coastal and inland Otago, via a joint venture arrangement with Electricity Invercargill Ltd.

During the year, TPCL received $60,000 from OJV relating to the rental of specialised substation equipment, otherwise there were no other related party transactions between OJV and TPCL during the reporting period.

Network Management Agreement ('Agency Agreement')

TPCL incurs 100% of its capital expenditure and the majority of its operating costs for its electricity distribution and metering businesses from PowerNet, in accordance with the explicit terms and conditions of the PowerNet Network Management Agreement (NMA).

While TPCL owns the Network Assets and provides electricity distribution services through their network across Southland (excluding parts of Invercargill city and the Bluff township area), under the agreement PowerNet will manage the network assets, will carry out an agreed capital works programme, has the exclusive right to provide line function services, and will provide the business administration services on behalf of TPCL.

PowerNet was established in 1994 to extract operational efficiencies from the merger of field work management, asset management and office based functions performed by TPCL and Electricity Invercargill Limited (EIL). In 1993, there were two autonomous lines companies in Southland (TPCL and EIL). Each had a separate staff, management and Board of Directors, and each had a different ownership structure. Directors of both companies recognised there would be significant economies of scale benefits if there were a single lines company covering the area. Due to different ownership a single lines company was not possible, however a single network management entity was a viable option.

The ongoing drive for efficiency by merging operations and achieving scale was recently identified by the Government Pricing Review and the terms of reference required investigation into the "PowerNet model" as the review looked at how other EDBs could potentially do the same.

PowerNet charges Agency Fees to the EDB's and metering businesses it manages under the NMA's. These charges recover costs incurred in the performance of the system control services, asset management, corporate, finance and commercial services.

These costs are charged to customers based on a cost allocation methodology applied within PowerNet. The allocation is based on various allocation drivers, including field operating orders, staff numbers, EDB asset size, EDB customers and a departmental assessment of indirect labour time splits. The allocation forms the basis of costs recovered from:

- the agency fee to be charged to the EDB's and metering businesses and
- the capital mark-up to recover costs allocated to EDB and meter capital projects

An independent review in 2018 of the allocation methodology ensured all parties that are charged agency and other fees by PowerNet are treated consistently and appropriately for each party.

4. PROCUREMENT POLICY

ID Determination 2.3.10 & 2.3.11

Under the Network Management Agreement (NMA), TPCL has contracted PowerNet to manage the operational functions, maintain the network assets, implement the Asset Management Plan, and provide business management services, and hence, act on behalf of TPCL when project managing and purchasing required goods and services in the course of carrying out the responsibilities of the Agreement. Due to the special relationship with TPCL, the PowerNet **Procurement Policy** (including the **Procurement Strategy**), is implied as also being the procurement practices followed by TPCL. Therefore, the Procurement Policy and Procurement Strategy provided for the purpose of this information disclosure, are as provided by PowerNet.

The PowerNet **Procurement Policy**, sets the procurement principles for staff to follow when engaging suppliers or sourcing goods and services. The PowerNet **Procurement Strategy** provides guidance on practices and processes for the business to follow when engaging with the suppliers of goods and services, and anywhere the business commits to a purchase obligation.

These documents are to ensure appropriate practices and controls are followed, and to make sure the best value and quality is achieved for the business and stakeholders.

5. APPLICATION OF PROCUREMENT POLICY

ID Determination 2.3.12 (1)

As noted above, the procurement policy and processes adopted by TPCL are based on the PowerNet Procurement Policy and Strategy (FNPO-035). Under the NMA, PowerNet is responsible for sourcing all materials and services required to maintain the TPCL network assets and project manage the replacement or development of new assets, on behalf of TPCL. PowerNet recovers this expenditure through charging TPCL for capital and maintenance work, and through applying an agency fee for recovering a share of the associated business services costs.

The **Procurement Policy** adopted by TPCL puts emphasis on making decisions in the interest of an asset's lifecycle cost – in particular, capital versus maintenance decisions; considerations when sourcing labour, materials and equipment, and engaging customers for external party works.

The **Procurement Strategy** document covers in detail the applicable processes and practices of purchasing goods and services.

While PowerNet is a related party of TPCL for reporting purposes, the NMA is a commercial arrangement and is structured as two separate legal entities, with different ownership interests, operating on an 'arms-length' basis.

Planning

Adequate planning is an important part of the TPCL procurement process. Each year the PowerNet Network Asset Engineers prepare the TPCL Asset Management Plan (AMP) a strategic, long-term view of the Network capabilities and constraints. The AMP provides an internal asset management framework for TPCL's network, including the Annual Works Programme (AWP), detailing the capital and operation expenditure (asset maintenance, replacement and/or development) required. The AMP is reviewed and approved by the TPCL board, prior to the PowerNet Engineers' and Project Managers' developing the AWP, as a key part of the annual business planning process. The AWP translates projects identified in the AMP into categorised work streams with detailed assumptions regarding the timing, materials and resources needed to complete the work, resulting in a more refined cost estimate, for Project Managers' to apply. The AMP is a 10 year view, whilst the AWP focuses on the upcoming 12 month period. In certain cases with large forecasted spend, a project business case is required in advance, for separate Board consideration and approval. The finalised AWP expenditure is included within the TPCL annual business plan approval process.

Project Manager's are assigned to implement the identified projects, within the guidelines of the project budget, and are responsible for managing the resources and making sure the project is completed to required standard.

Where required for high cost projects, or if specialised skills or equipment are required, a 'Request for Tender' process may be undertaken, to provide an indication of market supplier interest and greater certainty of project costs. The PowerNet Tendering Policy provides the steps that are to be followed when work is tendered. The decision to undertake a Tender process will be determined during the project planning phase.

Goods and services will be procured within approved budgets, with any exceptions requiring approval from a Senior Leader or Chief Executive Officer, in line with the financial authority limits. Written cost estimates or quotes are required from Suppliers depending on the value or nature of the job to manage cost expectations.

Resourcing

Having the combined network management of TPCL, EIL, OJV and ESL, gives PowerNet a stronger position to negotiation more favourable competitive prices for goods and services, through the greater purchasing volumes and activity, than would otherwise be possible by TPCL alone. A supplier agreement with Corys Electrical makes it possible to source the required specialised electrical materials at near wholesale prices, and the volume of work enables priority response and competitively low prices from many external service providers.

The market of available suppliers of high voltage electrical work in Southland is very small, and in some cases for specialised tasks, non-existent. PowerNet has learnt over the past 25 years through different operating models (from operating with internal field crews, to operating with fully outsourced labour arrangements), the most effective, efficient and reliable outcome for getting TPCL's Works Programme projects completed in a timely manner, to the required standard, is to secure required skills internally, and to apply these staff as needed, across the different networks PowerNet manages. In many cases, external contractors are still required for large projects or technically challenging tasks, where resources can be outsourced (eg. approximately 24% of the TPCL Capital project expenditure during the 2020/21 year is non-PowerNet labour cost). Having a team of experienced Line Mechanics and high voltage Technicians enables PowerNet to provide an effective faults response service, reducing the impact on customers of unplanned outages, and helping the TPCL network meet its regulatory outage performance targets (SAIDI & SAIFI targets). For this reason, in many cases for TPCL network asset maintenance tasks, the work is allocated to PowerNet internal labour teams with the appropriate skills and equipment.

While the project resources and materials required are planned by network engineers within the PowerNet Asset Management team, the selection of the Suppliers to provide the work is a responsibility of the respective Project Manager. In making the selection, the Project Manager is mindful of making decisions based on the best outcome on behalf of the network – and so, to protect the value and reliability of the Network Assets, the Project Manager selects the materials and scopes the design to meet the required network design standard. Outsourcing is considered for each element of the project if appropriate, and market testing performed where uncertainties exist in cost or difficulty. This selection process may not always result in the cheapest or easiest short-term option being applied, with decisions made to make sure the outcome is of a high quality and reliable standard, in the best long-term interests of the customers and stakeholders.

Materials are sourced by Corys Electrical who can provide a range of options for the Project Manager to select from, at competitively low prices in accordance with conditions in the PowerNet supply agreement.

Suitable Contractors must be capable of meeting the operating and health & safety standards of PowerNet, and there are specific controls to check new applicants, to make sure they have completed the requirements (eg. PreQual health & safety assessment) are reputable before allowing them to be selected.

Cost of assets, goods or services from Related Party

The costs PowerNet incurs undertaking the responsibilities of managing TPCL's network assets are charged to TPCL each month. Agreed charges are included within the Network Management Agreement, including monthly progress invoices in relation to the Annual Works Programme project activity expenditure. In return for the management of the network assets and related business support costs, PowerNet charges TPCL an Agency fee, and applies an internal commercial mark-up to recover its operating costs and enable a modest commercial profit.

6. PURCHASES REQUIRED FROM A RELATED PARTY

ID Determination 2.3.12 (2)

Activities for which TPCL customers are required to use PowerNet (Related Party) in relation to electricity distribution services are:

Fault Response and Reactive Maintenance

Under the Network Management Agreement, PowerNet is responsible for maintaining the TPCL Network Assets in good operational order, and in an overall standard equal or better to the initial condition. Returning power to consumers safely and quickly, following a fault or outage event, is an important requirement and performance measure for TPCL.

When a customer reports an outage, the PowerNet System Control operator will notify PowerNet staff to respond, (if they haven't done so already if an alarm system has been activated).

PowerNet provides on-call line mechanics and technicians, located across the Southland region, able to respond in a very short period of time to a fault call out, to provide a reliable and efficient fault response service, and minimise the impact of a power outage on TPCL network customers. Without these remote depot locations the duration (SAIDI) of outages on the TPCL network would be adversely affected. Having skilled labour, trained to the network accepted standard and practices, located at various depots across the network, and having appropriate tools and equipment capable of resolving an outage safely and quickly, is a key reason why PowerNet provides fault response services internally, rather than outsourcing.

New Connections

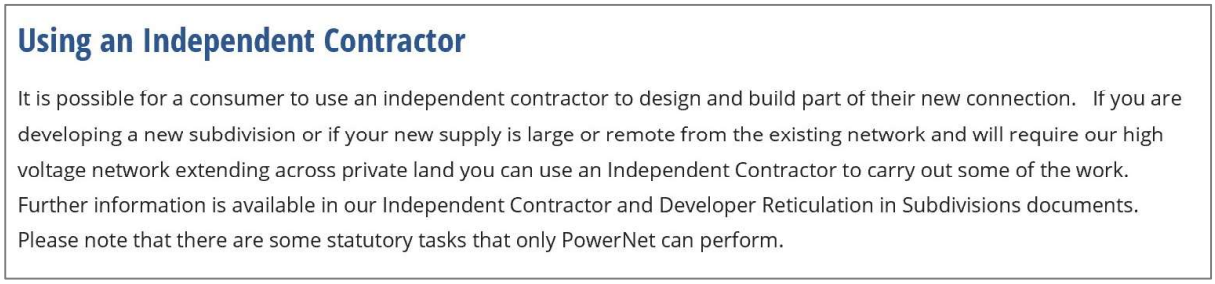
The process for requesting a new connection or capacity upgrade on the TPCL network is managed by the PowerNet Distribution team (PowerNet policy FNPO-025 Commercial Terms for New and Altered Customer Connections, or "Connections" policy). This is essential to maintain a consistent design specification standard for the TPCL network assets.

As highlighted in the Connections policy, depending on the nature of the customer work required, the Network will likely be required to manage parts of this work, especially where the work involves network equipment being installed or connection being made to Network assets. For high voltage lines installation (11kVA and above), requiring road side access, the Utilities Access Act 2010 controls who has the authorisation to operate in this space, and restricts the access to only approved utility companies. Hence, PowerNet, under the NMA, manages the construction of lines or installation of network equipment along road-sides on behalf of TPCL, or where special easements are required across private land. However, low voltage work on private land is the responsibility of the property owner.

An application must be completed by the customer for the PowerNet Connections team to review and provide an explanation of requirements relating to the work, and any associated costs (in the form of a letter of quotation). The quote must be accepted by the customer before PowerNet will begin any work on behalf of the Network.

If PowerNet are required to undertake construction or installation work, the Project Manager will evaluate what resources are required, and who can do the work. This work may be contracted to an external supplier however due to the small number of high voltage contractors available in Southland, this work is often undertaken by the PowerNet Distribution field staff.

The new connection process and responsibilities are explained on the PowerNet website, where details are provided for Customers to use an independent contractor:
https://powernet.co.nz/your-power-supply/getting-connected/



Using an Independent Contractor

It is possible for a consumer to use an independent contractor to design and build part of their new connection. If you are developing a new subdivision or if your new supply is large or remote from the existing network and will require our high voltage network extending across private land you can use an Independent Contractor to carry out some of the work. Further information is available in our Independent Contractor and Developer Reticulation in Subdivisions documents. Please note that there are some statutory tasks that only PowerNet can perform.

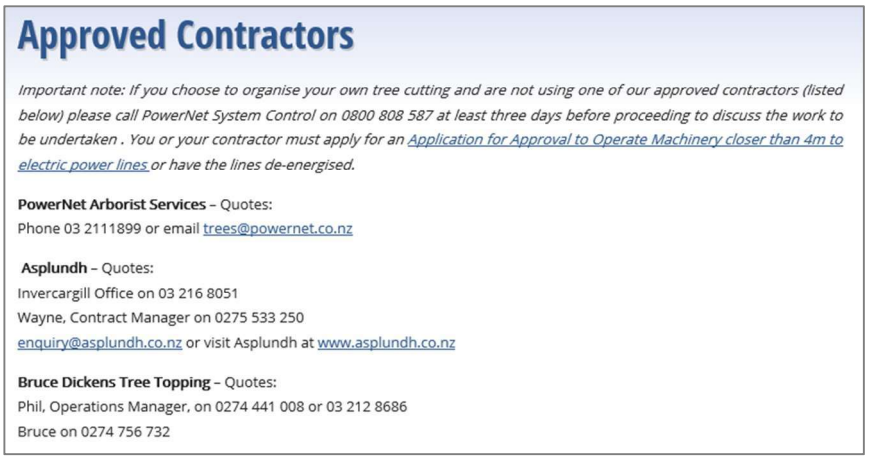
Arborist/Tree Management

PowerNet is responsible for vegetation management on the TPCL network, in accordance with the Network Management Agreement. Due to the large, mainly rural, area of the TPCL network, PowerNet has a supplier agreement with network approved external contractors, to undertake the trimming and cutting of trees and vegetation where required. Arborist crews inspect the network lines and identify areas of risk where trees are growing inside the legal 'growth limit zone'. In these circumstances, the property owner is notified of their obligations by issuing a 'Tree Cut/Trim Notice'. Under the Tree regulations and TPCL's tree management process – the first cut or trim is at the cost of TPCL (via PowerNet managed external contractor). Following the first cut, the tree owner is responsible for keeping the tree(s) clear of the 'Growth Limit Zone' around TPCL's power lines and equipment.

PowerNet provides advice on its website (https://powernet.co.nz/services/trees/) relating to tree regulations and owner's responsibilities, and offers a list of network approved contractors who can undertake tree cutting services on the TPCL network for the owner – making it clear owners are not obliged to use PowerNet's services.

The following content can be found on the PowerNet web page, under the services offered:

https://powernet.co.nz/services/trees/approved-contractors/



Approved Contractors

Important note: If you choose to organise your own tree cutting and are not using one of our approved contractors (listed below) please call PowerNet System Control on 0800 808 587 at least three days before proceeding to discuss the work to be undertaken . You or your contractor must apply for an Application for Approval to Operate Machinery closer than 4m to electric power lines or have the lines de-energised.

PowerNet Arborist Services – Quotes:
Phone 03 2111899 or email trees@powernet.co.nz

Asplundh – Quotes:
Invercargill Office on 03 216 8051
Wayne, Contract Manager on 0275 533 250
enquiry@asplundh.co.nz or visit Asplundh at www.asplundh.co.nz

Bruce Dickens Tree Topping – Quotes:
Phil, Operations Manager, on 0274 441 008 or 03 212 8686
Bruce on 0274 756 732

The Tree Cut/Trim Notice is issued to the tree owner, indicating available options for the work required. The tree owner responds with their preference – either to manage their own contractor, or engage PowerNet. If PowerNet is selected to do this work in TPCL's network area, instructions are provided to Asplundh to undertake the required work.

7. PROCUREMENT REPRESENTATIVE EXAMPLES

ID Determination 2.3.12 (3)

TPCL requires a range of services from PowerNet to manage the Network operations. These services may often have very different characteristics and may involve a different procurement process, to suit the work being undertaken. The following list illustrates the categories of transactions with different procurement processes:

i. **Major Construction Projects (System Growth/Asset Replacement & Renewal)**
Significant large-scale projects are managed by the PowerNet Asset Management – Major Projects team. These projects are often long term (greater than 12 months), complex in design, and greater than $1m in cost, with additional procurement requirements. Due to the large amount of dedicated resource and long period of time required, these projects are often subcontracted by PowerNet.

EXAMPLE: Kennington Second 33kV Line Project
The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for a 'Major Project' to upgrade aging assets.

Project Name:	Kennington 2nd 33kV Line Project
Project Date:	June 2019 – March 2021
Project Number:	10749
Project Expenditure:	$ 451,000 External labour & materials $ 166,000 PowerNet services --- $ 617,000 (2020/21 Project Expenditure) $ 1,148,000 (2019-2020) --- $ 1,765,000 (Total Project Expenditure)
Project Classification:	System Growth (Capital Expenditure)
Project Manager:	PowerNet Ltd
Subcontractors:	Decom Ltd

A second 33kV supply was established from the Invercargill-to-Gorge Road 33kV overhead line to Kennington Substation, to provide greater security should the current single 33kV supply to Kennington experience an outage for customers connected to Kennington Substation and surrounding area.

A review of available resources highlighted that due to the size and technical challenges with this project, and in the interest of a timely construction, it was decided to outsource the design and majority of the construction to external suppliers.

Market Testing: The majority of the Kennington Substation Upgrade project cost was outsourced by PowerNet. An external contractor completed the 33kV cable trenching and installation, and materials provided through the Corys supply agreement. The PowerNet project management and internal labour cost is benchmarked to local market rates.

ii. New Connection / Capacity Upgrade (System Growth)

New connections and capacity upgrades are generally customer driven, whether it be for a new property, or expansion of an existing property. Project size can range from a small connection of a newly built house, to the construction of a new manufacturing plant.

Characteristics:	Requirement:
- Customer driven enquiries. - Small sized projects. - Planning is high level. - Quote provided. - Customer contribution received. - Internal Distribution staff undertake work on the Networks. - External qualified electricians are given opportunity to undertake customer work, directly engaged by customer.	❖ General amount approved in Asset Management Plan. ❖ Cost estimate - Maximo work order ❖ Payment – Purchase Order

The procurement of goods and services for this type of work follows the same PowerNet procurement processes for a general construction project, only this work is more heavily influenced by a customer need rather than a network need. The PowerNet New Connection policy governs the requirements for this work.

EXAMPLE: New House Connection (November 2020)

The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for a 'New Connection' to the TPCL network:

Project Name:	New House Connection (TPCL Works programme)
Completion Date:	November 2020
Project Number:	CC 357412 / 357411
Project Expenditure:	$ 664 External materials $ 2,064 PowerNet services ---------- $ 2,728 Total Cost (2020/21)
Project Classification:	System Growth (Capital Expenditure)
Project Manager:	PowerNet Ltd
Construction:	PowerNet - Distribution Team
Subcontractors:	N/a

Project CC357412 new connection application was received by the PowerNet 'Connection' team staff during mid-2020. The customer had requested a new 15kVA single phase connection to be installed from an existing pole, for a new house.

Market Testing: PowerNet benchmarked internal labour rates favourably against similar Line Mechanic or Technician roles from other available external suppliers over the 2019-2021 period. Of the $3.7M capital expenditure spent on New Connections and Capacity Upgrades, 57% of this cost related to external labour and materials. The materials sourced through Corys Electrical supply agreement includes a range of contractual mechanisms to ensure efficient prices are being provided to PowerNet.

iii. Distribution & Technical Projects (Asset Replacement and Renewal)

Asset Replacement and Renewal projects are generally driven by internal asset condition and monitoring assessments, performed periodically by PowerNet staff on TPCL network assets. Depending on the nature of the work, this could be a small scale project relating to the replacement of an 11kV Line Pole (eg. 'Red Tag Pole') managed by the PowerNet Distribution Team, or a larger technical project (eg. 500kV transformer replacement or substation upgrade project) managed by the PowerNet Technicians team.

Team:	Characteristics:	Requirement:
Distribution	- Emergency fault repair work. - Network Lines repair and development. - Internal Distribution staff undertake work on Networks. - External contractors may be subcontracted by PowerNet to assist with this work.	❖ Planned - Asset Management Plan ❖ Project managed - Maximo work orders ❖ Payment – Purchase Order
Team:	**Characteristics:**	**Requirement:**
Technical Projects	- Technical specialised work. - Internal Technician staff undertake work on Networks. - External contractors with necessary skills may be subcontracted by PowerNet to assist with this work.	❖ Planned - Asset Management Plan ❖ May require Business Case approval ❖ Project managed - Maximo work order ❖ Payment – Purchase Order

EXAMPLE: ABS Replacement (Rural Southland – December 2020)

The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for a 'Technical' project for the TPCL network:

Project Name:	Replace & Relocate Wards Rd ABS (Longwoods)
Completion Date:	14/12/20
Project Number:	CC 360993
Project Expenditure:	$ 8,319 External labour & materials $ 14,311 PowerNet services (incl. mark-up) ---------- $ 22,630 Total Cost (2020/21)
Regulatory Classification:	Asset Replacement & Renewal (Capital Expenditure)
Project Manager:	PowerNet
Construction:	PowerNet - Distribution
Subcontractors:	Traffic Management Services

PowerNet undertook Project CC360993 to replace an Air Break Switch on an 11kV Feeder near Riverton, as it was at the end of its useful life. This work was identified through PowerNet asset inspection and condition monitoring, and was deemed essential to maintain security of supply within the area. A PowerNet Project Manager was assigned to plan and oversee the work. Consideration is given to the timing, to make sure resources are available, and to minimise the impact of a power outage to effected TPCL customers. PowerNet was assigned to undertake the work, being able to provide the skilled distribution services and equipment required. Materials were sourced through the Corys Supply Agreement.

Market Testing: The prices charged by PowerNet have been benchmarked against similar roles from other external Suppliers utilised during 2019-2021. The materials sourced through Corys Electrical supply agreement includes a range of contractual mechanisms to ensure efficient prices are being provided to PowerNet.

iv. Faults Response (Service interruptions and emergencies)

Fault response is a key service provided by PowerNet. Minimising power outage time of network faults, and minimising the number of customers impacted, is an important performance measure of TPCL network. As noted above, PowerNet Line Mechanics and Technicians provide an on-call service, able to respond quickly to an unplanned outage or event. PowerNet Line Mechanic crews are based in depots located across the Southland and Otago regions for quick response to fault call-outs and to minimise travel time across the network.

Market Testing: Market prices assumed where PowerNet is applying the same labour rates as applied across other spend categories which are more commonly market tested. The prices charged by PowerNet have been benchmarked against similar Line Mechanic or Technician roles from other external Suppliers utilised during 2019-2021.

v. Arborist Work (Vegetation Management)

Tree management costs are driven by work required to comply with Government regulations for proximity of branches and vegetation to power lines. TPCL is responsible for encouraging property owners to comply with the regulations. PowerNet manages this service on behalf of TPCL. Inspectors identify hazards, liaise with landowners and issue Cut/Trim notices to the landowner as required, and arrange for a TPCL external contractor to undertake the work.

Characteristics:	Requirement:
- Network vegetation management. - Some emergency fault repair work. - Internal Distribution staff undertake work on Networks. - External contractors subcontracted by PowerNet to complete this work.	❖ Planned - Asset Management Plan ❖ Project managed - Maximo work orders ❖ Payment – Purchase Order

EXAMPLE: Vegetation Management (Rural Southland – October 2020)

The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for Vegetation Management expenditure on TPCL network:

Project Name:	Vegetation Control (TPCL Works Programme)
Project Completion Date:	October 2020
Project Number:	CC 204213
Total Expenditure:	$ 1,270 External labour & materials $ 127 PowerNet services --------- $ 1,397 (2020/21)
Regulatory Classification:	Vegetation Management (Maintenance Expenditure)
Project Manager:	PowerNet Ltd
Subcontractors:	Asplundh Ltd

PowerNet became aware of trees growing within the permitable distance of power lines during a routine Lines inspection in the rural Southland area. Details of the location and work required

('dismantle trees to clear 11kV powerlines') were noted on the PowerNet Cut/Trim Notice (CTN204213), and provided to a network approved external contractor to provide a quote. PowerNet allocates this work based on capability and availability between the two network approved external contractors in Southland.

As this example was a 'first cut' notification, the cost of the work is charged on-charged to TPCL, rather than the property owner.

Market Testing: While PowerNet manages vegetation control work across TPCL network, almost all work is outsourced to external contractors, under a preferred supplier agreement, with set prices for different components of work undertaken. These prices are reviewed and agreed periodically by PowerNet, however, and are benchmarked where possible.

vi. Routine and Corrective Maintenance

Routine inspections and planned maintenance are important for maximising the useful life of TPCL network assets and equipment. PowerNet Network Asset Engineers undertake annual inspection work to identify assets that require maintenance.

EXAMPLE: Circuit Breaker Maintenance

The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for a 'Technical' planned maintenance project for the TPCL network:

Project Name:	MAK – 11kv Feeder CB Maintenance
Completion Date:	September 2020
Project Number:	358775
Project Expenditure:	$ 3,323 External material $ 11,916 PowerNet services (incl. mark-up) ---------- $ 15,239 Total Cost (2020/21)
Regulatory Classification:	Technical Planned Maintenance (Technical Maintenance)
Project Manager:	PowerNet Ltd
Inspection:	PowerNet - Technicians Team

PowerNet is tasked with the planned maintenance and inspection of TPCL Network assets. The inspections are carried out in line with manufacturer's recommendations.

Market Testing: Market prices assumed where PowerNet is applying the same labour rates as applied across other spend categories which are more commonly market tested. The prices charged by PowerNet have been benchmarked against similar Line Mechanic or Technician roles from other external Suppliers utilised during 2019-2021.

vii. **Business Services (Opex)**

Administration processes and systems associated with running TPCL network are managed by PowerNet support services teams (eg. Network Assets, Operations, Finance, HSE). A share of these costs are charged to TPCL by way of an Agency fee, which would otherwise be directly incurred by TPCL, if there was no 'Agency Agreement' (or NMA) in place with PowerNet.

Market Testing: Market testing the provision of business services is very difficult due to the lack of comparability available. However, the benefits of TPCL sharing the cost of running these management and administration systems with other EDB's EIL and OJV (economy of scale benefits), was recognised in an independent benchmarking exercise in 2018 of PowerNet business and network support services to TPCL/EIL/OJV, against other equivalent sized EDB's on a cost per ICP basis. The findings of the review rated TPCL favourably against similar sized EDB's in the same peer group.

APPENDIX B:

MAP OF NETWORK EXPENDITURE AND CONSTRAINTS

ID Determination 2.3.13 - 2.3.16

Regulatory requirements

- Electricity Distribution Information Disclosure Amendments Determination 2017 (NZCC 33), clauses 2.3.13 to 2.3.16.
- Input methodologies review – related party transactions final decision and determinations guidance 21 December 2017, table 5.1 (copied below, refer to ID for precise requirements).

The purpose of this section is to identify on a map the anticipated network expenditure and network constraints in accordance with the TPCL network 2021-2031 Asset Management Plan.

TPCL - 10 largest forecast Network Operating Expenditure projects (Maintenance)

- Clause 2.3.13(1), 2.3.14(1) and (2).

The 10 largest forecast Operating Expenditure projects in the 2021-2031 Asset Management Plan for TPCL network are explained below, and indicated on the Network map above where relative to a single area:

1. Incident Response – Distribution - $28.41m

   Provision is made for staff, plant and resources to be ready for lines faults and emergencies. Fault staff respond to make the area safe, isolate the faulty equipment or network section and undertake repairs to restore supply to all customers.

2. Technical Planned – Maintenance - $12.76m

   Routine inspection and testing of assets at zone substations. Includes such things as oil DGA, breakdown, moisture and acidity, operation counts, protection testing etc. Also covers responses to maintenance triggers, such as oil processing or recalibration of relays.

3. Distribution Rountine Inspections - $12.65 m

   Five yearly network inspections (20% inspected annually), other routine tests and minor maintenance works on distribution assets.

4. Vegetation Management - $9.50m

   Annual tree trimming in the vicinity of the overhead network to prevent contact with lines, maintaining network reliability.

5. General Distribution Refurbishment -$5.75m

   Refurbishment works for plant other than that located at distribution substations which won't impact on the valuation of the distribution asset. Covers items like cross-arms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.

6. Technical Routine Inspections - $5.57m

   Routine inspection and testing of assets at zone substations. Includes such things as partial discharge surveys on switchgear, oil DGA, breakdown, moisture and acidity, operation counts, protection testing etc. Also covers responses to maintenance triggers, such as oil processing or recalibration of relays.

7. Distribution Earthing maintenance - $3.67m

   Routine testing of earthing assets and connections to ensure safety and functional requirements are completed for all earths on a five yearly basis.

8. Technical Incident Reponses - $3.58m

   Provision is made for staff, plant and resources to be ready for substation faults and emergencies. Fault staff respond to make the area safe, isolate the faulty equipment or network section and undertake repairs to restore supply to all customers.

9. Distribution Reactive Maintenance - $3.10m

   Follow up work in the distribution area after the initial incident response work is complete.

10. Vegetation Inspection and Admin- $2.65m

    Routine inspection of overhead lines to identify trees in the vicinity of the overhead network to prevent contact with lines, maintaining network reliability and safety. Administration of the follow-up tree trimming notices issued.

Further detail relating to TPCL network Operating Expenditure in a table at the end of this section.

Please Note: All of these projects -

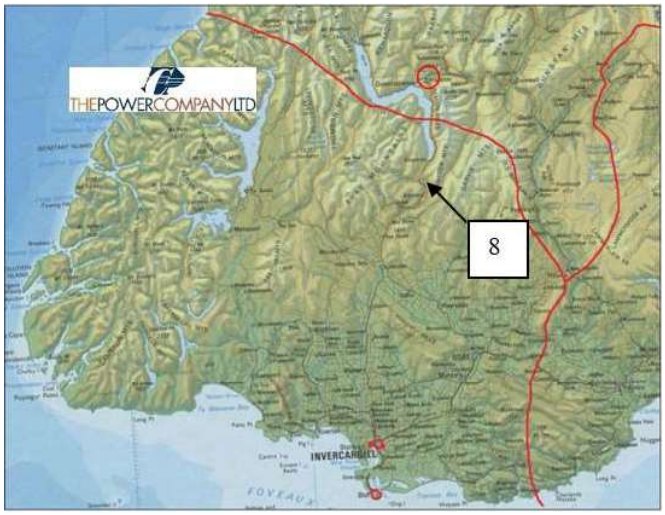
- Are network wide (apply to entire area as shown on map below).
- Have a contract in place that is with PowerNet Limited through a network management agreement (related party).
- Are forecast to require the supply of assets/goods or services by PowerNet Limited (related party).

Possible future constraints related to TPCL network Operating Expenditure projects:

There are no identified constraints impacting the network Operating Expenditure budget. All costs are driven by network maintenance requirements and inspection programming.

TPCL - 10 largest forecast Network Capital Expenditure projects

- Clause 2.3.13(2), 2.3.14(1) and (2).



The 10 largest forecast Capital Expenditure projects in the 2020-2030 Asset Management Plan for TPCL network are explained below, and indicated on the Network map above where relative to a single area:

1. 11kV Line Replacement - $61.10m

   Scheduled for every year, the on-going replacements of 11kV line assets. These are identified through routine inspection. As work is planned based on feeders, this renewal and refurbishment covers distribution lines, cables, dropouts and ABS's. This budget also covers Red tagged pole replacement, Increasing road crossing height, Minor distribution renewals and upgrades.

2. Condition Based Asset Replacements - $25.69m

   Scheduled for 2027 – 2030, these projects include the replacement or refurbishment of equipment arising outside the current asset management plan. Typically used for assets where performance and reliability deteriorates faster than expected and needs to be corrected in the medium term. This will typically occur on assets outside the planned asset management program and where general maintenance have limited success.

   Typical identification in the short to medium term with implementation from six to ten years.

3. Earth Upgrades - $18.82m

   Scheduled for every year, ineffective earthing may create hazardous voltage on and around network equipment (Earth Potential Rise; EPR) during fault situations, affecting safety for the public and for staff. Poor earthing can also prevent protection systems from operating correctly, which may affect the safety and reliability of the network. Routine earth site inspection and testing identifies any sites that require upgrades. Determining the most appropriate upgrade option can be quite complex, but the ultimate aim is to find the optimal trade-off between cost and risk reduction. Upgrade works may include additional earthing rods or banks, replacement of surface material (asphalt or gravel) to reduce risk, and installation of insulating fences or fence sections to reduce the risk of transfer to adjacent conductive fences.

4. Unspecified System Growth Projects - $17.19m

   Scheduled for 2021 – 2035, the projects budget is an estimate of costs for projects that are as yet unknown but from experience are considered likely to arise in the longer term (six to ten year time frame). Certainty for these estimates is obviously quite low. Potential large growth increases in

Athol, Lumsden and Riversdale areas could result in the extension and upgrade of the subtransmission network and conversion of some affected distribution networks to 22kV.

5. ABS Renewals - $11.80m

   Scheduled until 2030, when inspection indicates deterioration is sufficient enough to lose confidence in continued reliable operation and maintenance is considered uneconomic.

6. Customer Connections (≤ 20kVA) - $10.62m

   Scheduled for every year, planning for new connections uses averages based on historical trending, modified by any local knowledge if appropriate however customer requirements are generally unpredictable and quite variable. Larger customers especially, which have the greatest effect on the network, tend not to disclose their intentions until connection is required (perhaps trying to avoid alerting competitors to commercial opportunities), so cannot be easily planned for in advance. Various options are considered generally to determine the least cost option for providing the new connection. Work required depends on the customer's location relative to existing network and the capacity of that network to supply the additional load. This can range from a simple LV connection at a fuse in a distribution pillar box at the customer's property boundary, to upgrade of LV cables or replacement of overhead lines with cables of greater rating, up to requirement for a new transformer site with associated 11kV extension if required.

7. Transformer Replacement - $10.54m

   Scheduled for every year, the on-going replacements of distribution transformers which are generally identified during distribution inspections and targeted inspections based on age.

8. 22kV Upgrade Athol-Kingston - $6.84m

   Scheduled for 2021-2024, load growth occurring in and around Kingston township is forecast to exceed the ability of the 11kV network to supply adequate voltage. There is an existing 11kV regulator at Fairlight and an additional regulator on the feeder from Athol to Kingston is not desirable. This project will mole-plough a 22kV cable from Athol to Kingston which will initially operate at 11kV. After load growth exceeds the ability of 11kV to supply Kingston, Athol substation can be converted to 22kV supply with autotransformers used to step voltage back down to 11kV at the end of completed sections. At this point the 11kV line can be upgraded to 22kV to provide an alternate supply.

9. LV Pillar Box Replacements and Refurbishments - $6.84m

   Scheduled for every year, the on-going replacements of LV Pillar Box which are generally identified during inspections and targeted inspections based projects.

10. Customer Connections (> 100kVA) - $6.40m

    Scheduled for every year, planning for new connections uses averages based on historical trending, modified by any local knowledge if appropriate however customer requirements are generally unpredictable and quite variable. Larger customers especially, which have the greatest effect on the network, tend not to disclose their intentions until connection is required (perhaps trying to avoid alerting competitors to commercial opportunities), so cannot be easily planned for in advance. Various options are considered generally to determine the least cost option for providing the new connection. Work required depends on the customer's location relative to existing network and the capacity of that network to supply the additional load. This can range from a simple LV connection at a fuse in a distribution pillar box at the customer's property boundary, to upgrade of LV cables or replacement of overhead lines with cables of greater rating, up to requirement for a new transformer site with associated 11kV extension if required.

Further detail relating to TPCL network Operating Expenditure in a table at the end of this section.

Please Note: All of these projects -

- Are network wide (apply to entire area as shown on map below), with the exception of #8 which is pinpointed on the map below;
- Have a contract in place that is with PowerNet Limited through an agency agreement (related party), with the exception of #2 and #5;
- Are forecast to require the supply of assets/goods or services by PowerNet Limited (related party), with the exception of #2 and #5;

Possible future constraints related to TPCL network Capital Expenditure projects:

The following map indicates where potential future constraints may impact the TPCL network performance:

8. 22kV Upgrade Athol-Kingston - $6.84m
Constraint – Unable to maintain supply voltage due to forecast load growth, timing being 1-4 years.

TPCL - 10 largest forecast Network Operating Expenditure projects (Maintenance)

- Clause 2.3.13(1), 2.3.14(1) and (2).

Project	Project description	Likely timing	Value	Location	Contract in place?	Is contract with RP?	Forecast to include RP?	Currently not indicated for RP
#1	Incident Response - Distribution - Unplanned	Every Year	$ 28.41m	Network Wide	Yes	Yes	Very likely	N/A
#2	Technical Routine Maintenance	Every Year	$ 12.76m	Network Wide	Yes	Yes	Very likely	N/A
#3	Routine Distribution Inspections	Every Year	$ 12.65m	Network Wide	Yes	Yes	Very likely	N/A
#4	Vegetation Management	Every Year	$ 9.50m	Network Wide	Yes	Yes	Very likely	N/A
#5	General Distribution Refurbishment	Every Year	$ 5.75m	Network Wide	Yes	Yes	Very likely	N/A
#6	Technical Routine Inspections & Checks	Every Year	$ 5.57m	Network Wide	Yes	Yes	Very likely	N/A
#7	Distribution Earthing Maintenance	Every Year	$ 3.67m	Network Wide	Yes	Yes	Very likely	N/A
#8	Incident Response - Technical - Unplanned	Every Year	$ 3.58m	Network Wide	Yes	Yes	Very likely	N/A
#9	Distribution Routine Maintenance	Every Year	$ 3.10m	Network Wide	Yes	Yes	Very likely	N/A
#10	Vegetation Inspection and Admin	Every Year	$ 2.65m	Network Wide	Yes	Yes	Very likely	N/A

TPCL - 10 largest forecast Network Capital Expenditure projects

- Clause 2.3.13(2), 2.3.14(1) and (2).

Project	Project description	Likely timing	Value	Location	Contract in place?	Is contract with RP?	Forecast to include RP?	Currently not indicated for RP
#1	11kV Line Replacement	Every Year	$ 61.10m	Network Wide	Yes	Yes	Very likely	N/A
#2	Unspecified Asset Replacements	2027 - 2030	$ 25.69m	Network Wide	No	N/A	Very likely	N/A
#3	Earth Upgrades	Every Year	$ 18.82m	Network Wide	Yes	Yes	Very likely	N/A
#4	Unspecified Projects System Growth	2026 - 2030	$ 17.19m	Network Wide	No	N/A	Very likely	N/A
#5	ABS renewals	Every Year	$ 11.80m	Network Wide	Yes	Yes	Very likely	N/A
#6	Customer Connections (≤ 20kVA)	Every Year	$ 10.62m	Network Wide	Yes	Yes	Very likely	N/A
#7	Transformer Replacement	Every year	$ 10.54m	Network Wide	Yes	Yes	Very likely	N/A
#8	22kV Upgrade Athol - Kingston	2021-2024	$ 6.84m	#8 on map	Yes	Yes	Very likely	N/A
#9	LV Pillar Box Replacement and Refurbishment	Every Year	$ 6.84m	Network Wide	Yes	Yes	Very likely	N/A
#10	Customer Connections (≥ 100kVA)	Every Year	$ 6.40m	Network Wide	Yes	Yes	Very likely	N/A

Possible future constraints related to TPCL network Capital Expenditure projects:

- Clause 2.3.13(4), 2.3.14(1) and (2).

Description of constraint	Related to CapEx project #	Expected timing of constraint
Unable to maintain supply voltage due to forecast load growth	#8	1-2 years

Independent Assurance report

To the Directors of The Power Company Limited and the Commerce Commission

Assurance report pursuant to Electricity Distribution Information Disclosure Determination 2012

We have completed our reasonable assurance engagement in respect of the compliance of The Power Company Limited (the 'Company') with the Electricity Distribution Information Disclosure Determination 2012 (the 'Determination') for the disclosure year ended 31 March 2021 where we are required to opine on:

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

This assurance report should be read in conjunction with the Commerce Commission's Information Disclosure exemption, issued to all electricity distribution businesses on 17 May 2021 under clause 2.11 of the Determination. The Commerce Commission granted an exemption from the requirement that the assurance report, in respect of the information in Schedule 10 of the Determination, must take into account any issues arising out of the Company's recording of SAIDI, SAIFI, and number of interruptions due to successive interruptions.

Qualified Opinion

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

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

Basis for Qualified Opinion

As described in Box 1 of Schedule 15, there are inherent limitations in the ability of the Company to collect and record the network reliability information specifically the interconnection points ('ICP's') affected by an interruption and the duration of the interruption used in calculating the amounts required to be disclosed in Schedules 10(i) to 10(iv). Consequently, there is no independent evidence available to support the accuracy of the ICP's affected and duration of an interruption. Controls over the accuracy of ICP and interruption data included in the SAIDI and SAIFI outage statistics are limited throughout the year.

There are no practical audit procedures that we could adopt to independently confirm the accuracy of the ICP data used to record the number of ICP's affected and duration of the interruption for the purposes of inclusion in the amounts relating to SAIDI and SAIFI outage statistics set out in Schedules 10(i) to 10(iv). Because of the potential effect of the limitations described above, we are unable to form an opinion as to the accuracy of the data that forms the basis of the compilation of Schedules 10(i) to 10(iv). In this respect alone we have not obtained all the recorded evidence and explanations that we have required.

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

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

Our audit approach

Overview

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

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

- Financial information – any impact resulting in +/-1% of the Return of Investment ('ROI')
- Performance based schedules – 5% of non-financial measures
- Related party transactions – 2% of total related party transactions.

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

We have determined that there are two key assurance matters:

- Regulatory Asset Base
- Related Party Transactions

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

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

Scope
Our procedures included analytical procedures, evaluating the appropriateness of assumptions used and whether they have been consistently applied, agreement of the Disclosure Information to, or reconciling with, source systems and underlying records, an assessment of the significant judgements made by the Company in the preparation of the Disclosure Information and valuing the related party transactions, and evaluation of the overall adequacy of the presentation of supporting information and explanations. These procedures have been undertaken to form an opinion as to whether the Company has complied, in all material respects, with the Determination in the preparation of the Disclosure Information for the year ended 31 March 2021, and whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

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

Key assurance matter	How our procedures addressed the key assurance matter
Regulatory Asset Base The Regulatory Asset Base (RAB), as set out in Schedule 4, reflects the value of the Company's electricity distribution assets. These are valued using an indexed historic cost methodology prescribed by the Determination. It is a measure which is used widely and is key to measuring the Company's return on investment and therefore important when monitoring financial performance or setting electricity distribution prices. The RAB inputs, as set out in the IM Determination, are similar to those used in the measurement of fixed assets in the financial statements, however, there are a number of different requirements and complexities which require careful consideration. Due to the importance of the RAB within the regulatory regime, the incentives to overstate the RAB value, and complexities within the regulations, we have considered it to be a key area of focus.	We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Determination and the IM Determination. We have performed the following procedures: **Assets commissioned** • We reconciled the assets commissioned, as per the regulatory fixed asset register, to the asset additions disclosed in the audited annual financial statements and investigated any reconciling items; • We inspected the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the Determination, which are required to be removed from the RAB; • We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification;

Key assurance matter	How our procedures addressed the key assurance matter
	Depreciation • We compared the standard asset lives by asset category to those set out in the IM Determination; • We verified the spreadsheet formula utilised to calculate regulatory depreciation expense is in line with IM Determination clause 2.2.5; **Revaluation** • We recalculated the revaluation rate set out in the IM Determination using the relevant Consumer Price Index indices taken from the Statistics New Zealand website; • We tested the mathematical accuracy of the revaluation calculation performed by management; **Disposals** • We inspected the asset disposals within the accounting fixed asset register to ensure disposals in the RAB meet the definition of a disposal per the IM Determination. We have no matters to report from undertaking those procedures.
Related party transactions Disclosures over related party transactions including related party relationships, procurement policies/processes, application of these policies/processes and examples of market testing of transaction terms as required under the Determination, as amended and the IM Determination are set out in Appendix A. The Determination and the IM Determination require the Company to value its transactions with related parties, disclosed in Schedule 5b, in accordance with the principles-based approach to the arm's length valuation rule. This rule states that the value of goods or services acquired from a related party cannot be greater than if it had been acquired under the terms of an arm's length transaction with an unrelated party, nor may it exceed the actual cost to the related party. A sale or supply to a related party cannot be valued at an amount less than if it had been sold or supplied under the terms of an arm's-length transaction with	We have obtained an understanding of the compliance requirements relevant to related party transactions as set out in the Determination, and the IM Determination. We have ensured Schedule 5(b) and Appendix A includes all required disclosures including current procurement policies, descriptions of how they are applied in practice, representative example transactions and when and how market testing was last performed. We have performed the following procedures over Schedule 5(b) and Appendix A. **Completeness and accuracy of related party relationships and transactions** We have tested the completeness and accuracy of the related party relationships and transactions by: • Agreeing the disclosures within Schedule 5(b) to the audited financial statements for the year ended 31 March 2021 and to the accounting records, investigating any differences and determining whether any such differences are justified; and

Key assurance matter	How our procedures addressed the key assurance matter
an unrelated party. Arm's-length valuation, as defined in the IM Determination, is the value at which a transaction, with the same terms and conditions, would be entered into between a willing seller and a willing buyer who are unrelated and who are acting independently of each other and pursuing their own best interests. The Company is required to use an objective and independent measure to demonstrate compliance with the arm's-length principle. In the absence of an active market for similar transactions, assigning an objective arm's length value to a related party transaction is difficult and requires significant judgement. We have identified related party transactions at arm's-length as a key audit matter due to the judgement involved	• Applying our understanding of the business structure against the related party definition in IM Determination clause 1.1.4(2)(b) to assess management's identification of any "unregulated parts" of the entity. **Practical application of procurement policies** • Testing a sample of operating expenditure and capital expenditure transactions disclosed in Schedule 5(b) by inspecting supporting documentation to determine compliance with the disclosed procurement policy and practices. **Arm's length valuation rule** We obtained the Company's assessment of the available independent and objective measures used in supporting the arm's length valuation principle and performed the following procedures: • Re-performed the calculations and agreed key inputs and assumptions to supporting documentation; • Where benchmarking or other market information was used as independent and objective measures, we assessed whether the related party transaction values fell within an acceptable range. Qualitative factors were considered in determining the appropriate acceptable range. We have no matters to report from undertaking those procedures.

Directors' Responsibilities

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

Our Independence and Quality Control

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

In accordance with the Professional and Ethical Standard 3 (Amended) *Quality Control for Firms that Perform Audits and Reviews of Financial Statements*, *and Other Assurance Engagements* or other professional requirements, or requirements in law or regulation, that are at least as demanding, our firm maintains a comprehensive system of quality control including documented policies and procedures regarding compliance with ethical requirements, professional standards, and applicable legal and regulatory requirements.

We are independent of the Company. Our firm carries out other services for the Company in the areas of compliance with regulatory requirements of the Commerce Act 1986, financial statement audit and an industry update. The provision of these other services has not impaired our independence.

Assurance Practitioner's responsibilities

Our responsibility is to express an opinion on whether the Company has complied, in all material respects, with the Determination in the preparation of the Disclosure Information for the disclosure year ended 31 March 2021 and on whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

Our engagement has been conducted in accordance with ISAE (NZ) 3000 (Revised), Assurance Engagements Other than Audits or Reviews of Historical Financial Information and SAE 3100 (Revised) Compliance Engagements which require that we plan and perform our procedures to obtain reasonable assurance about whether the Company has complied in all material respects with the Determination in the preparation of the Disclosure Information for the disclosure year ended 31 March 2021, and whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

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

Inherent limitations

Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error or non-compliance may occur and not be detected. A reasonable assurance engagement for the disclosure year ended 31 March 2021 does not provide assurance on whether compliance with the Determination and the IM Determination will continue in the future.

Use of report

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

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

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

PricewaterhouseCoopers.

Chartered Accountants
25 August 2021

Christchurch, New Zealand

5. Schedule 18: Certification for Year-End Disclosures

Clause 2.9.2

We, Douglas William Fraser and Donald Owen Nicolson, being directors of The Power Company 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 Power Company 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.]

Douglas William Fraser

25 August 2021

Donald Owen Nicolson

25 August 2021

Footnote:
The Directors of The Power Company Limited note the amendment in respect to the Information Disclosure Exemption: Disclosure and auditing or reliability information within schedule 10, issued by the Commerce Commission on 17 May 2021 that has removed the auditor report requirements relating to the treatment of successive interruptions for reporting SAIDI, SAIFI, and interruptions, because of potential inconsistencies in treatment approaches across the industry.

Directors note that they do not appear to have been provided a similar exemption relating to treatment of successive interruptions regarding their certification. The information has been prepared on a basis consistent with the previous year's disclosure and The Power Company Limited has recorded successive interruptions, originating from the same cause, as single interruptions