THE POWER COMPANY LTD

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

FOR THE YEAR ENDED 31 MARCH 2022

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 2022**

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	20,744	447	102,995	1,859	35,020
Network	12,565	270	62,387	1,126	21,213
Non-network	8,179	176	40,608	733	13,808
Expenditure on assets	31,208	672	154,953	2,797	52,687
Network	31,208	672	154,953	2,797	52,687
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	72,809	1,567
Standard consumer line charge revenue	85,043	1,410
Non-standard consumer line charge revenue	31,801	967,265

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	21,525	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	16,475	28.51%
Pass-through and recoverable costs excluding financial incentives and wash-ups	13,419	23.22%
Total depreciation	15,969	27.64%
Total revaluations	28,991	50.17%
Regulatory tax allowance	4,476	7.75%
Regulatory profit/(loss) including financial incentives and wash-ups	36,028	62.35%
Total regulatory income	57,783	

1(v): Reliability

Interruption rate	20.74	*Interruptions per 100 circuit km*

Company Name **The Power Company Limited**
For Year Ended **31 March 2022**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).
EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref				
7	**2(i): Return on Investment**	**CY-2**	**CY-1**	**Current Year CY**
8		**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
9	**ROI – comparable to a post tax WACC**	**%**	**%**	**%**
10	Reflecting all revenue earned	6.04%	3.17%	8.66%
11	Excluding revenue earned from financial incentives	6.04%	3.17%	8.66%
12	Excluding revenue earned from financial incentives and wash-ups	6.04%	3.17%	8.66%
13				
14	**Mid-point estimate of post tax WACC**	4.27%	3.72%	3.52%
15	25th percentile estimate	3.59%	3.04%	2.84%
16	75th percentile estimate	4.95%	4.40%	4.20%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	6.47%	3.50%	8.96%
21	Excluding revenue earned from financial incentives	6.47%	3.50%	8.96%
22	Excluding revenue earned from financial incentives and wash-ups	6.47%	3.50%	8.96%
23				
24	**WACC rate used to set regulatory price path**	NA	NA	NA
25				
26	**Mid-point estimate of vanilla WACC**	4.69%	4.05%	3.82%
27	25th percentile estimate	4.01%	3.37%	3.14%
28	75th percentile estimate	5.37%	4.73%	4.50%
29				
30	**2(ii): Information Supporting the ROI**		**($000)**	
31				
32	Total opening RAB value	420,819		
33	*plus* Opening deferred tax	(22,973)		
34	**Opening RIV**		397,846	
35				
36	**Line charge revenue**		57,825	
37				
38	Expenses cash outflow	29,893		
39	*add* Assets commissioned	24,308		
40	*less* Asset disposals	777		
41	*add* Tax payments	2,206		
42	*less* Other regulated income	(42)		
43	**Mid-year net cash outflows**		55,673	
44				
45	**Term credit spread differential allowance**		408	
46				
47	Total closing RAB value	457,373		
48	*less* Adjustment resulting from asset allocation	0		
49	*less* Lost and found assets adjustment	–		
50	*plus* Closing deferred tax	(25,243)		
51	**Closing RIV**		432,130	
52				
53	**ROI – comparable to a vanilla WACC**			8.96%
54				
55	Leverage (%)			42%
56	Cost of debt assumption (%)			2.55%
57	Corporate tax rate (%)			28%
58				
59	**ROI – comparable to a post tax WACC**			8.66%
60				

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	8.79%
Year-end ROI – comparable to a post tax WACC	8.49%

** 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 2022

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

sch ref			($000)
7		**3(i): Regulatory Profit**	($000)
8		**Income**	
9		Line charge revenue	57,825
10	*plus*	Gains / (losses) on asset disposals	(749)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	706
12			
13		**Total regulatory income**	57,783
14		**Expenses**	
15	*less*	Operational expenditure	16,475
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	13,419
18			
19		**Operating surplus / (deficit)**	27,889
20			
21	*less*	Total depreciation	15,969
22			
23	*plus*	Total revaluations	28,991
24			
25		**Regulatory profit / (loss) before tax**	40,912
26			
27	*less*	Term credit spread differential allowance	408
28			
29	*less*	Regulatory tax allowance	4,476
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	36,028
32			

sch ref			
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	($000)	
34	**Pass through costs**		
35	Rates	263	
36	Commerce Act levies	186	
37	Industry levies	153	
38	CPP specified pass through costs	–	
39	**Recoverable costs excluding financial incentives and wash-ups**		
40	Electricity lines service charge payable to Transpower	12,584	
41	Transpower new investment contract charges	233	
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**		13,419
47			

sch ref				
48	**3(iii): Incremental Rolling Incentive Scheme**		($000)	
49			CY-1	CY
50			31 Mar 21	31 Mar 22
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 17	–	–
58	CY-4	31 Mar 18	–	–
59	CY-3	31 Mar 19	–	–
60	CY-2	31 Mar 20	–	–
61	CY-1	31 Mar 21	–	–
62	**Net incremental rolling incentive scheme**			–
63				
64	**Net recoverable costs allowed under incremental rolling incentive scheme**			–

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

Company Name	The Power Company Limited
For Year Ended	31 March 2022

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

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

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

sch ref

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

	RAB	RAB	RAB	RAB	RAB
for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
	($000)	($000)	($000)	($000)	($000)
Total opening RAB value	355,086	373,678	385,009	407,982	420,819
less **Total depreciation**	12,615	13,762	14,313	15,236	15,969
plus **Total revaluations**	3,886	5,526	9,710	6,184	28,991
plus **Assets commissioned**	25,100	20,360	28,192	22,706	24,308
less **Asset disposals**	744	792	616	818	777
plus **Lost and found assets adjustment**	2,964	–	–		–
plus **Adjustment resulting from asset allocation**					0
Total closing RAB value	373,678	385,009	407,982	420,819	457,373

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Total opening RAB value		420,819		420,819
less				
Total depreciation		15,969		15,969
plus				
Total revaluations		28,991		28,991
plus				
Assets commissioned (other than below)	–		–	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	24,308		24,308	
Assets commissioned		24,308		24,308
less				
Asset disposals (other than below)	777		777	
Asset disposals to a regulated supplier			–	
Asset disposals to a related party	–		–	
Asset disposals		777		777
plus **Lost and found assets adjustment**		–		–
plus **Adjustment resulting from asset allocation**				0
Total closing RAB value		457,373		457,373

** 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	1,142
CPI_4^{-4}	1,068
Revaluation rate (%)	6.93%

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Total opening RAB value	420,819		420,819	
less Opening value of fully depreciated, disposed and lost assets	2,410		2,410	
Total opening RAB value subject to revaluation	418,409		418,409	
Total revaluations		28,991		28,991

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction		Allocated works under construction	
Works under construction—preceding disclosure year		10,510		10,510
plus Capital expenditure	22,148		22,148	
less Assets commissioned	24,308		24,308	
plus Adjustment resulting from asset allocation				
Works under construction - current disclosure year		8,349		8,349
Highest rate of capitalised finance applied				

4(v): Regulatory Depreciation

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Depreciation - standard	15,969		15,969	
Depreciation - no standard life assets	–		–	
Depreciation - modified life assets	–		–	
Depreciation - alternative depreciation in accordance with CPP	–		–	
Total depreciation		15,969		15,969

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	60,332	4,372	111,463	143,489	19,930	55,958	17,692	7,578	7	420,819
less Total depreciation	1,926	111	4,081	6,368	701	1,780	736	265	1	15,969
plus Total revaluations	4,171	306	7,706	9,869	1,368	3,815	1,230	525		28,991
plus Assets commissioned	267	0	4,991	10,227	441	1,774	6,223	385		24,308
less Asset disposals			346			413	19			777
plus Lost and found assets adjustment										–
plus Adjustment resulting from asset allocation										–
plus Asset category transfers										–
Total closing RAB value	62,844	4,567	119,733	157,217	21,038	59,354	24,390	8,223	6	457,373

Asset Life

	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	
Weighted average remaining asset life	36.8	39.3	33.1	25.0	42.6	33.1	25.7	16.3	–	(years)
Weighted average expected total asset life	57.4	45.4	45.3	58.4	61.7	47.2	38.9	32.5	–	(years)

Company Name	The Power Company Limited
For Year Ended	31 March 2022

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**			40,912
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	24	*	
12		Amortisation of initial differences in asset values	6,941		
13		Amortisation of revaluations	1,943		
14					8,908
15					
16	*less*	Total revaluations	28,991		
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	233	*	
20		Notional deductible interest	4,611		
21					33,835
22					
23		**Regulatory taxable income**			15,984
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			15,984
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			4,476
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	111,054		
37	*less*	Amortisation of initial differences in asset values	6,941		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	96		
40		Closing unamortised initial differences in asset values			104,017
41					
42		Opening weighted average remaining useful life of relevant assets (years)			16
43					

5a(iv): Amortisation of Revaluations

			($000)
	Opening sum of RAB values without revaluations	372,280	
	Adjusted depreciation	14,026	
	Total depreciation	15,969	
	Amortisation of revaluations		1,943

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	(22,973)	
plus	Tax effect of adjusted depreciation	3,927	
less	Tax effect of tax depreciation	4,964	
plus	Tax effect of other temporary differences*	620	
less	Tax effect of amortisation of initial differences in asset values	1,943	
plus	Deferred tax balance relating to assets acquired in the disclosure year	–	
less	Deferred tax balance relating to assets disposed in the disclosure year	(90)	
plus	Deferred tax cost allocation adjustment	(0)	
	Closing deferred tax		(25,243)

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	190,248	
less	Tax depreciation	17,727	
plus	Regulatory tax asset value of assets commissioned	26,396	
less	Regulatory tax asset value of asset disposals	241	
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		198,676

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2022**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

sch ref			
7	**5b(i): Summary—Related Party Transactions**	**($000)**	**($000)**
8	**Total regulatory income**		18
9			
10	**Market value of asset disposals**		–
11			
12	Service interruptions and emergencies	3,584	
13	Vegetation management	1,365	
14	Routine and corrective maintenance and inspection	4,283	
15	Asset replacement and renewal (opex)	747	
16	**Network opex**		9,979
17	Business support	3,096	
18	System operations and network support	1,842	
19	**Operational expenditure**		14,917
20	Consumer connection	2,801	
21	System growth	2,675	
22	Asset replacement and renewal (capex)	13,704	
23	Asset relocations	211	
24	Quality of supply	447	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	4,948	
27	**Expenditure on non-network assets**		–
28	**Expenditure on assets**		24,786
29	Cost of financing		–
30	Value of capital contributions		–
31	Value of vested assets		–
32	**Capital Expenditure**		24,786
33	**Total expenditure**		39,703
34			
35	**Other related party transactions**		–

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

37	**Name of related party**	**Nature of opex or capex service provided**	**Total value of transactions ($000)**
38	PowerNet Limited	Service interruptions and emergencies	3,584
39	PowerNet Limited	Vegetation management	1,365
40	PowerNet Limited	Routine and corrective maintenance and inspection	4,283
41	PowerNet Limited	Asset replacement and renewal (opex)	747
42	PowerNet Limited	System operations and network support	1,842
43	PowerNet Limited	Business support	3,096
44	PowerNet Limited	Consumer connection	2,801
45	PowerNet Limited	System growth	2,675
46	PowerNet Limited	Asset replacement and renewal (capex)	13,704
47	PowerNet Limited	Asset relocations	211
48	PowerNet Limited	Quality of supply	447
49	PowerNet Limited	Other reliability, safety and environment	4,948
50			
51			
52			
53	**Total value of related party transactions**		39,703
54	** include additional rows if needed*		
55			

Company Name **The Power Company Limited**
For Year Ended **31 March 2022**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

7

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

9

sch ref	Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
11	US Private Placement (USPP) US $40M	4/2/2020	7/11/2019	10.0	BKBM plus margin	62,794	55,218	235	(63)
12	US Private Placement (USPP) US $25M	4/2/2020	7/11/2019	11.0	BKBM plus margin	39,246	34,511	177	(43)
13	US Private Placement (USPP) NZ $50M	20/5/2021	19/3/2021	12.0	3.80%	50,000	50,000	263	(58)
14									
15									
16	** include additional rows if needed*						139,729	675	(164)

17

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

19

sch ref			
20	**Gross term credit spread differential**		511
21			
22	Total book value of interest bearing debt	230,618	
23	Leverage	42%	
24	Average opening and closing RAB values	439,096	
25	**Attribution Rate (%)**		80%
26			
27	**Term credit spread differential allowance**		408

Company Name	The Power Company Limited
For Year Ended	31 March 2022

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		3,584			
Not directly attributable				–	
Total attributable to regulated service		3,584			
Vegetation management					
Directly attributable		1,365			
Not directly attributable				–	
Total attributable to regulated service		1,365			
Routine and corrective maintenance and inspection					
Directly attributable		4,283			
Not directly attributable				–	
Total attributable to regulated service		4,283			
Asset replacement and renewal					
Directly attributable		747			
Not directly attributable				–	
Total attributable to regulated service		747			
System operations and network support					
Directly attributable		2,503			
Not directly attributable				–	
Total attributable to regulated service		2,503			
Business support					
Directly attributable		3,354			
Not directly attributable		639	35	674	
Total attributable to regulated service		3,993			
Operating costs directly attributable		15,836			
Operating costs not directly attributable	–	639	35	674	–
Operational expenditure		16,475			

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	602
Not directly attributable	–
Total attributable to regulated service	602
Recoverable costs	
Directly attributable	12,817
Not directly attributable	–
Total attributable to regulated service	12,817

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 2022

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	62,844
Not directly attributable	–
Total attributable to regulated service	62,844
Subtransmission cables	
Directly attributable	4,567
Not directly attributable	–
Total attributable to regulated service	4,567
Zone substations	
Directly attributable	119,733
Not directly attributable	–
Total attributable to regulated service	119,733
Distribution and LV lines	
Directly attributable	157,217
Not directly attributable	–
Total attributable to regulated service	157,217
Distribution and LV cables	
Directly attributable	21,038
Not directly attributable	–
Total attributable to regulated service	21,038
Distribution substations and transformers	
Directly attributable	59,354
Not directly attributable	–
Total attributable to regulated service	59,354
Distribution switchgear	
Directly attributable	24,390
Not directly attributable	–
Total attributable to regulated service	24,390
Other network assets	
Directly attributable	8,223
Not directly attributable	–
Total attributable to regulated service	8,223
Non-network assets	
Directly attributable	6
Not directly attributable	–
Total attributable to regulated service	6
Regulated service asset value directly attributable	457,373
Regulated service asset value not directly attributable	–
Total closing RAB value	457,373

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 2022

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											
7											
8											
9					Allocator Metric (%)		Value allocated ($000)				
10	Line Item*	Allocation methodology type	Cost allocator	Allocator type	Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000)
11	**Service interruptions and emergencies**										
12										-	
13										-	
14										-	
15										-	
16	**Not directly attributable**						-	-	-	-	-
17	**Vegetation management**										
18										-	
19										-	
20										-	
21										-	
22	**Not directly attributable**						-	-	-	-	-
23	**Routine and corrective maintenance and inspection**										
24										-	
25										-	
26										-	
27										-	
28	**Not directly attributable**						-	-	-	-	-
29	**Asset replacement and renewal**										
30										-	
31										-	
32										-	
33										-	
34	**Not directly attributable**						-	-	-	-	-
35											
36	**System operations and network support**										
37										-	
38										-	
39										-	
40										-	
41	**Not directly attributable**						-	-	-	-	-
42	**Business support**										
43	Administration expenses	ABAA	Revenue	Proxy	94.81%	5.19%		639	35	674	
44										-	
45										-	
46										-	
47	**Not directly attributable**						-	639	35	674	-
48											
49	**Operating costs not directly attributable**						-	639	35	674	-
50											
51	**Pass through and recoverable costs**										
52	**Pass through costs**										
53										-	
54										-	
55										-	
56										-	
57	**Not directly attributable**						-	-	-	-	-
58	**Recoverable costs**										
59										-	
60										-	
61										-	
62										-	
63	**Not directly attributable**						-	-	-	-	-
64	** include additional rows if needed*										

Company Name: **The Power Company Limited**
For Year Ended: **31 March 2022**

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					Allocator Metric (%)		Value allocated ($000)				
10	Line Item*	Allocation methodology type	Allocator	Allocator type	Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000)
11	**Subtransmission lines**										
12										-	
13										-	
14										-	
15										-	
16	**Not directly attributable**						-	-	-	-	-
17	**Subtransmission cables**										
18										-	
19										-	
20										-	
21										-	
22	**Not directly attributable**						-	-	-	-	-
23	**Zone substations**										
24										-	
25										-	
26										-	
27										-	
28	**Not directly attributable**						-	-	-	-	-
29	**Distribution and LV lines**										
30										-	
31										-	
32										-	
33										-	
34	**Not directly attributable**						-	-	-	-	-
35	**Distribution and LV cables**										
36										-	
37										-	
38										-	
39										-	
40	**Not directly attributable**						-	-	-	-	-
41											
42	**Distribution substations and transformers**										
43										-	
44										-	
45										-	
46										-	
47	**Not directly attributable**						-	-	-	-	-
48											
49	**Distribution switchgear**										
50										-	
51										-	
52										-	
53										-	
54	**Not directly attributable**						-	-	-	-	-
55	**Other network assets**										
56										-	
57										-	
58										-	
59										-	
60	**Not directly attributable**						-	-	-	-	-
61	**Non-network assets**										
62										-	
63										-	
64										-	
65										-	
66	**Not directly attributable**						-	-	-	-	-
67											
68	**Regulated service asset value not directly attributable**						-	-	-	-	-
69	** include additional rows if needed*										

Company Name	The Power Company Limited
For Year Ended	31 March 2022

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

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

sch ref				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		2,801
9		System growth		2,675
10		Asset replacement and renewal		13,704
11		Asset relocations		211
12		Reliability, safety and environment:		
13		Quality of supply	447	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	4,948	
16		**Total reliability, safety and environment**		5,395
17		**Expenditure on network assets**		24,786
18		Expenditure on non-network assets		–
19				
20		**Expenditure on assets**		24,786
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		2,638
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		22,148
26		**6a(ii): Subcomponents of Expenditure on Assets (where known)**		**($000)**
27		Energy efficiency and demand side management, reduction of energy losses		–
28		Overhead to underground conversion		–
29		Research and development		–
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Half Hour Individuals	270	
33		Non- Domestic	589	
34		Domestic	1,941	
35				
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		2,801
39				
40	*less*	Capital contributions funding consumer connection expenditure	2,479	
41		**Consumer connection less capital contributions**		322

42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement**
43			**System Growth**	**and Renewal**
44			**($000)**	**($000)**
45		Subtransmission	12	209
46		Zone substations	2	1,971
47		Distribution and LV lines	1,453	6,419
48		Distribution and LV cables	1,005	–
49		Distribution substations and transformers	42	2,330
50		Distribution switchgear	84	2,449
51		Other network assets	78	326
52		**System growth and asset replacement and renewal expenditure**	2,675	13,704
53	*less*	Capital contributions funding system growth and asset replacement and renewal	–	
54		**System growth and asset replacement and renewal less capital contributions**	2,675	13,704
55				

56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		Line relocation	211	
59				
60				
61				
62				
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations		
65		**Asset relocations expenditure**		211
66	*less*	Capital contributions funding asset relocations	159	
67		**Asset relocations less capital contributions**		52

6a(vi): Quality of Supply

		($000)	($000)
	*Project or programme**		
	Supply Quality Upgrades	339	
	Network Improvements Projects	105	
	** include additional rows if needed*		
	All other projects programmes - quality of supply	3	
	Quality of supply expenditure		447
less	Capital contributions funding quality of supply		
	Quality of supply less capital contributions		447

6a(vii): Legislative and Regulatory

		($000)	($000)
	*Project or programme**		
	** 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

		($000)	($000)
	*Project or programme**		
	Earth Upgrades	3,986	
	Hillside Protection Remediation	475	
	** include additional rows if needed*		
	All other projects or programmes - other reliability, safety and environment	487	
	Other reliability, safety and environment expenditure		4,948
less	Capital contributions funding other reliability, safety and environment		
	Other reliability, safety and environment less capital contributions		4,948

6a(ix): Non-Network Assets

Routine expenditure

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

Atypical expenditure

	($000)	($000)
*Project or programme**		
** 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 2022

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

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

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	3,584	
9	Vegetation management	1,365	
10	Routine and corrective maintenance and inspection	4,283	
11	Asset replacement and renewal	747	
12	**Network opex**		9,979
13	System operations and network support	2,503	
14	Business support	3,993	
15	**Non-network opex**		6,496
16			
17	**Operational expenditure**		16,475
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		63
20	Direct billing*		–
21	Research and development		–
22	Insurance		374
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 2022**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

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

sch ref				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	58,517	57,825	(1%)
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	2,241	2,801	25%
11	System growth	2,694	2,675	(1%)
12	Asset replacement and renewal	12,503	13,704	10%
13	Asset relocations	118	211	79%
14	Reliability, safety and environment:			
15	Quality of supply	471	447	(5%)
16	Legislative and regulatory	-	–	–
17	Other reliability, safety and environment	4,174	4,948	19%
18	**Total reliability, safety and environment**	4,644	5,395	16%
19	**Expenditure on network assets**	22,200	24,786	12%
20	Expenditure on non-network assets	65	–	(100%)
21	Expenditure on assets	22,265	24,786	11%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	3,374	3,584	6%
24	Vegetation management	1,215	1,365	12%
25	Routine and corrective maintenance and inspection	4,910	4,283	(13%)
26	Asset replacement and renewal	880	747	(15%)
27	**Network opex**	10,380	9,979	(4%)
28	System operations and network support	1,954	2,503	28%
29	Business support	2,746	3,993	45%
30	**Non-network opex**	4,700	6,496	38%
31	**Operational expenditure**	15,080	16,475	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	–	63	–
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	324	374	16%
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 2022
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

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

sch ref	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
15	Low user	Residential	Standard	10,188	62,091
16	Domestic	Residential	Standard	17,163	157,728
17	Non-Domestic	Commerical	Standard	9,273	209,380
18	Individual non half hour	Commerical	Standard	62	7,203
19	Individual half hour	Commerical	Standard	205	175,304
20	Non-Standard	Commerical	Non-standard	4	182,056
21	Generation	Commerical	Non-standard	2	443
22					
23					
24					
25	*Add extra rows for additional consumer groups or price category codes as necessary*				
26			Standard consumer totals	36,891	611,706
27			Non-standard consumer totals	6	182,499
28			Total for all consumers	36,897	794,205

Billed quantities by price component

sch ref	Price component	Variable day energy sales	Variable day energy purchases				
13	Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	KWh				
15	Low user		51,238,306				
16	Domestic		125,203,168				
17	Non-Domestic		164,971,659				
18	Individual non half hour		5,682,886				
19	Individual half hour	123,642,974					
20	Non-Standard	116,376,969					
21	Generation	301,046					
22							
23							
24							
26	Standard consumer totals	123,642,974	347,096,019	–	–	–	–
27	Non-standard consumer totals	116,678,016	–	–	–	–	–
28	Total for all consumers	240,320,990	347,096,019	–	–	–	–

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	$6,771	$1,151	$5,639	$1,132	421.22	$6,656	($307)			
Domestic	Residential	Standard	$17,742	$2,877	$14,797	$2,945	9,067.10	$9,436	($761)			
Non-Domestic	Commerical	Standard	$21,796	$3,250	$18,164	$3,631	8,916.48	$13,451	($572)			
Individual non half hour	Commerical	Standard	$463	$84	$284	**$179**	17.00	$446				
Individual half hour	Commerical	Standard	$5,250	$526	$2,724	**$2,525**	2,961.45	$2,288				
Individual half hour	Commerical	Non-standard	$4,388	$241	$2,231	**$2,157**	4,388.01					
Generation	Commerical	Non-standard	$1,416	$49	$1,205	**$211**	1,415.58					
			–									
			–									
			–									
Add extra rows for additional consumer groups or price category codes as necessary												
		Standard consumer totals	$52,022	$7,888	$41,609	$10,413	$21,383	$32,278	($1,640)	–	–	–
		Non-standard consumer totals	$5,804	$291	$3,436	$2,367	$5,804	–	–	–	–	–
		Total for all consumers	$57,825	$8,179	$45,045	$12,780	$27,187	$32,278	($1,640)	–	–	–

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

Check: OK

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	6

Company Name	The Power Company Limited
For Year Ended	31 March 2022
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.	91,507	92,494	987	3
10	All	Overhead Line	Wood poles	No.	18,236	17,485	(751)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	891	891	0	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	13	13	0	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.	59	59	–	3
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	9	13	4	3
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	294	302	8	3
29	HV	Zone substation switchgear	33kV RMU	No.	–	2	2	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	21	23	2	3
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	32	34	2	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	163	158	(5)	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	45	48	3	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	61	61	–	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	6,717	6,719	3	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	9	9	–	3
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	118	121	4	3
39	HV	Distribution Cable	Distribution UG PILC	km	37	34	(3)	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.	30	27	(3)	3
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	20	28	8	3
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	13,858	13,796	(62)	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.	111	114	3	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	10,575	10,635	60	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	689	705	16	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	848	849	0	3
51	LV	LV Cable	LV UG Cable	km	216	224	8	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	355	359	4	3
53	LV	Connections	OH/UG consumer service connections	No.	38,361	38,735	374	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	603	665	62	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 2022
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 2022

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.	–	–	2,195	35,986	11,924	20,892	2,978	203	827	1,015	615	175	90	137	329	318	903	1,214	797	930	1,019	1,204	1,214	1,341	1,531	1,245	1,208	750	771	103	–	–	–	580	92,494		3
11	All	Overhead Line	Wood poles	No.	–	–	458	1,197	4,145	596	3,476	728	763	724	730	698	457	863	785	1,040	114	6	2	16	13	164	2	18	14	17	3	5	–	4	–	–	–	447	17,485		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	25	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.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		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	2	1	–	–	5	4	–	–	2	–	–	–	–	–	59		3
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	8	–	–	–	1	–	–	4	–	–	–	–	13		3
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			18	11	11	27	60	3	35	2	2	9	7	10	23	2	8	1	1	8	4	5	4	–	5	7	10	6	2	4	–	–	–	17	302		3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	2		N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	7	–	–	–	5	–	–	–	–	–	–	–	–	6	1	–	–	–	2	–	2	–	–	–	–	23		3
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	2	1	3	6	1	–	–	–	–	1	2	5	2	–	1	1	–	–	–	–	–	2	–	1	3	3	–	–	–	–	–	34		3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	–	14	48	–	–	1	–	–	–	–	6	–	2	–	–	17	10	13	15	9	6	7	5	4	1	–	–	–	–	–	158		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	3	18	6	–	–	1	3	1	–	–	1	–	1	–	–	5	1	–	–	2	1	–	2	3	–	–	–	–	–	48		3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	–	6	8	8	2	1	3	2	1	3	–	2	–	2	1	–	–	1	8	1	2	2	4	3	–	1	–	–	–	–	–	–	61		3
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3	0	191	719	3,241	1,063	305	47	98	101	71	59	55	54	72	102	76	49	50	55	38	75	35	36	11	21	20	15	17	11	–	–	–	28	6,719		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	6	5	2	4	3	5	9	4	5	8	4	3	2	1	5	1	4	6	3	1	15	1	3	1	0	–	–	–	8	121		3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	0	13	3	8	1	–	1	0	–	1	1	3	1	0	0	1	0	–	0	–	–	0	–	–	–	–	–	–	–	–	2	34		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	3	–	–	–	–	1	2	1	–	–	1	–	–	–	2	3	–	4	2	4	3	–	–	–	–	–	–	–	27		3
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	1	–	2	6	8	2	7	–	–	–	–	–	28		3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	36	1	179	323	1,312	2,049	1,420	111	337	405	292	323	261	364	416	463	473	437	388	372	330	398	304	235	287	301	314	329	345	80	–	–	–	911	13,796		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	3	7	10	7	2	1	3	1	2	3	–	4	23	5	15	6	1	–	–	–	–	114		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	32	1	154	68	1,195	1,846	1,320	94	304	366	252	240	227	309	366	400	400	377	333	319	251	317	241	174	204	184	194	200	205	52	–	–	–	10	10,635		3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	3	–	3	6	79	82	38	5	18	24	19	31	20	34	32	27	24	21	13	16	22	29	16	17	37	21	17	23	20	4	–	–	–	4	705		3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	4	–	1	6	5	5	16	13	3	–	–	–	2	8	–	–	5	–	1	1	–	2	–	–	–	–	72		3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	4	–	1	–	–	–	–	–	–	–	1	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7		3
51	LV	LV Line	LV OH Conductor	km	–	–	18	71	484	103	42	3	9	11	7	5	4	6	5	7	6	5	4	4	5	5	4	5	6	5	8	5	4	0	–	–	–	7	849		3
52	LV	LV Cable	LV UG Cable	km	–	–	0	2	80	20	11	1	1	4	4	7	7	14	15	6	7	5	4	3	3	2	3	1	3	3	4	2	3	0	–	–	–	6	224		3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	0	14	237	41	17	1	3	2	1	3	2	3	2	1	1	3	2	1	2	0	0	0	2	2	1	3	1	0	–	–	–	13	359		3
54	LV	Connections	OH/UG consumer service connections	No.	–	204	2,113	5,245	6,993	7,853	6,945	244	342	433	432	413	466	512	568	681	520	420	476	358	395	326	298	276	329	329	398	406	309	–	–	–	–	451	38,735		3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	8	9	41	97	17	11	1	3	4	20	8	27	18	8	5	4	29	15	26	37	36	48	44	33	60	37	8	–	–	–	11	665		3
56	All	SCADA and communications	SCADA and communications equipment operating as a single systen	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 2022**
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)	1	1	2
16	6.6kV to 11kV (inclusive—other than SWER)	6,718	155	6,873
17	Low voltage (< 1kV)	849	224	1,073
18	**Total circuit length (for supply)**	8,465	397	8,862
19				
20	Dedicated street lighting circuit length (km)	271	88	359
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	475	6%
25	Rural	4,552	54%
26	Remote only	804	9%
27	Rugged only	2,023	24%
28	Remote and rugged	611	7%
29	Unallocated overhead lines	–	–
30	**Total overhead length**	8,465	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	1,548	18%

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2022**

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 2022**
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

8	**9e(i): Consumer Connections**			
9	*Number of ICPs connected in year by consumer type*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11	Domestic		388	
12	Half Hour Individual		3	
13	Non Domestic		87	
14				
15				
16	** include additional rows if needed*			
17	**Connections total**		478	
18				
19	**Distributed generation**			
20	Number of connections made in year		56	**connections**
21	Capacity of distributed generation installed in year		0.38	**MVA**
22	**9e(ii): System Demand**			
23				
24			**Demand at time of maximum coincident demand (MW)**	
25	**Maximum coincident system demand**			
26		GXP demand	151	
27	*plus*	Distributed generation output at HV and above	10	
28	**Maximum coincident system demand**		161	
29	*less*	Net transfers to (from) other EDBs at HV and above	1.2	
30	**Demand on system for supply to consumers' connection points**		160	
31	**Electricity volumes carried**		**Energy (GWh)**	
32		Electricity supplied from GXPs	706	
33	*less*	Electricity exports to GXPs	105	
34	*plus*	Electricity supplied from distributed generation	256	
35	*less*	Net electricity supplied to (from) other EDBs	21	
36	**Electricity entering system for supply to consumers' connection points**		836	
37	*less*	Total energy delivered to ICPs	794	
38	**Electricity losses (loss ratio)**		41	5.0%
39				
40	**Load factor**		0.60	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43		Distribution transformer capacity (EDB owned)	470	
44		Distribution transformer capacity (Non-EDB owned, estimated)	46	
45	**Total distribution transformer capacity**		517	
46				
47	**Zone substation transformer capacity**		461	

Company Name	The Power Company Limited
For Year Ended	31 March 2022
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 **10(i): Interruptions**

sch ref	Interruptions by class	Number of interruptions
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	531
12	Class C (unplanned interruptions on the network)	1,304
13	Class D (unplanned interruptions by Transpower)	1
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)	2
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	–
19	**Total**	1,838

sch ref	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	925	379

sch ref	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.84	192.1
27	Class C (unplanned interruptions on the network)	2.62	174.8
28	Class D (unplanned interruptions by Transpower)	0.04	3.7
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	0.0
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	3.50	370.6

sch ref	Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
37	Classes B & C (interruptions on the network)	3.46	360.9

39 **10(ii): Class C Interruptions and Duration by Cause**

sch ref	Cause	SAIFI	SAIDI
42	Lightning	0.01	1.6
43	Vegetation	0.26	18.9
44	Adverse weather	0.31	31.1
45	Adverse environment	0.00	0.0
46	Third party interference	0.50	34.3
47	Wildlife	0.12	10.9
48	Human error	0.16	3.2
49	Defective equipment	0.86	49.4
50	Cause unknown	0.39	25.2

52 **10(iii): Class B Interruptions and Duration by Main Equipment Involved**

sch ref	Main equipment involved	SAIFI	SAIDI
55	Subtransmission lines	0.01	1.6
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	0.75	176.3
69	Distribution cables (excluding LV)	0.01	2.9
60	Distribution other (excluding LV)	0.07	11.3

61 **10(iv): Class C Interruptions and Duration by Main Equipment Involved**

sch ref	Main equipment involved	SAIFI	SAIDI
64	Subtransmission lines	0.35	9.6
65	Subtransmission cables	–	–
66	Subtransmission other	0.07	0.3
67	Distribution lines (excluding LV)	1.83	143.8
68	Distribution cables (excluding LV)	0.05	3.3
69	Distribution other (excluding LV)	0.31	17.9

70 **10(v): Fault Rate**

sch ref	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
72	Subtransmission lines	18	891	2.02
73	Subtransmission cables	–	14	–
74	Subtransmission other	1		
75	Distribution lines (excluding LV)	1,036	6,724	15.41
76	Distribution cables (excluding LV)	9	160	5.63
77	Distribution other (excluding LV)	240		
78	**Total**	1,304		

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 8.66%, which is 4.46% above the 75th percentile estimate of post-tax WACC of 4.20%. The Power Company also achieved an 8.96% vanilla ROI, which is 4.46% above the 75th percentile estimate of vanilla WACC of 4.50%.

The increase in the post tax ROI of 5.49% from 2021 is due to the CPI increase of 6.93%, up from 1.52% in 2021

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 (RAB) used the 31 March 2021 figure of \$420,819k as the starting point with inflationary indexing over the year to 31 March 2022 plus additions less disposals, resulting in a closing RAB balance of \$457,373k at 31 March 2022. 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 \$221k cost of easements and a tax deductible expense and \$12k relating to a non-deductible expense. 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:	$	2,215
	$	2,215
Tax Rate:		28%
Temporary Differences	$	620

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 via 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 reclassified.

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.

No items were reclassified.

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

    12.2 information on reclassified items in accordance with 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

Capital Expenditure:
The overall actual capex expenditure on network assets was 12% over budget.

Cost increases in materials resulting from supply shortages, commodity price increases, increased shipping costs and general inflationary pressures have led to increased capital expenditure costs.

Customer Connections

- 25% above budget
- Customer driven and above plan amount of new connection work was required, mainly domestic houses and subdivision reticulation work.

Asset replacement and renewal

- 10% over budget.
- The largest increase was the 11 kV line replacement with additional urgent work from the increased network inspections.
- ABS replacement work was prioritised due to safety concerns.
- Material costs increased significantly during the year due to COVID related supply issues.

Asset relocations:

- 79% over budget.
- Work mainly driven by customer request with the opportunity taken to move lines to the road side where it is economical.

Quality of supply:

- Overall spend was 5% under budget.
- Minor reduction in upgrade work.

Other Reliability, Safety and Environment:

- 19% over budget.
- Increased emphasis on earth upgrades to improve network safety with additional cost of materials and sub-contractors.
- Extra cost from the Hillside protection upgrade work due to additional scope of works.

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

Service interruptions and emergencies

- 6% over budget
- Higher unplanned distribution fault response due to weather conditions.

Vegetation management:

- 12% over budget
- The internal administration and inspection costs were higher than budget immediately prior to the new Asplundh contract being awarded from 1 April 2022.

Routine and corrective maintenance:

- 13% under budget.
- Few individual distribution earth maintenance projects with some work being carried out within the larger capital earth upgrade projects.
- The new inspection teams were still being set up and resourced during the year with the total inspection budgets being 10% underspent as a result.

Asset replacement and renewal maintenance:

- 15% under budget
- Fewer small defects identified with some work incorporated into full capital feeder refurbishment projects.

System operations, network support and business support

- 38% over budget
- This is due to an input error in the AMP. The actual budget is $6,478 and the actual is within budget.

Information relating to revenues and quantities for the disclosure year

15. In the box below provide-

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

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

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

Target revenue for the year was $58,517k, the total billed was $57,825 which is 692k (1%) below budget.

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 calculates SAIDI and SAIFI limits and targets for non-exempt networks to allow for assessment of performance on a consistent basis with other 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 360.93 and normalised SAIFI at 3.46 for 2021/22.
This compares with the 2020/21 year TPCL published ID Determination values for normalised SAIDI of 314.05 and normalised SAIFI of 3.53 for the 2020/21 year – meaning slightly less interruptions, but of a slightly longer duration compared with last year.
The total number of power interruptions on TPCL increased by 23% in 2021/22 compared with 2020/21. There was a decrease in Class B planned interruptions, but another increase in Class C unplanned interruptions similar to increases last year.

Although Class C SAIFI was the major contributor to overall SAIFI, it was a decrease from 2020/21. Class B SAIDI was higher than Class C indicating long duration Class B interruptions.

The most significant cause of Class C interruptions was defective equipment(predominately ABS switches and 11kV leads), which increased in frequency and duration compared with last year. Adverse weather, third party interference and cause unknown were also high contributors to Class C SAIDI.

86% of TPCL's network is distribution lines, accordingly the majority of interruptions occurred on these lines. However there was a marked decrease in interruption duration of Class B interruptions on distribution lines. Fault rates per 100km of line increased for all main equipment except sub transmission cables. Distribution line fault rate was 61% higher than the previous year.

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.

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 report released in December 2020:

	2022	2023	2024	2025	2026
Inflator (CAPEX & OPEX)	1.2%	1.4%	1.8%	2.1%	2.1%

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.

Voluntary explanatory comment on disclosed information

Schedule 10

Network reliability is compliant with quality requirements under DPP3, however due to the manual nature of the interruption reporting process, 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).

There is currently no independent evidence to support the accuracy of installation control points (‘ICP’s’) affected by an interruption, impacting the completeness and accuracy of ICP data included in the SAIDI and SAIFI interruption statistics.

A number of actions and initiatives are being taken to overcome limitations, including roll out and/or access to smart meter data, strengthening of processes relating to the deletion of outages from the outage system, and retention of documentation.

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.

APPENDICES

APPENDIX A:

THEPOWERCOMPANYLTD

Related Party Transactions:

Additional Information Disclosures

1. INTRODUCTION

For the purpose of meeting the 2022 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 2022 - 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 2022.

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, Lakeland Network Limited, and the Southern Generation Limited Partnership through their wholly owned subsidiary company Last Tango Limited.

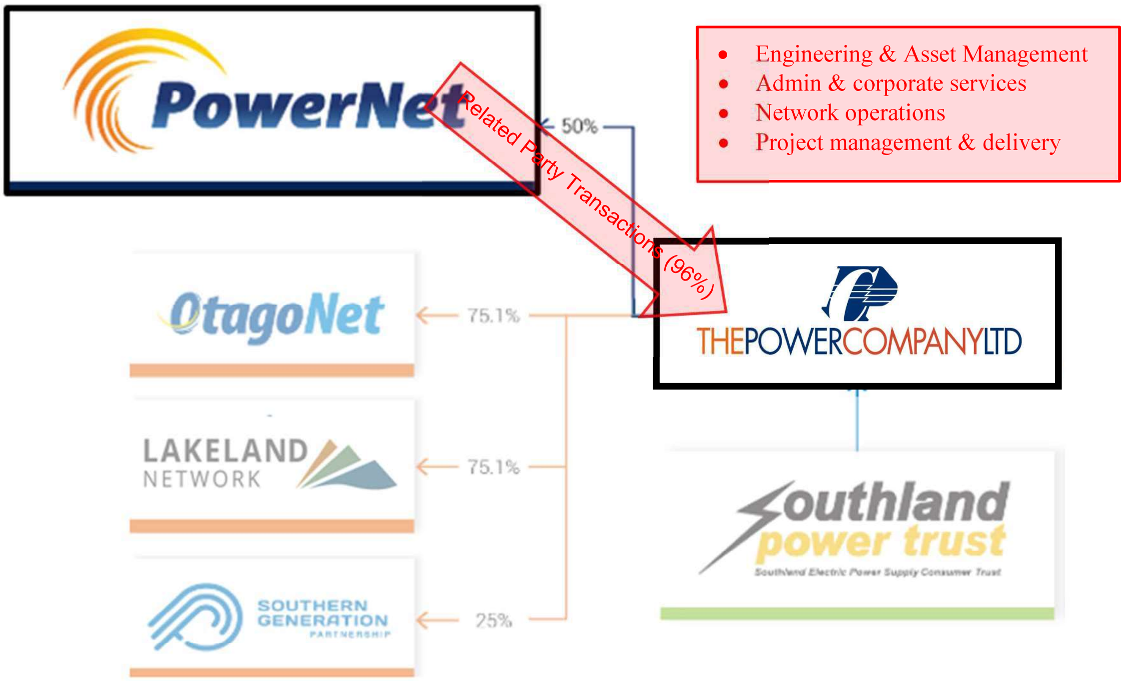
During the year ending 31 March 2022, TPCL had related party transactions with the following entities:

- 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 2022, is categorised as follows:

		($000)
Operating Expenditure:		
i.	Service interruptions and emergencies	3,584
ii.	Vegetation management	1,365
iii.	Routine and corrective maintenance and inspection	4,283
iv.	Asset replacement and renewal (Opex)	747
v.	System operations and network support	1,842
vi.	Business support	3,096
Capital Expenditure:		
vii.	Consumer connection	2,801
viii.	System growth	2,675
ix.	Asset replacement and renewal (Capex)	13,704
x.	Asset relocations	211
xi.	Quality of supply	447
xii.	Other reliability, safety and environment	4,948
	Total PowerNet Related Party expenditure	**39,703**

In the year to 31 March 2022, PowerNet provided 100% of the TPCL Lines Business Capital Expenditure, and 91% 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 acknowledged by the 2018 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 operating 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 LNL, gives PowerNet a stronger position to negotiate 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 20% of the TPCL Capital project expenditure during the 2021/22 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) and 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/individual-connection/

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.

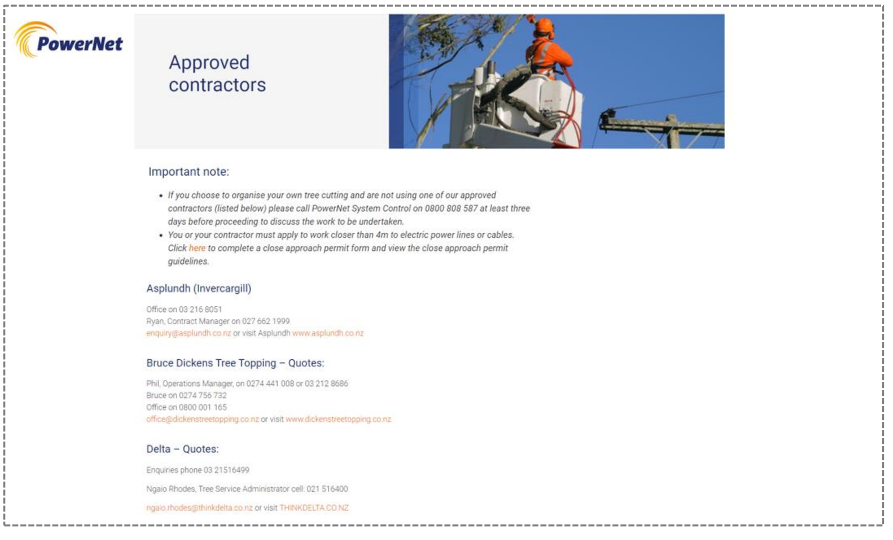
Arborist/Tree Management

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/


PowerNet

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 to work closer than 4m to electric power lines or cables. Click here to complete a close approach permit form and view the close approach permit guidelines.*

Asplundh (Invercargill)

Office on 03 216 8051
Ryan, Contract Manager on 027 662 1999
enquiry@asplundh.co.nz or visit Asplundh 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
Office on 0800 001 165
office@dickenstreetopping.co.nz or visit www.dickenstreetopping.co.nz

Delta – Quotes:

Enquiries phone 03 21516499

Ngaio Rhodes, Tree Service Administrator cell: 021 516400

ngaio.rhodes@thinkdelta.co.nz or visit THINKDELTA.CO.NZ

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 the respective sub-contractors 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. <u>Major Construction Projects (System Growth/Asset Replacement & Renewal)</u>

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.

<u>EXAMPLE: Athol to Kingston 11-22kV Upgrade Project</u>

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:	Athol to Kingston 11-22kV Upgrade Project
Project Date:	June 2020 – July 2022
Project Number:	10757
Project Expenditure:	$ 540,265 External labour & materials $ 253,302 PowerNet services ---------------- $ 793,567 2021/22 Project Expenditure $ 1,070,859 2020/21 Project Expenditure ---------------- $ 1,864,426 (Total Project Expenditure)
Project Classification:	System Growth (Capital)
Project Manager:	PowerNet Limited
Subcontractors:	PowerNet Ltd / Decom Ltd

There has been an increase in load coming online in the Kingston Area with the new housing development, sewage and water treatment station and several farms installing irrigation north of Garston. The size of the conductor from Garston ABS to Fairlight Regulator needed to be increased and two three phase regulator sites were required, one at Garston and the other at Allendale.

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 regulator design and construction to external suppliers.

PowerNet distribution teams from Gore and Lumsden carried out all of the linework.

Market Testing: The majority of the Upgrade project cost was carried out by PowerNet while the Civil and Electrical design of the regulator sites and the construction activities relating to those sites was outsourced by PowerNet. An external contractor completed the design and installation of the two three phase regulator sites, 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.

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 Subdivision Connection (February 2022)

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 Subdivision (TPCL Works programme)
Completion Date:	February 2022
Project Number:	CC 371297 / 371296
Project Expenditure:	$ 8,350 External materials & services $ 12,583 PowerNet services ------------ $ 20,933 Total Cost (2021/22)
Project Classification:	System Growth (Capital Expenditure)
Project Manager:	PowerNet Ltd
Construction:	PowerNet - Distribution Team
Subcontractors:	N/a

A customer installation connection application was received for Project CC371297 by PowerNet in mid 2021. The customer had requested a new electricity connection for a small subdivision in rural Southland, with a supply capacity of 15kVA single phase connection per section to be installed. The PowerNet distribution team undertook the work, being able to provide the skilled distribution services and equipment required. Materials were sourced through the Corys Supply Agreement.

Market Testing: PowerNet benchmarked internal labour rates favourably against similar Line Mechanic or Technician roles from other available external suppliers over the 2020-2022 period. Of the $2.8M capital expenditure spent on New Connections and Capacity Upgrades, 50% 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.

EXAMPLE: ABS Replacement (Southland – February 2022)

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

Project Name:	Replace Lochiel Cnr N ABS SH1 Lochiel (Defect 11322)
Completion Date:	03/02/2022
Project Number:	CC 390211
Project Expenditure:	\$ 9,120 External labour & materials \$ 9,036 PowerNet services -------------- \$ 18,156 Total Cost (2021/22)
Regulatory Classification:	Replacement & Renewal (Capital Expenditure)
Project Manager:	PowerNet – Barrie Duffin
Construction:	PowerNet - Distribution
Subcontractors:	Traffic Management Services

PowerNet undertook Project CC390211 to replace an Air Break Switch on an 11kV Feeder near Winton following a routine inspection that identified a defect that could trigger asset failure and replacement was deemed essential to maintain security of supply within the area. The ABS was subsequently replaced in a planned process. 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 affected 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 2020-2022. 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 2020-2022.

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.

EXAMPLE: Vegetation Management (Rural Southland – October 2021)

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 2021
Project Number:	CC 387111
Project Number:	$ 1,574 External labour & materials $ 157 PowerNet services ---------- $ 1,731 (2021/22)
Regulatory Classification:	Vegetation Management (Operating Expenditure)
Project Manager:	PowerNet Ltd
Subcontractors:	Asplundh Ltd

PowerNet became aware of trees growing within the permissible 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 (CTN226832), 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 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:	EDN– 11kv Feeder CB Maintenance
Completion Date:	June 2021
Project Number:	371660
Project Expenditure:	$ 180 External material $ 6,814 PowerNet services ------------ $ 6,994 Total Cost (2021/22)
Regulatory Classification:	Routine & Corrective 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 2020-2022.

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

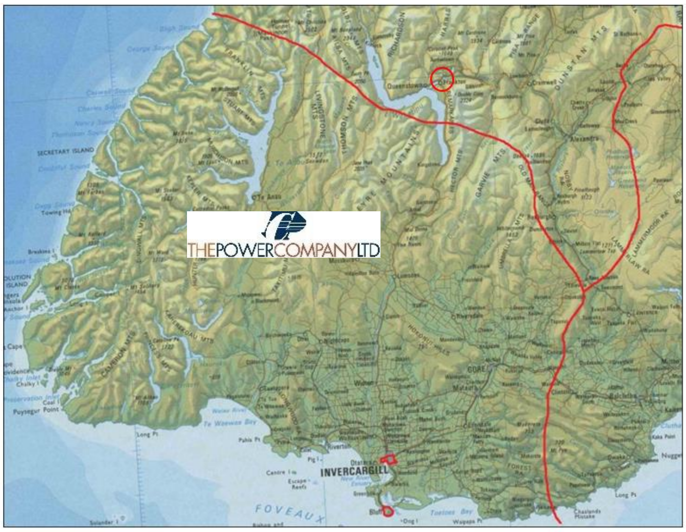
- Electricity Distribution Information Disclosure Amendments Determination 2017 (NZCC 33), clauses 2.3.13 to 2.3.16.

- 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 2022-2032 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 2022-2032 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 - $33.25m

   Provision is made for staff, plant and resources to be ready for line 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 - $13.10m

   Following the results of the routine inspection and testing of assets at zone substations, the resulting maintenance work on the substation equipment, switchgear, transformers, and protection relays.

3. Distribution Routine Inspections - $12.47 m

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

4. Vegetation Management - $11.50m

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

5. General Distribution Refurbishment -$5.95m

   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 & Checks - $5.43m

   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.

7. Distribution Routine Maintenance - $4.29m

   Routine and planned maintenance on lines, cables, transformers and other distribution components, includes temporary disconnections for customers.

8. Distribution Corrective Maintenance - $2.55m

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

9. Incident Reponse Technical – Unplanned - $2.09m

   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.

10. Technical Corrective Maintenance - $1.09m

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

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

Please Note: All of these projects -

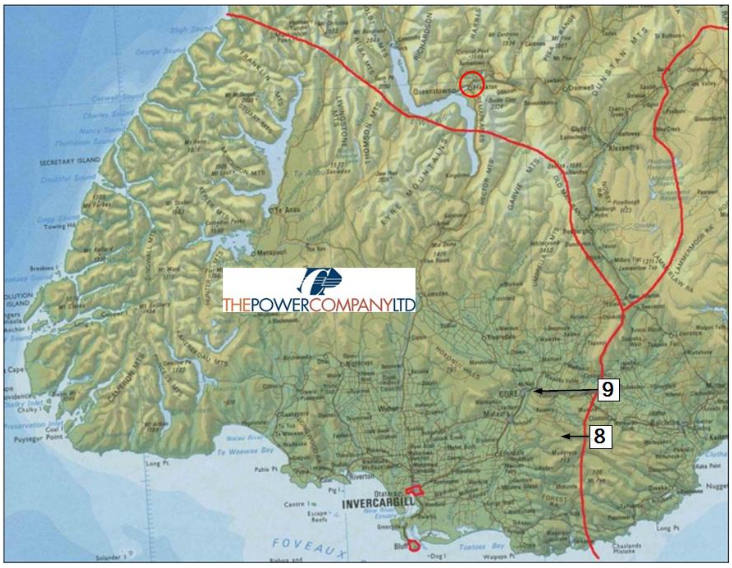
- Are network wide (apply to entire area as shown on map above).
- Have a contract in place that is with PowerNet Limited through a network management agreement (related party).
- Are forecast to require the supply of assets/goods or services by PowerNet Limited (related party).

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 2022-2032 Asset Management Plan for TPCL network are explained below, and indicated on the Network map above where relative to a single area:

1. <u>11kV Line Replacement - $69.90m</u>

   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. <u>Condition Based Asset Replacements - $35.05m</u>

   Scheduled for 2027 – 2032, 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. <u>Unspecified System Growth Projects - $23.03m</u>

   Scheduled for 2025 – 2032, 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.

4. <u>Earth Upgrades - $21.70m</u>

   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.

5. Transformer Replacement - $12.88m

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

6. Customer Connections (≤ 20kVA) - $11.69m

   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. ABS Renewals - $10.82m

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

8. Kaiwera Downs – Mercury 45 MW Wind Farm - $10.02m

   Scheduled for 2022 - 2024, this is a new 33 kV line from the Transpower Gore GXP to connect the new Mercury Energy 45 MW wind farm at Kaiwera Downs. The size of the peak generation at 45 MW requires a separate dedicated line back to the GXP.

9. McNab Substation upgrade to 33 kV - $8.90m

   Scheduled for 2022 - 2024, the existing McNab 11 kV switching station is to be upgraded to a 33/11 kV dual transformer substation to supply the new electrode boiler load at the Mataura Valley Milk Plant. The work will involve the two new transformers and 11 kV switchboard extension. The current supply cables are rated for 33 kV but will be extended from the South Gore substation to two new circuit breakers at the Transpower Gore GXP.

10. Customer Connections (> 100kVA) - $7.45m

    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.

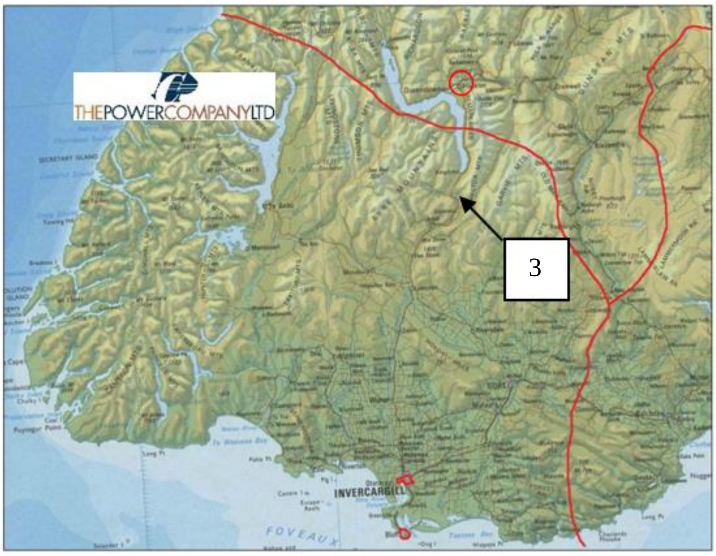
Further detail relating to TPCL network Capital Expenditure is in a table at the end of this section.

Please Note: All of these projects -

- Are network wide (apply to entire area as shown on map above), with the exception of #8 and # 9 which are pinpointed on the map above;
- Have a contract in place that is with PowerNet Limited through an agency agreement (related party;
- Are forecast to require the supply of assets/goods or services by PowerNet Limited (related party).

<u>Possible future constraints related to TPCL network Capital Expenditure projects:</u>

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



3. <u>Unspecified Projects System Growth</u>

Constraint – Unable to maintain supply voltage due to forecast load growth, timing being 3 - 10 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	$33.25m	Network Wide	Yes	Yes	Very likely	N/A
#2	Technical Planned Maintenance	Every Year	$ 13.10m	Network Wide	Yes	Yes	Very likely	N/A
#3	Routine Distribution Inspections	Every Year	$ 12.47m	Network Wide	Yes	Yes	Very likely	N/A
#4	Vegetation Management	Every Year	$ 11.50m	Network Wide	Yes	Yes	Very likely	N/A
#5	General Distribution Refurbishment	Every Year	$ 5.95m	Network Wide	Yes	Yes	Very likely	N/A
#6	Technical Routine Inspections & Checks	Every Year	$ 5.43m	Network Wide	Yes	Yes	Very likely	N/A
#7	Distribution Routine Maintenance	Every Year	$ 4.29m	Network Wide	Yes	Yes	Very likely	N/A
#8	Distribution Corrective Maintenance	Every Year	$ 2.55m	Network Wide	Yes	Yes	Very likely	N/A
#9	Incident Response Technical - Unplanned	Every Year	$ 2.09m	Network Wide	Yes	Yes	Very likely	N/A
#10	Technical Corrective Maintenance	Every Year	$ 1.09m	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	$ 69.90m	Network Wide	Yes	Yes	Very likely	N/A
#2	Condition Based Asset Replacements	2027 - 2032	$ 35.05m	Network Wide	No	N/A	Very likely	N/A
#3	Unspecified System Growth Projects	Every Year	$ 23.03m	Network Wide	Yes	N/A	Very likely	N/A
#4	Earth Upgrades	2025 - 2032	$ 21.70m	Network Wide	No	Yes	Very likely	N/A
#5	Transformer Replacement	Every Year	$ 12.88m	Network Wide	Yes	Yes	Very likely	N/A
#6	Customer Connections (≤ 20kVA)	Every Year	$ 11.69m	Network Wide	Yes	Yes	Very likely	N/A
#7	ABS Renewals	2022 - 2030	$ 10.82m	Network Wide	Yes	Yes	Very likely	N/A
#8	Kaiwera Downs – Mercury 45 MW Wind Farm	2022-2024	$ 10.02m	#8 on map	Yes	Yes	Very likely	N/A
#9	NcNab Substation Upgrade to 33 kV	2022-2024	$ 8.90m	Network Wide	Yes	Yes	Very likely	N/A
#10	Customer Connections (≥ 100kVA)	Every Year	$ 7.45m	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).

3. Unspecified Projects System Growth

   Constraint – Unable to maintain supply voltage due to forecast load growth, timing being 7-10 years.

Description of constraint	Related to CapEx project #	Expected timing of constraint
Unable to maintain supply voltage due to forecast load growth	#3	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 (Consolidated 9 December 2021)

We have completed the reasonable assurance engagement in respect of the compliance of The Power Company Limited (the "Company") with the Electricity Distribution Information Disclosure Determination 2012 (consolidated 9 December 2021) (the 'Determination') for the disclosure year ended 31 March 2022 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 (consolidated 20 May 2020) ('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 have conducted our engagement in accordance with the Standard on Assurance Engagements (SAE) 3100 (Revised) *Compliance Engagements* ("SAE 3100 (Revised)"), issued by the New Zealand Auditing and Assurance Standards Board. An engagement conducted in accordance with SAE (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 assurance 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 +/-100 basis points 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 2022, 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. Our procedures included the following: **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. **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;

Key Assurance Matter	How our procedures addressed the key assurance matter
	● 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.
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 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	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. Our procedures over Schedule 5(b) and Appendix A included the following: **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 2022 and to the accounting records, investigating any differences and determining whether any such differences are justified; and ● 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

Key Assurance Matter	How our procedures addressed the key assurance matter
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	values fell within an acceptable range. Qualitative factors were considered in determining the appropriate acceptable range.

Director's 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 regulatory advisory services, other regulatory requirements of the Commerce Act 1986, financial statement audit and tax pooling services. 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 2022 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 2022, 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.

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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 2022 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, as a body, 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 2022

Christchurch, New Zealand

5. Schedule 18: Certification for Year-End Disclosures

Clause 2.9.2

We, Douglas William Fraser and Peter William Moynihan, 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

24 August 2022

Peter William Moynihan

24 August 2022

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