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 2024

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 2024**

SCHEDULE 1: ANALYTICAL RATIOS

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

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

sch ref

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	23,500	529	121,673	2,236	41,205
Network	14,132	318	73,167	1,345	24,778
Non-network	9,369	211	48,506	892	16,427
Expenditure on assets	49,424	1,112	255,891	4,703	86,658
Network	49,424	1,112	255,891	4,703	86,658
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	76,091	1,711
Standard consumer line charge revenue	90,298	1,512
Non-standard consumer line charge revenue	34,772	943,522

1(iii): Service intensity measures

Demand density	18	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	95	*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	22,491	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	19,937	30.97%
Pass-through and recoverable costs excluding financial incentives and wash-ups	11,657	18.11%
Total depreciation	18,904	29.37%
Total revaluations	19,654	30.53%
Regulatory tax allowance	3,266	5.07%
Regulatory profit/(loss) including financial incentives and wash-ups	29,827	46.34%
Total regulatory income	64,370	

1(v): Reliability

Interruption rate	22.39	*Interruptions per 100 circuit km*

Company Name	The Power Company Limited
For Year Ended	31 March 2024

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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

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

sch ref				
7	**2(i): Return on Investment**	**CY-2**	**CY-1**	**Current Year CY**
9	**ROI – comparable to a post tax WACC**	**%**	**%**	**%**
10	Reflecting all revenue earned	8.66%	8.15%	5.69%
11	Excluding revenue earned from financial incentives	8.66%	8.15%	5.69%
12	Excluding revenue earned from financial incentives and wash-ups	8.66%	8.15%	5.69%
14	**Mid-point estimate of post tax WACC**	3.52%	4.88%	6.05%
15	25th percentile estimate	2.84%	4.20%	5.37%
16	75th percentile estimate	4.20%	5.56%	6.73%
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	8.96%	8.66%	6.39%
21	Excluding revenue earned from financial incentives	8.96%	8.66%	6.39%
22	Excluding revenue earned from financial incentives and wash-ups	8.96%	8.66%	6.39%
24	**WACC rate used to set regulatory price path**	NA	NA	NA
26	**Mid-point estimate of vanilla WACC**	3.82%	5.39%	6.75%
27	25th percentile estimate	3.14%	4.71%	6.07%
28	75th percentile estimate	4.50%	6.07%	7.43%

sch ref					
30		**2(ii): Information Supporting the ROI**		**($000)**	
32		Total opening RAB value	491,373		
33	*plus*	Opening deferred tax	(27,442)		
34		**Opening RIV**		463,931	
36		**Line charge revenue**		64,553	
38		Expenses cash outflow	31,595		
39	*add*	Assets commissioned	26,892		
40	*less*	Asset disposals	1,058		
41	*add*	Tax payments	(5)		
42	*less*	Other regulated income	(183)		
43		**Mid-year net cash outflows**		57,606	
45		**Term credit spread differential allowance**		433	
47		Total closing RAB value	517,957		
48	*less*	Adjustment resulting from asset allocation	(0)		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(30,713)		
51		**Closing RIV**		487,244	
53		**ROI – comparable to a vanilla WACC**			6.39%
55		Leverage (%)			42%
56		Cost of debt assumption (%)			5.97%
57		Corporate tax rate (%)			28%
59		**ROI – comparable to a post tax WACC**			5.69%

2(iii): Information Supporting the Monthly ROI

Opening RIV	N/A

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

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

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

Year-end ROI – comparable to a vanilla WACC	6.25%
Year-end ROI – comparable to a post tax WACC	5.55%

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

2(v): Financial Incentives and Wash-Ups

IRIS incentive adjustment		
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 2024**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

sch ref				
7		**3(i): Regulatory Profit**		**($000)**
8		**Income**		
9		Line charge revenue		64,553
10	*plus*	Gains / (losses) on asset disposals		(969)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		786
12				
13		**Total regulatory income**		64,370
14		**Expenses**		
15	*less*	Operational expenditure		19,937
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		11,657
18				
19		**Operating surplus / (deficit)**		32,776
20				
21	*less*	Total depreciation		18,904
22				
23	*plus*	Total revaluations		19,654
24				
25		**Regulatory profit / (loss) before tax**		33,526
26				
27	*less*	Term credit spread differential allowance		433
28				
29	*less*	Regulatory tax allowance		3,266
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		29,827
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	319	
36		Commerce Act levies	95	
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	10,791	
41		Transpower new investment contract charges	300	
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**		11,657
47				
48		**3(iv): Merger and Acquisition Expenditure**		
49				**($000)**
50		Merger and acquisition expenditure		–
51				
52		*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)*		
53		**3(v): Other Disclosures**		
54				**($000)**
55		Self-insurance allowance		–

Company Name	The Power Company Limited
For Year Ended	31 March 2024

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

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

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

sch ref		RAB CY-4 ($000)	RAB CY-3 ($000)	RAB CY-2 ($000)	RAB CY-1 ($000)	RAB CY ($000)
10	**Total opening RAB value**	385,009	407,982	420,819	457,373	491,373
12	*less* **Total depreciation**	14,313	15,236	15,969	17,599	18,904
14	*plus* **Total revaluations**	9,710	6,184	28,991	30,336	19,654
16	*plus* **Assets commissioned**	28,192	22,706	24,308	22,097	26,892
18	*less* **Asset disposals**	616	818	777	834	1,058
20	*plus* **Lost and found assets adjustment**	–	–	–	–	–
22	*plus* **Adjustment resulting from asset allocation**	–	–	–	–	(0)
24	**Total closing RAB value**	407,982	420,819	457,373	491,373	517,957

4(ii): Unallocated Regulatory Asset Base

sch ref		Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
29	**Total opening RAB value**		491,373		491,373
30	*less*				
31	**Total depreciation**		18,904		18,904
32	*plus*				
33	**Total revaluations**		19,654		19,654
34	*plus*				
35	Assets commissioned (other than below)				
36	Assets acquired from a regulated supplier				
37	Assets acquired from a related party	26,892		26,892	
38	**Assets commissioned**		26,892		26,892
39	*less*				
40	Asset disposals (other than below)	1,046		1,046	
41	Asset disposals to a regulated supplier				
42	Asset disposals to a related party	12		12	
43	**Asset disposals**		1,058		1,058
45	*plus* **Lost and found assets adjustment**		–		–
47	*plus* **Adjustment resulting from asset allocation**				(0)
49	**Total closing RAB value**		517,957		517,957

** 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	1,267
	CPI_4^{-4}	1,218
	Revaluation rate (%)	4.02%

		Unallocated RAB *		RAB	
		($000)	($000)	($000)	($000)
	Total opening RAB value	491,373		491,373	
less	Opening value of fully depreciated, disposed and lost assets	2,831		2,831	
	Total opening RAB value subject to revaluation	488,543		488,543	
	Total revaluations		19,654		19,654

4(iv): Roll Forward of Works Under Construction

		Unallocated works under construction		Allocated works under construction	
	Works under construction—preceding disclosure year		8,714		8,714
plus	Capital expenditure	29,674		29,674	
less	Assets commissioned	26,892		26,892	
plus	Adjustment resulting from asset allocation				
	Works under construction - current disclosure year		11,496		11,496
	Highest rate of capitalised finance applied				–

4(v): Regulatory Depreciation

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Depreciation - standard	18,904		18,904	
Depreciation - no standard life assets	–		–	
Depreciation - modified life assets	–		–	
Depreciation - alternative depreciation in accordance with CPP	–		–	
Total depreciation		18,904		18,904

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	66,724	5,548	126,181	168,298	22,230	62,461	31,044	8,887	–	491,373
less	Total depreciation	2,224	144	4,977	7,578	817	1,683	1,151	329	–	18,904
plus	Total revaluations	2,675	225	5,102	6,704	885	2,448	1,257	357		19,654
plus	Assets commissioned	3,951	1,897	4,178	6,973	404	2,440	6,703	345		26,892
less	Asset disposals			366			650	43			1,058
plus	Lost and found assets adjustment										–
plus	Adjustment resulting from asset allocation										–
plus	Asset category transfers										–
	Total closing RAB value	71,126	7,526	130,118	174,397	22,702	65,016	37,811	9,260	–	517,957
	Asset Life										
	Weighted average remaining asset life	35.2	39.0	31.5	24.1	41.6	32.3	27.8	15.6		(years)
	Weighted average expected total asset life	57.6	46.8	45.2	58.7	61.4	47.3	39.2	32.8		(years)

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2024**

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref					
7	**5a(i): Regulatory Tax Allowance**				**($000)**
8		**Regulatory profit / (loss) before tax**			33,526
9					
10	*plus*	Income not included in regulatory profit / (loss) before tax but taxable	–	*	
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible	–	*	
12		Amortisation of initial differences in asset values	6,921		
13		Amortisation of revaluations	2,706		
14					9,627
15					
16	*less*	Total revaluations	19,654		
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	114	*	
20		Notional deductible interest	11,721		
21					31,488
22					
23		**Regulatory taxable income**			11,664
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			11,664
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			3,266
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	96,892		
37	*less*	Amortisation of initial differences in asset values	6,921		
38	*plus*	Adjustment for unamortised initial differences in assets acquired			
39	*less*	Adjustment for unamortised initial differences in assets disposed	134		
40		Closing unamortised initial differences in asset values			89,837
41					
42		Opening weighted average remaining useful life of relevant assets (years)			14
43					

5a(iv): Amortisation of Revaluations

			($000)
	Opening sum of RAB values without revaluations	388,748	
	Adjusted depreciation	16,198	
	Total depreciation	18,904	
	Amortisation of revaluations		2,706

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	(27,442)	
plus	Tax effect of adjusted depreciation	4,535	
less	Tax effect of tax depreciation	5,360	
plus	Tax effect of other temporary differences*	(624)	
less	Tax effect of amortisation of initial differences in asset values	1,938	
plus	Deferred tax balance relating to assets acquired in the disclosure year		
less	Deferred tax balance relating to assets disposed in the disclosure year	(115)	
plus	Deferred tax cost allocation adjustment	0	
	Closing deferred tax		(30,713)

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	204,798	
less	Tax depreciation	19,141	
plus	Regulatory tax asset value of assets commissioned	39,780	
less	Regulatory tax asset value of asset disposals	259	
plus	Lost and found assets adjustment	–	
plus	Adjustment resulting from asset allocation	–	
plus	Other adjustments to the RAB tax value	(5,912)	
	Closing sum of regulatory tax asset values		219,265

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2024**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

sch ref

7	**5b(i): Summary—Related Party Transactions**	**($000)**	**($000)**	
8	**Total regulatory income**		512	
9				
10	**Market value of asset disposals**		12	
11				
12	Service interruptions and emergencies	5,780		
13	Vegetation management	1,529		
14	Routine and corrective maintenance and inspection	4,118		
15	Asset replacement and renewal (opex)	562		
16	**Network opex**		11,989	
17	Business support	3,662		
18	System operations and network support	2,963		
19	Non-network solutions provided by a related party or third party	–		*Not Required before DY2025*
20	**Operational expenditure**		18,614	
21	Consumer connection	15,669		
22	System growth	6,748		
23	Asset replacement and renewal (capex)	14,768		
24	Asset relocations	242		
25	Quality of supply	1,256		
26	Legislative and regulatory	–		
27	Other reliability, safety and environment	3,246		
28	**Expenditure on non-network assets**		–	
29	**Expenditure on assets**		41,930	
30	Cost of financing		–	
31	Value of capital contributions		–	
32	Value of vested assets		–	
33	**Capital Expenditure**		41,930	
34	**Total expenditure**		60,544	
35				
36	**Other related party transactions**		–	

37 **5b(iii): Total Opex and Capex Related Party Transactions**

	Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
38			
39	PowerNet Limited	Service interruptions and emergencies	5,780
40	PowerNet Limited	Vegetation management	1,529
41	PowerNet Limited	Routine and corrective maintenance and inspection	4,118
42	PowerNet Limited	Asset replacement and renewal (opex)	562
43	PowerNet Limited	System operations and network support	2,963
44	PowerNet Limited	Business support	3,116
45	PowerNet Limited	Consumer connection	15,669
46	PowerNet Limited	System growth	6,748
47	PowerNet Limited	Asset replacement and renewal (capex)	14,768
48	PowerNet Limited	Asset relocations	242
49	PowerNet Limited	Quality of supply	1,256
50	PowerNet Limited	Other reliability, safety and environment	3,246
51	Directors	Business support	547
52			
53			
54	**Total value of related party transactions**		60,544
55	** include additional rows if needed*		

Company Name	The Power Company Limited
For Year Ended	31 March 2024

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

7

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

9

sch ref	Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
10									
11	US Private Placement (USPP) US $40M	4/2/2020	7/11/2019	10.0	BKBM plus margin	62,794	58,345	235	(63)
12	US Private Placement (USPP) US $25M	4/2/2020	7/11/2019	11.0	BKBM plus margin	39,246	36,465	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*						144,810	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	250,067	
23	Leverage	42%	
24	Average opening and closing RAB values	504,665	
25	**Attribution Rate (%)**		85%
26			
27	**Term credit spread differential allowance**		433

Company Name	The Power Company Limited
For Year Ended	31 March 2024

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(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		5,780			
Not directly attributable				–	
Total attributable to regulated service		5,780			
Vegetation management					
Directly attributable		1,529			
Not directly attributable				–	
Total attributable to regulated service		1,529			
Routine and corrective maintenance and inspection					
Directly attributable		4,118			
Not directly attributable				–	
Total attributable to regulated service		4,118			
Asset replacement and renewal					
Directly attributable		562			
Not directly attributable				–	
Total attributable to regulated service		562			
Non-network solutions provided by a related party or third party *Not required before DY2025*					
Directly attributable		–			
Not directly attributable				–	
Total attributable to regulated service		–			
System operations and network support					
Directly attributable		3,850			
Not directly attributable				–	
Total attributable to regulated service		3,850			
Business support					
Directly attributable		3,656			
Not directly attributable		442	23	464	
Total attributable to regulated service		4,098			
Operating costs directly attributable		19,496			
Operating costs not directly attributable	–	442	23	464	–
Operational expenditure		19,937			

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	566
Not directly attributable	–
Total attributable to regulated service	566
Recoverable costs	
Directly attributable	11,091
Not directly attributable	
Total attributable to regulated service	11,091

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

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

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

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

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

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2024**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

7 **5e(i): Regulated Service Asset Values**

sch ref		Value allocated ($000s) Electricity distribution services
10	**Subtransmission lines**	
11	Directly attributable	71,126
12	Not directly attributable	
13	**Total attributable to regulated service**	71,126
14	**Subtransmission cables**	
15	Directly attributable	7,526
16	Not directly attributable	
17	**Total attributable to regulated service**	7,526
18	**Zone substations**	
19	Directly attributable	130,118
20	Not directly attributable	
21	**Total attributable to regulated service**	130,118
22	**Distribution and LV lines**	
23	Directly attributable	174,397
24	Not directly attributable	
25	**Total attributable to regulated service**	174,397
26	**Distribution and LV cables**	
27	Directly attributable	22,702
28	Not directly attributable	
29	**Total attributable to regulated service**	22,702
30	**Distribution substations and transformers**	
31	Directly attributable	65,016
32	Not directly attributable	
33	**Total attributable to regulated service**	65,016
34	**Distribution switchgear**	
35	Directly attributable	37,811
36	Not directly attributable	
37	**Total attributable to regulated service**	37,811
38	**Other network assets**	
39	Directly attributable	9,260
40	Not directly attributable	
41	**Total attributable to regulated service**	9,260
42	**Non-network assets**	
43	Directly attributable	–
44	Not directly attributable	
45	**Total attributable to regulated service**	–
46		
47	**Regulated service asset value directly attributable**	517,957
48	**Regulated service asset value not directly attributable**	–
49	**Total closing RAB value**	517,957
50		

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

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

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

Company Name **The Power Company Limited**
For Year Ended **31 March 2024**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref	Line Item*	Allocation methodology type	Cost allocator	Allocator type	Allocator Metric (%)		Value allocated ($000)				OVABAA allocation increase ($000)
10					Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	
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	**Non-network solutions provided by a related party or third party**	*Not required before DY2025*									
37										-	
38										-	
39										-	
40										-	
41	Not directly attributable						-	-	-	-	-
43	**System operations and network support**										
44										-	
45										-	
46										-	
47										-	
48	Not directly attributable						-	-	-	-	-
49	**Business support**										
50	Administration expenses	ABAA	Revenue	Proxy	95.07%	4.93%		442	23	464	
51										-	
52										-	
53										-	
54	Not directly attributable						-	442	23	464	-
55											
56											
57	Operating costs not directly attributable						-	442	23	464	-
58	**Pass through and recoverable costs**										
59	**Pass through costs**										
60										-	
61										-	
62										-	
63										-	
64	Not directly attributable						-	-	-	-	-
65	**Recoverable costs**										
66										-	
67										-	
68										-	
69										-	
70	Not directly attributable						-	-	-	-	-
71	** include additional rows if needed*										

Company Name	The Power Company Limited
For Year Ended	31 March 2024

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref					Allocator Metric (%)		Value allocated ($000)				
	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 2024

SCHEDULE 5h: REPORT ON CYBERSECURITY EXPENDITURE

This schedule requires details on the cybersecurity expenditure for various categories. 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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7				
8	**5h(i): Actual Expenditure Capex (where known)**			
9				
10	Cybersecurity (Commission only)	–		
11				
12	**5h(ii): Actual Expenditure Opex (where known)**			
13				
14	Cybersecurity (Commission only)	106		
15				
16	**5h(iii): Actual vs Forecast (where known)**			
17		**Target ($000)**	**Actual ($000)**	**% variance**
18	Cybersecurity (Commission only)	–	106	–
19				
20				
21				
22				
23				

Company Name	The Power Company Limited
For Year Ended	31 March 2024

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

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

sch ref				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		15,669
9		System growth		6,748
10		Asset replacement and renewal		14,768
11		Asset relocations		242
12		Reliability, safety and environment:		
13		Quality of supply	1,256	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	3,246	
16		**Total reliability, safety and environment**		4,502
17		**Expenditure on network assets**		41,930
18		Expenditure on non-network assets		–
19				
20		**Expenditure on assets**		41,930
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		12,255
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		29,674
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		–
31		**6a(iii): Consumer Connection**		
32		*Consumer types defined by EDB**	**($000)**	**($000)**
33		Half Hour Individuals	13,379	
34		Non- Domestic	384	
35		Domestic	1,906	
36				
37				
38		** include additional rows if needed*		
39		**Consumer connection expenditure**		15,669
40				
41	*less*	Capital contributions funding consumer connection expenditure	11,675	
42		**Consumer connection less capital contributions**		3,994
43		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement**
44			**System Growth**	**and Renewal**
45			**($000)**	**($000)**
46		Subtransmission	127	226
47		Zone substations	167	2,889
48		Distribution and LV lines	2,033	5,084
49		Distribution and LV cables	1,574	106
50		Distribution substations and transformers	1,773	2,389
51		Distribution switchgear	1,075	3,989
52		Other network assets		85
53		**System growth and asset replacement and renewal expenditure**	6,748	14,768
54	*less*	Capital contributions funding system growth and asset replacement and renewal	432	81
55		**System growth and asset replacement and renewal less capital contributions**	6,316	14,687
56				
57		**6a(v): Asset Relocations**		
58		*Project or programme**	**($000)**	**($000)**
59		Line relocation	242	
60				
61				
62				
63				
64		** include additional rows if needed*		
65		All other projects or programmes - asset relocations		
66		**Asset relocations expenditure**		242
67	*less*	Capital contributions funding asset relocations	67	
68		**Asset relocations less capital contributions**		175

Row		Description	($000)	($000)
69				
70		**6a(vi): Quality of Supply**		
71		*Project or programme**	($000)	($000)
72		Supply Quality Upgrades	179	
73		Network Improvements Projects	391	
74		Mobile Substation Site Made Ready	51	
75		Otatara Regulator and Automation	635	
76				
77		** include additional rows if needed*		
78		All other projects programmes - quality of supply		
79		**Quality of supply expenditure**		1,256
80	*less*	Capital contributions funding quality of supply		
81		**Quality of supply less capital contributions**		1,256
82		**6a(vii): Legislative and Regulatory**		
83		*Project or programme**	($000)	($000)
84				
85				
86				
87				
88				
89		** include additional rows if needed*		
90		All other projects or programmes - legislative and regulatory		
91		**Legislative and regulatory expenditure**		–
92	*less*	Capital contributions funding legislative and regulatory		
93		**Legislative and regulatory less capital contributions**		–
94		**6a(viii): Other Reliability, Safety and Environment**		
95		*Project or programme**	($000)	($000)
96		Earth Upgrades	3,105	
97		Comms Projects	79	
98		Kennington Fibre install	17	
99		Critical Spares	45	
100				
101		** include additional rows if needed*		
102		All other projects or programmes - other reliability, safety and environment		
103		**Other reliability, safety and environment expenditure**		3,246
104	*less*	Capital contributions funding other reliability, safety and environment		
105		**Other reliability, safety and environment less capital contributions**		3,246
106				
107		**6a(ix): Non-Network Assets**		
108		**Routine expenditure**		
109		*Project or programme**	($000)	($000)
110				
111				
112				
113				
114				
115		** include additional rows if needed*		
116		All other projects or programmes - routine expenditure		
117		**Routine expenditure**		–
118		**Atypical expenditure**		
119		*Project or programme**	($000)	($000)
120				
121				
122				
123				
124				
125				
126		All other projects or programmes - atypical expenditure		
127		**Atypical expenditure**		–
128				
129		**Expenditure on non-network assets**		–

Company Name	The Power Company Limited
For Year Ended	31 March 2024

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

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

sch ref			($000)	($000)
7	**6b(i): Operational Expenditure** *Required for DY2024 and DY2025 only*		($000)	($000)
8	Service interruptions and emergencies		5,780	
9	Vegetation management		1,529	
10	Routine and corrective maintenance and inspection		4,118	
11	Asset replacement and renewal		562	
12	**Network opex**			11,989
13	Non-network solutions provided by a related party or third party	*Required for DY2025 only*		
14	System operations and network support		3,850	
15	Business support		4,098	
16	**Non-network opex**			7,948
17				
18	**Operational expenditure**			19,937
19	**6b(i): Operational Expenditure** *Not Required before DY2026*		($000)	($000)
20	Service interruptions and emergencies:			
21	Vegetation-related			
22	Other			
23	**Total service interruptions and emergencies**		–	
24	Vegetation management:			
25	Assessment and notification costs			
26	Felling or trimming vegetation - in-zone			
27	Felling or trimming vegetation - out-of-zone			
28	Other			
29	**Total vegetation management**		–	
30				
31	Routine and corrective maintenance and inspection:			
32	Asset replacement and renewal			
33	**Network opex**			–
34	Non-network solutions provided by a related party or third party			
35	System operations and network support			
36	Business support			
37	**Non-network opex**			–
38				
39	**Operational expenditure**			–
40	**6b(ii): Subcomponents of Operational Expenditure (where known)**			
41	Energy efficiency and demand side management, reduction of energy losses			150
42	Direct billing*			–
43	Research and development			–
44	Insurance			529
45	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*			

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2024**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

sch ref				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	64,282	64,553	0%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	11,758	15,669	33%
11	System growth	4,565	6,748	48%
12	Asset replacement and renewal	18,016	14,768	(18%)
13	Asset relocations	130	242	86%
14	Reliability, safety and environment:			
15	Quality of supply	1,039	1,256	21%
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	3,765	3,246	(14%)
18	**Total reliability, safety and environment**	4,804	4,502	(6%)
19	**Expenditure on network assets**	39,273	41,930	7%
20	Expenditure on non-network assets	15	–	(100%)
21	Expenditure on assets	39,288	41,930	7%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	4,085	5,780	41%
24	Vegetation management	1,225	1,529	25%
25	Routine and corrective maintenance and inspection	4,808	4,118	(14%)
26	Asset replacement and renewal	1,018	562	(45%)
27	**Network opex**	11,136	11,989	8%
28	Non-network solutions provided by a related party or third party *Not Required before DY2025*	–	–	–
29	System operations and network support	3,541	3,850	9%
30	Business support	4,286	4,098	(4%)
31	**Non-network opex**	7,827	7,948	2%
32	**Operational expenditure**	18,963	19,937	5%
33	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
34	Energy efficiency and demand side management, reduction of energy losses	63	–	(100%)
35	Overhead to underground conversion	–	–	–
36	Research and development	–	–	–
37				
38	**7(v): Subcomponents of Operational Expenditure (where known)**			
39	Energy efficiency and demand side management, reduction of energy losses	–	150	–
40	Direct billing	–	–	–
41	Research and development	–	–	–
42	Insurance	390	529	36%
43				

44 *1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of this determination*

45 *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 2024
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.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

sch ref

8(i): Billed Quantities by Price Component

Billed quantities by price component *Not Required after DY2024*

Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Variable day energy sales	Variable Peak energy purchases	Variable Shoulder energy purchases	Variable Night energy purchases		
				Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh		
Low user	Residential	Standard	10,072	61,095		27,528,918	23,447,481	17,126,033		
Domestic	Residential	Standard	18,037	165,343		70,013,614	60,453,810	46,157,793		
Non-Domestic	Commerical	Standard	9,338	219,644		94,616,256	81,384,252	61,385,311		
Individual Non Half Hour	Commerical	Standard	51	6,793		2,926,276	2,517,039	1,898,515		
Individual Half Hour	Commerical	Standard	214	178,421	125,994,831					
Hour	Commerical	Non-standard	5	216,526	143,989,882					
Generation	Commerical	Non-standard	3	552	352,740					
	[Select one]	[Select one]								
	[Select one]	[Select one]								
	[Select one]	[Select one]								
Add extra rows for additional consumer groups or price category codes as necessary										
		Standard consumer totals	37,712	631,296	125,994,831	195,085,064	167,802,582	126,567,651	–	–
		Non-standard consumer totals	8	217,078	144,342,621	–	–	–	–	–
		Total for all consumers	37,720	848,374	270,337,453	195,085,064	167,802,582	126,567,651	–	–

Billed quantities by price component *Not Required before DY2025*

Standardised price component	[Select one]		[Select one]		[Select one]		[Select one]	
EDB defined price component								
	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity
Standard consumer totals	–	–	–	–	–	–	–	–
Non-standard consumer totals	–	–	–	–	–	–	–	–
Total for all consumers	–	–	–	–	–	–	–	–

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	Standardised connection types	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Total distribution line charge revenue *Not Required after DY2024*	Total transmission line charge revenue *Not Required after DY2024*
Low user	Residential	Standard	$7,343	6,230	1,114
Domestic	Residential	Standard	$19,810	17,644	2,166
Non-Domestic	Commerical	Standard	$23,998	21,482	2,516
Individual Non Half Hour	Commerical	Standard	$501	344	156
Individual Half Hour	Commerical	Standard	$5,353	1,098	4,255
Hour	Commerical	Non-standard	$5,689	4,819	870
Generation	Commerical	Non-standard	$1,859	1,845	14
	[Select one]	[Select one]	–		
	[Select one]	[Select one]	–		
	[Select one]	[Select one]	–		
Add extra rows for additional consumer groups or price category codes as necessary					
		Standard consumer totals	$57,005	$46,798	$10,207
		Non-standard consumer totals	$7,548	$6,664	$884
		Total for all consumers	$64,553	$53,462	$11,091
				Check	OK

Line charge revenues ($000) by price component *Not Required after DY2024*

Consumer group name or price category code	Fixed	Variable Day energy Sales	Variable Peak energy purchases	Variable Shoulder energy purchases	Variable Night energy purchases	Notional Discount	Total distribution line charge revenue	Total transmission line charge revenue
Rate (eg, $ per day, $ per kWh, etc.)	$/Day	$/kWh	$/kWh	$/kWh	$/kWh			
Low user	$1,254		$3,898	$2,944	$343	($1,095)	–	–
Domestic	$10,159		$6,555	$5,056	$923	($2,883)	–	–
Non-Domestic	$10,781		$8,806	$6,754	$1,228	($3,571)	–	–
Individual Non Half Hour	$45		$274	$210	$38	($66)	–	–
Individual Half Hour	$3,416	$2,551				($614)	–	–
Hour	$5,953					($264)	–	–
Generation	$1,897					($39)	–	–
							–	–
							–	–
							–	–
Standard consumer totals	$25,655	$2,551	$19,533	$14,963	$2,531	($8,228)	–	–
Non-standard consumer totals	$7,850	–	–	–	–	($302)	–	–
Total for all consumers	$33,505	$2,551	$19,533	$14,963	$2,531	($8,530)	–	–
							Check	Error

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

Line charge revenues ($000) by price component *Not Required before DY2025*

Standardised price component	[Select one]			[Select one]			[Select one]			[Select one]		
EDB defined price component												
	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)
			–			–			–			–
			–			–			–			–
			–			–			–			–
			–			–			–			–
			–			–			–			–
			–			–			–			–
			–			–			–			–
			–			–			–			–
			–			–			–			–
			–			–			–			–
Standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–
Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–
Total for all consumers	–	–	–	–	–	–	–	–	–	–	–	–

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

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	8

Company Name	The Power Company Limited
For Year Ended	31 March 2024
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

9a: Asset Register

	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	92,995	93,676	681	3
10	All	Overhead Line	Wood poles	No.	17,103	16,657	(446)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	897	910	13	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	13	34	22	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	(0)	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	57	(1)	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	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	13	13	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	295	305	10	3
29	HV	Zone substation switchgear	33kV RMU	No.	2	2	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	23	23	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	35	35	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	157	161	4	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	47	46	(1)	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	61	61	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	6,723	6,724	1	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	122	113	(9)	3
39	HV	Distribution Cable	Distribution UG PILC	km	36	36	(0)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	28	28	–	3
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	34	33	(1)	3
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	13,133	13,194	61	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.	116	114	(2)	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	10,681	10,712	31	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	725	747	22	3
48	HV	Distribution Transformer	Voltage regulators	No.	76	81	5	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	7	7	–	3
50	LV	LV Line	LV OH Conductor	km	849	849	(0)	3
51	LV	LV Cable	LV UG Cable	km	232	239	7	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	363	365	2	3
53	LV	Connections	OH/UG consumer service connections	No.	38,968	39,405	437	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	703	722	19	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 2024
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

9b: Asset Age Profile

8 Disclosure Year (year ended)

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
9																																									
10	All	Overhead Line	Concrete poles / steel structure	No.	–	–	2,182	35,793	11,807	20,696	2,963	202	835	1,018	613	173	88	136	328	317	901	1,214	796	929	1,016	1,202	1,214	1,366	1,551	1,260	1,289	787	857	748	673	124	–	598	93,676		3
11	All	Overhead Line	Wood poles	No.	–	–	434	1,106	3,697	547	3,373	726	739	715	698	661	453	858	777	1,026	112	6	2	16	13	164	2	18	12	17	3	10	–	6	5	–	–	461	16,657		3
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	129	125	125	139	137	59	35	8	24	–	–	0	27	22	1	–	0	–	–	36	13	–	12	1	–	0	–	0	15	1	–	2	910		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	12	0	4	0	0	7	–	–	4	34		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	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	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	–	1	1	–	–	–	–	1	–	–	–	–	1	1	1	1	1	8	3	3	–	–	–	–	–	–	4	57		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.	–	–	–	–	–	–	10	7	1	–	–	2	2	2	13	–	5	–	–	3	2	1	–	–	5	4	–	–	2	–	–	–	–	–	59		4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	8	–	–	–	1	–	–	4	–	–	–	–	13		4
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	18	11	11	29	60	3	35	2	1	9	7	10	24	3	7	1	1	8	4	5	4	–	5	7	10	6	2	3	4	1	–	14	305		3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	2		4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	7	–	–	–	5	–	–	–	–	–	–	–	–	7	1	–	–	–	1	–	2	–	–	–	–	23		4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	1	1	3	6	–	–	–	–	–	1	2	3	2	–	1	1	–	–	–	–	–	2	–	1	4	3	2	2	–	–	–	35		4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	–	14	48	–	–	1	–	–	1	–	6	–	2	–	–	17	10	13	16	9	6	7	5	4	1	–	1	–	–	–	161		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	3	18	6	–	–	1	3	1	–	–	1	–	1	–	–	4	1	–	–	2	1	–	1	2	–	–	1	–	–	46		3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	–	6	5	8	2	1	3	2	1	3	–	2	–	2	1	–	–	–	8	1	2	2	3	2	–	1	–	–	4	2	–	–	61		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3	0	187	709	3,220	1,054	305	47	96	102	68	52	53	54	72	102	76	49	50	55	38	75	36	34	12	21	31	16	18	38	13	9	–	29	6,724		3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
38	HV	Distribution Line	SWER conductor	km	–	–	–	4	1	–	–	–	–	–	–	–	–	–	–	4	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	9		3
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	–	0	15	5	5	2	4	3	5	9	4	5	8	4	3	2	1	5	1	4	6	3	1	2	2	3	1	1	2	0	–	8	113		3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	0	13	3	8	1	–	1	0	–	3	1	3	1	0	0	1	0	–	0	–	–	0	–	–	–	–	–	–	–	–	2	36		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	–	–	1	–	–	–	–	28		3
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	2	6	14	2	7	–	–	–	–	–	33		3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	9	1	164	248	1,142	1,837	1,325	100	307	372	259	280	232	314	375	418	427	399	367	346	292	351	286	214	248	276	295	305	325	336	347	72	–	925	13,194		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	–	–	–	6	–	3	3	7	10	7	2	1	3	1	1	–	–	4	23	5	15	7	2	2	1	–	–	114		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	8	1	145	62	1,109	1,732	1,271	92	295	359	244	235	223	302	361	392	393	370	331	316	247	314	240	172	202	181	194	199	202	229	213	40	–	38	10,712		3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	3	5	77	78	36	5	17	23	19	30	25	33	32	27	24	21	13	16	21	29	16	17	34	21	18	21	19	25	34	3	–	5	747		3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	4	–	1	6	4	5	15	13	3	–	–	–	–	8	–	–	4	–	1	1	–	9	–	4	–	3	81		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	477	102	41	3	9	11	7	5	4	6	6	7	6	5	4	4	5	5	4	6	6	5	8	5	4	4	4	0	–	8	849		3
52	LV	LV Cable	LV UG Cable	km	–	–	0	2	80	20	11	1	1	4	4	7	13	14	15	6	7	5	4	3	3	2	3	1	3	4	6	2	4	2	3	0	–	8	239		3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	0	14	236	41	17	1	3	2	1	3	4	3	2	1	1	3	2	1	2	0	0	1	2	2	1	5	1	1	0	0	–	14	365		3
54	LV	Connections	OH/UG consumer service connections	No.	–	202	2,101	5,223	6,965	7,804	6,917	243	342	431	431	413	463	509	565	681	513	417	471	358	397	329	301	281	338	338	407	410	438	441	373	82	–	221	39,405		3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	8	9	41	90	16	11	1	3	4	17	8	25	18	8	5	3	27	15	25	37	35	49	44	37	59	39	33	34	5	–	16	722		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 2024**
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 9c: Overhead Lines and Underground Cables

sch ref		Overhead (km)	Underground (km)	Total circuit length (km)
10				
11	**Circuit length by operating voltage (at year end)**			
12	> 66kV	–	–	–
13	50kV & 66kV	531	–	531
14	33kV	379	35	414
15	SWER (all SWER voltages)	5	4	9
16	22kV (other than SWER)	0	1	1
17	6.6kV to 11kV (inclusive—other than SWER)	6,723	149	6,872
18	Low voltage (< 1kV)	849	239	1,088
19	**Total circuit length (for supply)**	8,488	428	8,915
20				
21	Dedicated street lighting circuit length (km)	271	94	365
22	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			
23				

sch ref	**Overhead circuit length by terrain (at year end)**	Circuit length (km)	(% of total overhead length)
24			
25	Urban	475	6%
26	Rural	4,556	54%
27	Remote only	804	9%
28	Rugged only	2,043	24%
29	Remote and rugged	610	7%
30	Unallocated overhead lines	–	–
31	**Total overhead length**	8,488	100%
32			

sch ref		Circuit length (km)	(% of total circuit length)
33			
34	Length of circuit within 10km of coastline or geothermal areas (where known)	1,543	17%
35			

sch ref		Circuit length (km)	(% of total overhead length)	
36				
37	Overhead circuit requiring vegetation management	1,599	19%	*Not required after DY2025*

sch ref		Total newly identified throughout the disclosure year	Total remaining at high risk at the disclosure year-end	
38				
39	Number of overhead circuit sites at high risk from vegetation damage		–	*Not required before DY2026*
40				

41 **Breakdown of overhead circuit sites at high risk from vegetation damage at disclosure year-end**

sch ref	Category of overhead circuit site	Number of overhead circuit sites at high risk from vegetation damage at disclosure year-end	Number of overhead circuit sites involving critical assets at disclosure year-end	
42				
43	[Single tree]			*Not required before DY2026*
44	[Single tree - Urban]			*Not required before DY2026*
45	[Single tree - Rural]			*Not required before DY2026*
46	[Row of trees]			*Not required before DY2026*
47	[Span between two poles (X metres)]			*Not required before DY2026*
48	[Other]			*Not required before DY2026*
49	**Total number of sites**	–	–	*Not required before DY2026*

50 ** Insert new rows in table above Total line as necessary*

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2024**

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 *	Average number of ICPs in disclosure year	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 2024**
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

9e(i): Consumer Connections and Decommissionings

Number of ICPs connected during year by consumer type

*Consumer types defined by EDB**	**Number of connections (ICPs)**
Domestic	330
Half Hour Individual	11
Low User	16
Non Domestic	147
[EDB consumer type]	
** include additional rows if needed*	
Connections total	504

Number of ICPs decommissioned during year by consumer type

*Consumer types defined by EDB**	**Number of decommissionings**
Low user	3
Domestic	32
Non-Domestic	36
Individual Half Hour	3
[EDB consumer type]	
** include additional rows if needed*	
Decommissionings total	74

Distributed generation

Number of connections made in year	55	**connections**
Capacity of distributed generation installed in year	43.34	**MVA**

9e(ii): System Demand

Maximum coincident system demand		**Demand at time of maximum coincident demand (MW)**
	GXP demand	102
plus	Distributed generation output at HV and above	60
	Maximum coincident system demand	162
less	Net transfers to (from) other EDBs at HV and above	(2)
	Demand on system for supply to consumers' connection points	164

Electricity volumes carried		**Energy (GWh)**	
	Electricity supplied from GXPs	664	
less	Electricity exports to GXPs	225	
plus	Electricity supplied from distributed generation	462	
less	Net electricity supplied to (from) other EDBs	2	
	Electricity entering system for supply to consumers' connection points	898	
less	Total energy delivered to ICPs	848	
	Electricity losses (loss ratio)	50	5.6%
	Load factor	0.63	

9e(iii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	484
Distribution transformer capacity (Non-EDB owned)	24
Total distribution transformer capacity	508

	(MVA)
Zone substation transformer capacity (EDB owned)	488
Zone substation transformer capacity (Non-EDB owned)	13
Total zone substation transformer capacity	501

Company Name	The Power Company Limited
For Year Ended	31 March 2024
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 **10(i): Interruptions**

sch ref	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)	1,463
13	Class D (unplanned interruptions by Transpower)	
14	Class E (unplanned interruptions of EDB owned generation)	
15	Class F (unplanned interruptions of generation owned by others)	
16	Class G (unplanned interruptions caused by another disclosing entity)	2
17	Class H (planned interruptions caused by another disclosing entity)	
18	Class I (interruptions caused by parties not included above)	
19	**Total**	1,996

sch ref	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	960	503

sch ref	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)		
26	Class B (planned interruptions on the network)	0.6661	167.55
27	Class C (unplanned interruptions on the network)	4.4171	359.12
28	Class D (unplanned interruptions by Transpower)		
29	Class E (unplanned interruptions of EDB owned generation)		
30	Class F (unplanned interruptions of generation owned by others)		
31	Class G (unplanned interruptions caused by another disclosing entity)	0.0144	0.15
32	Class H (planned interruptions caused by another disclosing entity)		
33	Class I (interruptions caused by parties not included above)		
34	**Total**	5.10	526.8

sch ref	Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI	
37	Classes B & C (interruptions on the network)	5.0830	461.38	*Not required after DY2024*

sch ref	Transitional SAIFI and SAIDI (previous method)	SAIFI	SAIDI
40	Class B (planned interruptions on the network)	0.6659	167.55
41	Class C (unplanned interruptions on the network)	3.7624	359.12

43 *Where EDBs do not currently record their SAIFI and SAIDI values using the 'multi-count' approach, they shall continue to record their SAIFI and SAIDI values on the same basis that they employed as at 31 March 2023 as 'Transitional SAIFI' and 'Transitional SAIDI' values, in addition to their SAIFI and SAIDI values (Classes B & C) using the 'multi-count approach'.* ***This is a transitional reporting requirement that shall be in place for the 2024, 2025, and 2026 disclosure years.***

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

sch ref	Cause	SAIFI	SAIDI	
47	Lightning	0.0370	2.51	
48	Vegetation	1.0128	92.60	
49	Adverse weather	0.8175	101.35	
50	Adverse environment	0.0313	3.97	
51	Third party interference	0.5810	39.07	
52	Wildlife	0.2563	18.03	
53	Human error	0.0972	8.86	
54	Defective equipment	1.2354	69.43	
55	Cause unknown	0.3480	22.89	*Not required after DY2024*
56	Other cause	0.0006		*Not required before DY2025*
57	Unknown			*Not required before DY2025*

sch ref	Breakdown of third party interference	SAIFI	SAIDI
60	Dig-in		
61	Overhead contact	0.1794	15.14
62	Vandalism	0.0133	0.92
63	Vehicle damage	0.3489	20.66
64	Other	0.0394	2.35

sch ref	Breakdown of vegetation interruptions (vegetation cause)	SAIFI	SAIDI	
67	In-zone			*Not required before DY2026*
68	Out-of-zone			*Not required before DY2026*

70 **10(iii): Class B Interruptions and Duration by Main Equipment Involved**

sch ref	Main equipment involved	SAIFI	SAIDI
73	Subtransmission lines	0.0049	1.42
74	Subtransmission cables		
75	Subtransmission other		
76	Distribution lines (excluding LV)	0.5891	152.84
77	Distribution cables (excluding LV)	0.0125	3.60
78	Distribution other (excluding LV)	0.0597	9.68

79 **10(iv): Class C Interruptions and Duration by Main Equipment Involved**

sch ref	Main equipment involved	SAIFI	SAIDI
82	Subtransmission lines	0.9083	57.22
83	Subtransmission cables		
84	Subtransmission other	0.1062	2.65
85	Distribution lines (excluding LV)	2.9779	266.83
86	Distribution cables (excluding LV)	0.0321	1.74
87	Distribution other (excluding LV)	0.3926	30.68

88 **10(v): Fault Rate**

sch ref	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
90	Subtransmission lines	19	910	2.09
91	Subtransmission cables		35	–
92	Subtransmission other	2		
93	Distribution lines (excluding LV)	1,089	6,729	16.18
94	Distribution cables (excluding LV)	11	153	7.18
95	Distribution other (excluding LV)	342		
96	**Total**	1,463		

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 5.68%, which is 1.05% below the 75^{th} percentile estimate of post-tax WACC of 6.73%. The Power Company also achieved an 6.38% vanilla ROI, which is 1.05% below the 75^{th} percentile estimate of vanilla WACC of 7.43%.

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, the Seaward Bush to Bluff 33kv distribution lines, and insurance reimbursement for customer claims.

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 2023 figure of $491,373k as the starting point with inflationary indexing over the year to 31 March 2024 plus additions less disposals, resulting in a closing RAB balance of $517,957k at 31 March 2024. 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 deductible expenditure not included in regulatory profit is the $114k cost of easements which is a tax 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:	$ 3,444
	$ 3,444
Tax Rate:	28%
Temporary Differences	$ 964

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 100% directly attributable to electricity distribution services.

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. When the work performed is not material in relation to the overall value of the asset, it is classified as routine and corrective maintenance and inspection. 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)

In the box below, comment on variance in actual to forecast expenditure for the disclosure year, as reported in Schedule 7. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

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

No items were reclassified during the disclosure year. Refer to each classification under point 12 and 13 above.

Capital Expenditure:

The overall actual capex expenditure on network assets was 7% over budget.

Customer connections

- 33% over budget
- Customer-initiated work primarily influences this budget, and we are seeing greater-than expected growth in 'Customer Connections (≥ 100kVA).' Additionally, the spending for the multi-year project 'Kaiwera Downs—Mercury 45MW wind farm' has been deferred from FY22/23 to FY23/24 compared to the forecast. However, this deferral does not significantly affect the total project cost.

System Growth

- 48% over budget
- Some of the work that has been scheduled in FY24/25 on the 22kV Athol-Kingston project was brought forward to ensure there is sufficient workforce to conduct the customer driven work for the FY24/25.
- Unplanned work at the Edendale Substation driven by customer growth.

Asset replacement and renewal

- 18% under budget.
- Orawia Substation project has been delayed due to not accessible to the mobile substation and getting the construction contact sign with contractors.
- RMU replacement has been delayed due to resource constraints.
- Power Transformer Refurbishment has been delayed due to the tap changers failure at Te Anau substation which require delivery of the tap changer from overseas.
- Link box replacement project has been delayed as requested from the Gore District Council.
- Circuit Breaker Replacement has been delayed due to late delivery of circuit breakers.

Asset relocations:

- 86% over budget.
- Work mainly driven by customer request and Territorial Local Authority work programme with the opportunity taken to move lines to the roadside where it is economical.

Quality of supply:

- 21% over budget.
- Asbestos was found during the installation of the communication masks at the Transpower GXP resulting in unexpected cost in the projects.
- The Otatara Regulator project budget was underestimated in the planning process, and during the project execution, there have been a number of variations, including a change in the site's location due to an easement issue.

Other Reliability, Safety and Environment:

- 14% under budget.
- The delivery timeline of critical spare equipment such as regulator and controller has been delayed from forecast resulted in costs being incurred in the FY24/25 instead of FY23/24.

Operational Expenditure:
Total operational expenditure was 5% over budget.

Service interruptions and emergencies

- 41% over budget.
- Higher unplanned distribution and technical fault response costs due to faults from weather conditions and some increased material costs.
- Mobile Substation has been deployed to Te Anau Substation to maintain the security of supply in the region due to tap changers failure in the zone substation transformers.

Vegetation management:

- 25% over budget
- New Asplundh contract rates and amount of work completed was higher than budgeted, with more trees being identified and cut.

Routine and corrective maintenance:

- 14% under budget.
- Corrective maintenance higher due to increased number of follow up repairs, linked to incident response spend.
- Connections maintenance incurred an additional cost from smart meter data providers.
- Routine maintenance work below budget due to resource constraints.

Asset replacement and renewal maintenance:

- 45% under budget.
- Work is largely driven from the inspection programme subject to the refurbishment work identified during the year.

Information relating to revenues and quantities for the disclosure year

14. In the box below provide-

14.1 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

14.2 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 $64,282k, the total billed was $64,553k.

Network Reliability for the Disclosure Year (Schedule 10)

15. In the box below, comment on network reliability for the disclosure year, as disclosed in Schedule 10.

Box 13: Commentary on network reliability for the disclosure year

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

TPCL has calculated and disclosed SAIDI and SAIFI metrics consistent with the 2012 Electricity Distribution Business (EDB) ID Determination, incorporating all amendments up to 29 February 2024.

SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) are consumer-focused measures of average outage duration and frequency. SAIDI is calculated based on the duration of each interruption stage and the number of consumers affected. SAIFI is now calculated using the ‘multi-count’ methodology, which includes successive interruptions within a main outage.

In previous years, TPCL did not include successive interruptions after the initial interruption when calculating SAIFI. To maintain continuity, this calculation method is recorded in Schedule 10, reference rows 39-41 (Transitional SAIFI and SAIDI – previous method). Only these and the normalised SAIFI figures are comparable to previous disclosures.

For the 2023/24 regulatory year, TPCL has disclosed a normalised SAIDI of 461.38 and a normalised SAIFI of 5.08. The normalised SAIDI is 14% higher than the previous year. TPCL's ID Determination values for the 2022/23 year were 403.39 for normalised SAIDI and 4.41 for normalised SAIFI, indicating more interruptions and longer durations on average compared to last year.

The total number of power interruptions on TPCL's network has increased since 2022/23. Class B (planned) interruptions and Class C (unplanned) interruptions rose by 10% and 9%, respectively. Class C SAIFI of 4.42 contributed 87% of the total network SAIFI. Class C SAIDI remained relatively stable compared to the previous year, with only a 3% increase, while Class B (planned) SAIDI was 13% higher than in 2022/23.

In terms of SAIDI, vegetation and adverse weather were the most significant causes of Class C interruptions, accounting for 26% and 28%, respectively. Defective equipment was the most significant cause of Class C interruptions based on SAIFI, representing 28% of the total.

TPCL’s network consists of 86% distribution lines (excluding LV), with 91% of planned interruptions and 74% of unplanned interruptions occurring on these lines, as measured by SAIDI.

The fault rate per 100 km was stable for both distribution and subtransmission lines. The distribution cable fault rate doubled to 7.18 faults per 100 km compared to the previous year (3.7 faults per km). No faults occurred on subtransmission cables this year.

Insurance cover

16. In the box below, provide details of any insurance cover for the assets used to provide electricity distribution services, including-

    16.1 The EDB's approaches and practices in regard to the insurance of assets used to provide electricity distribution services, including the level of insurance;

    16.2 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 $203.05 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

17. 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:

    17.1 a description of each error; and

    17.2 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 2022:

	2024	2025	2026	2027	2028
Inflator (CAPEX & OPEX)	6.9%	4.5%	2.8%	2.2%	2.0%

In addition to the general inflation, material costs have increased by a weighted average of 5.2% in 2022 and labour and external services costs have increased by 6.5%. These increases are included in the CAPEX forecasts for 2023 onwards.

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.

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

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 the assessment of performance on a consistent basis with other networks. However, due to the manual nature of the interruption reporting process, there are inherent limitations in TPCL's ability to collect and record the network reliability information required to be disclosed in Schedule 10 (i) to 10 (iv).

TPCL is leveraging its investment in advanced meters by using alarm information raised by the meters to confirm installation control points (ICPs) affected by an interruption. This improves the completeness and accuracy of ICP data included in the SAIDI and SAIFI interruption statistics. Additionally, they are undertaking an initiative to use this data to confirm outage duration.

Currently, TPCL System Control uses a live map of advanced meters to highlight areas that are currently without power, potentially reducing SAIDI.

Schedule 5a(vi) and 5a(viii)

In March 2024, the New Zealand Government enacted the Taxation (Annual Rates for 2023/24, Multinational Tax and Remedial Matters) Bill. As a result, from the 2024/25 income tax year onwards, The Power Company Ltd can no longer claim any tax depreciation on their buildings with estimated useful lives of 50 years or more in New Zealand. The Company assessed the impact of this change in regulatory assets, which resulted in the removal of buildings from the tax asset register amounting to $5,912,000. An associated increased deferred tax liability of $1,588,000 was also recognised during the year.

APPENDICES

A. Related Party Transaction Additional Information Disclosure

APPENDIX A:

Related Party Transactions:

Additional Information Disclosures

1. INTRODUCTION

For the purpose of meeting the 2024 Related Party Transaction reporting requirements, in accordance with section 2.3.6 of the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC 2.

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

- **The Power Company Limited's Information Disclosure**, for the year ended 31 March 2024 - 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 Power Company Limited (TPCL) network assets, being greater than $20 million for the year ending 31 March 2024.

Full Disclosure requires additional information be provided associated with related party transactions, including related party relationships, procurement policies and processes, application of these policies and 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 at least every 3 years.

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.

TPCL has an interest in the PowerNet Limited Joint Venture, the OtagoNet Joint Venture (OJV), Lakeland Network Limited, and the Southern Generation Limited Partnership through its wholly owned subsidiary company Last Tango Limited.

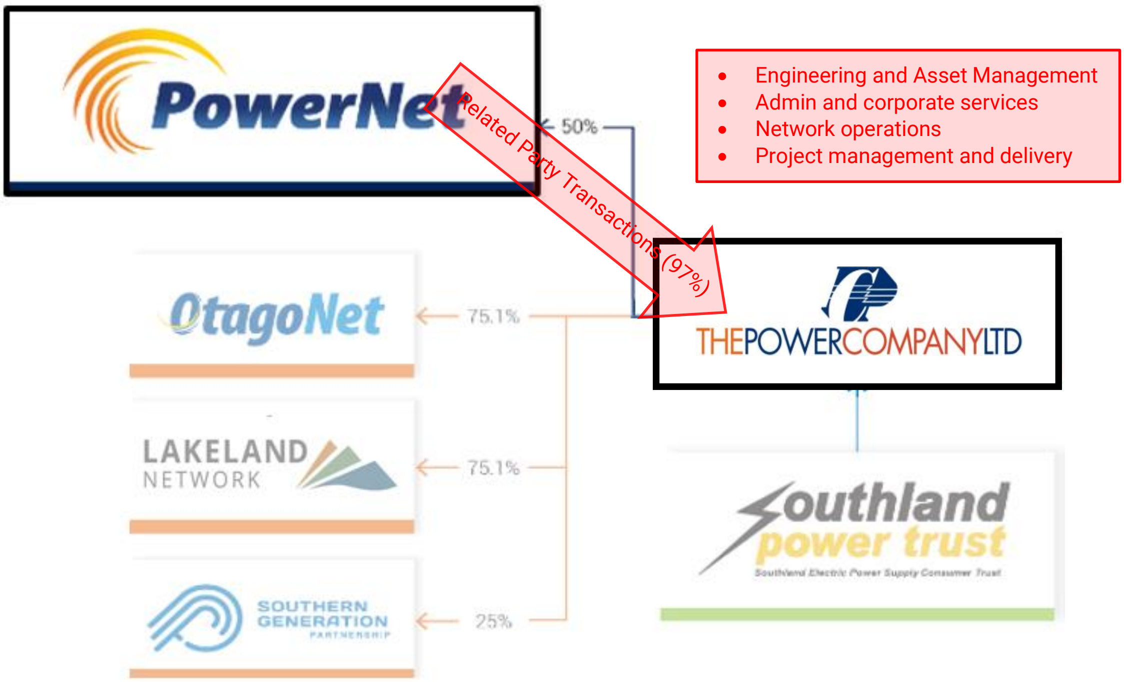
During the year ending 31 March 2024, TPCL had related party transactions with the following entities:

- Goods and services provided by – PowerNet Limited (PowerNet);
- Goods and services provided to – PowerNet OtagoNet Joint Venture, (OJV)
- Directors Services are provided to – PowerNet, OJV, Roaring Forties Energy General Partnership (RFEGP).

Company Structure

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. 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 2024, is categorised as follows:

		($000)
Operating Expenditure:		
i.	Service interruptions and emergencies	5,780
ii.	Vegetation management	1,529
iii.	Routine and corrective maintenance and inspection	4,118
iv.	Asset replacement and renewal (Opex)	562
v.	System operations and network support	2,963
vi.	Business support	3,116
Capital Expenditure:		
vii.	Consumer connection	15,669
viii.	System growth	6,748
ix.	Asset replacement and renewal (Capex)	14,768
x.	Asset relocations	242
xi.	Quality of supply	1,256
xii.	Other reliability, safety and environment	3,246
	Total PowerNet Related Party expenditure	**59,997**

In the year to 31 March 2024, PowerNet provided 100% of TPCL's 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 Management Agreement (MA) with TPCL.

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's EDB and meter business
- Health, 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 OJV electricity distribution network , based in coastal and inland Otago, via a joint venture arrangement with Electricity Invercargill Limited (EIL).

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.

c. Directors Fees

In the year to 31 March 2024, TPCL paid Directors Fees which represented 3% of all Operating Expenditure.

	($'000)
Operating Expenditure:	
Directors Fees	547
Total Related Party expenditure to Directors by TPCL	**547**

The directors are appointed by the shareholder Southland Electric Power Supply Consumer Trust (SEPSCT). Fees are set on an annual basis and are bulk funded as agreed between the SEPSCT Trustees and the TPCL Board members. A report from independent consultants was obtained in relation to director's fees and this information was used when setting the directors fees. Directors fees expenditure that related to PowerNet was $254,000, OJV $148,000 and the Roaring Forties Energy General Partnership was $53,000.

Management Agreement

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

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, carry out the agreed Capital Works Programme, provide line function services, and 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 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 drivers 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 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 a Management Fee to the EDB's and metering businesses it manages under the MA's. These charges recover costs incurred in the performance of the system control services, asset management, corporate, finance and commercial services.

These network management costs are charged to PowerNet 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 management fee charged to the EDB's and metering businesses, and
- mark-up applied to capital expenditure to recover costs allocated to EDB and meter capital projects.

An independent review in 2022 of the allocation methodology ensured all parties that are charged management and other fees by PowerNet are treated consistently and appropriately for each party. No changes have been made to the methodology since 2022.

4. PROCUREMENT POLICY

ID Determination 2.3.10 and 2.3.11

Under the Management Agreement (MA), 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 MA, PowerNet is responsible for sourcing all materials and services required to maintain TPCL's 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 a management 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 MA 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 TPCL's's procurement process. Each year the PowerNet Network Asset Engineers prepare TPCL's's 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 TPCL's's 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 TPCL's's 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, 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 26% of TPCL's Capital project expenditure during the 2023/24 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 TPCL's network meet outage performance targets (SAIDI and 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 and safety standards of PowerNet, and there are specific controls to check new applicants, to make sure they have completed the requirements (eg. PreQual health and 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 Management Agreement, including the application of unit rate pricing and monthly progress invoices in relation to the Annual Works Programme project activity expenditure. Unit Rate pricing was introduced in April 2023 for PowerNet labour and plant resources charged on network project activity. The unit rates are based on standard usage of time and resources for particular tasks. An important aspect of the transition has been monitoring the unit rate progress carefully to ensure the rates are set appropriately. Industry expertise was utilised in establishing the unit rates, which are reviewed quarterly with approved adjustments made if required. Otherwise the unit rates are approved annually by each network during the annual business planning process.
In return for the management of the network assets and related business support costs, PowerNet charges TPCL a management 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 Management Agreement, PowerNet is responsible for maintaining TPCL's 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 TPCL's 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 TPCL's 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 TPCL's 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 roadside 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 roadsides 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.

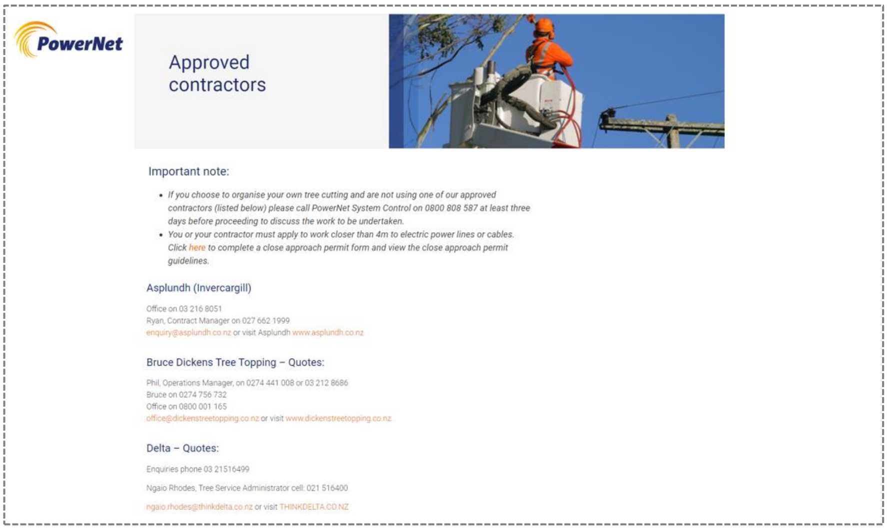
Arborist/Tree Management

PowerNet is responsible for vegetation management on TPCL's network, in accordance with the Management Agreement. Due to the large, mainly rural, area of TPCL's 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 TPCL's 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. **Major Construction Projects (System Growth/Asset Replacement and Renewal)**
Significant large-scale projects are managed by the PowerNet Asset Management – Major Projects team. These projects are often long term (greater than 12 months), complex in design, and greater than $1m in cost, with additional procurement requirements. Due to the large amount of dedicated resource and long period of time required, these projects are often subcontracted by PowerNet.

EXAMPLE: Athol to Kingston 11-22kV Upgrade Project
The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for a 'Major Project' to upgrade aging assets.

Project Name:	Athol to Kingston 11-22kV Upgrade Project
Project Date:	June 2020 – March 2024
Project Number:	10757
Project Expenditure:	$ 3,316,000 External labour and materials $ 2,054,000 PowerNet services ---------------- $ 5,370,000 2022/23 Project Expenditure $ 997,000 2022/23 Project Expenditure $ 793,000 2021/22 Project Expenditure $ 1,071,000 2020/21 Project Expenditure ---------------- $ 8,231,000 (Total Project Expenditure)
Project Classification:	System Growth (Capital)
Project Manager:	PowerNet Limited
Subcontractors:	PowerNet Limited / Decom Limited

An increase in electricity consumption is expected in the Kingston Area with a new housing development, sewage and water treatment station and several farms installing irrigation north of Garston. It was identified the feeder line from Athol to Kingston required upgrading to manage the future capacity increase. The project is split into geographical stages and is expected to take several years to complete. The 2023/24 project activity includes building a 66kV direct line from Athol to Kingston.

A review of available resources highlighted due to the size and technical challenges with this project, and in the interest of a timely construction, it was decided to outsource the majority of Stage 1 (regulator site construction) to external suppliers.
PowerNet distribution teams from Gore, Lumsden and Balclutha undertook the linework, which constituted Stages 2 and 3.

Market Testing: The majority of the project expenditure related to outsourced activities to external providers and materials provided through the 2022 Corys supply agreement. The PowerNet project management and internal labour cost is benchmarked to local market rates. Where a unit rate pricing has been applied for internal labour and plant utilisation on a project, comparison is made to the actual time and resources incurred to make sure there are no material variances.

ii. **New Connection / Capacity Upgrade (System Growth/Consumer Connections)**

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 Connection (Rural Southland – June 2023)

The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for a new customer connection to TPCL's network:

Project Name:	New Supply – Otapiri, Winton (TPCL Works programme)
Completion Date:	June 2023
Project Number:	CC 440138 / 440137
Project Expenditure:	$ 27,474 External materials and services $ 22,750 PowerNet services ------------ $ 50,225 Total Cost (2023/24)
Project Classification:	System Growth (Capital Expenditure)
Project Manager:	PowerNet Limited
Construction:	PowerNet - Distribution Team
Subcontractors:	Traffic Management, Harry's Machines Earthworks (trenching)

A customer connection application was submitted to PowerNet for Project CC440138 for a new 15 kVA supply on a rural Southland property. 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 2022-2024 period. Of the $15.7M capital expenditure spent on New Connections and Capacity Upgrades, 68% 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. Where a unit rate pricing has been applied for internal labour and plant utilisation on a project, comparison is made to the actual time and resources incurred to make sure there are no material variances.

iii. <u>Distribution and Technical Capital Projects (Asset Replacement and Renewal)</u>

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 or an Air-Break Swich 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.

<u>EXAMPLE: Air Break Switch (ABS) Replacement (Southland – August 2023)</u>

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

Project Name:	ABS replacement Omaui Rd Greenhills
Completion Date:	August 2023
Project Number:	CC 475673
Project Expenditure:	$ 6,728 External labour and materials $ 6,154 PowerNet services -------------- $ 12,882 Total Cost (2023/24)
Regulatory Classification:	Replacement and Renewal (Capital Expenditure)
Project Manager:	PowerNet Limited
Construction:	PowerNet – Distribution
Subcontractors:	Harry's Machines Earthworks (civil works)

PowerNet undertook Project CC475673 to replace an ABS on an 11kV Feeder near Greenhills 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 2022-2024. The materials sourced through Corys Electrical supply agreement includes a range of contractual mechanisms to ensure efficient prices are being provided to PowerNet. Where a unit rate pricing has been applied for internal labour and plant utilisation on a project, comparison is made to the actual time and resources incurred to make sure there are no material variances.

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 2022-2024.

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 approved arborist contractor Asplundh 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. The Tree Cut/Trim Notice issued to the tree owner, indicates available options for the work required. The tree owner responds with their preference – either to manage their own contractor, or to engage a PowerNet approved contractor. This ensures the costs involved are at current market rates.

EXAMPLE: Vegetation Management (Rural Southland – January 2024)

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:	January 2024
Project Number:	CC 492097
Project Number:	$ 6,152 External labour and materials $ 1,230 PowerNet services ---------- $ 7,383 (2023/24)
Regulatory Classification:	Vegetation Management (Operating Expenditure)
Project Manager:	PowerNet Limited
Subcontractors:	Asplundh Limited

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 ('tree clusters require trimming to comply with the Electricity (Hazard from Trees) Regulation 2003') were noted on the PowerNet Cut/Trim Notice (CTN-2067), 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, 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. **Asset Maintenance (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: Zone Substation Routine Maintenance

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

Project Name:	Makarewa Zone Sub - Earth Mat 10Year Maintenance
Completion Date:	February 2024
Project Number:	475311
Project Expenditure:	$ - External material $ 4,471 PowerNet services ----------- $ 4,471 Total Cost (2023/24)
Regulatory Classification:	Routine and Corrective Maintenance (Technical Maintenance)
Project Manager:	PowerNet Limited
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 2022-2024.

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 a management fee, which would otherwise be directly incurred by TPCL, if there was no management agreement 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 2022 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

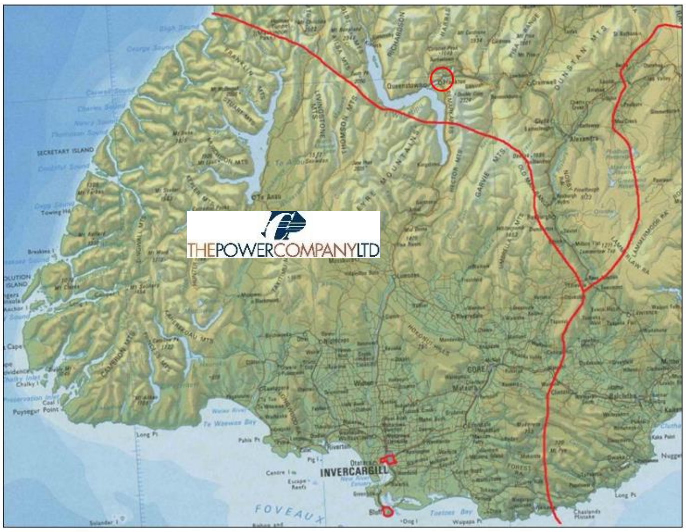
Regulatory requirements

- 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 TPCL's network 2024-2034 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 2024-2034 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 - $36.07m

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

2. Distribution Routine Inspections - $18.69 m

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

3. Vegetation Management - $12.78m

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

4. Technical Routine Maintenance - $12.29m

   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.

5. Distribution Routine Maintenance - $6.33m

   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 and Checks - $5.33m

   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 Replacement and Renewal - $4.47m

   All OPEX work where the primary driver is the repair of distribution assets that have been found during inspection to fall short of the required standard; also includes scheduled replacements of parts/fluids under a preventative maintenance programme, and expenses incurred due to obsolescence. Excludes CAPEX (work that will have a material effect on the functionality or the life of capital assets). Covers items like crossarms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.

8. Distribution Corrective Maintenance - $4.27m

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

9. Technical Corrective Maintenance - $2.62m

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

10. Power Transformer Replacement and Renewal - $2.52m
    A budget to allow refurbishment works that won't impact on the valuation of the power transformers. Covers items like painting.

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

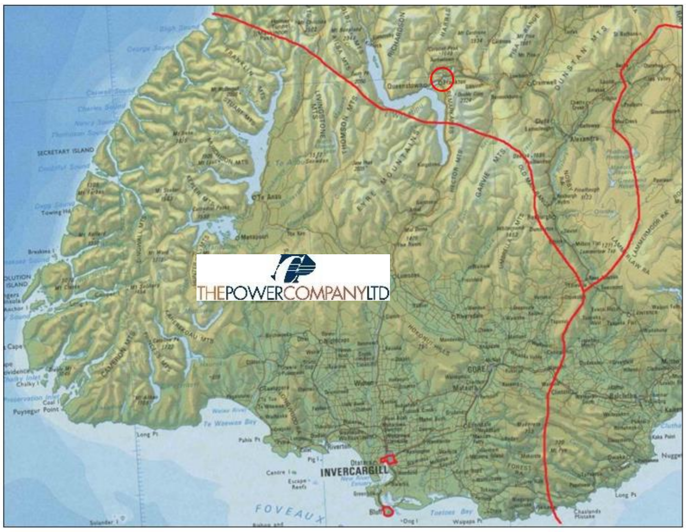
Please Note: All of these projects -

- Are network wide (apply to entire area as shown on map above).
- Have a contract in place that is with PowerNet through a management agreement (related party).
- Are forecast to require the supply of assets/goods or services by PowerNet (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 2024-2034 Asset Management Plan for TPCL network are explained below, and indicated on the Network map above where relative to a single area:

1. Invercargill 66kV Expansion – 89.22m

   TPCL is experiencing significant development in the Awarua and Makarewa region resulted in network constraints. A multiyear programme has been developed to provide a new 66kV supply to Awarua region and transferring some of the load from the Makarewa region from North Makarewa Grid Exit Point (GXP) to the Invercargill GXP via the new 66 kV connection, triggered by the development in the Awarua region. This work would relieve the capacity constraint on the North Makarewa region, improve resilience to western Southland and defer major investments such as the GXP upgrade.

2. Distribution Line Replacement - $71.73m

   Scheduled for every year, the on-going replacements of distribution 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.

3. Network Resilience Improvement - $32.41m

   In electricity networks, reliability primarily focuses on the prevention of power outages and the consistent delivery of electricity, emphasising the quality and stability of service. Resilience focuses on the network's ability to recover and adapt to disruptions, ensuring that power can be restored quickly after incidents or adverse events. Both reliability and resilience are critical for maintaining a dependable and secure electricity distribution network, and they often go hand in hand to provide a high level of service to customers, especially in the face of changing climate conditions and other external challenges.

   This provision is for reliability and resilience projects that are yet to be identified and are expected to be implemented in 2029-34.

4. <u>Earth Upgrades - $20.90m</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. <u>Distribution Transformer Replacement - $20.20m</u>

   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. <u>Open Country Dairy 66kV Expansion - $19.25m</u>

   This customer-driven project was initiated by Open Country Dairy to provide the required electricity infrastructure to its plant in the Awarua region to supply the new high-pressure electrode boiler at the site. This work involves the construction of a new 66kV 19.5km overhead line and substation. The project is due for completion in late 2025.

7. <u>Customer Connections (≤ 20kVA) - $16.89m</u>

   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. 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.

8. <u>ABS Renewals - $14.29m</u>

   Scheduled for every year, but decreasing from 2028, ABSs are replaced when inspection indicates deterioration is sufficient to lose confidence in continued reliable operation and maintenance is considered uneconomic to maintain.

9. <u>New Subdivisions - $11.78m</u>

   Scheduled for every year, planning for new subdivision developments, uses averages based on historical trending, modified by any local knowledge if appropriate however customer requirements are generally unpredictable and quite variable. Various options are considered generally to determine the least cost option for providing the new connection. Work required depends on the development’s location relative to existing network and the capacity of that network to supply the additional load. This can range from a simple LV extension for a small development close to a strong supply, through to upgrading of 11 kV cables with new switchgear and transformers. if required.

10. Condition Based Asset Replacements - $10.24m

    Scheduled for 2029 – 2034, 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 programme and where general maintenance will have limited success.

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

Further detail relating to TPCL network Capital 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 through a management agreement (related party;
- Are forecast to require the supply of assets/goods or services by PowerNet (related party).

Possible future constraints related to TPCL network Capital Expenditure projects:

3. Invercargill 66kV Expansion

   Constraint – Unable to meet the growth of the network due to the projected development in the Awarua and Makarewa region, timing being 3 - 5 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	Every Year	$36.07m	Network Wide	Yes	Yes	Very likely	N/A
#2	Distribution Routine Inspections	Every Year	$ 18.69m	Network Wide	Yes	Yes	Very likely	N/A
#3	Vegetation Management	Every Year	$ 12.78m	Network Wide	Yes	Yes	Very likely	N/A
#4	Technical Routine Maintenance	Every Year	$ 12.29m	Network Wide	Yes	Yes	Very likely	N/A
#5	Distribution Routine Maintenance	Every Year	$ 6.33m	Network Wide	Yes	Yes	Very likely	N/A
#6	Technical Routine Inspections and Checks	Every Year	$ 5.34m	Network Wide	Yes	Yes	Very likely	N/A
#7	Distribution Replacement and Renewal	Every Year	$ 4.47m	Network Wide	Yes	Yes	Very likely	N/A
#8	Distribution Corrective Maintenance	Every Year	$ 4.22m	Network Wide	Yes	Yes	Very likely	N/A
#9	Technical Corrective Maintenance	Every Year	$ 2.62m	Network Wide	Yes	Yes	Very likely	N/A
#10	Power Transformer Replacement and Renewal	Every Year	$ 2.52m	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	Invercargill 66kV Expansion	2024 - 2033	$ 89.22m	Network Wide	Yes	Yes	Very likely	N/A
#2	Distribution Line Replacement	Every Year	$ 71.73m	Network Wide	Yes	Yes	Very likely	N/A
#3	Network Resilience Improvement	2029-2034	$ 32.41m	Network Wide	Yes	Yes	Very likely	N/A
#4	Earth Upgrades	Every Year	$ 20.90m	Network Wide	Yes	Yes	Very likely	N/A
#5	Distribution Transformer Replacement	Every Year	$ 20.20m	Network Wide	Yes	Yes	Very likely	N/A
#6	Open Country Dairy 66kV Expansion	2024-2026	$ 19.25m	Awarua	Yes	Yes	Very likely	N/A
#7	Customer Connections (≤ 20kVA)	Every Year	$ 16.89m	Network Wide	Yes	Yes	Very likely	N/A
#8	ABS Renewals	Every Year	$ 14.29m	Network Wide	Yes	Yes	Very likely	N/A
#9	New Subdivisions	Every Year	$ 11.78m	Network Wide	Yes	Yes	Very likely	N/A
#10	Condition Based Asset Replacements	2029-2034	$ 10.27m	Network Wide	Yes	Yes	Very likely	N/A

Possible future constraints related to TPCL network Capital Expenditure projects:

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

Description of constraint	Related to CapEx project #	Expected timing of constraint
Unable to meet the growth of the network due to the projected development in the Awarua and Makarewa region	#1	3-5 years

Independent Assurance Report

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

Assurance report pursuant to the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC 2

We have undertaken a reasonable assurance engagement in respect of the compliance of The Power Company Limited (the "Company") with the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC 2, (the "Determination") for the disclosure year ended 31 March 2024 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 (limited to SAIDI and SAIFI information), the related party transactions 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 23 April 2024) ("the IM Determination").

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 the Schedules 10(i) to 10(iv). Consequently, there is no independent evidence available to support the completeness and accuracy of recorded faults, and control over the completeness and accuracy of interconnection point ('ICP') data included in the SAIDI and SAIFI calculations was limited throughout the year.

There are no practical audit procedures that we could adopt to independently confirm that all the faults and ICP data were properly recorded for the purposes of inclusion in the amounts relating to quality measures set out in Schedules 10(i) to 10(iv).

Because of the potential effect of these limitations, we are unable to obtain sufficient appropriate audit evidence to confirm the completeness and accuracy of the data that forms the basis of the compilation of Schedules 10(i) to 10(iv).

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 Informatio*n.

We believe the evidence we have obtained is sufficient and appropriate 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 2024, 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 Power Company Limited'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 Power Company Limited'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 over the regulatory asset base included the following: **Assets commissioned** • We considered the nature of 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 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 material reconciling items; and • We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification. **Depreciation** • We compared the spreadsheet formula utilised to calculate regulatory depreciation expense with IM Determination clause 2.2.5; • We compared the standard asset lives by asset category to those set out in the IM Determination; and • We have performed a reasonableness test to ensure regulatory depreciation expense is calculated in line with IM Determination clause 2.2.5; **Revaluation** • We recalculated the revaluation rate set out in the IM Determination using the relevant

Key Assurance Matter	How our procedures addressed the key assurance matter
	Consumer Price Index indices taken from the Statistics New Zealand website; and ● We tested the mathematical accuracy of the revaluation calculation performed by management. **Disposals** ● We reconciled the disposals, as per the regulatory fixed asset register, to the asset disposals disclosed in the audited annual financial statements and investigated any material reconciling items; and ● 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 IMs;
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 and the IM Determination are set out in Appendix A. The Determination and the IM Determination require The Power Company Limited 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.	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 the related party transactions 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 2024 and to the accounting records, investigating any material 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

Key Assurance Matter	How our procedures addressed the key assurance matter
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 Power Company Limited is required to use an objective and independent measure to demonstrate compliance with the arm's-length principle. In the absence of an active market for similar transactions, assigning an objective arm's length value to a related party transaction is difficult and requires significant judgement. We have identified related party transactions at arm's-length as a key audit matter due to the judgement involved.	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 Power Company Limited's assessment of available independent and objective measures used in supporting the arm's length valuation principal and performed the following procedures: • Re-performed the calculations within The Power Company Limited's benchmarking assessment and agreed key inputs and assumptions to supporting documentation; • Where benchmarking or other market information was used as independent and objective measures, we assessed whether the related party transaction values fell within a reasonable range. Qualitative factors were considered in determining the appropriate acceptable range.

Directors' Responsibilities

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

Our Independence and Quality Management

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.

We apply Professional and Ethical Standard 3 *Quality Management for Firms that Perform Audits or Reviews of Financial Statements, or Other Assurance or Related Services Engagements*, which requires our firm to design, implement and operate a system of quality management including policies or procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

We are independent of The Power Company. Our firm carries out other services for the Company in the areas of compliance with regulatory requirements of the Commerce Act 1986, audit of the financial statements, and provision of regulatory training and advisory 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 2024 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) and SAE 3100 (Revised) 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 2024, and whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

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

Inherent Limitations
Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error or non-compliance may occur and not be detected. A reasonable assurance engagement for the disclosure year ended 31 March 2024 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
30 August 2024

Christchurch, New Zealand

5. Schedule 18: Certification for Year-End Disclosures

Clause 2.9.2

We, Peter William Moynihan and Murray John Wallace, 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.]

Peter William Moynihan

29 August 2024

Murray John Wallace

29 August 2024