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 2019

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 2019

SCHEDULE 1: ANALYTICAL RATIOS

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

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

sch ref

1(i): Expenditure metrics

	Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
Operational expenditure	21,833	450	111,328	1,830	36,287
Network	14,445	298	73,660	1,211	24,009
Non-network	7,387	152	37,669	619	12,278
Expenditure on assets	31,550	651	160,877	2,644	52,437
Network	31,550	651	160,877	2,644	52,437
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	84,046	1,734
Standard consumer line charge revenue	93,063	1,567
Non-standard consumer line charge revenue	44,053	1,202,622

1(iii): Service intensity measures

Demand density	17	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	84	*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	20,632	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	16,198	26.01%
Pass-through and recoverable costs excluding financial incentives and wash-ups	14,886	23.90%
Total depreciation	13,762	22.10%
Total revaluations	5,526	8.87%
Regulatory tax allowance	3,301	5.30%
Regulatory profit/(loss) including financial incentives and wash-ups	19,660	31.57%
Total regulatory income	62,281	

1(v): Reliability

Interruption rate	13.28	*Interruptions per 100 circuit km*

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Company Name	The Power Company Limited
For Year Ended	31 March 2019

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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

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

sch ref

2(i): Return on Investment

	CY-2	CY-1	Current Year CY
	31 Mar 17	31 Mar 18	31 Mar 19
ROI – comparable to a post tax WACC	%	%	%
Reflecting all revenue earned	5.53%	4.39%	4.98%
Excluding revenue earned from financial incentives	5.53%	4.39%	4.98%
Excluding revenue earned from financial incentives and wash-ups	5.53%	4.39%	4.98%
Mid-point estimate of post tax WACC	4.77%	5.04%	4.75%
25th percentile estimate	4.05%	4.36%	4.07%
75th percentile estimate	5.48%	5.72%	5.43%
ROI – comparable to a vanilla WACC			
Reflecting all revenue earned	6.07%	4.98%	5.49%
Excluding revenue earned from financial incentives	6.07%	4.98%	5.49%
Excluding revenue earned from financial incentives and wash-ups	6.07%	4.98%	5.49%
WACC rate used to set regulatory price path	NA	NA	NA
Mid-point estimate of vanilla WACC	5.31%	5.60%	5.26%
25th percentile estimate	4.59%	4.92%	4.58%
75th percentile estimate	6.03%	6.29%	5.94%

2(ii): Information Supporting the ROI

			($000)	
	Total opening RAB value	373,678		
plus	Opening deferred tax	(16,508)		
Opening RIV			357,170	
Line charge revenue			62,353	
	Expenses cash outflow	31,084		
add	Assets commissioned	20,360		
less	Asset disposals	792		
add	Tax payments	1,276		
less	Other regulated income	(72)		
Mid-year net cash outflows			51,999	
Term credit spread differential allowance			–	
	Total closing RAB value	385,009		
less	Adjustment resulting from asset allocation	(0)		
less	Lost and found assets adjustment	–		
plus	Closing deferred tax	(18,533)		
Closing RIV			366,476	
ROI – comparable to a vanilla WACC				5.49%
	Leverage (%)			42%
	Cost of debt assumption (%)			4.33%
	Corporate tax rate (%)			28%
ROI – comparable to a post tax WACC				4.98%

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	5.35%
Year-end ROI – comparable to a post tax WACC	4.84%

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

2(v): Financial Incentives and Wash-Ups

Net recoverable costs allowed under incremental rolling incentive scheme	–	
Purchased assets – avoided transmission charge		
Energy efficiency and demand incentive allowance		
Quality incentive adjustment		
Other financial incentives		
Financial incentives		–
Impact of financial incentives on ROI		–
Input methodology claw-back		
CPP application recoverable costs		
Catastrophic event allowance		
Capex wash-up adjustment		
Transmission asset wash-up adjustment		
2013–15 NPV wash-up allowance		
Reconsideration event allowance		
Other wash-ups		
Wash-up costs		–
Impact of wash-up costs on ROI		–

Company Name	The Power Company Limited
For Year Ended	31 March 2019

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

sch ref				
7		**3(i): Regulatory Profit**		**($000)**
8		**Income**		
9		Line charge revenue		62,353
10	*plus*	Gains / (losses) on asset disposals		(724)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		652
12				
13		**Total regulatory income**		62,281
14		**Expenses**		
15	*less*	Operational expenditure		16,198
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		14,886
18				
19		**Operating surplus / (deficit)**		31,197
20				
21	*less*	Total depreciation		13,762
22				
23	*plus*	Total revaluations		5,526
24				
25		**Regulatory profit / (loss) before tax**		22,961
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		3,301
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		19,660
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	207	
36		Commerce Act levies	99	
37		Industry levies	140	
38		CPP specified pass through costs	–	
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	14,204	
41		Transpower new investment contract charges	237	
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**		14,886
47				
48		**3(iii): Incremental Rolling Incentive Scheme**	**($000)**	
49			**CY-1**	**CY**
50			**31 Mar 18**	**31 Mar 19**
51		Allowed controllable opex	–	–
52		Actual controllable opex	–	–
53				
54		Incremental change in year		–
55				
56			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
57		CY-5 31 Mar 14	–	–
58		CY-4 31 Mar 15	–	–
59		CY-3 31 Mar 16	–	–
60		CY-2 31 Mar 17	–	–
61		CY-1 31 Mar 18	–	–
62		**Net incremental rolling incentive scheme**		–
63				
64		**Net recoverable costs allowed under incremental rolling incentive scheme**		–
65		**3(iv): Merger and Acquisition Expenditure**		
70				**($000)**
66		Merger and acquisition expenditure		–
67				
68		*Provide commentary on the benefits of merger and acquisition expenditure to the electricity distribution business, including required disclosures in accordance with section 2.7, in Schedule 14 (Mandatory Explanatory Notes)*		
69		**3(v): Other Disclosures**		
70				**($000)**
71		Self-insurance allowance		–

Company Name	The Power Company Limited
For Year Ended	31 March 2019

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

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

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

sch ref

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

for year ended	RAB 31 Mar 15 ($000)	RAB 31 Mar 16 ($000)	RAB 31 Mar 17 ($000)	RAB 31 Mar 18 ($000)	RAB 31 Mar 19 ($000)
Total opening RAB value	315,316	325,146	339,946	355,086	373,678
less Total depreciation	11,941	12,233	12,755	12,615	13,762
plus Total revaluations	264	1,900	7,349	3,886	5,526
plus Assets commissioned	22,169	25,526	20,976	25,100	20,360
less Asset disposals	663	393	429	744	792
plus Lost and found assets adjustment	–	–	–	2,964	–
plus Adjustment resulting from asset allocation	–	–	–	–	(0)
Total closing RAB value	325,146	339,946	355,086	373,678	385,009

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
Total opening RAB value		373,678		373,678
less				
Total depreciation		13,762		13,762
plus				
Total revaluations		5,526		5,526
plus				
Assets commissioned (other than below)	–		–	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	20,360		20,360	
Assets commissioned		20,360		20,360
less				
Asset disposals (other than below)	749		749	
Asset disposals to a regulated supplier	–		–	
Asset disposals to a related party	43		43	
Asset disposals		792		792
plus Lost and found assets adjustment		–		–
plus Adjustment resulting from asset allocation				(0)
Total closing RAB value		385,009		385,009

** 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	1,026
CPI_4^{-4}	1,011
Revaluation rate (%)	1.48%

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Total opening RAB value	373,678		373,678	
less Opening value of fully depreciated, disposed and lost assets	1,208		1,208	
Total opening RAB value subject to revaluation	372,470		372,470	
Total revaluations		5,526		5,526

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction		Allocated works under construction	
Works under construction—preceding disclosure year		13,992		13,992
plus Capital expenditure	21,549		21,549	
less Assets commissioned	20,360		20,360	
plus Adjustment resulting from asset allocation			-	
Works under construction - current disclosure year		15,181		15,181
Highest rate of capitalised finance applied				-

4(v): Regulatory Depreciation

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Depreciation - standard	13,762		13,762	
Depreciation - no standard life assets	-		-	
Depreciation - modified life assets	-		-	
Depreciation - alternative depreciation in accordance with CPP	-		-	
Total depreciation		13,762		13,762

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	55,283	3,042	92,166	130,363	19,318	53,829	12,624	7,046	7	373,678
less Total depreciation	1,742	75	3,234	5,671	633	1,632	546	229		13,762
plus Total revaluations	818	45	1,368	1,932	285	784	189	104	-	5,526
plus Assets commissioned	3,973	(630)	7,837	6,567	250	1,227	961	175		20,360
less Asset disposals			191			576	26			792
plus Lost and found assets adjustment										-
plus Adjustment resulting from asset allocation	-	-	-	-	-	-	-	-	-	-
plus Asset category transfers										-
Total closing RAB value	58,332	2,383	97,946	133,191	19,219	53,633	13,202	7,096	7	385,009

Asset Life

	Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	
Weighted average remaining asset life	37.0	40.3	33.9	24.1	44.1	34.2	25.5	16.8	-	(years)
Weighted average expected total asset life	56.7	45.7	45.9	57.9	62.2	47.1	39.8	32.1	-	(years)

Company Name	The Power Company Limited
For Year Ended	31 March 2019

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref					
7	**5a(i): Regulatory Tax Allowance**				**($000)**
8		**Regulatory profit / (loss) before tax**			22,961
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	7,029		
13		Amortisation of revaluations	1,233		
14					8,262
15					
16	*less*	Total revaluations	5,526		
17		Income included in regulatory profit / (loss) before tax but not taxable	–	*	
18		Discretionary discounts and customer rebates	7,532		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax	17	*	
20		Notional deductible interest	6,359		
21					19,435
22					
23		**Regulatory taxable income**			11,788
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			11,788
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			3,301
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	133,542		
37	*less*	Amortisation of initial differences in asset values	7,029		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	610		
40		Closing unamortised initial differences in asset values			125,904
41					
42		Opening weighted average remaining useful life of relevant assets (years)			19
43					

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5a(iv): Amortisation of Revaluations

			($000)
	Opening sum of RAB values without revaluations	341,991	
	Adjusted depreciation	12,529	
	Total depreciation	13,762	
	Amortisation of revaluations		1,233

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	(16,306)	
plus	Tax effect of adjusted depreciation	3,508	
less	Tax effect of tax depreciation	4,190	
plus	Tax effect of other temporary differences*	323	
less	Tax effect of amortisation of initial differences in asset values	1,968	
plus	Deferred tax balance relating to assets acquired in the disclosure year	-	
less	Deferred tax balance relating to assets disposed in the disclosure year	(100)	
plus	Deferred tax cost allocation adjustment	0	
	Closing deferred tax		(18,533)

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	159,836	
less	Tax depreciation	14,963	
plus	Regulatory tax asset value of assets commissioned	23,071	
less	Regulatory tax asset value of asset disposals	305	
plus	Lost and found assets adjustment		
plus	Adjustment resulting from asset allocation		
plus	Other adjustments to the RAB tax value		
	Closing sum of regulatory tax asset values		167,639

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2019**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

sch ref			
7	**5b(i): Summary—Related Party Transactions**	**($000)**	**($000)**
8	**Total regulatory income**		16
9			
10	**Market value of asset disposals**		32
11			
12	Service interruptions and emergencies	3,885	
13	Vegetation management	1,630	
14	Routine and corrective maintenance and inspection	4,467	
15	Asset replacement and renewal (opex)	735	
16	**Network opex**		10,717
17	Business support	2,872	
18	System operations and network support	1,290	
19	**Operational expenditure**		14,879
20	Consumer connection	3,481	
21	System growth	6,550	
22	Asset replacement and renewal (capex)	10,381	
23	Asset relocations	120	
24	Quality of supply	625	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	2,249	
27	**Expenditure on non-network assets**		–
28	**Expenditure on assets**		23,406
29	Cost of financing		–
30	Value of capital contributions		–
31	Value of vested assets		–
32	**Capital Expenditure**		23,406
33	**Total expenditure**		38,286
34			
35	**Other related party transactions**		–

sch ref			
36	**5b(iii): Total Opex and Capex Related Party Transactions**		
37	**Name of related party**	**Nature of opex or capex service provided**	**Total value of transactions ($000)**
38	PowerNet Limited	Service interruptions and emergencies	3,885
39	PowerNet Limited	Vegetation management	1,630
40	PowerNet Limited	Routine and corrective maintenance and inspection	4,467
41	PowerNet Limited	Asset replacement and renewal (opex)	735
42	PowerNet Limited	System operations and network support	1,290
43	PowerNet Limited	Business support	2,872
44	PowerNet Limited	Consumer connection	3,481
45	PowerNet Limited	System growth	6,550
46	PowerNet Limited	Asset replacement and renewal (capex)	10,381
47	PowerNet Limited	Asset relocations	120
48	PowerNet Limited	Quality of supply	625
49	PowerNet Limited	Other reliability, safety and environment	2,249
50			
51			
52			
53	**Total value of related party transactions**		38,286
54	** include additional rows if needed*		
55			

Company Name	The Power Company Limited
For Year Ended	31 March 2019

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

This schedule is only to be completed if, as at the date of the most recently published financial statements, the weighted average original tenor of the debt portfolio (both qualifying debt and non-qualifying debt) is greater than five years.

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

sch ref

7

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

9

sch ref	Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
10									
11									
12									
13									
14									
15									
16	* include additional rows if needed						–	–	–

17

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

sch ref			
19			
20	**Gross term credit spread differential**		–
21			
22	Total book value of interest bearing debt		
23	Leverage	42%	
24	Average opening and closing RAB values		
25	**Attribution Rate (%)**		–
26			
27	**Term credit spread differential allowance**		–

Company Name	The Power Company Limited
For Year Ended	31 March 2019

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(i): Operating Cost Allocations

	Value allocated ($000s)				
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
Service interruptions and emergencies					
Directly attributable		3,885			
Not directly attributable				–	
Total attributable to regulated service		3,885			
Vegetation management					
Directly attributable		1,630			
Not directly attributable				–	
Total attributable to regulated service		1,630			
Routine and corrective maintenance and inspection					
Directly attributable		4,467			
Not directly attributable				–	
Total attributable to regulated service		4,467			
Asset replacement and renewal					
Directly attributable		735			
Not directly attributable				–	
Total attributable to regulated service		735			
System operations and network support					
Directly attributable		1,867			
Not directly attributable				–	
Total attributable to regulated service		1,867			
Business support					
Directly attributable		3,116			
Not directly attributable		471	26	497	
Total attributable to regulated service		3,587			
Operating costs directly attributable		15,701			
Operating costs not directly attributable	–	471	26	497	–
Operational expenditure		16,172			

5d(ii): Other Cost Allocations

Pass through and recoverable costs	($000)
Pass through costs	
Directly attributable	445
Not directly attributable	–
Total attributable to regulated service	445
Recoverable costs	
Directly attributable	14,441
Not directly attributable	–
Total attributable to regulated service	14,441

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 2019

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	58,332
Not directly attributable	–
Total attributable to regulated service	58,332
Subtransmission cables	
Directly attributable	2,383
Not directly attributable	–
Total attributable to regulated service	2,383
Zone substations	
Directly attributable	97,946
Not directly attributable	–
Total attributable to regulated service	97,946
Distribution and LV lines	
Directly attributable	133,191
Not directly attributable	–
Total attributable to regulated service	133,191
Distribution and LV cables	
Directly attributable	19,219
Not directly attributable	–
Total attributable to regulated service	19,219
Distribution substations and transformers	
Directly attributable	53,633
Not directly attributable	–
Total attributable to regulated service	53,633
Distribution switchgear	
Directly attributable	13,202
Not directly attributable	
Total attributable to regulated service	13,202
Other network assets	
Directly attributable	7,096
Not directly attributable	
Total attributable to regulated service	7,096
Non-network assets	
Directly attributable	7
Not directly attributable	
Total attributable to regulated service	7
Regulated service asset value directly attributable	385,009
Regulated service asset value not directly attributable	–
Total closing RAB value	385,009

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

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

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

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

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

Company Name: The Power Company Limited
For Year Ended: 31 March 2019

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5d (Cost allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref	Line Item*	Allocation methodology type	Cost allocator	Allocator type	Allocator Metric (%)		Value allocated ($000)				OVABAA allocation increase ($000)
					Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	
11	**Service interruptions and emergencies**										
12										-	
13										-	
14										-	
15										-	
16	Not directly attributable						-	-	-	-	-
17	**Vegetation management**										
18										-	
19										-	
20										-	
21										-	
22	Not directly attributable						-	-	-	-	-
23	**Routine and corrective maintenance and inspection**										
24										-	
25										-	
26										-	
27										-	
28	Not directly attributable						-	-	-	-	-
29	**Asset replacement and renewal**										
30										-	
31										-	
32										-	
33										-	
34	Not directly attributable						-	-	-	-	-
35											
36	**System operations and network support**										
37										-	
38										-	
39										-	
40										-	
41	Not directly attributable						-	-	-	-	-
42	**Business support**										
43	Administration expenses	ABAA	Revenue	Proxy	94.85%	5.15%		471	26	497	
44										-	
45										-	
46										-	
47	Not directly attributable						-	471	26	497	-
48											
49	Operating costs not directly attributable						-	471	26	497	-
50											
51	**Pass through and recoverable costs**										
52	**Pass through costs**										
53										-	
54										-	
55										-	
56										-	
57	Not directly attributable						-	-	-	-	-
58	**Recoverable costs**										
59										-	
60										-	
61										-	
62										-	
63	Not directly attributable						-	-	-	-	-
64	** include additional rows if needed*										

Company Name: The Power Company Limited
For Year Ended: 31 March 2019

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5e (Report on Asset Allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref											
7											
8											
9					Allocator Metric (%)		Value allocated ($000)				
10	Line Item*	Allocation methodology type	Allocator	Allocator type	Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000)
11	Subtransmission lines										
12										-	
13										-	
14										-	
15										-	
16	Not directly attributable						-	-	-	-	-
17	Subtransmission cables										
18										-	
19										-	
20										-	
21										-	
22	Not directly attributable						-	-	-	-	-
23	Zone substations										
24										-	
25										-	
26										-	
27										-	
28	Not directly attributable						-	-	-	-	-
29	Distribution and LV lines										
30										-	
31										-	
32										-	
33										-	
34	Not directly attributable						-	-	-	-	-
35	Distribution and LV cables										
36										-	
37										-	
38										-	
39										-	
40	Not directly attributable						-	-	-	-	-
41											
42	Distribution substations and transformers										
43										-	
44										-	
45										-	
46										-	
47	Not directly attributable						-	-	-	-	-
48											
49	Distribution switchgear										
50										-	
51										-	
52										-	
53										-	
54	Not directly attributable						-	-	-	-	-
55	Other network assets										
56										-	
57										-	
58										-	
59										-	
60	Not directly attributable						-	-	-	-	-
61	Non-network assets										
62										-	
63										-	
64										-	
65										-	
66	Not directly attributable						-	-	-	-	-
67											
68	Regulated service asset value not directly attributable						-	-	-	-	-
69	* include additional rows if needed										

Company Name	The Power Company Limited
For Year Ended	31 March 2019

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

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

6a(i): Expenditure on Assets

		($000)	($000)
	Consumer connection		3,481
	System growth		6,550
	Asset replacement and renewal		10,381
	Asset relocations		120
	Reliability, safety and environment:		
	Quality of supply	625	
	Legislative and regulatory	–	
	Other reliability, safety and environment	2,249	
	Total reliability, safety and environment		2,874
	Expenditure on network assets		23,406
	Expenditure on non-network assets		–
	Expenditure on assets		23,406
plus	Cost of financing		–
less	Value of capital contributions		1,858
plus	Value of vested assets		–
	Capital expenditure		21,549

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

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

6a(iii): Consumer Connection

		($000)	($000)
	*Consumer types defined by EDB**		
	Non Half Hour Individuals	2,130	
	Non- Domestic	458	
	Domestic	894	
	** include additional rows if needed*		
	Consumer connection expenditure		3,481
less	Capital contributions funding consumer connection expenditure	1,619	
	Consumer connection less capital contributions		1,862

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

		System Growth ($000)	Asset Replacement and Renewal ($000)
	Subtransmission	3,660	883
	Zone substations	2,371	715
	Distribution and LV lines		5,199
	Distribution and LV cables	519	63
	Distribution substations and transformers		1,241
	Distribution switchgear		1,931
	Other network assets		351
	System growth and asset replacement and renewal expenditure	6,550	10,381
less	Capital contributions funding system growth and asset replacement and renewal		144
	System growth and asset replacement and renewal less capital contributions	6,550	10,237

6a(v): Asset Relocations

		($000)	($000)
	*Project or programme**		
	** include additional rows if needed*		
	All other projects or programmes - asset relocations	120	
	Asset relocations expenditure		120
less	Capital contributions funding asset relocations	95	
	Asset relocations less capital contributions		25

69		**6a(vi): Quality of Supply**		
70		*Project or programme**	($000)	($000)
71				
72				
73				
74				
75				
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply	625	
78		**Quality of supply expenditure**		625
79	*less*	Capital contributions funding quality of supply		
80		**Quality of supply less capital contributions**		625
81		**6a(vii): Legislative and Regulatory**		
82		*Project or programme**	($000)	($000)
83				
84				
85				
86				
87				
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory		
90		**Legislative and regulatory expenditure**		–
91	*less*	Capital contributions funding legislative and regulatory		
92		**Legislative and regulatory less capital contributions**		–
93		**6a(viii): Other Reliability, Safety and Environment**		
94		*Project or programme**	($000)	($000)
95		Earth Upgrades	423	
96		NER Installations	1,179	
97				
98				
99				
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment	647	
102		**Other reliability, safety and environment expenditure**		2,249
103	*less*	Capital contributions funding other reliability, safety and environment		
104		**Other reliability, safety and environment less capital contributions**		2,249
105				
106		**6a(ix): Non-Network Assets**		
107		**Routine expenditure**		
108		*Project or programme**	($000)	($000)
109				
110				
111				
112				
113				
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure		
116		**Routine expenditure**		–
117		**Atypical expenditure**		
118		*Project or programme**	($000)	($000)
119				
120				
121				
122				
123				
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure		
126		**Atypical expenditure**		–
127				
128		**Expenditure on non-network assets**		–

Company Name	The Power Company Limited
For Year Ended	31 March 2019

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

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

sch ref		($000)	($000)
7	**6b(i): Operational Expenditure**		
8	Service interruptions and emergencies	3,885	
9	Vegetation management	1,630	
10	Routine and corrective maintenance and inspection	4,467	
11	Asset replacement and renewal	735	
12	**Network opex**		10,717
13	System operations and network support	1,867	
14	Business support	3,613	
15	**Non-network opex**		5,481
16			
17	**Operational expenditure**		16,198
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		125
20	Direct billing*		–
21	Research and development		–
22	Insurance		316
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	The Power Company Limited
For Year Ended	31 March 2019

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

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

sch ref		Target ($000) [1]	Actual ($000)	% variance
7	**7(i): Revenue**			
8	Line charge revenue	60,102	62,353	4%
		Forecast ($000) [2]	**Actual ($000)**	**% variance**
9	**7(ii): Expenditure on Assets**			
10	Consumer connection	4,329	3,481	(20%)
11	System growth	7,645	6,550	(14%)
12	Asset replacement and renewal	8,958	10,381	16%
13	Asset relocations	54	120	121%
14	Reliability, safety and environment:			
15	Quality of supply	751	625	(17%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	3,126	2,249	(28%)
18	**Total reliability, safety and environment**	3,878	2,874	(26%)
19	**Expenditure on network assets**	24,865	23,406	(6%)
20	Expenditure on non-network assets	500	–	(100%)
21	Expenditure on assets	25,365	23,406	(8%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	3,177	3,885	22%
24	Vegetation management	1,485	1,630	10%
25	Routine and corrective maintenance and inspection	4,897	4,467	(9%)
26	Asset replacement and renewal	1,322	735	(44%)
27	**Network opex**	10,881	10,717	(2%)
28	System operations and network support	2,874	1,867	(35%)
29	Business support	4,322	3,613	(16%)
30	**Non-network opex**	7,196	5,481	(24%)
31	**Operational expenditure**	18,078	16,198	(10%)
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses		–	–
34	Overhead to underground conversion		–	–
35	Research and development		–	–
36				
37	**7(v): Subcomponents of Operational Expenditure (where known)**			
38	Energy efficiency and demand side management, reduction of energy losses	125	125	–
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	1,185	316	(73%)
42				

43 *1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of this determination*

44 *2 From the CY+1 nominal dollar expenditure forecasts disclosed in accordance with clause 2.6.6 for the forecast period starting at the beginning of the disclosure year (the second to last disclosure of Schedules 11a and 11b)*

Company Name	The Power Company Limited
For Year Ended	31 March 2019
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Billed quantities by price component					
				Price component	Variable day energy sales	Variable day energy purchases				
				Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	Kwh				
Low user	Residential	Standard	8,970	53,568	-	44,200,317				
Domestic	Residential	Standard	17,509	169,891	-	128,893,115				
Non-Domestic	Commerical	Standard	9,202	217,476	-	163,772,810				
Individual non half hour	Commerical	Standard	72	9,878	-	7,455,446				
Individual half hour	Commerical	Standard	200	154,584	124,226,232	-				
Non-Standard	Commerical	Non-standard	5	136,496	91,211,509	-				
Add extra rows for additional consumer groups or price category codes as necessary										
		Standard consumer totals	35,953	605,397	124,226,232	344,321,689	-	-	-	-
		Non-standard consumer totals	5	136,496	91,211,509	-	-	-	-	-
		Total for all consumers	35,958	741,892	215,437,741	344,321,689	-	-	-	-

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

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

								Line charge revenues ($000) by price component						
							Price component	Fixed	Variable					
Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Rate (eg, $ per day, $ per kWh, etc.)	$/Day	$/kwh					*Add extra columns for additional line charge revenues by price component as necessary*
Low user	Residential	Standard	$6,438		$5,380	$1,058		$364	$6,074					
Domestic	Residential	Standard	$19,632		$16,418	$3,214		$8,588	$11,044					
Non-Domestic	Commerical	Standard	$23,183		$19,417	$3,766		$9,319	$13,864					
Individual non half hour	Commerical	Standard	$745		$518	$227		$106	$639					
Individual half hour	Commerical	Standard	$6,343		$2,736	$3,607		$3,473	$2,869.70					
Non-Standard	Commerical	Non-standard	$5,913		$3,344	$2,570		$5,913	-					
Generation	Commerical	Non-standard	$100		$100			$100	-					
			-											
			-											
			-											
Add extra rows for additional consumer groups or price category codes as necessary														
		Standard consumer totals	$56,340	-	$44,468	$11,872		$21,849	$34,491	-	-	-	-	
		Non-standard consumer totals	$6,013	-	$3,443	$2,570		$6,013	-	-	-	-	-	
		Total for all consumers	$62,353	-	$47,912	$14,441		$27,862	$34,491	-	-	-	-	
					Check	OK								

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	5

Company Name	The Power Company Limited
For Year Ended	31 March 2019
Network / Sub-network Name	

SCHEDULE 9a: ASSET REGISTER

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

sch ref

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	89,204	89,884	680	3
10	All	Overhead Line	Wood poles	No.	19,786	19,254	(532)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	913	898	(15)	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	10	8	(2)	3
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	–	3
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.	52	54	2	3
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.	55	58	3	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	8	8	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	290	292	2	3
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	19	20	1	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	33	30	(3)	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	147	148	1	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	48	48	–	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	62	62	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	6,700	6,710	10	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	5	8	3	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	86	111	25	3
39	HV	Distribution Cable	Distribution UG PILC	km	45	42	(4)	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.	35	35	–	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	5	7	2	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	13,665	13,719	54	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.	99	97	(2)	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	10,478	10,504	26	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	642	659	17	3
48	HV	Distribution Transformer	Voltage regulators	No.	71	71	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	7	7	N/A
50	LV	LV Line	LV OH Conductor	km	850	849	(1)	3
51	LV	LV Cable	LV UG Cable	km	229	231	2	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	352	353	1	3
53	LV	Connections	OH/UG consumer service connections	No.	37,489	37,775	286	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	560	586	26	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 2019
Network / Sub-network Name:

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 Disclosure Year (year ended): 31 March 2019

Number of assets at disclosure year end by installation date

#	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	-	-	2,236	36,680	12,172	21,581	3,010	204	748	1,009	608	176	85	134	329	320	846	1,205	783	911	961	1,148	1,180	1,288	1,205	782	42	-	-	-	-	-	-	241	89,884	-	3
11	All	Overhead Line	Wood poles	No.	-	-	557	1,388	5,230	732	3,803	734	701	738	764	738	457	727	808	1,042	127	7	2	16	9	164	3	17	16	-	-	-	-	-	-	-	-	474	19,254	-	3
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	131	148	126	141	136	59	14	8	26	-	-	0	25	21	1	-	0	-	-	36	11	-	12		-	-	-	-	-	-	-	2	898	-	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	-	-	0	-	-	-	-	-	-	1	-	0	-	-	-	-	-	-	-	-	3	8	-	3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	1	-	3
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	7	6	-	2	1	-	-	-	-	1	-	-	-	-	1	1	1	1	1	7	2	-	-	-	-	-	-	-	4	54	-	3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	-	-	11	6	1	-	-	2	2	2	13	-	5	-	-	3	2	1	-	-	6	4	-	-	-	-	-	-	-	-	58	-	4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	8	-	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	18	13	16	30	62	3	15	2	2	12	7	10	23	3	8	1	1	7	4	5	4	-	7	7	-	-	-	-	-	-	-	12	292	-	3
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	-	-	-	-	1	-	-	-	5	-	-	-	-	-	-	-	-	7	1	-	-	-	-	-	-	-	-	-	-	20	-	4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	-	2	1	3	7	2	-	-	-	-	1	2	5	2	-	1	1	-	-	-	-	2	1	-	-	-	-	-	-	-	-	-	30	-	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	-	-	17	48	-	-	1	-	-	-	-	6	-	2	-	-	20	7	13	13	9	7	5	-	-	-	-	-	-	-	-	148	-	4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	3	20	6	-	-	1	4	1	1	-	2	-	1	-	-	5	1	-	-	2	1	-	-	-	-	-	-	-	-	48	-	4
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	-	-	6	8	9	2	1	3	2	1	3	-	2	-	2	1	-	3	1	6	1	2	2	4	3	-	-	-	-	-	-	-	-	62	-	4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3	0	193	725	3,274	1,079	312	43	99	102	70	61	57	53	72	101	76	49	51	54	36	74	34	36	8	17	-	-	-	-	-	-	-	28	6,710	-	3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
38	HV	Distribution Line	SWER conductor	km	-	-	-	4	1	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	4
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	-	0	16	4	5	2	4	3	5	8	4	5	6	4	2	2	1	4	1	3	5	3	1	14	-	-	-	-	-	-	-	8	111	-	3
40	HV	Distribution Cable	Distribution UG PILC	km	-	-	-	0	15	6	8	1	0	1	0	-	1	1	3	1	1	0	1	0	-	0	-	-	0	-	-	-	-	-	-	-	-	2	42	-	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	4	4	-	-	-	-	1	2	1	-	1	1	-	-	-	1	1	-	6	1	4	1	-	-	-	-	-	-	-	35	-	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	-	1	2	-	-	-	-	-	-	-	1	7	-	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	9	1	200	379	1,347	2,163	1,461	117	319	407	308	333	267	353	434	502	556	532	460	420	352	424	340	263	289	292	65	-	-	-	-	-	-	1,106	13,719	-	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	9	-	-	-	11	1	5	4	8	15	6	2	1	3	1	2	2	-	4	20	-	-	-	-	-	-	-	-	97	-	4
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	8	1	176	69	1,299	2,004	1,379	101	314	379	263	250	234	310	379	403	410	387	344	326	259	324	245	177	212	183	36	-	-	-	-	-	-	36	10,504	-	3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	3	8	87	88	43	5	17	21	19	31	19	39	33	30	24	20	14	17	20	30	14	17	34	19	3	-	-	-	-	-	-	4	659	-	3
49	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	-	-	-	-	-	4	-	2	6	5	5	16	14	3	-	-	-	2	8	2	-	4	-	-	-	-	-	-	-	-	-	71	-	4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	-	4	-	1	-	-	-	-	-	-	-	1	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	-	N/A
51	LV	LV Line	LV OH Conductor	km	-	-	20	72	499	105	42	1	9	11	7	5	4	7	5	6	6	5	5	4	5	5	4	5	5	4	-	-	-	-	-	-	-	5	849	-	3
52	LV	LV Cable	LV UG Cable	km	-	-	0	2	81	20	12	1	1	4	4	7	8	17	21	8	8	6	5	4	4	3	4	2	2	2	-	-	-	-	-	-	-	4	231	-	3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	-	-	0	14	239	40	17	1	1	2	1	3	3	4	2	2	1	3	1	1	2	0	0	0	2	0	-	-	-	-	-	-	-	12	353	-	3
54	LV	Connections	OH/UG consumer service connections	No.	-	210	2,140	5,297	7,059	7,951	7,031	249	343	441	435	418	470	516	570	683	525	424	476	361	403	328	302	277	334	331	75	-	-	-	-	-	-	126	37,775	-	3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	-	8	23	57	129	19	12	9	1	4	20	8	29	19	9	5	4	31	13	22	30	21	49	34	10	-	-	-	-	-	-	18	586	-	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single syster	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 2019
Network / Sub-network Name	

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

This schedule requires a summary of the key characteristics of the overhead line and underground cable network. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	–	–	–
12	50kV & 66kV	462	–	462
13	33kV	436	9	445
14	SWER (all SWER voltages)	5	3	8
15	22kV (other than SWER)	0	1	1
16	6.6kV to 11kV (inclusive—other than SWER)	6,710	148	6,858
17	Low voltage (< 1kV)	849	231	1,080
18	**Total circuit length (for supply)**	8,461	392	8,853
19				
20	Dedicated street lighting circuit length (km)	270	83	353
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			–
22				

23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**
24	Urban	474	6%
25	Rural	4,572	54%
26	Remote only	809	10%
27	Rugged only	1,990	24%
28	Remote and rugged	604	7%
29	Unallocated overhead lines	12	0%
30	**Total overhead length**	8,461	100%
31			
32		**Circuit length (km)**	**(% of total circuit length)**
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,691	19%
34		**Circuit length (km)**	**(% of total overhead length)**
35	Overhead circuit requiring vegetation management	1,447	17%

Company Name	The Power Company Limited
For Year Ended	31 March 2019

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref	Location *	Number of ICPs served	Line charge revenue ($000)
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			

26 ** Extend embedded distribution networks table as necessary to disclose each embedded network owned by the EDB which is embedded in another EDB's network or in another embedded network*

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

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

9e(i): Consumer Connections

Number of ICPs connected in year by consumer type

*Consumer types defined by EDB**	Number of connections (ICPs)
Domestic	249
Half Hour Individual	–
Low User	7
Non Domestic	81
** include additional rows if needed*	
Connections total	337

Distributed generation

Number of connections made in year	40	connections
Capacity of distributed generation installed in year	0.28	MVA

9e(ii): System Demand

		Demand at time of maximum coincident demand (MW)
	Maximum coincident system demand	
	GXP demand	103
plus	Distributed generation output at HV and above	44
	Maximum coincident system demand	147
less	Net transfers to (from) other EDBs at HV and above	1
	Demand on system for supply to consumers' connection points	145

		Energy (GWh)	
	Electricity volumes carried		
	Electricity supplied from GXPs	612	
less	Electricity exports to GXPs	139	
plus	Electricity supplied from distributed generation	327	
less	Net electricity supplied to (from) other EDBs	14	
	Electricity entering system for supply to consumers' connection points	785	
less	Total energy delivered to ICPs	742	
	Electricity losses (loss ratio)	43	5.5%
	Load factor	0.62	

9e(iii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	446
Distribution transformer capacity (Non-EDB owned, estimated)	47
Total distribution transformer capacity	493
Zone substation transformer capacity	459

Company Name	The Power Company Limited
For Year Ended	31 March 2019
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	Number of interruptions	
10	Class A (planned interruptions by Transpower)		
11	Class B (planned interruptions on the network)	606	
12	Class C (unplanned interruptions on the network)	568	
13	Class D (unplanned interruptions by Transpower)	1	
14	Class E (unplanned interruptions of EDB owned generation)		
15	Class F (unplanned interruptions of generation owned by others)		
16	Class G (unplanned interruptions caused by another disclosing entity)	1	
17	Class H (planned interruptions caused by another disclosing entity)		
18	Class I (interruptions caused by parties not included above)		
19	Total	1,176	
20			
21	**Interruption restoration**	≤3Hrs	>3hrs
22	Class C interruptions restored within	390	178
23			
24	**SAIFI and SAIDI by class**	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)		
26	Class B (planned interruptions on the network)	0.52	118.7
27	Class C (unplanned interruptions on the network)	2.47	158.8
28	Class D (unplanned interruptions by Transpower)	0.23	2.2
29	Class E (unplanned interruptions of EDB owned generation)		
30	Class F (unplanned interruptions of generation owned by others)		
31	Class G (unplanned interruptions caused by another disclosing entity)	0.00	0.0
32	Class H (planned interruptions caused by another disclosing entity)		
33	Class I (interruptions caused by parties not included above)		
34	Total	3.22	279.7
35			
36	**Normalised SAIFI and SAIDI**	Normalised SAIFI	Normalised SAIDI
37	Classes B & C (interruptions on the network)	2.99	277.5
38			
39	**10(ii): Class C Interruptions and Duration by Cause**		
40			
41	**Cause**	SAIFI	SAIDI
42	Lightning	0.14	10.3
43	Vegetation	0.25	21.7
44	Adverse weather	0.06	23.7
45	Adverse environment	0.00	0.0
46	Third party interference	0.38	26.4
47	Wildlife	0.09	6.9
48	Human error	0.27	5.3
49	Defective equipment	0.78	49.4
50	Cause unknown	0.50	15.0
51			
52	**10(iii): Class B Interruptions and Duration by Main Equipment Involved**		
53			
54	**Main equipment involved**	SAIFI	SAIDI
55	Subtransmission lines		
56	Subtransmission cables		
57	Subtransmission other	0.01	1.4
58	Distribution lines (excluding LV)	0.50	115.2
69	Distribution cables (excluding LV)	0.00	0.0
60	Distribution other (excluding LV)	0.01	2.0
61	**10(iv): Class C Interruptions and Duration by Main Equipment Involved**		
62			
63	**Main equipment involved**	SAIFI	SAIDI
64	Subtransmission lines	0.33	8.1
65	Subtransmission cables	–	–
66	Subtransmission other	0.07	2.5
67	Distribution lines (excluding LV)	1.84	132.3
68	Distribution cables (excluding LV)	0.08	6.0
69	Distribution other (excluding LV)	–	–

sch ref				
70	**10(v): Fault Rate**			
71	**Main equipment involved**	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
72	Subtransmission lines	14	898	1.56
73	Subtransmission cables	–	9	–
74	Subtransmission other	4		
75	Distribution lines (excluding LV)	479	6,715	7.13
76	Distribution cables (excluding LV)	6	152	3.96
77	Distribution other (excluding LV)	64		
78	Total	567		

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 WACC of 4.97%, which is .46% below the 75th percentile estimate of post-tax WACC of 5.43% and a 5.48% vanilla WACC, which is .46% below the 75th percentile estimate of vanilla WACC of 5.94%.

No items were reclassified in the disclosure year.

Regulatory Profit (Schedule 3)

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

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

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

Box 2: Explanatory comment on regulatory profit

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

No items were reclassified in the disclosure year.

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

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

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

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

Box 3: Explanatory comment on merger and acquisition expenditure
There were no merger or acquisition expenses incurred in the disclosure year.

Value of the Regulatory Asset Base (Schedule 4)

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

Box 4: Explanatory comment on the value of the regulatory asset based (rolled forward)
The calculation of the Regulatory Asset Base used the 31 March 2018 figure of $373,678k as the starting point with inflationary indexing over the year to 31 March 2019 plus additions less disposals totalling $385,009k. Subtransmission cables have negative assets commissioned due to the timing of receipt of capital contributions No items were reclassified.

Regulatory tax allowance: disclosure of permanent differences (5a(i) of Schedule 5a)

8. In the box below, provide descriptions and workings of the material items recorded in the following asterisked categories of 5a(i) of Schedule 5a-

    8.1 Income not included in regulatory profit / (loss) before tax but taxable;

    8.2 Expenditure or loss in regulatory profit / (loss) before tax but not deductible;

    8.3 Income included in regulatory profit / (loss) before tax but not taxable;

    8.4 Expenditure or loss deductible but not in regulatory profit / (loss) before tax.

Box 5: Regulatory tax allowance: permanent differences
The expenditure deductible but not in regulatory profit is the $17k cost of easements which is a tax deductible expense. Income included in regulatory profit / (loss) before tax but not taxable is the $5,526k revaluations for the year. There are no other permanent differences.

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

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

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

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

Taxable Capital Contributions:	$	1,876
	$	1,876
Tax Rate:		28%
Temporary Differences	$	525

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

All costs were either passed through by PowerNet as agent or were invoiced to The Power Company Limited and hence directly attributable with the exception of some Business support costs which have been apportioned using the ABAA method.

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.

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

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

Box 9: Explanation of capital expenditure for the disclosure year
The materiality threshold of programmes or projects identified during the disclosure year was set at $500k. Lower value projects with defined scope were included in the list for specific identification within categories. No items were reclassified during the disclosure year.

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

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

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

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

Box 10: Explanation of capital expenditure for the disclosure year
Reactive and minor maintenance is performed on The Power Company Limited's transformers and lines and this is classified as refurbishment and renewal maintenance when the work performed is not material in relation to the overall value of the asset. No items were reclassified during the disclosure year. There was no material atypical expenditure disclosed in Schedule 6b.

Variance between forecast and actual expenditure (Schedule 7)

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

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

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

The overall actual expenditure on network assets was 8% under budget.

Consumer connection:

- Overall spend was 20% under budget
- Mataura Valley Milk 18% underspend due to project delays and final completion deferred to minimise impact of customer outages

Asset replacement and renewal:

- 16% overspend to manage the risk effectively of work identified during inspections - largely focused on pole replacements and low conductor remedial work.
- 11kV line replacement work was 52% over budget due to the prioritization of red tagged pole replacement works.

Asset Relocations:

- 121% over budget. This type of work is customer driven with the reactive element much higher than estimated due to increased customer relocations requested.

Reliability, Safety and Environment:

- 26% under budget.
- Quality of supply project for Mobile Substation is 40% under budget because readiness has been delayed so that it can be scheduled to coincide with other work and minimise overall cost.
- Earth upgrades 46% under budget due to resourcing constraints.
- Substation safety 37% over budget as project costs were higher than expected on the Mataura arc flash project.
- Riversdale 33kV backup 63% under budget. Project delayed.
- Orawia substation upgrade 64% under budget as the remainder of the project is postponed until 23/24 to allow higher priority capex projects.

Operational Expenditure:

Network operational expenditure was 10% under budget.

Service interruptions and emergencies:

- 22% above budget.
- Incident response Technical was 35% under budget due to less faults because of the favourable weather and improved maintenance practices.
- The larger Incident response Distribution budget was 28% over budget due to the nature of the faults encountered, requiring a higher amount of expenditure

Vegetation management:

- 10% over budget additional spend needed to manage high risk vegetation appropriately.

Routine and corrective maintenance and inspection:

- 9% under budget due to focus on capital pole replacement.

Asset replacement and renewal:

- 44% under budget due to focus on capital pole replacement rather than minor maintenance

System Operations and Network support 35% under budget

- Insurance Captive is not yet operational which makes up 21% of the budget.

Business Support

- 16% below budget due to the change in allocation methods to ABBA.

Information relating to revenues and quantities for the disclosure year

15. In the box below provide-

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

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
The line pricing methodology revenue target of $60,102k. The total billed of $62,353k was above budget by $2,251k due to increased growth in the variable charges allowed for in the pricing model and the Transpower HVDC charge not included in the budget.

Network Reliability for the Disclosure Year (Schedule 10)

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

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 SAIDI of 277.5 minutes exceeded the Statement of Intent target of 182.81 minutes; and was higher than the 2017/18 measure of 259.9 minutes. The SAIFI of 2.99 times exceeded the Statement of Intent target of 2.84 times and was higher than the 2017/18 measure of 2.93 times. The Power Company Limited has significantly reduced the amount of live line work and adjusted work practises to align with industry best practice guidelines. This reduction in live line work and adjusted work practices is reflected in increased planned and unplanned SAIDI and SAIFI. Due to its consumer ownership The Power Company Limited is not subject to Default Price-Quality Path regulation and had therefore not commented on performance relative to Commerce Commission quality limits. The information has been prepared on a basis consistent with the previous year's disclosure and has not recorded successive interruptions. Schedule 10 will be reviewed to be in line with the determination in future years. There are inherent limitations in the ability of The Power Company Limited to collect and record the network reliability information required to be disclosed in Reports 10(i) to 10(iv). Consequently there is no independent evidence available to support the accuracy of recorded faults and control over and accuracy of installation control point ('ICP') data, included in the SAIDI and SAIFI calculations, is limited throughout the year.

Insurance cover

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

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

17.2 In respect of any self insurance, the level of reserves, details of how reserves are managed and invested, and details of any reinsurance.

Box 14: Explanation of insurance cover

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

- Substations and network equipment are insured for $165.46 million.

Lines and cables are not insured.

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

Amendments to previously disclosed information

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

    18.1 a description of each error; and

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

Box 15: Disclosure of amendment to previously disclosed information
No amendments were disclosed.

SCHEDULE 14A MANDATORY EXPLANATORY NOTES ON FORECAST INFORMATION

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

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

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

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

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

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

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

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

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

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

Nominal Prices are based on publicly available New Zealand Treasury's economic forecast indicated in the Budget Economic and Fiscal Update report released in December 2017:

	2019	2020	2021	2022	2023
Inflator (CAPEX & OPEX)	1.9%	2.1%	2.2%	2.2%	2.0%

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

SCHEDULE 15 VOLUNTARY EXPLANATORY NOTES

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

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

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

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

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

3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Schedule 10 - The information has been prepared on a basis consistent with the previous year's disclosure and has not recorded successive interruptions. Schedule 10 will be reviewed to be in line with the determination in future years.

The SAIDI of 277.5 minutes exceeded the Statement of Intent target of 182.81 minutes; and was lower than the 2017/18 measure of 259.9 minutes.

The SAIFI of 2.99 times exceeded the Statement of Intent target of 2.84 times and was higher than the 2017/18 measure of 2.93 times.

The Power Company Limited has significantly reduced the amount of live line work and adjusted work practises to align with industry best practice guidelines. This reduction in live line work and adjusted work practices is reflected in increased planned and unplanned SAIDI and SAIFI.

Due to its consumer ownership The Power Company Limited is not subject to Default Price-Quality Path regulation and had therefore not commented on performance relative to Commerce Commission quality limits.

There are inherent limitations in the ability of The Power Company Limited to collect and record the network reliability information required to be disclosed in Reports 10(i) to 10(iv). Consequently there is no independent evidence available to support the accuracy of recorded faults and control over and accuracy of installation control point ('ICP') data, included in the SAIDI and SAIFI calculations, is limited throughout the year.

APPENDICES

APPENDIX A:

THEPOWERCOMPANYLTD

Related Party Transactions:

Additional Information Disclosures

1. INTRODUCTION

For the purpose of meeting the 2019 Related Party Transaction reporting requirements, in accordance with section 2.3.6 of the Electricity Information Disclosure Determination 2012, (Consolidated in 2018), issued 3 April 2018.

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

- **The Power Company Limited's 2019 Information Disclosure**, for the year ended 31 March 2019 - 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 by a related party on the The Power Company Limited (TPCL) network assets being greater than $20 million for the year ending 31 March 2019.

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

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

3. RELATED PARTY RELATIONSHIPS

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

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

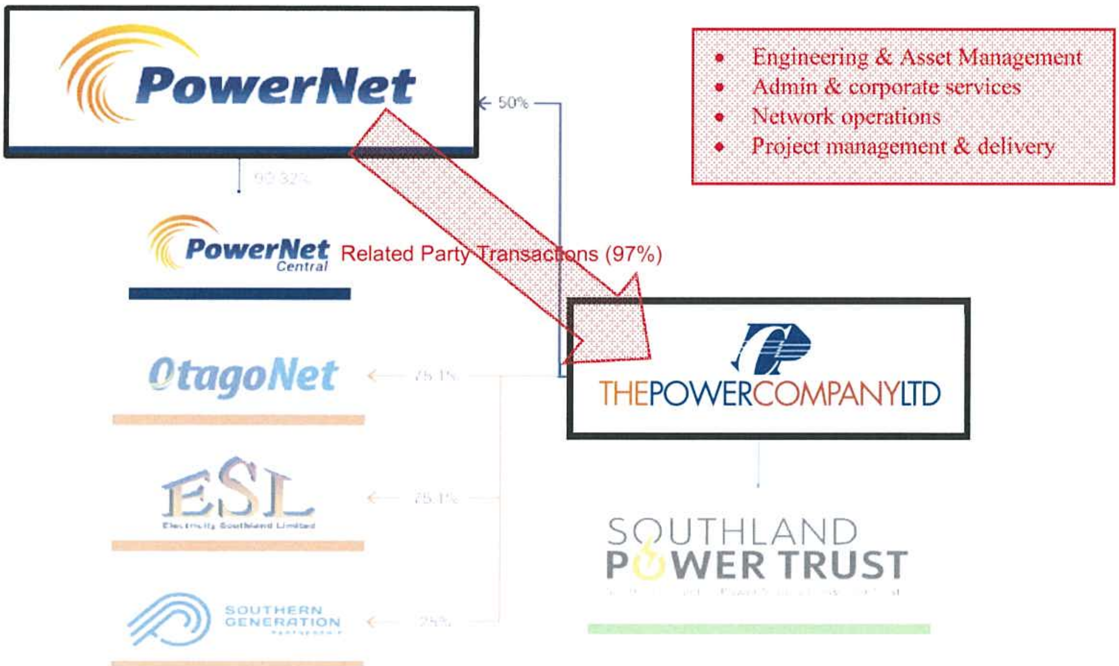
During the year ending 31 March 2019, TPCL had related party transactions with the following entities:

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

Company Structure

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

ID Determination reference: 2.3.8



a. **PowerNet Limited**

TPCL holds a 50% shareholding in electricity network management company PowerNet Limited. PowerNet provides a range of field contracting, asset management, system control and business services to TPCL. The value of regulatory related goods and services provided to TPCL by PowerNet, for the year ended 31 March 2019, is categorised as follows:

		($000)
Operating Expenditure:		
i.	Service interruptions and emergencies	3,885
ii.	Vegetation management	1,630
iii.	Routine and corrective maintenance and inspection	4,467
iv.	Asset replacement and renewal (Opex)	735
v.	System operations and network support	1,290
vi.	Business support	2,873
Capital Expenditure:		
vii.	Consumer connection	3,481
viii.	System growth	6,550
ix.	Asset replacement and renewal (Capex)	10,381
x.	Asset relocations	120
xi.	Quality of supply	625
xii.	Other reliability, safety and environment	2,249
	Total PowerNet Related Party expenditure	**38,286**

In the year to 31 March 2019, PowerNet provided 100% of the TPCL Lines Business Capital Expenditure, and 92% of all Operating Expenditure. The high percentage of related party transactions relative to total expenditure is due to PowerNet operating under a Network Management Agreement (NMA) with TPCL, in the form of an "agency agreement".

Services provided under the agreement include:

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

PowerNet holds an ownership interest of approximately 90% in PowerNet Central Ltd (formerly Peak Power Services Ltd), a Central Otago based electricity distribution maintenance contracting business, servicing the Electricity Southland Ltd network assets.

b. OtagoNet Joint Venture

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

There were no related party transactions between OJV and TPCL during the reporting period.

c. **Electricity Southland Limited**

TPCL has a 75.1% ownership interest in the Electricity Southland Ltd (ESL) electricity distribution network, based in Central Otago. The ESL network is consolidated within the OtagoNet JV network for regulatory reporting purposes.

There were no related party transactions between ESL and TPCL during the reporting period.

d. **Southern Generation Limited Partnership**

TPCL has 25% ownership interest in Southern Generation Limited Partnership, investing in wind and hydro electricity generation – clean, green renewable energies that fit with TPCL's other strategies.

There were no related party transactions between SGLP and TPCL during the reporting period.

Network Management Agreement ('Agency Agreement')

TPCL incurs 100% of its capital expenditure and the majority of its operating costs for its electricity distribution and metering businesses from PowerNet, in accordance with the explicit terms and conditions of the PowerNet Network Management Agreement (NMA).
While TPCL owns the Network Assets and provides Line Function Services in Southland (excluding parts of Invercargill city and the Bluff township area), under the agreement PowerNet will manage the network assets, will carry out an agreed Capital Works programme, has the exclusive right to provide Line Function Services, and will provide the business administration services on behalf of TPCL.

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

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

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

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

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

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

4. PROCUREMENT POLICY

ID Determination 2.3.10 & 2.3.11

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

Procurement Policy (FNPO-035-Policy)

PowerNet Limited (PowerNet) aims to obtain the best long-term value for money across all its spend categories. In doing so, PowerNet's procurement processes will be guided by the following general principles:

- ✓ Plan and manage for the best outcome
- ✓ Be fair to all suppliers
- ✓ Choose the right supplier
- ✓ Adhere to the rules

Asset 'whole-of-life' cost focus

- The lowest lifecycle (whole-of-life) cost shall be sought.
- Consideration must be given in regard to the Capital versus Maintenance expenditure trade-offs for network assets and equipment.

Sourcing of labour

- Necessary skills, equipment and availability will be considered when resourcing labour – whether using internal or external sources. External contractors must comply with PowerNet health and safety and operating certification requirements.
- PowerNet recognises that the across the Southland-Otago region there is a limited pool of line mechanic and technical contractors, and accordingly relies heavily on its own internal field crews.
- Large specific network projects should be competitively tendered where possible, both to ensure that the lowest price has been obtained, and also to provide cost comparison information for PowerNet.

Sourcing of materials and equipment

- Routine supply of materials shall be through the Corys Electrical Agreement, which includes various mechanisms to ensure prices are efficient.
- Supply of non-routine materials or specialist equipment shall be competitive. The formality of the process shall be commensurate with the value of the purchase.

External party works

- Activities for which PowerNet has a statutory responsibility, but is not required to perform the function (e.g. vegetation management or new connections) will be made clear to those external parties (or customers). Communications with those consumers shall include a list of optional accredited external contractors who they can choose to undertake their work.

The above guidelines must be applied by all staff at PowerNet. Further detail is available within associated internal procurement process and procedure standards.

5. APPLICATION OF PROCUREMENT POLICY

ID Determination 2.3.12 (1)

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

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

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

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

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

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

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

Resourcing

Having the combined network management of TPCL, EIL, OJV and ESL, gives PowerNet a stronger position to negotiation more favourable competitive prices for goods and services, through the greater purchasing volumes and activity, than would otherwise be possible by TPCL alone. A supplier agreement with Corys Electrical makes it possible to source the required specialised electrical materials at market competitive 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. TPCL has learned 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. almost 30% of the TPCL Capital project expenditure during the 2018/19 year is non-PowerNet labour cost). Having a team of experienced Line Mechanics and high voltage Technicians enables PowerNet to provide an effective faults response service, reducing the impact on customers of unplanned outages, and helping the TPCL network meet its regulatory outage performance targets (SAIDI & SAIFI targets). For this reason, in many cases for TPCL network asset maintenance tasks, the work is allocated to PowerNet internal labour teams with the appropriate skills and equipment.

While the project resources and materials required are planned by network engineers within the PowerNet Asset Management team, the selection of the Suppliers to provide the work is a responsibility of the respective Project Manager. In making the selection, the Project Manager is mindful of making decisions based on the best outcome on behalf of the network – and so, to protect the value and reliability of the Network Assets, the Project Manager selects the materials and scopes the design to meet the required network design standard. Outsourcing is considered for each element of the project if appropriate, and market testing performed where uncertainties exist in cost or difficulty. This selection process may not always result in the lowest capital investment cost. Any new assets included on to the TPCL network are analysed in terms of the Net Present Value of their full life cycle costs in line with good and internationally occupied Asset Management practices. We ensure 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 a market competitive prices.

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

Project Management Reporting

PowerNet operates a job costing system (Maximo) to track direct project costs (materials, labour and services). Project Managers' record the project details by way of setting up a Maximo 'work order' for different stages or components of work required. Maximo is integrated with the Technology One (Tech One) Accounts Payable system operated by the PowerNet Finance department. Purchase Requisitions are raised in Tech One for the purchase of materials and external services, with project cost details accumulating within Maximo. Purchase Requisitions must be approved by an employee with an appropriate financial authority level, as documented in the PowerNet Financial Authority Policy. If above $1 million, a Business Case is required for Board approval prior to approval being administered. Purchase Orders can't be provided to suppliers until approval is granted in TechOne. TechOne records the approval details for audit trail purposes.

Once the Project Manager is satisfied the project work has been completed to the required standard, and all costs associated to the work have been received and recorded against the Maximo Work Order – a project close out process begins. Documentation is prepared by administrators and project managers as necessary, to have the final costs summarised and compared to original budget with explanation where a material under or over spend variance exists. Once the documentation is ready, a final review is done and the project close out signed-off by a person with appropriate Network Asset Works Programme financial approval level. For a capital project, the final project cost is invoiced to TPCL, for payment within the standard PowerNet payment terms (20^{th} of month following invoice date).

Under the Financial Authorities Policy relating to the PowerNet management of TPCL, those authorised under PowerNet's financial delegation have financial delegated authority on behalf of TPCL.

Cost of assets, goods or services from Related Party

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

6. PURCHASES REQUIRED FROM A RELATED PARTY

ID Determination 2.3.12 (2)

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

- Fault repairs;
- Requests for a new connection to TPCL's network; and
- Removing trees or vegetation from proximity of power lines.

Fault Response and Reactive Maintenance

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

When a customer reports an outage, the PowerNet System Control operator will notify PowerNet staff to respond, (if they haven't done so already if an alarm system has been activated).
PowerNet provides on-call line mechanics and technicians, located across the Southland region, able to respond in a very short period of time to a fault call out, to provide a reliable and efficient fault response service, and minimise the impact of a power outage on TPCL network customers. Without these remote depot locations the duration (SAIDI) of outages on the TPCL network would be adversely affected. Having skilled labour, trained to the network accepted standard and practices, located at various depots across the network, and having appropriate tools and equipment capable of resolving an outage safely and quickly, is a key reason why PowerNet provides fault response services internally, rather than outsourcing.

New Connections

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

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

For example, if a customer required a new connection for a new Dairy shed, PowerNet will manage the line extension along the road, but the customer is encouraged to manage the construction of the line from the road (from the network connection point to the ICP) to the Dairy Shed, through an external contractor of their choice. In the case of a high voltage line (11kVA or above), the network assumes ownership of the new line and is responsible for the future maintenance or repair of that line.

Therefore, it is important that the customer's external contractor has their design and construction details approved by PowerNet engineers on behalf of TPCL, to make sure the design is to the required, acceptable TPCL network standard.

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

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

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

Using an Independent Contractor

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

Arborist/Tree Management

All electricity network companies are required under Government regulations (Electricity (Hazards from Trees) Regulations 2003) to ensure trees do not grow too close to their electricity lines or equipment. Vegetation management in TPCL is a core network maintenance activity that uses similar equipment (live line bucket trucks) and requires similar live line training skills for the operators.

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

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

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

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

Approved Contractors

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

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

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

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

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

7. PROCUREMENT REPRESENTATIVE EXAMPLES

ID Determination 2.3.12 (3)

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

i. **Major Construction Projects (System Growth/Asset Replacement & Renewal)**

Significant large-scale projects are managed by the PowerNet Asset Management – Major Projects team. These projects are often long term (greater than 12 months), complex in design, and greater than $1m in cost, with additional procurement requirements. As such, a business case is required for board approval prior to commitments being made, and the projects are often separately recognised in the approved TPCL Asset management Plan, and annual Business Plan.

Due to the large amount of dedicated resource and long period of time required, these projects are often subcontracted by PowerNet. Detailed design work can be technically challenging and time consuming, and is also subcontracted by PowerNet. Market testing of suppliers occurs periodically for design and construction work (request for tender/quotation), to make sure the subcontracting cost is reasonable. The majority of project materials are sourced through Corys Electrical, or in special circumstances of dedicated large cost items (eg. substation transformer), they may be sourced directly from the overseas manufacturer. A PowerNet Project Manager is assigned to oversee the project, manage the flow of work, manage the work orders and purchase orders used to track expenditure, and pay suppliers. Often multiple work orders are raised for managing the different components of the project. Due to the typically longer project period, PowerNet issues progress invoices to TPCL during the project. A project close-out process occurs on completion of construction milestones, approved by either the Project Manager or person with the appropriate delegated financial authority level.

EXAMPLE: Lumsden Substation 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:	Lumsden Substation Upgrade (Oreti Valley Project)
Project Date:	August 2017 – February 2019
Project Number:	10739
Project Expenditure:	$ 4,374,000 External labour & materials $ 970,000 PowerNet services (incl. mark-up) ---------------- $ 5,344,000 (Project Total) $ 3,651,000 (2016-2018) $ 1,693,000 (2018/19) ---------------- $ 5,344,000
Project Classification:	System Growth (Capital Expenditure)
Project Manager:	PowerNet Ltd
Subcontractors:	Decom Ltd

The Lumsden Substation Upgrade is one of several substation assets included in the wider Oreti Valley Project (OVP), replacing and upgrading several aging assets in the rural Northern Southland area experiencing electricity consumption growth with the expansion of the dairy industry in recent years. The Lumsden substation assets were nearing end of life and in need of renewal. The OVP includes upgrading substations at Centre Bush, Dipton and Lumsden, a new 66kV line between Winton and Centre Bush and upgrading the 33kV lines to 66kV between Centre Bush and Mossburn.

The Lumsden Substation had been identified for being upgraded in the 2017-2027 Asset Management Plan approved by the TPCL board of Directors in November 2016. Due to the size project and large cost involved, once the design scope had been agreed a Business Case was prepared by the PowerNet Network Asset Engineers, and presented for approval in mid-2017. The project was included in the 2017/18 Annual Works Programme prepared by PowerNet, and assigned to a Project Manager in the PowerNet Major Projects team. In accordance with PowerNet project management and procurement processes, the Project Manager then prepared the internal project management system (Maximo) to record the necessary project budget details, and work orders for each significant component of the project.

A review of available resources highlighted that due to the size and technical challenges with this project, and in the interest of a timely construction, it was decided to outsource the design and majority of the construction to external suppliers. Smaller civil works were outsourced to alternative suppliers available in the area, and the PowerNet Line Mechanics assisted where necessary. The sourcing of materials began through Corys Electrical, and selection of a construction contractor was decided. Based on the highly regarded performance of the external contractor awarded the construction of the nearby Dipton Substation Upgrade from an open tender process, the same external contractor was retained for this project too. The detailed design drawings were outsourced following a process of gathering external expressions of interest, and awarded in due course.

Once construction began, project costs were raised by way of raising purchase orders for approval and payment of invoices, and the tracking project costs occurred within Maximo work orders. Upon completion the Project Manager would complete project close-out documentation, and make sure a leader with appropriate financial approval would authorise the on-charge of project costs to the customer TPCL. The upgraded Lumsden Substation was commissioned in late 2018, with final costs received over the following few months.

Market Testing: The majority of the Lumsden Substation Upgrade project cost was outsourced by PowerNet. The results of a recent tender process for the nearby Dipton Substation Upgrade project, were considered when awarding the construction work to Decom Limited for Lumsden. The rates provided by the external contractor were consistent with the tender prices. As noted above, the detailed design work was similarly awarded based on the previous performance. The PowerNet business services and mark-ups allocated to this project reflect a share of the administration costs that would otherwise be required if TPCL had its own management and administration team. While it is difficult to market test this charge, PowerNet applies a model which allocates the business services costs based on estimated time incurred by PowerNet staff, on work required for the respective network. This model is reviewed periodically by an independent consultant to support the allocation basis. In addition, TPCL undertake periodic independent reviews of Major Projects to assess the spend against the regulatory criteria of prudency and efficiency. The review of the 2018/19 projects concluded the majority of spend reviewed was considered both prudent and efficient, and therefore met the regulatory expenditure objective.

ii. New Connection / Capacity Upgrade (System Growth)

New connections and capacity upgrades are generally customer driven, whether it be for a new property, or expansion of an existing property. Project size can range from a small connection of a newly built house, to the construction of a new manufacturing plant. For smaller scale projects, PowerNet assigns a Project Manager from the Connections team. Large scale projects may be assigned to the Major Projects team, and comply with the procurement processes noted above for Major Construction Projects. Smaller scale Connections projects do not require a business case (less than $1m project cost) or separate inclusion within the AMP or Business Plan line items. Due to the large number of low value connections or line upgrades, and the shorter lead-time from an enquiry to the work being completed, the majority of these projects are approved within an estimated grouped allowance value in the annual TPCL Business Plan.

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

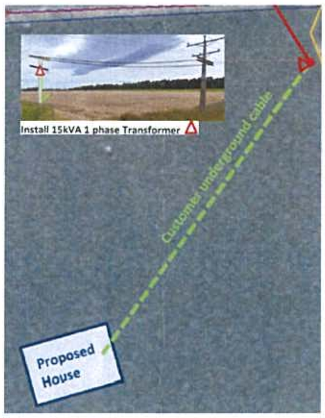
The procurement of goods and services for this type of work follows the same PowerNet procurement processes for a general construction project, only this work is more heavily influenced by a customer need rather than a network need. The PowerNet New Connection policy governs the requirements for this work. PowerNet assigns a project Manager to oversee the operational requirements, resourcing internal staff or external contractors depending on the availability and capability required, and making sure the work meets TPCL's network specifications. Often with this work, a customer contribution may be required where the cost to the network may greater than the economic benefit. Hence, if this wasn't for the customer request, then TPCL wouldn't otherwise be required to do this work.
New connection work is often small in nature and doesn't require the services of an outsourced engineer, however in circumstances of larger new connections or planned upgrades, the PowerNet Project manager will review the degree of complexity and resources available and outsource the work as required. The recent construction of the Mataura Valley Milk Dairy plant near Gore, is an example of this, where design work was outsourced, and various construction components were also outsourced, to meet the customers requirements.

On a smaller scale, a customer may request a new connection for a new dairy shed on a rural property. PowerNet engineers will assess the network requirements for reaching the new connection point, and whether the current line feeding the electricity has the capacity to carry the extra load, and if upgrading any network assets is required. The customer is provided with details, once the assessment has been completed, of the work to be managed by the PowerNet (network extension or upgrade to the network connection point), and the work the customer may manage through a network approved contractor of their choice (from network connection point to the Dairy Shed). If the cost of this work to TPCL is greater than the expected economic benefit, a quote for the customer contribution is provided. Work only commences when the Customer agrees to the terms and conditions of the quote.

<u>EXAMPLE: New House Connection (Rural Southland – June 2018)</u>

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

Project Name:	New House Connection (TPCL Works programme)
Completion Date:	June 2018
Project Number:	CC 336477 / 336480
Project Expenditure:	$ 6,000 External materials $ 9,000 PowerNet services (incl. mark-up) ------------ $ 15,000 Total Cost (2018/19)
Project Classification:	System Growth (Capital Expenditure)
Project Manager:	PowerNet Ltd
Construction:	PowerNet - Distribution Team
Subcontractors:	N/a



Project CC336477 new connection application was received by the PowerNet 'Connection' team staff during mid 2018. Customer had requested a new 15kVA single phase line be installed from an existing feeder, for a new house being built on a subdivided property. The request was assigned to a PowerNet Connections Project Manager who assessed the requirements, and prepared a work plan. Within the standard connection procurement process, if the requested work requires a contribution from the customer, the Project Manager prepares a Quote letter detailing the work required, and any associated contribution payment due from the Customer if the quote was accepted. The letter explains options for who can undertake the required work. High voltage work is the responsibility of the Network (PowerNet on behalf of TPCL) due to network regulations, however it is highlighted any low voltage cable installation work could be undertaken by a network approved contractor of their choice. In accordance with the PowerNet new connection policy, work would not begin until acceptance of the quote and 50% payment of the customer contribution is received.

This project is an example where a short lead-time (1-2 months) and relatively low cost work is required ($13,000), hence this project is not separately identified in the TPCL annual Business Plan, but rather included within the estimated allowance included in the Business Plan for new connection work.

The Project Manager created the project work order in Maximo, and assigned the work based on a review of the available resources, and timing, with consideration to other outage work scheduled in the area. In this instance, a PowerNet Distribution crew was assigned to undertake the Network required work, which coincided with other Network outage work scheduled in the area at that time, hence minimise the impact on customers of multiple power outages. The network connection design followed the standard Network specification drawings, not requiring any external design services, and the materials were sourced through Corys Electrical, at near wholesale prices in accordance with the Corys Supply Agreement.

In accordance with PowerNet project management and procurement processes, upon completion of the work, the Project Manager completed the project close-out documentation, and a role with appropriate financial approval authorised the on-charge of PowerNet's project related costs to TPCL, for payment under the standard payment terms and conditions.

Market Testing: The prices charged by PowerNet have been benchmarked against similar Line Mechanic or Technician roles from other external Suppliers utilised during 2017-2019. PowerNet labour rates were within +/-13% of the benchmarked rates. Of the $3.5M capital expenditure spent on New Connections and Capacity Upgrades, 69% 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. The PowerNet business services and mark-ups allocated to this project reflect a share of the administration costs that would otherwise be required if TPCL had its own management and administration team. The recent benchmarking of PowerNet business and network support services provided rated well on a cost per ICP basis, against other equivalent EDB's to TPCL.

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

Asset Replacement and Renewal projects are generally driven by internal asset condition and monitoring assessments, performed periodically by PowerNet staff on TPCL network assets. Depending on the nature of the work, this work could be a small scale project relating to the replacement of an 11kV Line Pole (eg. 'Red Tag Pole') managed by the PowerNet Distribution Team, or a larger technical project (eg. 500kV transformer replacement or substation upgrade project) managed by the PowerNet Technicians team. Similar to the previous expenditure examples, where the work is significant and identified separately within the AMP or annual Business Plan, the procurement processes for large-scale projects will apply. However where the work is smaller in scale, there is likely to be only one work order raised per job, and the project may be grouped together with other small, similar type work in the AMP and Business Plan.

The respective Project Managers will review available resources, and prioritise the PowerNet Line Mechanics or Technician staff to undertake the work based on availability and technical requirements. PowerNet specialises in offering these services, and has qualified Line Mechanics and Technicians and equipment available to work on these projects, while also being able to respond quickly to an unplanned outage or event. Outsourcing may occur where necessary, however based on experience due to the lack of local Line Mechanic contractors in Southland, PowerNet has been required recently to source external labour from outside the local area (eg. Network Waitaki, Buller Electrical). High Voltage Technicians Design work is for general replacement work is provided by way of TPCL network standard design.

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

Project costs are tracked in Maximo, and payments made to suppliers following the standard PowerNet payment terms and conditions. Upon completion the Project Manager would complete project close-out documentation, and a leader with appropriate financial approval will authorise the on-charge of project costs to TPCL.

EXAMPLE: WaikakaTransformer Replacement (Rural Southland – Nov 2018)
The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for a 'Technical' project for the TPCL network:

Project Name:	Waikaka Zone Substation – T1 Transformer Replacement (TPCL Works Programme)
Completion Date:	November 2018
Project Number:	CC 337748
Project Expenditure:	$ 37,000 External labour & materials $ 102,000 PowerNet services (incl. mark-up) -------------- $ 139,000 Total Cost (2018/19)
Regulatory Classification:	Asset Replacement & Renewal (Capital Expenditure)
Project Manager:	PowerNet Ltd
Construction:	PowerNet - Technicians Team
Subcontractors:	Wilson Contractors Ltd (civil construction), PBA Ltd (transformer fittings)

PowerNet undertook Project CC337748 to replace the T1 transformer as part of the Waikaka Zone Substation upgrade, based in rural Southland. This work was identified through PowerNet asset condition monitoring, and was deemed essential to maintain security of supply within the area. The work was prioritised in the approved 2018-19 TPCL Business Plan, under a separate line item. The standard PowerNet project management procurement processes are followed for asset renewal expenditure of this type. A PowerNet Project Manager is assigned to plan and oversee the work. The labour and materials requirements are assessed and project details are managed within the Maximo work order system, similar to other construction projects. Consideration is given to the timing of the work, to make sure resources are available, and to minimise the impact of a power outage to effected TPCL customers. PowerNet was assigned to undertake the work, being able to provide the skilled substation technician services required. Additional services were outsourced (eg. Civil construction works, and relocation of the transformer). The transformer was replaced by a similar unit that had become available from the recently upgraded Dipton Substation. Other materials were sourced through Corys Electrical, at competitive market prices in accordance with the Corys Supply Agreement.

In accordance with PowerNet project management and procurement processes, upon completion of the work, the Project Manager completed the project close-out documentation, and a role with appropriate financial approval authorised the on-charge of PowerNet's project related costs to TPCL, for payment under the standard payment terms and conditions.

Market Testing: The prices charged by PowerNet have been benchmarked against similar roles from other external Suppliers utilised during 2017-2019. PowerNet labour rates within +/-13% of the benchmarked rates. The materials sourced through Corys Electrical supply agreement includes a range of contractual mechanisms to ensure efficient prices are being provided to PowerNet. The PowerNet business services and mark-ups allocated to this project reflect a share of the administration costs that would otherwise be required if TPCL had its own management and administration team. The recent benchmarking of PowerNet business and network support services provided rated favourably on a cost per ICP basis, against other equivalent EDB's to TPCL.

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. Providing a faults call-out service (standby operation) out of small remote depots, comes at a cost which is recovered from the various EDB's covered by PowerNet (including TPCL), in the form of a faults standby payment, varying for each depot, dependent on the depot overheads costs. With an immediate response required, the procurement processes allow the flexibility for Distribution staff to respond immediately with the necessary materials (from fault stock items held at Depots or from Corys on-call arrangement if urgent) or equipment available anytime during the day or night. Purchase details for goods required are recorded on a manual 'Activity Report' which is later provided to the PowerNet Project Manager for approval and raising the relevant work order after the event has been resolved. In all other situations, the purchase of goods and services are approved prior to the work being undertaken.

The depots are based in Invercargill, Balclutha, Gore, Lumsden, Te Anau, Ranfurly, Palmerston and Stewart Island. Due to the quick response time required, outsourcing only occurs where the PowerNet resources are not capable of providing the services (eg. use of a digger or other specialised equipment). An estimated allowance for the fault repair work is approved in the annual Business Plan. Repair costs are tracked and payments made to suppliers following the standard project and finance software, within the standard PowerNet payment terms and conditions. Upon completion the respective PowerNet Project Manager completes a project close-out document, and the repair costs are on-charged in the monthly maintenance costs to TPCL.

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 2017-2019. PowerNet labour rates were within +/-13% of the benchmarked rates.

v. **Arborist Work (Vegetation Management)**

Tree management costs are driven by Government regulations for proximity of branches and vegetation to power lines. TPCL is responsible for encouraging property owners to comply with the regulations. PowerNet manages this service on behalf of TPCL. Inspectors identify hazards, and an administrator issues Tree Cut Notices to the property owner. Under TPCL's tree management policy, the first cut is provided at the cost of TPCL, with the property owner charged the cost of any further tree cutting cost. Due to the large volume of work required on TPCL network, and the large set-up cost, the tree cut work is outsourced to two network approved external contractors, under special operating agreements. The agreements also provide for immediate response to outage call-outs. An estimated allowance for the Vegetation Management work is included and approved in the annual Business Plan.

Vegetation management costs are tracked and payments made to suppliers following the standard project and finance software, within the standard PowerNet payment terms and conditions. Upon completion of a job, the respective PowerNet Project Manager completes a project close-out document, and the costs are on-charged to TPCL in the monthly maintenance invoice.

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

EXAMPLE: Vegetation Management (Rural Southland – Oct 2018)

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

Project Name:	Vegetation Control (TPCL Works Programme)
Project Completion Date:	October 2018
Project Number:	CC 341470
Total Expenditure:	\$ 2,300 External labour & materials \$ 200 PowerNet services (incl. mark-up) ---------- \$ 2,500 (2018/19)
Regulatory Classification:	Vegetation Management (Maintenance Expenditure)
Project Manager:	PowerNet Ltd
Subcontractors:	Asplundh Ltd

The Arborist team became aware of trees growing within the permitable distance of power lines during a routine Lines inspection in the rural Southland area. Details of the location and work required ('height reduce trees to clear 11kV lines by 2.6 metres') were noted on the PowerNet Cut/Trim Notice (CTN40914), and provided to a network approved external contractor to provide a quote. External contractors are required to have 'PreQual' Health & Safety approval and be certified to operate near the network power lines. These requirements limits the number available to undertake this work to two main contractors. 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 in full to PowerNet (and on-charged to TPCL), rather than the property owner. The external

contractor provides an estimated cost for the work to PowerNet, which once approved, schedules for the cut/trim work to be completed.
The work is overseen by the PowerNet Arborist Project Supervisor, who raises the necessary work orders to track the expenditure, and arrange for payment to the external contractor upon completion, under the standard PowerNet payment terms and conditions.

Market Testing: While PowerNet manages vegetation control work across TPCL network, almost all work is outsourced to external contractors, under a preferred supplier agreement, with set prices for different components of work undertaken. In 2016, TPCL reviewed the option of PowerNet establishing a vegetation control team to service TPCL network also, however it was found the commitment was not cost effective compared to the cost of the established external contractors. These prices are reviewed and agreed periodically by PowerNet, however, with a lack of alternate contractors available in the region, benchmarking of prices is difficult.

vi. Routine and Corrective Maintenance

Routine inspections and planned maintenance are important for maximising the useful life of network assets and equipment. TPCL spent 40% of its annual maintenance expenditure on planned maintenance activity in 2018/19.
PowerNet Network Asset Engineers identify an estimated allowance for routine and corrective maintenance and inspection costs in the Asset Management Plan. This is translated into different maintenance line item tasks in the Annual Business Plan and Annual Works Programme with the help of Project Managers. The work is split between identifiable assets that require maintenance activity, and other work for a service or task across many network assets. As such these costs are classified as operating costs, rather than capital expenditure.
The procurement process for actual activity is captured by way of Maximo Work orders, which are linked to a general maintenance line item (eg. "Technical Routine Inspections & Checks") in the TPCL Annual Works Programme maintenance expenditure. Work orders for corrective maintenance to individual assets are tracked in Maximo against budgeted costs, and work order close-out processes occur similar to other project work. General maintenance tasks are tracked to a work order, however the orders remain open through-out the year, as costs accumulate within the budgeted allowance.

EXAMPLE: Circuit Breaker Maintenance

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

Project Name:	MAT CB Maintenance
Completion Date:	December 2018
Project Number:	335592
Project Expenditure:	$ 461 External material $ 13,063 PowerNet services (incl. mark-up) ------------ $ 13,524 Total Cost (2018/19)
Regulatory Classification:	Technical Planned Maintenance (Technical Maintenance)
Project Manager:	PowerNet Ltd
Inspection:	PowerNet - Technicians Team

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

A work order is raised, with a budget based on historic information and the job is assigned and scheduled. A release request is submitted to system control to arrange for switching to take the equipment out of service. The work is performed and the asset test information is updated. The budget for planned inspection and maintenance work is approved in the annual Business Plan. Costs are tracked and payments made to suppliers following the standard PowerNet payment terms and conditions. Upon completion the respective PowerNet supervisor completes a close-out document, and the costs are on-charged in the monthly maintenance costs to TPCL.

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 2017-2019. PowerNet labour rates were within +/-13% of the benchmarked rates.

vii. **Business Services (Opex)**

Administration processes and systems associated with running TPCL network are managed by PowerNet support services teams (eg. Network Assets, Operations, Finance, HSE). A share of these costs are charged to TPCL by way of an Agency fee, which would otherwise be directly incurred by TPCL, if there was no 'Agency Agreement' (or NMA) in place with PowerNet. For example, TPCL requires the PowerNet Finance staff to manage its 'Accounts' administration processes (billing and payments), which include billing and collecting revenue from customers, and arrange for the payment of invoices. These costs are charged out to TPCL, and the other EDB's under PowerNet management, at cost, based on a time based allocation methodology.

The calculation of the Agency fee is generated based on guidance provided in the Agency Agreement (or NMA) between TPCL and PowerNet. The fee is reviewed each year during the annual business plan process, with cost allocations between different EDB's network and other business functions agreed (eg. metering, external work). This process includes open discussion between EDB's (PowerNet's customers) to ensure appropriate and fair allocation of PowerNet business services costs and efficiency benefits. External advice is provide to customers through a regular review of the PowerNet business plan model and allocation of costs between the parties.

The majority of the business services costs incurred by PowerNet in the course of managing the networks will be managed through the PowerNet Purchase Order system. The Purchase Order system applies financial authority limits to different roles in accordance with the requirements of the PowerNet Procurement Strategy and Financial Approvals Policy. Where there may be a direct cost to TPCL, the TPCL Purchase Order system processes the payment, in the same manner as PowerNet uses to control the processing of its invoices and payments.
For example, Audit fees will be directly charged to TPCL, of which a purchase order is raised and the standard approval and payment processes occurs.

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

APPENDIX B:

MAP OF NETWORK EXPENDITURE AND CONSTRAINTS

ID Determination 2.3.13 - 2.3.16

Regulatory requirements

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

The purpose of this section is to identify on a map the anticipated network expenditure and network constraints in respect of the TPCL network.

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 2019-2029 Asset Management Plan for TPLC network are explained below, and indicated on the Network map above where relative to a single area:

1. Incident Response – Distribution - $29.83m

   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. Vegetation Management - $17.13m

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

3. Distribution Inspections - $13.93 m

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

4. Technical Planned Maintenance $13.92m

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

5. General Distribution Refurbishment -$6.8m

   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 crossarms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.

6. Technical Routine Inspections - $6.05m

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

7. Distribution Earthing maintenance - $6.05m

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

8. Technical Incident Reponses - $5.15m

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

9. Distribution Planned Maintenance - $3.54m

   Generally reactive work undertaken to correct issues found during the routine distribution inspection. Also a general budget for all minor distribution work.

10. Distribution Reactive Maintenance - $2.82m

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

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

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

Possible future constraints related to TPCL network Operating Expenditure projects:

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

TPCL - 10 largest forecast Network Capital Expenditure projects

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

The 10 largest forecast Capital Expenditure projects in the 2019-2029 Asset Management Plan for TPLC network are explained below, and indicated on the Network map above where relative to a single area:

1. 11kV Line Replacement - $66.16m

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

2. ABS Renewals - $14.42m

   Scheduled for 2019 – 2025, when inspection indicates deterioration is sufficient enough to lose confidence in continued reliable operation and maintenance is considered uneconomic.

3. Customer Connections (≤20kVA) - $9.81m

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

4. Transformer Replacement - $7.45m

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

5. Ground Mount Platform Transformers - $6.88m

   Scheduled for 2019 – 2034, this project will renew large platform or pole mounted distribution transformers (greater than 100 kVA) with ground mount units to minimise seismic risk. There are 145 of these transformers around TPCL's network.

6. Customer Connections (> 100kVA) - $5.61m

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

7. Customer Connections(21-99kVA) - $4.91m

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

8. Lumsden/ Riversdale 22kV Line Upgrades - $3.65m

   Scheduled for 2020-2029, load growth north of Riversdale is forecast to exceed the capacity of the existing 3MVA 11kV voltage regulator at Elders Corner. A larger regulator is considered not optimal as the existing conductor upstream and downstream of the regulator would also need to be upgraded to allow for additional load. In addition, load growth has also eroded backup capability between Lumsden and Riversdale substations. Lumsden being upgraded to be able to supply 22kV and Riversdale will have 22kV autotransformers installed on key feeders. This project intends to upgrade the lines north of Riversdale to 22kV and key sections of line between the two substations to improve MV backups.

9. <u>22kV Upgrade Athol-Kingston - $3.49m</u>

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

10. <u>Earth Upgrades - $3.06m</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.

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

Please Note: All of these projects -

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

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

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

8. <u>Lumsden/ Riversdale 22kV Line Upgrades</u>

   Constraint – Unable to maintain supply voltage due to the forecast load growth, timing being 2-3 years.

   Constraint – Regulator capacity due to forecast load growth, timing being 1-2 years.

9. <u>22kV Upgrade Athol-Kingston - $3.49m</u>

   Constraint – Unable to maintain supply voltage due to forecast load growth, 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[1]	Likely timing[2]	Value[3]	Location[4]	Contract in place[5]	Is contract with RP[6]	Forecast to include RP[7]	Currently not indicated for RP[8]
#1	Incident Response - Distribution - Unplanned	Every year	$29.83m	Network Wide	Yes	Yes	Very likely	N/A
#2	Vegetation Management	Every year	$17.13m	Network Wide	Yes	Yes	Very likely	N/A
#3	Distribution Inspections	Every year	$13.93m	Network Wide	Yes	Yes	Very likely	N/A
#4	Technical Planned Maintenance	Every year	$13.92m	Network Wide	Yes	Yes	Very likely	N/A
#5	General Distribution Refurbishment	Every year	$6.80m	Network Wide	Yes	Yes	Very likely	N/A
#6	Technical Inspections	Every year	$6.05m	Network Wide	Yes	Yes	Very likely	N/A
#7	Distribution Earthing Maintenance	Every year	$5.15m	Network Wide	Yes	Yes	Very likely	N/A
#8	Incident Response - Distribution - Fixed Fee	Every year	$4.96m	Network Wide	Yes	Yes	Very likely	N/A
#9	Incident Response - Technical - Unplanned	Every year	$3.54m	Network Wide	Yes	Yes	Very likely	N/A
#10	Distribution Planned Maintenance	Every year	$2.82m	Network Wide	Yes	Yes	Very likely	N/A

1 Clause 2.3.13(1).
2 Clause 2.3.13(1).
3 Clause 2.3.13(1).
4 Clause 2.3.13(1).
5 Clause 2.3.14(1)(a).
6 Clause 2.3.14(1)(a).
7 Clause 2.3.14(1)(b).
8 Clause 2.3.14(1)(c).

TPCL - 10 largest forecast Network Capital Expenditure projects

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

Project	Project description	Likely timing	Value	Location	Contract in place?	Is contract with RP?	Forecast to include RP?	Currently not indicated for RP
#1	11kV Line Replacement	Every year	$66.16m	Network Wide	Yes	Yes	Very likely	N/A
#2	ABS Renewals	2019-2025	$14.42m	Network Wide	Yes	Yes	Very likely	N/A
#3	Customer Connections (≤20kVA)	Every year	$9.81m	Network Wide	Yes	Yes	Very likely	N/A
#4	Transformer Replacement	Every year	$7.45m	Network Wide	Yes	Yes	Very likely	N/A
#5	Ground Mount Platform Transformers	2019-2034	$6.88m	Network Wide	Yes	Yes	Very likely	N/A
#6	Customer Connections (≥100kVA)	Every year	$5.61m	Network Wide	Yes	Yes	Very likely	N/A
#7	Customer Connections (21 to 99kVA)	Every year	$4.91m	Network Wide	Yes	Yes	Very likely	N/A
#8	Lumsden / Riversdale 22kV Line Upgrades	2020-2029	$3.65m	#8	Yes	Yes	Very likely	N/A
#9	22kV Upgrade Athol - Kingston	2021-2024	$3.49m	#9	Yes	Yes	Very likely	N/A
#10	Earth Upgrades	Every year	$3.06m	Network Wide	Yes	Yes	Very likely	N/A

Possible future constraints related to TPCL network Capital Expenditure projects:

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

Description of constraint	Related to CapEx project #	Expected timing of constraint
Unable to maintain supply voltage due to forecast load growth	#8	2-3 years
Regulator capacity due to forecast load growth	#8	1-2 years
Unable to maintain supply voltage due to forecast load growth	#9	3-5 years

Independent Appraiser's Report

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

Independent Appraiser Report on Related Party Transactions Pursuant to Electricity Distribution Information Disclosure Determination 2012

We have completed our reasonable assurance engagement in respect of the compliance of The Power Company Limited (the 'Company') with the related party requirements, as set out in the Electricity Distribution Information Disclosure Determination 2012 (the 'ID Determination') for the disclosure year ended 31 March 2019 where we are required to report on:

- 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 ID Determination, and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 ('the IM Determination'); and

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

Qualified Opinion

In our opinion, except for the matters described in the *Basis for Qualified Opinion* section of our report:

- the basis for valuation of related party transactions for the disclosure year ended 31 March 2019 complies, in all material respects, with the ID Determination and the IM Determination; and

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

Basis for Qualified Opinion

The information provided by the Company to support the arm's length valuation for certain related party expenditures could not be verified against independent objective measures. Sufficient appropriate audit evidence could therefore not be obtained to conclude on whether the basis for valuation of these related party expenditures complies, in all material respects, with the ID Determination and IM Determination. Additional information regarding the Company's steps and our procedures are noted under Step 4 on pages 9 to 10 of this report. This limitation in evidence is in respect of related party capital expenditure of $2,576,000 and operating expenditure of $718,000 included in schedule 5b of the Company's 2019 Information Disclosure Schedules.

Consequently, we were unable to determine whether any adjustments to these amounts would be necessary to ensure compliance with the ID Determination and IM Determination.

We conducted our engagement in accordance with ISAE (NZ) 3000 (Revised), *Assurance Engagements Other than Audits or Reviews of Historical Financial Information* and SAE 3100 (Revised) *Compliance Engagements* to obtain reasonable assurance that the Company has complied in all material respects with the relevant related party valuation requirements as set out in the ID Determination and the IM Determination for the year ended 31 March 2019.

In forming our qualified opinion, except as explained in the *Basis for Qualified Opinion* section of our report, we have obtained sufficient recorded evidence and all the information and explanations we have required.

Our Independence and Quality Control

We have complied with the independence and other ethical requirements of Professional and Ethical Standard 1 (Revised) issued by the New Zealand Auditing and Assurance Standards Board, which is founded on the fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behaviour.

The firm applies Professional and Ethical Standard 3 (Amended) and accordingly maintains a comprehensive system of quality control including documented policies and procedures regarding compliance with ethical requirements, professional standards, and applicable legal and regulatory requirements.

We are independent of the Company. Other than our role as financial statement auditors our firm carries out other services for the Company in the areas of compliance with regulatory requirements of the Commerce Act 1986, the provision of regulatory update advisory services and tax pooling. The provision of these other services has not impaired our independence as Appraiser of the Company.

Our approach

Materiality

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

Quantitative materiality level was determined as 2% of total related party transactions. Qualitative factors were also considered when assessing the arm's length valuation rules on related party transactions.

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 related party information as a whole.

Key assumptions we made in carrying out our procedures

In carrying out our procedures we have relied on the Company's internal controls relating to the identification of related party transactions and the valuation of related party transactions that we tested, and placed reliance on, during our audit of the financial statements for the year ended 31 March 2019 in relation to our work as the independent appraiser for the disclosure year ended 31 March 2019.

Basis used for sampling of related party transactions

We obtained the Company's assessment of their compliance with the relevant related party valuation requirements in the ID Determination and IM Determination.

We selected a sample of related party transactions on a haphazard basis across a range of transactions and services, and agreed these to the supporting information provided by the Company to demonstrate the independent and objective measure used for those transactions and services, to determine whether it has been valued in accordance with the related party valuation requirements in the ID Determination and IM Determination.

Steps and analysis undertaken in testing compliance

Step 1) Identifying related party relationships and transactions

Summary of steps undertaken by the Company to demonstrate compliance

The Company identified all related party relationships in accordance with the ID Determination, and disclosed these in Appendix A to the 2019 Information Disclosure Schedules as prepared and published under the ID Determination.

During the year related party transactions occurred with PowerNet Limited (50% shareholding) (PowerNet).

- PowerNet provides network management services to The Power Company (TPC), OtagoNet Joint Venture (OJV), Electricity Invercargill Ltd (EIL) and Electricity Southland Ltd (ESL), under equivalent NMAs.
- PowerNet subcontracts external parties to assist it in providing these services where appropriate.
- PowerNet recovers its costs from TPC and the other network companies through an agency fee for network management/business support services, direct pass through of labour and material charges, and a commercial mark-up on capital and maintenance to recover PowerNet's costs and contribute to profit.
- PowerNet also undertakes contestable works for other customers on the same terms.

Related party transactions with PowerNet during the year ended 31 March 2019:

Operating Expenditure (opex):		***$'000***
i.	Service interruption and emergencies	3,885
ii.	Vegetation management	1,630
iii.	Routine & corrective maintenance	4,467
iv.	Asset replacement and renewal	735
v.	System operations & network support	1,290
vi.	Business support	2,872
	Total opex	**14,879**
Capital Expenditure (capex):		
vii.	Consumer connection	3,481
viii.	System growth	6,550
ix.	Asset replacement and renewal	10,381
x.	Asset relocations	120
xi.	Quality of supply	625
xii.	Other reliability, safety and environment	2,249
	Total capex	**23,406**
Total PowerNet Related Party Expenditure		**38,285**

Our procedures undertaken

We have tested the completeness and accuracy of the related party relationships and transactions by:

- Agreeing the disclosures within Appendix A and Schedule 5b of the 2019 Information Disclosure schedules to the audited financial statements for the year ended 31 March 2019 and to the accounting records, investigating any differences and determining whether any such differences are justified; and
- Applying our understanding of the business structure against the related party definition in the IM Determination clause 1.1.4(2)(b) to assess TPC's identification of any "unregulated parts" of the entity.

Step 2) Outlining the intent behind the agency agreement with PowerNet

Summary of steps undertaken by the Company to demonstrate compliance

TPC incurs 100% of its capex and the majority of its operating costs for its electricity distribution business from PowerNet, in accordance with the explicit terms and conditions of the PowerNet Network Management Agreement (NMA).

While TPC owns the network assets, under the NMA PowerNet manage the network assets, carry out an agreed capital works programme, have the exclusive right to provide line function services and provide the business administration services on behalf of TPC.

PowerNet was established in 1994 to extract operational efficiencies from the merger of field work management, asset management and office based functions performed by TPC and Electricity Invercargill Limited (EIL). In 1993, there were two autonomous lines companies in Southland (TPC and EIL). Each had separate staff, management and Board of Directors, and each had a different ownership structure. We understand the 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 we understand a single lines company was not considered possible, however a single network management entity was a viable option.

PowerNet increased its operations to include OJV and ESL, and therefore extended its scale and opportunity for efficiency. Part of the policy intent of the new related party rules is to address concerns that related parties may be inefficient which may cause the Company to overcharge consumers. TPC notes that the intent of the PowerNet Group structure and NMA was to generate cost efficiencies and savings through economy of scale, improve network reliability and secure qualified staff to efficiently maintain the network assets within the region.

Our procedures undertaken

The background information provided by TPC is in line with our understanding of the intent behind the group structure and agency/management agreement between TPC and PowerNet.

We obtained the minutes of board meetings and noted:

- Approval of the NMA and annual business plan by the TPC Board;
- A focus on ensuring efficient cost and effective management of the network with regular measurement of performance and monitoring in the monthly board reports;
- External reports obtained and presented to the TPC Board on prudency and efficiency of forecast spends and benchmarking of operational cost efficiency; and
- An independent report obtained focussed on the appropriate allocation of PowerNet costs between the four network customers.

We obtained all PowerNet's NMAs and note the agreements are consistent for TPC, EIL and OJV. This equivalence demonstrates that the transactions with TPC are consistent with the regional market.

Step 3) Assessing compliance with the definition of an arm's length transaction (in accordance with ISA (NZ) 550)

From 1 April 2018, a principles based approach to the valuation of related party transactions is being applied. All related party transactions must meet the arm's length valuation rule for ID disclosures, based on the following definition of arm's length transaction from the International Standard for Auditing (NZ) 550: *"a transaction conducted on such terms and conditions as between a willing buyer and a willing seller who are unrelated and are acting independently of each other and pursuing their own best interests"*.

Summary of steps undertaken by the Company to demonstrate compliance

TPC acknowledges that meeting the 'arm's length' valuation criteria, as defined above, is challenging due to the ownership structure and significant amount of work PowerNet manages on behalf of TPC under the NMA.

TPC performed an analysis of the arm's length definition and have set out its interpretation in Appendix A to the 2019 Information Disclosure Schedules. Key points are summarised below:

i. *Terms and conditions*

The TPC purchasing terms and conditions applied to PowerNet, are the same as applied to other suppliers. In turn, the purchasing terms and conditions PowerNet applies, are the same to TPC as any other customer.

ii. *Willing buyer and willing seller who are unrelated*
The internal labour rates applied, and commercial mark-up rates are the same to TPC and all other customers for similar services, indicating that the parties are acting consistent with the principle of willing buyer and willing seller who are unrelated.

iii. *Acting independently*
TPC is related to PowerNet by way of 50% ownership share, however with regards to acting independently, PowerNet operates with the level of independence of a separate entity, due to the other 50% ownership being held by separately owned EIL. Each entity has its own board of directors who act independently in their roles.

iv. *Pursuing their own best interests*
Both shareholders of PowerNet have different ownership structures (TPC owned by a Consumer Trust, and EIL owned by the Invercargill City Council), and different regulatory requirements. This unrelated ownership ensures a review process when preparing budgets and analysing performance, to make sure one shareholder is not disadvantaged over the other with each entity pursuing their own best interest.

Our procedures undertaken
PowerNet performed 100% of TPC's capex and 92% of TPC's opex during the year ended 31 March 2019. Whilst PowerNet performs the majority of TPC's capex and opex work, we note that 44% of the costs relate to external materials and labour obtained at arm's length.

We have performed the following procedures over TPC's arm's length definition assessment:

i. *Terms and conditions*
Agreed the TPC standard terms and conditions to the PowerNet standard terms and conditions (applied to both TPC and external customers) and noted no variation.

ii. *Willing buyer and willing seller who are unrelated*
Obtained a copy of a contract with an unrelated PowerNet customer and agreed the internal labour rates and commercial mark-up to that charged to TPC.

iii. *Acting independently*
We note even though TPC, EIL and PowerNet all have individual boards acting independently there are common Directors across the Boards with the PowerNet Board represented by a 50:50 composition from the TPC and EIL Boards. We note that the PowerNet Board has obligations to all of its customers, through its terms and conditions of supply. From a PowerNet perspective, Directors must meet their fiduciary duties by honouring those obligations. They cannot favour TPC because PowerNet has multiple customers.

iv. *Pursuing their own best interest*

We considered evidence obtained through our other procedures which indicates how each entity pursues its own best interest below:

How does PowerNet pursue its own best interests?

- It ensures all customers have the same terms of trade;
- It seeks customer approval of its annual works programme;
- It sub-contracts work where there are better outcomes for its customers; and
- It negotiates wholesale purchase agreements to minimise costs.

How TPC pursues its own best interests?

- It ensures PowerNet's other customers do not receive favourable terms;
- It monitors the performance of PowerNet; and
- It approves PowerNet's work plans for its network.

Step 4) Obtaining independent and objective measures to support the arm's length principle

Summary of steps undertaken by the Company to demonstrate compliance

The independent and objective measures used by TPC to demonstrate prices paid are no more than arm's length transaction value are as follows.

External labour & materials (opex and capex)

- Sourced from external suppliers, on a traditional arm's length basis
- Cost efficiencies gained through supplier agreements e.g. electrical supply agreements ensure prices are no more than market rates due to wholesale agreements consistent with the scale of PowerNet's operations

Mark-up external labour & materials (opex)

- Cost efficiencies gained through economies of scale
- Transparency of cost allocation process based on cost drivers and consistent mark-up rates for customers
- External non-network customer work being awarded to PowerNet based on the same opex rates as charged to Electricity Distribution Business (EDB) customers

Mark-up external labour and materials (capex)

- Cost efficiencies gained through economies of scale
- Transparency of cost allocation process based on cost drivers and consistent mark-up rates for customers

Internal labour & equipment charges (opex and capex)

- Unit rates are consistent for each EDB and PowerNet's other customers
- Labour rates are benchmarked against competitors, and fall within expected ranges
- Independent engineer review of prudency and efficiency of works programme

Business, system, network support (opex)

- Shared services model provides scale efficiencies to TPC
- Share of PowerNet's costs assigned to TPC based on measurable and transparent cost drivers, applied consistently across all of PowerNet's customers

Our procedures undertaken

We obtained the Company's assessment of the available independent and objective measures used in supporting the arm's length valuation principle.

We noted that procedures are in place for monitoring of costs. We performed the following procedures over a sample of transactions at the work order level:

- Agreed the make-up of costs (as reported by TPC above) to the work order within the Tech1 system;
- Agreed individual costs to supporting invoices (from external suppliers) or agreed rates (such as labour and equipment rates);
- Agreed the internal labour rates and mark-ups charged to those used in the labour rates benchmarking analysis;
- Tested appropriate approval of project costs at completion of the project by the project manager; and
- Tested compliance with the procurement policy/process as disclosed in Appendix A to the Information Disclosure Schedules.

We performed the following procedures on the individual components of costs as outlined by TPC to gain comfort over the appropriateness of and level of comfort obtained from the independent and objective measures provided:

External labour and material (Opex - $2.8m and Capex - $13.7m)

- Obtained a copy of the electrical supply agreement, which covers a significant portion fo the costs and noted quarterly reviews of prices and performance; and
- Agreed external costs, for a sample of work orders, to supporting invoices from external suppliers.

Mark-up external labour & materials (Capex - $2.6m and Opex - $718k)

- Obtained the NMA and minutes of TPC board meetings and noted approval by the TPC Board of the cost allocation methods;
- Obtained all of the PowerNet NMAs and note consistent terms and mark-up rates are applied to PowerNet's EDB customers; and
- Obtained an independent advisor report prepared on the reasonableness of the allocation of costs between the PowerNet EDB customers. We note the report supports the transparent and consistent application of cost allocation between PowerNet's EDB customers.

The evidence supporting the costs associated with the mark-up on external labour and material on capex and opex are consistent across PowerNet's EDB customers. However, the capex and opex mark-up rates have not been compared to external capex and opex mark-up rates and therefore no independent objective measures were provided to support the arm's length valuation principle. We have considered the impact of the lack of independent and objective measures to support the arm's length principle on our opinion due to the material value of the expenditure. Refer to the Basis for our Qualified Opinion section of the report for further details.

Internal labour & equipment charges (Opex - $7.2m and Capex - $7.1m)

- Obtained a copy of the independent electrical engineer's report on the 2018/19 works programme review which assessed the forecast spend of a sample of projects for prudency and efficiency. We note even though all projects selected met the prudency criteria only the capex and vegetation management opex projects met the efficiency criteria. For the remaining opex projects TPC could not demonstrate that the unit costs rates for the exclusive services performed by PowerNet are comparable to market rates;
- We obtained subsequent benchmarking performed by TPC over opex and capex labour and equipment rates;
- Agreed PowerNet labour and equipment rates to a sample of work orders to ensure they agree to rates charged to TPC during the year;
- Agreed market/competitor rates to supporting documentation such as quotes or invoices;
- Recalculated the variances and average percentages between PowerNet rates and other market rates;
- Considered the reasonableness of the variance of labour rates between PowerNet and market rates and accept the PowerNet rates as within an acceptable range when compared to the industry benchmarking performed by TPC. The majority of the rates are below the benchmarked market rates with the remaining rates considered within an acceptable range of up to 15%.

Business, system & network support (Opex - $4.2m)

- Obtained a copy of the NMA and understood how costs are recovered through the agency fee;
- Obtained the NMA and minutes of board meetings and note approval by the TPC board of the agency fee;
- Obtained the TPC business plan FY18/19 and note approval by the TPC board of the basis for allocation of the agency fee;
- Obtained an independent advisor report prepared on the reasonableness of the allocation of costs between the PowerNet EDB customers. We note the report supports the transparent and consistent application of cost allocation between PowerNet's EDB customers;
- Obtained benchmarking performed on business and system support costs through the use of the historic information disclosure schedules and note TPC's business and system support costs per Installation Control Point (ICP) rate well in comparison to its peer group (by size and ICP density). These costs have also reduced over the past five years, whereas industry and peer group averaged costs per ICP have remained relatively constant, in nominal terms.

Director's Responsibilities

The Directors are responsible on behalf of the Company for:

- compliance with the ID Determination and the valuation of related party transactions in accordance with the ID Determination and the IM Determination; and
- the identification of risks that threaten such compliance and controls which will mitigate those risks and monitor ongoing compliance.

Appraisers' Responsibilities

Our responsibility is to prepare an independent appraiser report in accordance with clause 2.8.4 of the ID Determination. In preparing the report we are required to express an opinion on whether, for the disclosure year ended 31 March 2019, the basis for valuation of related party transactions complies, in all material respects, with the ID Determination and the IM Determination, and whether the steps taken by the Company to test whether it complies, are considered to be, in all material respects, reasonable in the circumstances.

Our engagement has been conducted in accordance with ISAE (NZ) 3000 (Revised), *Assurance Engagements Other than Audits or Reviews of Historical Financial Information* and SAE 3100 (Revised) *Compliance Engagements* which require that we plan and perform our procedures to obtain reasonable assurance.

An assurance engagement to report on the Company's compliance with the ID Determination and the IM Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the relevant related party valuation requirements of the ID 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 relevant related party valuation requirements of the ID 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 with compliance requirements may occur and not be detected.

A reasonable assurance engagement for the disclosure year ended 31 March 2019 does not provide assurance on whether compliance with the relevant related party valuation requirements of the ID Determination and the IM Determination will continue in the future.

Who we report to

This report has been prepared for the Directors and the Commerce Commission in accordance with clause 2.8.4 of the ID 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 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 appraiser's report is Elizabeth Adriana (Adri) Smit, who is a licensed auditor with the New Zealand Institute of Chartered Accountants which forms part of Chartered Accountants Australia and New Zealand.

PricewaterhouseCoopers.

Chartered Accountants
2 September 2019

Christchurch, New Zealand

Independent Auditor's Report

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

Assurance Report Pursuant to Electricity Distribution Information Disclosure Determination 2012

We have completed our reasonable assurance engagement in respect of the compliance of The Power Company Limited (the 'Company') with the Electricity Distribution Disclosure Information Determination 2012 (the 'Information Disclosure Determination') for the disclosure year ended 31 March 2019 where we are required to opine on:

- whether the Company has complied, in all material respects, with the Information Disclosure Determination, in preparing the information disclosed under schedules 1 to 4, 5a to 5g, 6a and 6b, 7, the related party transactions information disclosed in Appendix A, and the explanatory notes disclosed in boxes 1 to 11 in Schedule 14 ('the Disclosure Information'); and

- whether the Company's basis for valuation of related party transactions ('valuation of related party transactions'), has complied, in all material respects, with clause 2.3.6 of the Information Disclosure Determination, and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 ('the Input Methodologies Determination').

Qualified Opinion

In our opinion, except for the matters described in the *Basis for Qualified Opinion* section of our report:

- As far as appears from our examination, proper records have been kept by the Company to enable the complete and accurate compilation of the Disclosure Information;

- 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 Company has complied, in all material respects, with the Information Disclosure Determination in preparing the Disclosure Information; and

- The basis for valuation of related-party transactions complies, in all material respects, with the Information Disclosure Determination and the Input Methodologies Determination.

Basis for Qualified Opinion

The information provided by the Company to support the arm's length valuation for certain related party expenditures could not be verified against independent objective measures. Sufficient appropriate audit evidence could therefore not be obtained to conclude on whether the basis for valuation of these related party expenditures complies, in all material respects, with the Information Disclosure Determination and Input Methodologies Determination. This limitation in evidence is in respect of the following related party expenditure amounts included in schedule 5b of the Disclosure Information:

- Operating expenditure of $718,000
- Capital expenditure of $2,576,000

Consequently, we were unable to determine whether any adjustments to these amounts would be necessary to ensure compliance with the Information Disclosure Determination and Input Methodologies Determination.

We conducted our engagement in accordance with ISAE (NZ) 3000 (Revised), Assurance Engagements Other than Audits or Reviews of Historical Financial Information and SAE 3100 (Revised) *Compliance Engagements* to obtain reasonable assurance that the Company has complied in all material respects with the Information Disclosure Determination and Input Methodologies Determination in the preparation of the Schedules for the year ended 31 March 2019.

In forming our qualified opinion, except as explained in the *Basis for qualified opinion* section of our report, we have obtained sufficient recorded evidence and all the information and explanations we have required.

Our Independence and Quality Control

We have complied with the independence and other ethical requirements of Professional and Ethical Standard 1 (Revised) issued by the New Zealand Auditing and Assurance Standards Board, which is founded on the fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behaviour.

The firm applies Professional and Ethical Standard 3 (Amended) and accordingly maintains a comprehensive system of quality control including documented policies and procedures regarding compliance with ethical requirements, professional standards, and applicable legal and regulatory requirements.

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

Our audit approach

Overview

Our assurance engagement is designed to obtain reasonable assurance about the Company's qualitative and quantitative compliance, in all material respects, with the Information Disclosure Determination and Input Methodologies Determination.

Quantitative materiality levels are determined for individual schedules included in the Disclosure Information based on the nature of the information set out in the schedules.

Profit based schedules –5% of Regulatory profit before tax
Asset based schedules –1% of Regulatory asset base
Performance based schedules – 5% of non-financial measures
Related party transactions – 2% of total related party transactions. Qualitative factors were also considered when assessing the arm's length valuation rules on related party transactions.

We have determined that there is one key assurance matter:

- Regulatory Asset Base

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 Information Disclosure Determination in the preparation of the Disclosure Information for the year ended 31 March 2019, and whether the basis for valuation of related party transactions complies, in all material respects, with the Information Disclosure Determination and the Input Methodologies 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 determine the matters described below to be Key Assurance Matters.

Key assurance matter	How our procedures addressed the key assurance matter
Regulatory Asset Base The Regulatory Asset Base (RAB), as set out in Schedule 4, reflects the value of the Company's electricity distribution assets. These are valued using an indexed historic cost methodology prescribed by the Determination. It is a measure which is used widely and is key to measuring the Company's return on investment and therefore important when monitoring financial performance or setting electricity distribution prices. The RAB inputs, as set out in the Input Methodologies, 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 Information Disclosure Determination (ID Determination) and the Input Methodologies (IMs). We have performed the following procedures: *Assets commissioned* • We reconciled the assets commissioned as per the regulatory fixed asset register to the asset additions disclosed in the audited annual financial statements, and investigated any reconciling items; • We inspected the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the ID Determination, which are required to be removed from the RAB; • We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification; *Depreciation* • We compared the standard asset lives by asset category to those set out in the IMs; • For assets with no standard asset lives we assessed the reasonableness of the lives used by reference to the accounting depreciation rates; • We tested the mathematical accuracy of the depreciation calculation on a sample basis and that it is performed in line with IM clause 2.2.5; *Revaluation*

Key assurance matter	How our procedures addressed the key assurance matter
	• We recalculated the revaluation rate set out in the Input Methodologies using the relevant Consumer Price Index indices taken from the Statistics New Zealand website; • We tested the mathematical accuracy of the revaluation calculation performed by management; *Disposals* • We inspected the asset disposals within the accounting fixed asset register to ensure disposals in the RAB meet the definition of a disposal per the IMs; We have no matters to report from undertaking those procedures.

Director's Responsibilities

The Directors are responsible on behalf of the Company for

- compliance with the Information Disclosure Determination and the valuation of related party transactions in accordance with the Information Disclosure Determination and the Input Methodologies Determination; and
- the identification of risks that threaten such compliance and controls which will mitigate those risks and monitor ongoing compliance.

Auditors' Responsibilities

Our responsibility is to express an opinion on whether the Company has complied, in all material respects, with the Information Disclosure Determination in the preparation of the Disclosure Information for the disclosure year ended 31 March 2019 and on whether the basis for valuation of related party transactions complies, in all material respects, with the Information Disclosure Determination and the Input Methodologies Determination.

Our engagement has been conducted in accordance with ISAE (NZ) 3000 (Revised), Assurance Engagements Other than Audits or Reviews of Historical Financial Information and SAE 3100 (Revised) *Compliance Engagements* which require that we plan and perform our procedures to obtain reasonable assurance about whether the Company has complied in all material respects with the Information Disclosure Determination in the preparation of the Disclosure Information for the disclosure year ended 31 March 2019, and whether the basis for valuation of related party transactions complies, in all material respects, with the Information Disclosure Determination and the Input Methodologies Determination.

An assurance engagement to report on the Company's compliance with the Information Disclosure Determination and the Input Methodologies Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the requirements of the Information Disclosure Determination and the Input Methodologies Determination. The procedures selected depend on our judgement, including the identification and assessment of risks of material non-compliance with the requirements of the Information Disclosure Determination and the Input Methodologies 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 with compliance requirements may occur and not be detected.

A reasonable assurance engagement for the disclosure year ended 31 March 2019 does not provide assurance on whether compliance with the requirements of the Information Disclosure Determination and the Input Methodologies Determination will continue in the future.

Who we report to

This report has been prepared for the Directors and the Commerce Commission in accordance with clause 2.8.1(1) of the Information Disclosure 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 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
2 September 2019

Christchurch, New Zealand

5. Schedule 18: Certification for Year-End Disclosures

Clause 2.9.2

We, Douglas William Fraser and Donald Owen Nicolson, being directors of The Power Company Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) the information prepared for the purposes of clauses 2.3.1, 2.3.2, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.7.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination; and

b) the historical information used in the preparation of Schedules 8, 9a, 9b, 9c, 9d, 9e, 10, and 14 has been properly extracted from The Power Company Limited's accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained

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

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

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

Douglas William Fraser **Donald Owen Nicolson**

30 August 2019