Electricity Information Disclosure 2017

24/08/2017

Contents

Introduction

This disclosure of information is submitted by Powerco Limited ("Powerco") pursuant to subpart 9 of Part 4 of the Commerce Act 1986 ("Act") and in accordance with the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 ("IDD") and all its subsequent amendments including the 2015 information disclosure amendments.

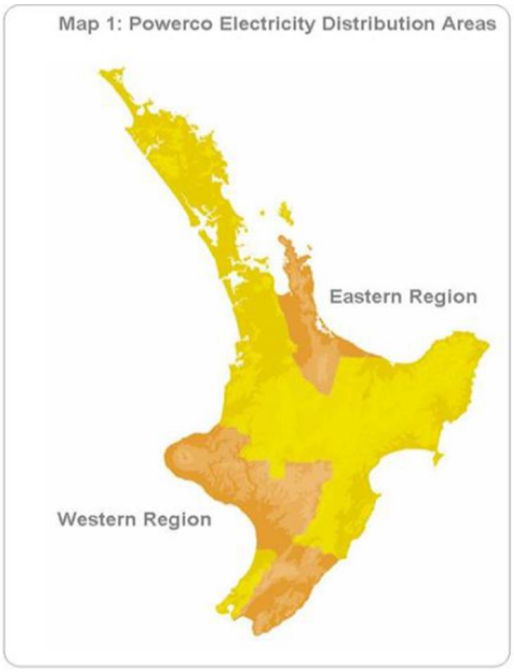
Part 4 of the Act provides a regulatory regime for electricity lines services and sets out the requirements of information disclosure regulation. The purpose of the information disclosure regulation is to ensure that sufficient information is readily available to enable interested persons to assess whether the purpose of Part 4 of the Act is being met. The purpose of Part 4 is to promote the long-term benefit of consumers by promoting outcomes that are consistent with those produced in competitive markets.

For the purpose of regulatory compliance, Powerco is a provider of "electricity lines services", as defined by section 52C of the Act, and is required to comply with the requirements of Part 4 of the Act.

The IDD requires disclosure of the following information for the 2017 disclosure year:

Schedule	Information provided
1	Analytical Ratios
2	Return on investment
3	Regulatory profit
4	Regulatory asset base (rolled forward)
5a	Regulatory tax allowance
5b	Related party transactions
5c	Term credit spread differential
5d	Report on cost allocation
5e	Report on asset allocation
6a	Capital expenditure
6b	Operational expenditure
7	Actual capital and operational expenditure compared to forecast
8	Billed quantities and line charge revenues
9a	Asset register
9b	Asset age profile
9c	Overhead line and underground cable information
9d	Embedded networks
9e	Network demand
10	Network reliability

The IDD also requires that network and billed quantity information be provided for each sub-network (i.e. each geographically separate part) of a supplier's network. Powerco has two sub-networks which it terms the Eastern Region and Western Region of the North Island. These regions are shown in Map 1.



The following schedules are provided separately for Powerco Limited, Powerco's Western Network and Powerco's Eastern Network:

Schedule 8	Billed quantities and line charge revenue
Schedule 9a	Asset register
Schedule 9b	Asset age profile
Schedule 9c	Overhead line and underground cable information
Schedule 9e	Network demand
Schedule 10	Network reliability

Schedules 14 and 15 provide mandatory and voluntary notes to accompany the schedules relating to the current disclosure year.

Directors' certification of the 2017 information disclosure is provided at the end of this document.

Further information on Powerco's long term forecasts are included in our Asset Management Plan available on our website at http://www.powerco.co.nz. The Asset Management Plan for the year commencing 1 April 2017 will be available on our website from 12 June 2017.

Schedule 1: Analytical Ratios

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**

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	16,227	220	81,407	2,623	23,312
Network	7,132	97	35,778	1,153	10,246
Non-network	9,095	123	45,629	1,470	13,066
Expenditure on assets	33,892	460	170,025	5,478	48,689
Network	33,022	448	165,659	5,337	47,439
Non-network	870	12	4,366	141	1,250

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	83,222	1,129
Standard consumer line charge revenue	99,688	996
Non-standard consumer line charge revenue	37,367	124,430

1(iii): Service intensity measures

Demand density	32	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	162	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	12	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	13,564	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	73,524	20.16%
Pass-through and recoverable costs excluding financial incentives and wash-ups	119,866	32.87%
Total depreciation	62,497	17.14%
Total revaluations	32,664	8.96%
Regulatory tax allowance	26,835	7.36%
Regulatory profit/(loss) including financial incentives and wash-ups	114,599	31.43%
Total regulatory income	364,656	

1(v): Reliability

Interruption rate	20.87	*Interruptions per 100 circuit km*

Schedule 2: Return on Investment

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**

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 15	31 Mar 16	31 Mar 17
ROI – comparable to a post tax WACC	%	%	%
Reflecting all revenue earned	5.64%	6.36%	7.19%
Excluding revenue earned from financial incentives	5.64%	6.36%	7.19%
Excluding revenue earned from financial incentives and wash-ups	5.64%	6.36%	7.22%
Mid-point estimate of post tax WACC	6.10%	5.37%	4.77%
25th percentile estimate	5.39%	4.66%	4.05%
75th percentile estimate	6.82%	6.09%	5.48%
ROI – comparable to a vanilla WACC			
Reflecting all revenue earned	6.43%	7.01%	7.73%
Excluding revenue earned from financial incentives	6.43%	7.01%	7.73%
Excluding revenue earned from financial incentives and wash-ups	6.43%	7.01%	7.77%
WACC rate used to set regulatory price path	8.77%	7.19%	7.19%
Mid-point estimate of vanilla WACC	6.89%	6.02%	5.31%
25th percentile estimate	6.17%	5.30%	4.59%
75th percentile estimate	7.60%	6.74%	6.03%

2(ii): Information Supporting the ROI

		($000)		
	Total opening RAB value	1,528,013		
plus	Opening deferred tax	(49,319)		
Opening RIV			1,478,694	
Line charge revenue			377,067	
	Expenses cash outflow	193,389		
add	Assets commissioned	108,878		
less	Asset disposals	14,730		
add	Tax payments	12,052		
less	Other regulated income	(12,411)		
Mid-year net cash outflows			312,000	
Term credit spread differential allowance			–	
	Total closing RAB value	1,592,546		
less	Adjustment resulting from asset allocation	218		
less	Lost and found assets adjustment	–		
plus	Closing deferred tax	(64,102)		
Closing RIV			1,528,226	
ROI – comparable to a vanilla WACC				7.73%
	Leverage (%)			44%
	Cost of debt assumption (%)			4.41%
	Corporate tax rate (%)			28%
ROI – comparable to a post tax WACC				7.19%

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	7.52%
Year-end ROI – comparable to a post tax WACC	6.97%

** 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	–	
Recoverable customised price-quality path costs	–	
Catastrophic event allowance	–	
Capex wash-up adjustment	(636)	
Transmission asset wash-up adjustment	–	
2013–2015 NPV wash-up allowance	–	
Reconsideration event allowance	–	
Other wash-ups	–	
Wash-up costs		(636)
Impact of wash-up costs on ROI		–0.03%

A monthly ROI must only be calculated if during the first three months or last three months of the 2017 disclosure year, the value of assets commissioned by Powerco had exceeded 10% of the total opening regulatory asset base values. These criteria have not been met and Powerco has elected to report the ROI for the full disclosure year only.

Schedule 3: Regulatory Profit

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

sch ref			($000)	
7	**3(i): Regulatory Profit**			
8		**Income**		
9		Line charge revenue	377,067	
10	*plus*	Gains / (losses) on asset disposals	(14,631)	
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	2,221	
12				
13		**Total regulatory income**	364,656	
14		**Expenses**		
15	*less*	Operational expenditure	73,524	
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	119,866	
18				
19		**Operating surplus / (deficit)**	171,267	
20				
21	*less*	Total depreciation	62,497	
22				
23	*plus*	Total revaluations	32,664	
24				
25		**Regulatory profit / (loss) before tax**	141,434	
26				
27	*less*	Term credit spread differential allowance	–	
28				
29	*less*	Regulatory tax allowance	26,835	
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	114,599	
32				
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**		($000)	
34		**Pass through costs**		
35		Rates	1,898	
36		Commerce Act levies	505	
37		Industry levies	1,138	
38		CPP specified pass through costs	–	
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	100,403	
41		Transpower new investment contract charges	6,898	
42		System operator services	–	
43		Distributed generation allowance	9,024	
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**		119,866
47				

3(iii): Incremental Rolling Incentive Scheme

($000)

	CY-1 31 Mar 16	CY 31 Mar 17
Allowed controllable opex	–	–
Actual controllable opex	–	–
Incremental change in year		–

		Previous years' incremental change	Previous years' incremental change adjusted for inflation
CY-5	31 Mar 12	–	–
CY-4	31 Mar 13	–	–
CY-3	31 Mar 14	–	–
CY-2	31 Mar 15	–	–
CY-1	31 Mar 16	–	–
Net incremental rolling incentive scheme			–
Net recoverable costs allowed under incremental rolling incentive scheme			–

3(iv): Merger and Acquisition Expenditure

	($000)
Merger and acquisition expenditure	–

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).

3(v): Other Disclosures

	($000)
Self-insurance allowance	–

Schedule 4: Value of Regulatory Asset Base

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**

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 13 ($000)	RAB 31 Mar 14 ($000)	RAB 31 Mar 15 ($000)	RAB 31 Mar 16 ($000)	RAB 31 Mar 17 ($000)
	Total opening RAB value		1,362,264	1,385,118	1,439,789	1,476,717	1,528,013
less	**Total depreciation**		58,272	59,857	57,918	59,697	62,497
plus	**Total revaluations**		11,627	21,063	1,198	8,575	32,664
plus	**Assets commissioned**		77,635	101,470	102,247	113,407	108,878
less	**Asset disposals**		8,111	8,275	8,941	11,131	14,730
plus	**Lost and found assets adjustment**		-	-	-	-	–
plus	**Adjustment resulting from asset allocation**		(25)	270	342	141	218
	Total closing RAB value		1,385,118	1,439,789	1,476,717	1,528,013	1,592,546

4(ii): Unallocated Regulatory Asset Base

		Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
	Total opening RAB value		1,533,572		1,528,013
less					
	Total depreciation		63,776		62,497
plus					
	Total revaluations		32,774		32,664
plus					
	Assets commissioned (other than below)	109,792		108,796	
	Assets acquired from a regulated supplier	–		–	
	Assets acquired from a related party	81		81	
	Assets commissioned		109,873		108,878
less					
	Asset disposals (other than below)	14,730		14,730	
	Asset disposals to a regulated supplier	–		–	
	Asset disposals to a related party	–		–	
	Asset disposals		14,730		14,730
plus	**Lost and found assets adjustment**		–		–
plus	**Adjustment resulting from asset allocation**				218
	Total closing RAB value		1,597,714		1,592,546

** 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	1,226
	$CPI_4{}^{-4}$	1,200
	Revaluation rate (%)	2.17%

		Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
	Total opening RAB value	1,533,572		1,528,013	
less	Opening value of fully depreciated, disposed and lost assets	20,908		20,434	
	Total opening RAB value subject to revaluation	1,512,664		1,507,579	
	Total revaluations		32,774		32,664

4(iv): Roll Forward of Works Under Construction

		Unallocated works under construction		Allocated works under construction	
Works under construction—preceding disclosure year			47,987		47,387
plus	Capital expenditure	130,916		130,090	
less	Assets commissioned	109,873		108,878	
plus	Adjustment resulting from asset allocation			23	
Works under construction - current disclosure year			69,030		68,623
	Highest rate of capitalised finance applied				5.23%

4(v): Regulatory Depreciation

		Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
	Depreciation - standard	55,570		55,498	
	Depreciation - no standard life assets	8,206		6,999	
	Depreciation - modified life assets	–		–	
	Depreciation - alternative depreciation in accordance with CPP	–		–	
Total depreciation			63,776		62,497

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
RAPS Batteries	no standard life	22	85	104
RAPS Control Unit	no standard life	10	115	122
RAPS Generator	no standard life	31	342	365
RAPS PV array	no standard life	4	91	93

** 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		68,432	27,864	153,097	391,395	312,838	251,601	124,375	166,744	31,665	1,528,013
less	Total depreciation	2,101	873	6,922	14,151	14,835	8,444	5,636	3,321	6,214	62,497
plus	Total revaluations	1,465	602	3,265	8,388	6,766	5,317	2,677	3,635	550	32,664
plus	Assets commissioned	2,079	2,602	20,170	19,482	19,914	13,574	16,359	9,851	4,848	108,878
less	Asset disposals	747	0	1,052	4,144	416	6,049	1,810	469	40	14,730
plus	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
plus	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	9	209	218
plus	Asset category transfers	957	1,208	8,311	9,281	9,493	6,625	9,071	(44,946)	–	–
Total closing RAB value		70,086	31,402	176,868	410,252	333,760	262,623	145,035	131,503	31,017	1,592,546
Asset Life											
	Weighted average remaining asset life	42	40	31	36	31	36	29	40	21	(years)
	Weighted average expected total asset life	60	51	50	59	48	53	39	42	28	(years)

Schedule 5a: Regulatory Tax Allowance

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**

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**			141,434
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	277	*	
12		Amortisation of initial differences in asset values	10,447		
13		Amortisation of revaluations	4,427		
14					15,151
15					
16	*less*	Total revaluations	32,664		
17		Income included in regulatory profit / (loss) before tax but not taxable	–	*	
18		Discretionary discounts and customer rebates	–		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax	–	*	
20		Notional deductible interest	28,080		
21					60,744
22					
23		**Regulatory taxable income**			95,840
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			95,840
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			26,835
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	271,615		
37	*less*	Amortisation of initial differences in asset values	10,447		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	4,220		
40		Closing unamortised initial differences in asset values			256,948
41					
42		Opening weighted average remaining useful life of relevant assets (years)			26
43					
44	**5a(iv): Amortisation of Revaluations**				**($000)**
45					
46		Opening sum of RAB values without revaluations	1,426,961		
47					
48		Adjusted depreciation	58,070		
49		Total depreciation	62,497		
50		Amortisation of revaluations			4,427
51					
52	**5a(v): Reconciliation of Tax Losses**				**($000)**
53					
54		**Opening tax losses**	–		
55	*plus*	Current period tax losses	–		
56	*less*	Utilised tax losses	–		
57		**Closing tax losses**			–

5a(vi): Calculation of Deferred Tax Balance

			($000)	($000)
		Opening deferred tax	(49,319)	
plus		Tax effect of adjusted depreciation	16,260	
less		Tax effect of tax depreciation	26,211	
plus		Tax effect of other temporary differences*	(129)	
less		Tax effect of amortisation of initial differences in asset values	2,925	
plus		Deferred tax balance relating to assets acquired in the disclosure year	–	
less		Deferred tax balance relating to assets disposed in the disclosure year	1,752	
plus		Deferred tax cost allocation adjustment	(25)	
		Closing deferred tax		(64,102)

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)	($000)
		Opening sum of regulatory tax asset values	952,402	
less		Tax depreciation	93,612	
plus		Regulatory tax asset value of assets commissioned	106,799	
less		Regulatory tax asset value of asset disposals	20,987	
plus		Lost and found assets adjustment	–	
plus		Adjustment resulting from asset allocation	130	
plus		Other adjustments to the RAB tax value	–	
		Closing sum of regulatory tax asset values		944,732

Schedule 5b: Related Party Transactions

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

This schedule provides information on the valuation of related party transactions, in accordance with section 2.3.6 and 2.3.7 of the ID 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

5b(i): Summary—Related Party Transactions

	($000)
Total regulatory income	–
Operational expenditure	–
Capital expenditure	–
Market value of asset disposals	–
Other related party transactions	81

5b(ii): Entities Involved in Related Party Transactions

Name of related party	Related party relationship
Powerline Limited (trading as Basepower)	Wholly owned subsidiary of Powerco

** include additional rows if needed*

5b(iii): Related Party Transactions

Name of related party	Related party transaction type	Description of transaction	Value of transaction ($000)	Basis for determining value
Powerline Limited (trading as Basepower)	Capex	Supplies remote area power and storage units	81	IM clause 2.2.11(5)(a)(i)

** include additional rows if needed*

Schedule 5c: Term Credit Spread Differential

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

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

Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Cost of executing an interest rate swap	Debt issue cost readjustment
2005 Guaranteed Bonds - 2	28/09/2005	26/09/2005	12	6.74%	50,000,000	49,977,925	75,000	9,610	(102,083)
USPP (2011) US$72m/NZ$91.4m	7/06/2011	7/06/2011	9	BKBM+1.945%	91,370,558	106,889,750	137,056	0	(142,132)
USPP (2011) US$90m/NZ$114.2m	7/06/2011	7/06/2011	12	BKBM+1.835%	114,213,198	136,756,987	171,320	0	(233,185)
USPP (2011) US$83m/NZ$105.3m	7/06/2011	7/06/2011	15	BKBM+1.980%	105,329,949	128,074,912	157,995	0	(245,770)
2011 Wholesale Bond - Fixed rate	20/12/2011	20/12/2011	7	6.31%	65,000,000	65,734,529	97,500	13,134	(65,000)
2011 Wholesale Bond - Floating rate	20/12/2011	20/12/2011	7	BKBM + 2.60%	35,000,000	35,395,516	52,500	7,072	(35,000)
USPP(2013) US$25m/NZ$30.4m	23/01/2013	1/11/2012	12	BKBM + 2.20%	30,439,547	35,304,599	45,659	0	(62,147)
USPP(2013) US$80m/NZ$97.4m	23/01/2013	1/11/2012	15	BKBM + 2.21%	97,406,551	111,137,399	146,110	0	(227,282)
NZD USPP(2014) NZ$135m	15/10/2014	3/07/2014	12.5	6.62%	135,000,000	136,053,079	202,500	20,408	(283,500)
2015 Wholesale Bond - Fixed rate	28/09/2015	16/09/2015	7	4.76%	150,000,000	149,751,117	225,000	22,463	(150,000)
2016 Wholesale Bond - Fixed rate	15/11/2016	4/11/2016	8	4.67%	100,000,000	100,465,780	150,000	20,093	(131,250)
** include additional rows if needed*						1,055,541,593	1,460,640	92,781	(1,677,350)

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

Gross term credit spread differential		(123,929)
Total book value of interest bearing debt	1,322,074,000	
Leverage	44%	
Average opening and closing RAB values	1,560,279,569	
Attribution Rate (%)		52%
Term credit spread differential allowance		–

Schedule 5d: Cost Allocations

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**

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		6,509			
Not directly attributable	–	–	–	–	–
Total attributable to regulated service		6,509			
Vegetation management					
Directly attributable		6,017			
Not directly attributable	–	–	–	–	–
Total attributable to regulated service		6,017			
Routine and corrective maintenance and inspection					
Directly attributable		10,193			
Not directly attributable	–	–	–	–	–
Total attributable to regulated service		10,193			
Asset replacement and renewal					
Directly attributable		9,595			
Not directly attributable	–	–	–	–	–
Total attributable to regulated service		9,595			
System operations and network support					
Directly attributable		8,452			
Not directly attributable	–	814	170	985	–
Total attributable to regulated service		9,267			
Business support					
Directly attributable		8,231			
Not directly attributable	–	23,712	5,039	28,751	–
Total attributable to regulated service		31,944			
Operating costs directly attributable		48,997			
Operating costs not directly attributable	–	24,526	5,210	29,736	–
Operational expenditure		73,524			

5d(ii): Other Cost Allocations

Pass through and recoverable costs	($000)
Pass through costs	
Directly attributable	3,374
Not directly attributable	167
Total attributable to regulated service	3,541
Recoverable costs	
Directly attributable	116,325
Not directly attributable	–
Total attributable to regulated service	116,325

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

Schedule 5e: Asset Allocations

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**

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
10	**Subtransmission lines**	
11	Directly attributable	70,086
12	Not directly attributable	–
13	**Total attributable to regulated service**	70,086
14	**Subtransmission cables**	
15	Directly attributable	31,402
16	Not directly attributable	–
17	**Total attributable to regulated service**	31,402
18	**Zone substations**	
19	Directly attributable	176,867
20	Not directly attributable	–
21	**Total attributable to regulated service**	176,867
22	**Distribution and LV lines**	
23	Directly attributable	410,251
24	Not directly attributable	–
25	**Total attributable to regulated service**	410,251
26	**Distribution and LV cables**	
27	Directly attributable	333,759
28	Not directly attributable	–
29	**Total attributable to regulated service**	333,759
30	**Distribution substations and transformers**	
31	Directly attributable	262,622
32	Not directly attributable	–
33	**Total attributable to regulated service**	262,622
34	**Distribution switchgear**	
35	Directly attributable	145,035
36	Not directly attributable	–
37	**Total attributable to regulated service**	145,035
38	**Other network assets**	
39	Directly attributable	131,503
40	Not directly attributable	–
41	**Total attributable to regulated service**	131,503
42	**Non-network assets**	
43	Directly attributable	6,452
44	Not directly attributable	24,568
45	**Total attributable to regulated service**	31,019
46		
47	**Regulated service asset value directly attributable**	1,567,978
48	**Regulated service asset value not directly attributable**	24,568
49	**Total closing RAB value**	1,592,546
50		

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

($000)

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

($000)

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

($000)

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

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

† include additional rows if needed

Schedule 6a: Capital Expenditure

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**

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

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

sch ref

6a(i): Expenditure on Assets

			($000)	($000)
8		Consumer connection		38,513
9		System growth		34,292
10		Asset replacement and renewal		65,962
11		Asset relocations		2,516
12		Reliability, safety and environment:		
13		Quality of supply	5,232	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	3,102	
16		**Total reliability, safety and environment**		8,334
17		**Expenditure on network assets**		149,617
18		Expenditure on non-network assets		3,943
19				
20		**Expenditure on assets**		153,560
21	*plus*	Cost of financing		2,078
22	*less*	Value of capital contributions		25,549
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		130,090

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

			($000)
27		Energy efficiency and demand side management, reduction of energy losses	273
28		Overhead to underground conversion	289
29		Research and development	–

6a(iii): Consumer Connection

		*Consumer types defined by EDB**	($000)	($000)
32		Small	22,591	
33		Commercial	12,714	
34		Industrial	3,208	
35				
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		38,513
39				
40	*less*	Capital contributions funding consumer connection expenditure	24,600	
41		**Consumer connection less capital contributions**		13,913

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

			System Growth ($000)	Asset Replacement and Renewal ($000)
45		Subtransmission	11,392	6,289
46		Zone substations	4,314	6,302
47		Distribution and LV lines	3,537	32,836
48		Distribution and LV cables	3,843	3,770
49		Distribution substations and transformers	1,760	9,436
50		Distribution switchgear	75	6,081
51		Other network assets	9,371	1,248
52		**System growth and asset replacement and renewal expenditure**	34,292	65,962
53	*less*	Capital contributions funding system growth and asset replacement and renewal	–	8
54		**System growth and asset replacement and renewal less capital contributions**	34,292	65,954
55				

6a(v): Asset Relocations

		*Project or programme**	($000)	($000)
58		NZTA SH2 / Te Puna Road Roundabout, Tauranga	582	
59		B2B NZTA Project, Tauranga	320	
60		Whanganui HV Ducts	203	
61		Cessna Road 33kV cabling, Palmerston North	173	
62		Todd Energy OHUG Otaraoa Road, Waitara	144	
		Fonterra OHUG Bedford St, Hawera	121	
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	973	
65		**Asset relocations expenditure**		2,516
66	*less*	Capital contributions funding asset relocations	941	
67		**Asset relocations less capital contributions**		1,575
68				

6a(vi): Quality of Supply

	Project or programme*	($000)	($000)
	Automation Projects	4,289	
	Automation - Tuhitarata Substation Recloser	161	
	Distribution Backfeed enhancement	72	
	Subtransmission & Zone Security Enhancement	77	
	Tom Muir Drive 11kV Cable	206	
	Thames 11kV Backfeed	185	
	Elizabeth St Cable	169	
	** include additional rows if needed*		
	All other projects programmes - quality of supply	73	
	Quality of supply expenditure		5,232
less	Capital contributions funding quality of supply	–	
	Quality of supply less capital contributions		5,232

6a(vii): Legislative and Regulatory

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

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

	Project or programme*	($000)	($000)
	LV safety improvements - other	260	
	Zone sub seismic and safety - other	268	
	Zone sub equipment upgrades	119	
	Inglewood LV fusing	212	
	Taranaki fusing and bare conductor upgrade	668	
	Anzac parade cable duct repair	607	
	Aongatete substation seismic strengthening	347	
	Kerepehi substation seismic strengthening	197	
	Pongakawa substation seismic strengthening	182	
	** include additional rows if needed*		
	All other projects or programmes - other reliability, safety and environment	241	
	Other reliability, safety and environment expenditure		3,102
less	Capital contributions funding other reliability, safety and environment	–	
	Other reliability, safety and environment less capital contributions		3,102

6a(ix): Non-Network Assets

Routine expenditure

	Project or programme*	($000)	($000)
	Improve and Expand Network Data & Tools	273	
	IT Renewal	1,292	
	** include additional rows if needed*		
	All other projects or programmes - routine expenditure	679	
	Routine expenditure		2,244

Atypical expenditure

	Project or programme*	($000)	($000)
	Customer Engagement	208	
	Enterprise Asset Management System	480	
	Improve Network Operations (OMS/DMS)	350	
	** include additional rows if needed*		
	All other projects or programmes - atypical expenditure	660	
	Atypical expenditure		1,699

	Expenditure on non-network assets	3,943

Schedule 6b: Operational Expenditure

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**

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	6,509	
9	Vegetation management	6,017	
10	Routine and corrective maintenance and inspection	10,193	
11	Asset replacement and renewal	9,595	
12	**Network opex**		32,314
13	System operations and network support	9,267	
14	Business support	31,944	
15	**Non-network opex**		41,210
16			
17	**Operational expenditure**		73,524
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		29
20	Direct billing*		–
21	Research and development		272
22	Insurance		1,096
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Schedule 7: Forecast v Actual Expenditure

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

sch ref				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	378,112	377,067	(0.3%)
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	21,421	38,513	80%
11	System growth	47,206	34,292	(27%)
12	Asset replacement and renewal	60,964	65,962	8%
13	Asset relocations	2,909	2,516	(14%)
14	Reliability, safety and environment:			
15	Quality of supply	3,890	5,232	34%
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	1,495	3,102	108%
18	**Total reliability, safety and environment**	5,385	8,334	55%
19	**Expenditure on network assets**	137,885	149,617	9%
20	Expenditure on non-network assets	9,471	3,943	(58%)
21	Expenditure on assets	147,356	153,560	4%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	7,374	6,509	(12%)
24	Vegetation management	5,859	6,017	3%
25	Routine and corrective maintenance and inspection	10,689	10,193	(5%)
26	Asset replacement and renewal	9,068	9,595	6%
27	**Network opex**	32,990	32,314	(2%)
28	System operations and network support	13,502	9,267	(31%)
29	Business support	28,642	31,944	12%
30	**Non-network opex**	42,144	41,210	(2%)
31	**Operational expenditure**	75,134	73,524	(2%)
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses	–	273	–
34	Overhead to underground conversion	–	289	–
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	–	29	–
39	Direct billing	–	–	–
40	Research and development	–	272	–
41	Insurance	–	1,096	–
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)*			

Schedule 8: Billed Quantities and Line Charge Revenue

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**
Network / Sub-Network Name	**Powerco Limited**

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

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)	Price component	Fixed	Fixed	Variable	Demand	Demand	Power Factor	Fixed
					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	ICP days	kVA of capacity	kWh	kW of Demand - AMD	kW of Demand - OPD	kVArh of demand	Fixture count
Unmetered	Streetlights	Standard	500	8,927		-	-	8,927,229	-	-	-	9,144,599
Small	Residential/Small Commercial	Standard	331,550	2,563,999		116,229,400	-	2,686,791,954	3,666,074	-	-	-
Medium	Commercial	Standard	1,375	247,625		462,668	-	247,624,690	31,096	14,564	13,132	-
Large	Large Commercial/Industrial	Standard	258	513,193		-	2,887,771	513,192,803	135,431	66,496	1,026	-
Large	Large Commercial/Industrial	Non-standard	360	1,197,122		122,458	-	1,197,122,265	-	-	153,030	-
Add extra rows for additional consumer groups or price category codes as necessary												
		Standard consumer totals	333,683	3,333,744		116,692,068	2,887,771	3,456,536,676	3,832,601	81,060	14,158	9,144,599
		Non-standard consumer totals	360	1,197,122		122,458	–	1,197,122,265	–	–	153,030	–
		Total for all consumers	334,042	4,530,866		116,814,525	2,887,771	4,653,658,941	3,832,601	81,060	167,188	9,144,599

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

Line charge revenues ($000) by price component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Price component	Fixed	Fixed	Variable	Demand	Demand	Power Factor	Fixed
							Rate (eg, $ per day, $ per kWh, etc.)	$/ICP/Day	$/kVA of capacity	$/kWh	$/kW of demand - AMD	$/kVA of demand OPD	$/kVArh of demand	$/streetlight/day
-	Streetlights	Standard	1,637	-	912	725		-	-	78	-	-	-	1,560
Small	Residential/Small Commercial	Standard	283,090	-	203,526	79,563		30,949	-	179,016	73,125	-	-	-
Medium	Commercial	Standard	21,902	-	16,150	5,752		5,802	-	9,453	4,435	2,120	92	-
Large	Large Commercial/Industrial	Standard	25,706	-	15,854	9,852		-	5,511	188	10,206	9,794	7	-
Large	Large Commercial/Industrial	Non-standard	44,732	-	21,779	22,954		35,880	-	7,781	-	-	1,071	-
Add extra rows for additional consumer groups or price category codes as necessary														
		Standard consumer totals	$332,334	–	$236,443	$95,892		$36,751	$5,511	$188,734	$87,766	$11,913	$99	$1,560
		Non-standard consumer totals	$44,732	–	$21,779	$22,954		$35,880	–	$7,781	–	–	$1,071	–
		Total for all consumers	$377,067	–	$258,221	$118,846		$72,631	$5,511	$196,515	$87,766	$11,913	$1,170	$1,560

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	17	**Check**	**OK**

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**
Network / Sub-Network Name	**Western Region**

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

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)	Price component	Fixed	Fixed	Variable	Demand	Demand	Power Factor
					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	ICP Days	kVA of Capacity	kWh	kW of Demand - AMD	kW of Demand - OPD	kVArh of Demand
E1	Residentail/Small Commercial	Standard	178,278	1,409,511		61,742,885	-	1,532,303,254	3,666,074	-	-
E100	Commercial	Standard	223	94,848		81,094	-	94,848,096	31,096	14,564	-
E300/E300R	Large Commercial/Industrial	Standard	244	509,855		-	2,828,371	509,855,125	135,431	66,496	-
Special	Large Commercial/Industrial	Non-standard	30	217,978		12,045	-	217,978,043	-	-	11,950

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

Standard consumer totals	178,745	2,014,214	61,823,979	2,828,371	2,137,006,475	3,832,601	81,060	–
Non-standard consumer totals	30	217,978	12,045	–	217,978,043	–	–	11,950
Total for all consumers	178,775	2,232,192	61,836,024	2,828,371	2,354,984,518	3,832,601	81,060	11,950

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

Line charge revenues ($000) by price component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Price component	Fixed	Fixed	Variable	Demand	Demand	Power Factor
							Rate (eg, $ per day, $ per kWh, etc.)	$/ICP/Day	$/kVA of capacity	$/kWh	$/kW of demand - AMD	$/kVA of demand - OPD	$/kVArh of demand
E1	Residentail/Small Commercial	Standard	$153,784	-	113,009	40,775		2,061	-	78,599	73,125	-	-
E100	Commercial	Standard	$7,337	-	5,218	2,119		782	-	-	4,435	2,120	-
E300/E300R	Large Commercial/Industrial	Standard	$25,393	-	15,604	9,789		-	5,394	-	10,206	9,794	-
Special	Large Commercial/Industrial	Non-standard	$7,182	-	3,507	3,675		7,098	-	-	-	-	84
			–										
			–										
			–										
			–										
			–										
			–										

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

Standard consumer totals	$186,515	–	$133,832	$52,683	$2,843	$5,394	$78,599	$87,766	$11,913	–
Non-standard consumer totals	$7,182	–	$3,507	$3,675	$7,098	–	–	–	–	$84
Total for all consumers	$193,696	–	$137,339	$56,358	$9,941	$5,394	$78,599	$87,766	$11,913	$84

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	9	**Check**	**OK**

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**
Network / Sub-Network Name	**Eastern Region**

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

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)	Price component	Fixed	Fixed	Variable	Demand	Demand	Power Factor	Fixed
					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	ICP days	kVA of capacity	kWh	kW of Demand - AMD	kW of Demand - OPD	kVArh of demand	Fixture count
V01, V02, T01, T02	Streetlights	Standard	500	8,927		-	-	8,927,229	-	-	-	9,144,599
V05, V06, T05, T06	Residential/Small Commercial	Standard	153,273	1,154,489		54,486,515	-	1,154,488,699	-	-	-	-
V24, V28, T22, T24, T41	Commercial	Standard	1,152	152,777		381,574	-	152,776,594	-	-	13,132	-
T43	Large Commercial/Industrial	Standard	14	3,338		-	59,400	3,337,678	-	-	1,026	-
V40, T50, V60, T60	Large Commercial/Industrial	Non-standard	330	979,144		110,413	-	979,144,222	-	-	141,079	-

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

Standard consumer totals	154,938	1,319,530	54,868,089	59,400	1,319,530,201	–	–	14,158	9,144,599
Non-standard consumer totals	330	979,144	110,413	–	979,144,222	–	–	141,079	–
Total for all consumers	155,268	2,298,674	54,978,501	59,400	2,298,674,423	–	–	155,238	9,144,599

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

Line charge revenues ($000) by price component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Price component	Fixed	Fixed	Variable	Demand	Demand	Power Factor	Fixed
							Rate (eg, $ per day, $ per kWh, etc.)	$/ICP/Day	$/kVA of capacity	$/kWh	$/kW of demand AMD	$/kVA of demand OPD	$/kVArh of demand	$/streetlight/day
V01, V02, T01, T02	Streetlights	Standard	$1,637	-	912	725		-	-	78	-	-	-	1,560
V05, V06, T05, T06	Residential/Small Commercial	Standard	$129,306	-	90,518	38,788		28,888	-	100,417	-	-	-	-
V24, V28, T22, T24, T41	Commercial	Standard	$14,564	-	10,931	3,633		5,020	-	9,453	-	-	92	-
T43	Large Commercial/Industrial	Standard	$312	-	249	63		-	117	188	-	-	7	-
V40, T50, V60, T60	Large Commercial/Industrial	Non-standard	$37,551	-	18,272	19,279		28,782	-	7,781	-	-	988	-
			–											
			–											
			–											
			–											
			–											

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

Standard consumer totals	$145,820	–	$102,611	$43,209	$33,908	$117	$110,135	–	–	$99	$1,560
Non-standard consumer totals	$37,551	–	$18,272	$19,279	$28,782	–	$7,781	–	–	$988	–
Total for all consumers	$183,371	–	$120,883	$62,488	$62,691	$117	$117,916	–	–	$1,087	$1,560

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end 8

Check OK

Schedule 9a: Asset Register

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Powerco Limited**

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.	222,299	223,957	1,658	4
10	All	Overhead Line	Wood poles	No.	38,440	36,809	(1,631)	3
11	All	Overhead Line	Other pole types	No.	4,947	4,908	(39)	2
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1,499	1,513	13	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	–	–	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	122	140	17	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	20	19	(2)	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	–	–	4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	6	6	0	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	–	–	4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	–	–	4
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	–	–	4
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	–	–	4
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	–	–	4
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	135	135	–	2
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	–	–	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	–	–	4
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	18	18	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	23	22	(1)	3
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	860	879	19	3
29	HV	Zone substation switchgear	33kV RMU	No.	6	6	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	98	119	21	3
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	195	192	(3)	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	825	805	(20)	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	54	50	(4)	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	206	211	5	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	14,755	14,741	(14)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	–	–	4
37	HV	Distribution Line	SWER conductor	km	79	79	0	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	1,762	1,800	38	3
39	HV	Distribution Cable	Distribution UG PILC	km	211	209	(2)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	11	11	–	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	533	614	81	3
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	353	397	44	3
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	38,188	38,516	328	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	2,397	2,414	17	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	2,037	2,214	177	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	28,362	26,512	(1,850)	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	8,008	8,173	165	3
48	HV	Distribution Transformer	Voltage regulators	No.	112	120	8	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	5,154	4,135	(1,019)	2
50	LV	LV Line	LV OH Conductor	km	5,421	5,405	(16)	3
51	LV	LV Cable	LV UG Cable	km	4,018	4,113	96	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	2,779	2,871	92	2
53	LV	Connections	OH/UG consumer service connections	No.	263,576	269,880	6,304	2
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	2,366	2,328	(38)	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	48	46	(2)	4
57	All	Load Control	Centralised plant	Lot	38	37	(1)	3
58	All	Load Control	Relays	No	2,312	2,393	81	3
59	All	Civils	Cable Tunnels	km	-	–	–	4

Not all assets on Powerco's network are reported in this schedule. The Commerce Commission have advised that if assets do not clearly fit into one of the categories in schedule 9a they should be excluded from the schedule.

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Western Region**

SCHEDULE 9a: ASSET REGISTER

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

sch ref	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	142,223	143,577	1,354	4
10	All	Overhead Line	Wood poles	No.	33,260	31,877	(1,383)	3
11	All	Overhead Line	Other pole types	No.	2,039	2,014	(25)	2
12	HV	Subtransmission	Subtransmission OH up to 66kV conductor	km	955	969	14	4
13	HV	Subtransmission	Subtransmission OH 110kV+ conductor	km	-	–	–	4
14	HV	Subtransmission	Subtransmission UG up to 66kV (XLPE)	km	41	45	4	3
15	HV	Subtransmission	Subtransmission UG up to 66kV (Oil pressurised)	km	20	19	(2)	4
16	HV	Subtransmission	Subtransmission UG up to 66kV (Gas pressurised)	km	-	–	–	4
17	HV	Subtransmission	Subtransmission UG up to 66kV (PILC)	km	6	6	(0)	4
18	HV	Subtransmission	Subtransmission UG 110kV+ (XLPE)	km	-	–	–	4
19	HV	Subtransmission	Subtransmission UG 110kV+ (Oil pressurised)	km	-	–	–	4
20	HV	Subtransmission	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	–	–	4
21	HV	Subtransmission	Subtransmission UG 110kV+ (PILC)	km	-	–	–	4
22	HV	Subtransmission	Subtransmission submarine cable	km	-	–	–	4
23	HV	Zone substation B	Zone substations up to 66kV	No.	77	77	–	2
24	HV	Zone substation B	Zone substations 110kV+	No.	-	–	–	4
25	HV	Zone substation s	50/66/110kV CB (Indoor)	No.	-	–	–	4
26	HV	Zone substation s	50/66/110kV CB (Outdoor)	No.	-	–	–	4
27	HV	Zone substation s	33kV Switch (Ground Mounted)	No.	12	11	(1)	3
28	HV	Zone substation s	33kV Switch (Pole Mounted)	No.	527	541	14	3
29	HV	Zone substation s	33kV RMU	No.	5	5	–	4
30	HV	Zone substation s	22/33kV CB (Indoor)	No.	64	65	1	3
31	HV	Zone substation s	22/33kV CB (Outdoor)	No.	106	106	–	3
32	HV	Zone substation s	3.3/6.6/11/22kV CB (ground mounted)	No.	470	450	(20)	3
33	HV	Zone substation s	3.3/6.6/11/22kV CB (pole mounted)	No.	53	49	(4)	3
34	HV	Zone Substation T	Zone Substation Transformers	No.	114	117	3	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	10,121	10,107	(14)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	–	–	4
37	HV	Distribution Line	SWER conductor	km	17	17	–	4
38	HV	Distribution Cabl	Distribution UG XLPE or PVC	km	605	615	11	3
39	HV	Distribution Cabl	Distribution UG PILC	km	103	101	(2)	3
40	HV	Distribution Cabl	Distribution Submarine Cable	km	-	–	–	4
41	HV	Distribution switc	3.3/6.6/11/22kV CB (pole mounted) - reclosers and secti	No.	293	322	29	3
42	HV	Distribution switc	3.3/6.6/11/22kV CB (Indoor)	No.	168	197	29	3
43	HV	Distribution switc	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	23,489	23,671	182	3
44	HV	Distribution switc	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	1,011	1,006	(5)	3
45	HV	Distribution switc	3.3/6.6/11/22kV RMU	No.	829	911	82	3
46	HV	Distribution Tran	Pole Mounted Transformer	No.	19,210	17,251	(1,959)	3
47	HV	Distribution Tran	Ground Mounted Transformer	No.	3,152	3,203	51	3
48	HV	Distribution Tran	Voltage regulators	No.	69	70	1	3
49	HV	Distribution Subs	Ground Mounted Substation Housing	No.	2,002	1,640	(362)	2
50	LV	LV Line	LV OH Conductor	km	3,464	3,467	3	3
51	LV	LV Cable	LV UG Cable	km	2,148	2,193	45	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	1,349	1,355	6	2
53	LV	Connections	OH/UG consumer service connections	No.	145,220	147,305	2,085	2
54	All	Protection	Protection relays (electromechanical, solid state and nu	No.	1,316	1,225	(91)	3
55	All	SCADA and comm	SCADA and communications equipment operating as a s	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	4	4	–	4
57	All	Load Control	Centralised plant	Lot	26	25	(1)	3
58	All	Load Control	Relays	No	1,165	1,203	38	3
59	All	Civils	Cable Tunnels	km	-	–	–	4

Not all assets on Powerco's network are reported in this schedule. The Commerce Commission have advised that if assets do not clearly fit into one of the categories in schedule 9a they should be excluded from the schedule.

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Eastern Region**

SCHEDULE 9a: ASSET REGISTER

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

sch ref	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	80,076	80,380	304	4
10	All	Overhead Line	Wood poles	No.	5,180	4,932	(248)	3
11	All	Overhead Line	Other pole types	No.	2,908	2,894	(14)	2
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	545	544	(0)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	–	–	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	81	95	13	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	–	–	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	–	–	4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	0	0	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	–	–	4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	–	–	4
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	–	–	4
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	–	–	4
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	–	–	4
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	58	58	–	2
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	–	–	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	–	–	4
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	18	18	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	11	11	–	3
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	333	338	5	3
29	HV	Zone substation switchgear	33kV RMU	No.	1	1	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	34	54	20	3
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	89	86	(3)	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	355	355	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	1	1	–	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	92	94	2	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	4,634	4,634	(0)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	–	–	4
37	HV	Distribution Line	SWER conductor	km	61	61	0	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	1,157	1,184	27	3
39	HV	Distribution Cable	Distribution UG PILC	km	109	108	(0)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	11	11	–	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sec	No.	240	292	52	3
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	185	200	15	3
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	14,699	14,845	146	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMI	No.	1,386	1,408	22	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	1,208	1,303	95	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	9,152	9,261	109	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	4,856	4,970	114	3
48	HV	Distribution Transformer	Voltage regulators	No.	43	50	7	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	3,152	2,495	(657)	2
50	LV	LV Line	LV OH Conductor	km	1,956	1,937	(19)	3
51	LV	LV Cable	LV UG Cable	km	1,870	1,920	51	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	1,430	1,516	86	2
53	LV	Connections	OH/UG consumer service connections	No.	118,356	122,575	4,219	2
54	All	Protection	Protection relays (electromechanical, solid state and r	No.	1,050	1,103	53	3
55	All	SCADA and communications	SCADA and communications equipment operating as a	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	44	42	(2)	4
57	All	Load Control	Centralised plant	Lot	12	12	–	3
58	All	Load Control	Relays	No	1,147	1,190	43	3
59	All	Civils	Cable Tunnels	km	-	–	–	4

Not all assets on Powerco's network are reported in this schedule. The Commerce Commission have advised that if assets do not clearly fit into one of the categories in schedule 9a they should be excluded from the schedule.

Schedule 9b: Asset Age Profile

Company Name	Powerco Limited
For Year Ended	31 March 2017
Network / Sub-network Name	Powerco Limited

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 2017

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	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.	18	927	5,379	33,063	57,533	51,278	27,499	3,420	3,190	2,128	2,390	1,967	1,840	1,915	2,175	2,456	2,786	2,589	2,249	2,442	3,327	3,432	3,397	4,086	2,471	–	223,957	6,967	3
11	All	Overhead Line	Wood poles	No.	31	48	988	7,418	9,506	7,827	8,252	426	262	390	443	313	248	149	199	98	74	90	31	3	3	2	7	1	–	–	36,809	1,993	3
12	All	Overhead Line	Other pole types	No.	–	–	2	15	4,352	26	54	21	64	41	41	39	54	68	32	30	25	7	11	2	8	1	11	–	4	–	4,908	4,305	2
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	19	94	343	355	307	229	9	0	3	2	2	14	2	9	4	11	3	34	17	1	15	0	21	18	–	1,513	0	3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	0	20	7	22	7	1	6	1	1	1	2	5	2	7	7	19	6	5	1	2	3	17	–	140	4	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	15	2	1	–	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	19	1	4
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	1	4	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	6	–	4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	1	5	48	13	13	–	–	–	–	2	29	2	6	1	1	1	3	2	3	3	1	1	–	–	135	39	2
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.	–	–	–	–	2	4	1	–	–	–	–	2	1	1	4	–	–	–	–	–	–	–	3	–	–	–	18	–	2
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	2	–	–	–	–	–	–	1	–	–	2	1	–	4	3	4	2	2	1	–	–	22	–	2
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	164	167	199	118	10	6	3	4	6	12	1	11	9	16	15	14	28	25	7	23	37	4	–	879	22	2
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	1	–	–	–	–	–	–	–	2	–	–	3	–	–	–	–	–	–	–	–	–	6	–	2
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	23	–	–	–	–	–	–	5	6	6	5	24	13	–	9	8	4	16	–	–	119	–	2
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	1	28	33	36	25	5	2	1	3	3	5	3	3	6	4	1	2	1	4	7	9	7	3	–	192	8	2
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	95	179	97	111	4	9	–	7	19	10	17	36	18	27	14	20	20	29	48	20	24	1	–	805	49	2
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	2	1	2	12	–	–	–	2	–	1	–	2	–	4	3	–	4	–	4	7	–	6	–	50	–	3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	6	48	72	28	8	2	2	2	2	–	7	2	4	–	5	2	1	5	6	3	6	–	–	–	211	19	2
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	81	116	1,379	2,995	3,532	3,566	1,474	46	72	104	81	78	69	85	82	68	86	93	67	97	132	121	117	118	84	–	14,741	32	3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
38	HV	Distribution Line	SWER conductor	km	–	–	0	14	30	11	7	–	–	–	5	–	–	–	0	1	0	0	–	–	–	–	10	–	–	0	–	79	–	3
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	0	5	34	216	418	300	49	42	26	30	42	48	57	59	60	53	48	42	39	40	41	57	49	46	–	1,800	51	3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	1	25	70	73	21	2	3	3	3	1	1	2	2	0	0	0	0	0	0	0	0	–	1	–	209	5	3
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	2	7	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	0	0	–	11	–	3
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	1	32	36	39	4	9	15	7	19	20	18	11	16	28	27	24	28	34	39	54	92	61	–	614	29	2
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	10	64	137	52	54	6	1	–	–	4	3	10	2	2	3	9	11	4	9	4	7	4	1	–	397	46	2
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	17	18	666	2,524	7,374	6,364	5,442	448	1,048	987	713	760	959	733	843	805	804	793	708	812	867	1,184	1,290	1,370	987	–	38,516	487	2
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	3	11	140	595	466	344	40	45	39	46	78	66	88	78	53	73	43	45	35	28	11	13	18	56	–	2,414	29	2
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	3	38	143	178	272	31	62	40	55	62	79	104	126	107	105	77	78	90	86	104	135	143	96	–	2,214	20	3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	25	29	768	2,650	3,820	3,933	4,478	461	448	509	586	674	725	689	573	740	667	553	504	545	552	684	684	643	572	–	26,512	26	4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	1	7	64	390	1,146	1,486	1,180	177	176	165	158	254	274	359	294	289	237	167	163	187	135	210	286	225	143	–	8,173	12	4
49	HV	Distribution Transformer	Voltage regulators	No.	–	1	1	2	8	3	11	1	1	7	2	3	4	8	2	15	3	5	3	6	4	9	8	9	4	–	120	6	4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	2	–	3	140	997	1,368	845	96	80	63	113	113	40	28	33	39	26	25	12	14	13	21	18	17	29	–	4,135	3	3
51	LV	LV Line	LV OH Conductor	km	1	63	333	1,449	1,669	1,045	445	41	32	26	28	25	21	21	22	25	18	24	15	13	20	20	16	20	14	–	5,405	47	2
52	LV	LV Cable	LV UG Cable	km	0	0	8	146	1,051	901	710	58	60	49	56	96	110	114	131	127	113	58	44	40	37	47	48	65	43	–	4,113	292	2
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	17	99	379	801	524	411	42	40	25	26	68	69	61	63	50	54	30	23	18	13	13	15	20	12	–	2,871	177	2
54	LV	Connections	OH/UG consumer service connections	No.	24	201	2,388	16,081	113,093	46,453	31,464	2,809	2,803	2,320	2,906	3,330	3,741	3,429	3,941	3,937	3,474	3,221	3,495	2,853	3,513	3,515	3,829	3,776	3,284	–	269,880	71,841	2
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	118	493	260	189	72	6	11	7	25	39	50	28	58	73	14	66	50	63	157	242	215	92	–	2,328	172	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	1	–	2
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	1	–	31	2	–	–	–	–	–	–	–	–	2	1	–	6	1	–	2	–	–	–	46	1	4
58	All	Load Control	Centralised plant	Lot	–	–	–	–	5	5	8	–	1	–	–	–	1	–	–	–	3	2	1	6	1	2	–	2	–	–	37	3	3
59	All	Load Control	Relays	No	–	–	9	18	1,068	168	118	45	19	24	11	38	25	60	82	38	67	83	64	32	202	71	60	62	29	–	2,393	914	2
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A

Not all assets on Powerco's network are reported in this schedule. The Commerce Commission have advised that if assets do not clearly fit into one of the categories in schedule 9b they should be excluded from the schedule.

Company Name	Powerco Limited
For Year Ended	31 March 2017
Network / Sub-network Name	Western Region

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 2017

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	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.	18	923	4,173	17,939	29,617	34,806	21,833	3,357	3,029	1,666	1,876	1,418	1,353	1,220	1,331	1,406	1,662	1,455	1,429	1,580	2,244	2,487	2,339	2,881	1,535	–	143,577	6,967	3
11	All	Overhead Line	Wood poles	No.	31	47	691	7,002	8,460	6,862	6,234	411	237	387	442	311	239	149	194	64	61	20	23	3	3	1	5	–	–	–	31,877	1,993	3
12	All	Overhead Line	Other pole types	No.	–	–	1	11	1,796	18	38	12	9	8	17	32	30	9	2	6	4	2	10	1	1	1	2	–	4	–	2,014	4,305	2
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	19	57	249	229	192	145	2	0	2	2	1	11	–	3	–	11	2	0	2	0	5	0	20	16	–	969	0	3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	0	5	5	3	3	0	6	0	1	0	–	4	0	6	0	4	0	1	0	1	1	4	–	45	4	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	15	2	1	–	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	19	1	4
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	1	4	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	6	–	4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	1	3	40	9	10	–	–	–	2	1	–	5	–	–	1	2	–	1	1	1	–	–	–	–	77	39	2
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.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4	3	–	2	2	–	–	–	11	–	2
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	91	103	148	86	10	6	3	4	6	6	1	2	–	3	2	8	17	8	4	13	18	2	–	541	22	2
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	1	–	–	–	–	–	–	–	1	–	–	3	–	–	–	–	–	–	–	–	–	5	–	2
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	23	–	–	–	–	–	–	5	6	–	5	14	7	–	4	1	–	–	–	–	65	–	2
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	25	19	28	9	–	–	1	1	1	2	2	2	2	1	–	2	–	2	1	5	2	1	–	106	8	2
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	50	127	47	77	–	9	–	5	17	4	–	29	1	–	–	19	4	17	11	20	12	1	–	450	49	2
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	2	–	2	12	–	–	–	2	–	1	–	2	–	4	3	–	4	–	4	7	–	6	–	49	–	3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	6	30	46	11	5	1	2	1	2	–	2	–	2	–	1	1	–	–	1	–	6	–	–	–	117	19	2
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	81	116	1,287	2,167	2,072	2,516	1,017	42	52	87	63	49	43	39	39	29	38	26	30	43	58	65	63	52	33	–	10,107	32	3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
38	HV	Distribution Line	SWER conductor	km	–	–	–	–	5	9	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	3	–	–	–	–	17	–	3
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	0	4	29	119	127	81	12	9	11	6	8	10	14	16	22	17	19	12	12	16	19	18	21	13	–	615	51	3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	0	23	42	19	7	0	0	2	3	1	1	2	1	0	0	0	0	0	0	0	0	–	1	–	101	5	3
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	3
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	1	29	34	23	4	7	13	7	9	14	10	2	13	17	9	8	19	14	16	18	34	21	–	322	29	2
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	9	30	69	32	15	6	–	–	–	–	2	6	–	–	2	3	7	4	5	–	3	3	1	–	197	46	2
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	17	18	624	1,668	5,460	3,618	2,762	292	846	776	502	471	578	390	461	458	436	384	384	461	447	668	782	703	465	–	23,671	487	2
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	3	7	94	237	144	112	28	25	23	32	35	18	22	30	18	37	14	18	14	16	9	6	14	50	–	1,006	29	2
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	3	36	79	106	90	7	49	26	33	21	17	34	41	24	27	33	19	37	38	53	55	50	33	–	911	20	3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	25	28	760	2,157	2,621	2,361	2,565	329	333	378	387	381	476	417	300	372	377	245	342	371	319	452	435	420	400	–	17,251	26	4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	1	6	46	180	503	479	421	90	67	115	68	79	88	120	76	103	96	45	69	75	70	122	143	88	53	–	3,203	12	4
49	HV	Distribution Transformer	Voltage regulators	No.	–	1	1	2	8	2	7	–	1	7	–	–	2	5	1	8	3	1	1	4	2	4	7	3	–	–	70	6	4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	2	–	1	55	383	449	331	55	38	48	74	56	21	12	17	17	6	11	5	7	7	12	15	8	10	–	1,640	3	3
51	LV	LV Line	LV OH Conductor	km	1	63	275	988	908	630	272	40	28	22	22	20	18	17	16	17	13	20	11	10	17	16	13	18	11	–	3,467	47	2
52	LV	LV Cable	LV UG Cable	km	0	0	8	87	624	498	332	30	27	31	31	36	49	50	62	65	64	33	27	18	20	25	25	30	20	–	2,193	292	2
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	17	86	267	400	236	133	16	14	12	12	15	23	17	20	18	23	8	8	4	5	4	6	6	4	–	1,355	177	2
54	LV	Connections	OH/UG consumer service connections	No.	24	201	1,717	8,776	52,705	26,229	16,921	2,090	1,940	1,954	2,177	2,318	2,788	2,633	2,723	2,733	2,394	2,135	2,253	1,725	2,255	2,280	2,251	2,320	1,763	–	147,305	71,841	2
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	70	229	110	111	64	6	9	3	22	20	27	2	20	32	12	45	21	25	89	158	98	52	–	1,225	172	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	1	–	2
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4	–	–	–	–	–	–	4	1	4
58	All	Load Control	Centralised plant	Lot	–	–	–	–	4	5	8	–	1	–	–	–	–	–	–	–	–	–	–	5	–	1	–	1	–	–	25	3	3
59	All	Load Control	Relays	No	–	–	–	7	844	85	26	10	12	20	7	27	5	13	23	14	7	8	14	3	9	14	26	22	7	–	1,203	914	2
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A

Not all assets on Powerco's network are reported in this schedule. The Commerce Commission have advised that if assets do not clearly fit into one of the categories in schedule 9b they should be excluded from the schedule.

Company Name	Powerco Limited
For Year Ended	31 March 2017
Network / Sub-network Name	Eastern Region

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 2017

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	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.	–	4	1,206	15,124	27,916	16,472	5,666	63	161	462	514	549	487	695	844	1,050	1,124	1,134	820	862	1,083	945	1,058	1,205	936	–	80,380	2,752	3
11	All	Overhead Line	Wood poles	No.	–	1	297	416	1,046	965	2,018	15	25	3	1	2	9	–	5	34	13	70	8	–	–	1	2	1	–	–	4,932	278	3
12	All	Overhead Line	Other pole types	No.	–	–	1	4	2,556	8	16	9	55	33	24	7	24	59	30	24	21	5	1	1	7	–	9	–	–	–	2,894	2,541	2
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	37	94	127	115	84	7	–	1	1	1	3	2	6	4	0	0	34	15	1	10	0	0	2	–	544	–	3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	16	1	19	5	1	–	0	0	1	2	1	2	1	6	14	5	4	0	1	1	13	–	95	1	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	0	–	4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	–	2	8	4	3	–	–	–	–	–	28	2	1	1	1	–	1	2	2	2	–	1	–	–	58	3	2
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.	–	–	–	–	2	4	1	–	–	–	–	2	1	1	4	–	–	–	–	–	–	–	3	–	–	–	18	–	2
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	2	–	–	–	–	–	–	1	–	–	2	1	–	–	–	4	–	–	1	–	–	11	–	2
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	73	64	51	32	–	–	–	–	–	6	–	9	9	13	13	6	11	17	3	10	19	2	–	338	5	2
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	1	–	2
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	6	–	10	6	–	5	7	4	16	–	–	54	–	2
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	1	3	14	8	16	5	2	–	2	2	3	1	1	4	3	1	–	1	2	6	4	5	2	–	86	2	2
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	45	52	50	34	4	–	–	2	2	6	17	7	17	27	14	1	16	12	37	–	12	–	–	355	10	2
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	–	18	26	17	3	1	–	1	–	–	5	2	2	–	4	1	1	5	5	3	–	–	–	–	94	5	2
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	–	–	92	828	1,460	1,049	457	5	20	17	17	29	26	46	42	39	48	67	37	54	74	55	53	66	51	–	4,634	8	3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
38	HV	Distribution Line	SWER conductor	km	–	–	0	14	25	2	7	–	–	–	5	–	–	–	0	1	0	0	–	–	–	7	–	–	0	–	61	–	3
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	1	4	97	291	219	37	33	14	24	33	38	43	43	38	36	29	29	27	25	22	39	28	33	–	1,184	10	3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	0	3	27	54	15	2	3	1	0	0	0	1	1	0	0	–	–	–	–	–	–	–	–	–	108	0	3
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	2	7	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	0	0	–	11	–	3
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	3	2	16	–	2	2	–	10	6	8	9	3	11	18	16	9	20	23	36	58	40	–	292	2	2
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	1	34	68	20	39	–	1	–	–	4	1	4	2	2	1	6	4	–	4	4	4	1	–	–	200	2	2
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	–	42	856	1,914	2,746	2,680	156	202	211	211	289	381	343	382	347	368	409	324	351	420	516	508	667	522	–	14,845	27	2
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	4	46	358	322	232	12	20	16	14	43	48	66	48	35	36	29	27	21	12	2	7	4	6	–	1,408	11	2
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	2	64	72	182	24	13	14	22	41	62	70	85	83	78	44	59	53	48	51	80	93	63	–	1,303	13	3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	1	8	493	1,199	1,572	1,913	132	115	131	199	293	249	272	273	368	290	308	162	174	233	232	249	223	172	–	9,261	4	4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	1	18	210	643	1,007	759	87	109	50	90	175	186	239	218	186	141	122	94	112	65	88	143	137	90	–	4,970	5	4
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	1	4	1	–	–	2	3	2	3	1	7	–	4	2	2	2	5	1	6	4	–	50	–	4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	2	85	614	919	514	41	42	15	39	57	19	16	16	22	20	14	7	7	6	9	3	9	19	–	2,495	1	3
51	LV	LV Line	LV OH Conductor	km	–	–	58	461	761	415	172	1	4	4	6	5	3	4	6	8	5	4	4	2	3	3	3	1	4	–	1,937	5	2
52	LV	LV Cable	LV UG Cable	km	–	–	1	59	427	403	378	29	33	18	25	60	61	63	69	62	49	25	17	23	17	21	23	35	23	–	1,920	64	2
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	13	112	401	288	278	26	26	13	14	53	46	44	43	32	32	21	15	14	8	8	8	13	8	–	1,516	106	2
54	LV	Connections	OH/UG consumer service connections	No.	–	–	671	7,305	60,388	20,224	14,543	719	863	366	729	1,012	953	796	1,218	1,204	1,080	1,086	1,242	1,128	1,258	1,235	1,578	1,456	1,521	–	122,575	38,908	2
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	48	264	150	78	8	–	2	4	3	19	23	26	38	41	2	21	29	38	68	84	117	40	–	1,103	77	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	1	–	2
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	1	–	31	2	–	–	–	–	–	–	–	–	2	1	–	2	1	–	2	–	–	–	42	1	4
58	All	Load Control	Centralised plant	Lot	–	–	–	–	1	–	–	–	–	–	–	–	1	–	–	–	3	2	1	1	1	1	–	1	–	–	12	–	3
59	All	Load Control	Relays	No	–	–	9	11	224	83	92	35	7	4	4	11	20	47	59	24	60	75	50	29	193	57	34	40	22	–	1,190	109	2
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A

Not all assets on Powerco's network are reported in this schedule. The Commerce Commission have advised that if assets do not clearly fit into one of the categories in schedule 9b they should be excluded from the schedule.

Schedule 9c: Overhead Lines and Underground Cables

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Powerco Limited**

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

		Overhead (km)	Underground (km)	Total circuit length (km)
10	**Circuit length by operating voltage (at year end)**			
11	> 66kV	–	–	–
12	50kV & 66kV	163	6	169
13	33kV	1,350	159	1,508
14	SWER (all SWER voltages)	79	–	79
15	22kV (other than SWER)	121	1	122
16	6.6kV to 11kV (inclusive—other than SWER)	14,620	2,019	16,639
17	Low voltage (< 1kV)	5,405	4,113	9,518
18	**Total circuit length (for supply)**	21,737	6,297	28,034
19				
20	Dedicated street lighting circuit length (km)	1,076	1,795	2,871
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			–
22				

		Circuit length (km)	(% of total overhead length)
23	**Overhead circuit length by terrain (at year end)**		
24	Urban	2,464	11%
25	Rural	7,796	36%
26	Remote only	–	–
27	Rugged only	11,157	51%
28	Remote and rugged	319	1%
29	Unallocated overhead lines	–	–
30	**Total overhead length**	21,737	100%
31			

		Circuit length (km)	(% of total circuit length)
32			
33	Length of circuit within 10km of coastline or geothermal areas (where known)	11,163	40%

		Circuit length (km)	(% of total overhead length)
34			
35	Overhead circuit requiring vegetation management	21,737	100%

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Western Region**

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

		Overhead (km)	Underground (km)	Total circuit length (km)
10	**Circuit length by operating voltage (at year end)**			
11	> 66kV	–	–	–
12	50kV & 66kV	–	–	–
13	33kV	969	70	1,038
14	SWER (all SWER voltages)	17	–	17
15	22kV (other than SWER)	121	1	122
16	6.6kV to 11kV (inclusive—other than SWER)	9,986	715	10,702
17	Low voltage (< 1kV)	3,467	2,193	5,661
18	**Total circuit length (for supply)**	14,560	2,979	17,540
19				
20	Dedicated street lighting circuit length (km)	753	602	1,355
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			–

		Circuit length (km)	(% of total overhead length)
23	**Overhead circuit length by terrain (at year end)**		
24	Urban	1,586	11%
25	Rural	4,390	30%
26	Remote only	–	–
27	Rugged only	8,265	57%
28	Remote and rugged	319	2%
29	Unallocated overhead lines	–	–
30	**Total overhead length**	14,560	100%

		Circuit length (km)	(% of total circuit length)
32			
33	Length of circuit within 10km of coastline or geothermal areas (where known)	5,341	30%

		Circuit length (km)	(% of total overhead length)
34			
35	Overhead circuit requiring vegetation management	14,560	100%

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Eastern Region**

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	163	6	169
13	33kV	381	89	470
14	SWER (all SWER voltages)	61	–	61
15	22kV (other than SWER)	–	–	–
16	6.6kV to 11kV (inclusive—other than SWER)	4,634	1,303	5,937
17	Low voltage (< 1kV)	1,937	1,920	3,857
18	**Total circuit length (for supply)**	7,177	3,318	10,495
19				
20	Dedicated street lighting circuit length (km)	324	1,193	1,516
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	878	12%	
25	Rural	3,407	47%	
26	Remote only	–	–	
27	Rugged only	2,892	40%	
28	Remote and rugged	–	–	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	7,177	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	5,822	55%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	7,177	100%	

Schedule 9d: Embedded Networks

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**

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*

Powerco has no networks embedded in another network

Schedule 9e: Demand

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Powerco Limited**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

9e(i): Consumer Connections

Number of ICPs connected in year by consumer type

*Consumer types defined by EDB**	Number of connections (ICPs)
Residential/Small Commercial	5,056
Commercial	37
Large Commercial/Industrial	7
Connections total	5,100

** include additional rows if needed*

Distributed generation

Number of connections made in year	523	connections
Capacity of distributed generation installed in year	1.95	MVA

9e(ii): System Demand

		Demand at time of maximum coincident demand (MW)	
	Maximum coincident system demand		
	GXP demand	793	
plus	Distributed generation output at HV and above	111	
	Maximum coincident system demand	903	
less	Net transfers to (from) other EDBs at HV and above	–	
	Demand on system for supply to consumers' connection points	903	
	Electricity volumes carried	**Energy (GWh)**	
	Electricity supplied from GXPs	4,413	
less	Electricity exports to GXPs	282	
plus	Electricity supplied from distributed generation	672	
less	Net electricity supplied to (from) other EDBs	–	
	Electricity entering system for supply to consumers' connection points	4,802	
less	Total energy delivered to ICPs	4,531	
	Electricity losses (loss ratio)	271	5.7%
	Load factor	0.61	

9e(iii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	3,154
Distribution transformer capacity (Non-EDB owned, estimated)	117
Total distribution transformer capacity	3,271
Zone substation transformer capacity	2,160

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Eastern Region**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

9e(i): Consumer Connections

Number of ICPs connected in year by consumer type

*Consumer types defined by EDB**	Number of connections (ICPs)
Residential/Small Commercial	3,397
Commercial	37
Large Commercial/Industrial	6
Connections total	3,440

** include additional rows if needed*

Distributed generation

Number of connections made in year	209	connections
Capacity of distributed generation installed in year	1	MVA

9e(ii): System Demand

		Demand at time of maximum coincident demand (MW)
	Maximum coincident system demand	
	GXP demand	428
plus	Distributed generation output at HV and above	40
	Maximum coincident system demand	468
less	Net transfers to (from) other EDBs at HV and above	–
	Demand on system for supply to consumers' connection points	468

		Energy (GWh)	
	Electricity volumes carried		
	Electricity supplied from GXPs	2,479	
less	Electricity exports to GXPs	244	
plus	Electricity supplied from distributed generation	173	
less	Net electricity supplied to (from) other EDBs	–	
	Electricity entering system for supply to consumers' connection points	2,408	
less	Total energy delivered to ICPs	2,299	
	Electricity losses (loss ratio)	110	4.5%
	Load factor	0.59	

9e(iii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	1,551
Distribution transformer capacity (Non-EDB owned, estimated)	40
Total distribution transformer capacity	1,590
Zone substation transformer capacity	1,069

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Western Region**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

9e(i): Consumer Connections

Number of ICPs connected in year by consumer type

	*Consumer types defined by EDB**	Number of connections (ICPs)
	Residential/Small Commercial	1,659
	Commercial	–
	Large Commercial/Industrial	1

** include additional rows if needed*

	Connections total	1,660

Distributed generation

	Number of connections made in year	314	connections
	Capacity of distributed generation installed in year	1	MVA

9e(ii): System Demand

		Demand at time of maximum coincident demand (MW)
	Maximum coincident system demand	
	GXP demand	328
plus	Distributed generation output at HV and above	117
	Maximum coincident system demand	445
less	Net transfers to (from) other EDBs at HV and above	–
	Demand on system for supply to consumers' connection points	445

		Energy (GWh)	
	Electricity volumes carried		
	Electricity supplied from GXPs	1,934	
less	Electricity exports to GXPs	38	
plus	Electricity supplied from distributed generation	499	
less	Net electricity supplied to (from) other EDBs	–	
	Electricity entering system for supply to consumers' connection points	2,394	
less	Total energy delivered to ICPs	2,232	
	Electricity losses (loss ratio)	162	6.8%
	Load factor	0.61	

9e(iii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	1,603
Distribution transformer capacity (Non-EDB owned, estimated)	77
Total distribution transformer capacity	1,680
Zone substation transformer capacity	1,091

Schedule 10: Reliability

Company Name	Powerco Limited
For Year Ended	31 March 2017
Network / Sub-network Name	Powerco Limited

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

10(i): Interruptions

	Number of interruptions
Interruptions by class	
Class A (planned interruptions by Transpower)	5
Class B (planned interruptions on the network)	1,701
Class C (unplanned interruptions on the network)	3,497
Class D (unplanned interruptions by Transpower)	5
Class E (unplanned interruptions of EDB owned generation)	–
Class F (unplanned interruptions of generation owned by others)	–
Class G (unplanned interruptions caused by another disclosing entity)	–
Class H (planned interruptions caused by another disclosing entity)	–
Class I (interruptions caused by parties not included above)	643
Total	5,851

	≤3Hrs	>3hrs	
Interruption restoration			
Class C interruptions restored within	2,155	1,342	**Total**

	SAIFI	SAIDI
SAIFI and SAIDI by class		
Class A (planned interruptions by Transpower)	0.02	6.86
Class B (planned interruptions on the network)	0.23	45.85
Class C (unplanned interruptions on the network)	2.45	196.20
Class D (unplanned interruptions by Transpower)	0.07	6.36
Class E (unplanned interruptions of EDB owned generation)	–	–
Class F (unplanned interruptions of generation owned by others)	–	–
Class G (unplanned interruptions caused by another disclosing entity)	–	–
Class H (planned interruptions caused by another disclosing entity)	–	–
Class I (interruptions caused by parties not included above)	0.10	18.55
Total	2.87	273.82

	Normalised SAIFI	Normalised SAIDI
Normalised SAIFI and SAIDI		
Classes B & C (interruptions on the network)	2.66	224.10

	SAIFI reliability limit	SAIDI reliability limit
Quality path normalised reliability limit		
SAIFI and SAIDI limits applicable to disclosure year*	2.52	210.60

** not applicable to exempt EDBs*

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

	SAIFI	SAIDI
Cause		
Lightning	0.03	2.24
Vegetation	0.26	26.34
Adverse weather	0.10	9.98
Adverse environment	0.10	16.13
Third party interference	0.17	16.03
Wildlife	0.12	6.90
Human error	0.10	2.92
Defective equipment	0.88	70.72
Cause unknown	0.70	44.94

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

	SAIFI	SAIDI
Main equipment involved		
Subtransmission lines	0.0	0.3
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.18	39.11
Distribution cables (excluding LV)	0.01	0.92
Distribution other (excluding LV)	0.04	5.54

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

	SAIFI	SAIDI
Main equipment involved		
Subtransmission lines	0.51	33.42
Subtransmission cables	–	–
Subtransmission other	0.07	4.65
Distribution lines (excluding LV)	1.59	142.32
Distribution cables (excluding LV)	0.18	9.47
Distribution other (excluding LV)	0.11	6.34

10(v): Fault Rate

	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Main equipment involved			
Subtransmission lines	199	1,513	13.15
Subtransmission cables	–	164	–
Subtransmission other	12		
Distribution lines (excluding LV)	4,509	14,820	30.43
Distribution cables (excluding LV)	77	2,020	3.81
Distribution other (excluding LV)	259		
Total	5,056		

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Western Region**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

10(i): Interruptions

	Number of interruptions
Interruptions by class	
Class A (planned interruptions by Transpower)	5
Class B (planned interruptions on the network)	816
Class C (unplanned interruptions on the network)	2,567
Class D (unplanned interruptions by Transpower)	3
Class E (unplanned interruptions of EDB owned generation)	–
Class F (unplanned interruptions of generation owned by others)	–
Class G (unplanned interruptions caused by another disclosing entity)	–
Class H (planned interruptions caused by another disclosing entity)	–
Class I (interruptions caused by parties not included above)	369
Total	3,760

	≤3Hrs	>3hrs
Interruption restoration		
Class C interruptions restored within	1,549	1,018

	SAIFI	SAIDI
SAIFI and SAIDI by class		
Class A (planned interruptions by Transpower)	0.04	12.8
Class B (planned interruptions on the network)	0.21	44.4
Class C (unplanned interruptions on the network)	2.85	242.8
Class D (unplanned interruptions by Transpower)	0.06	4.6
Class E (unplanned interruptions of EDB owned generation)	–	–
Class F (unplanned interruptions of generation owned by others)	–	–
Class G (unplanned interruptions caused by another disclosing entity)	–	–
Class H (planned interruptions caused by another disclosing entity)	–	–
Class I (interruptions caused by parties not included above)	0.13	21.6
Total	3.28	326.2

	Normalised SAIFI	Normalised SAIDI
Normalised SAIFI and SAIDI		
Classes B & C (interruptions on the network)	2.93	238.8

	SAIFI reliability limit	SAIDI reliability limit
Quality path normalised reliability limit		
SAIFI and SAIDI limits applicable to disclosure year*	–	–

** not applicable to exempt EDBs*

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

	SAIFI	SAIDI
Cause		
Lightning	0.05	3.8
Vegetation	0.28	32.8
Adverse weather	0.08	14.3
Adverse environment	0.15	26.3
Third party interference	0.20	15.9
Wildlife	0.18	8.8
Human error	0.06	2.6
Defective equipment	1.06	88.2
Cause unknown	0.79	50.1

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

	SAIFI	SAIDI
Main equipment involved		
Subtransmission lines	0.00	0.1
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.17	38.3
Distribution cables (excluding LV)	0.00	0.6
Distribution other (excluding LV)	0.03	5.4

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

	SAIFI	SAIDI
Main equipment involved		
Subtransmission lines	0.49	27.7
Subtransmission cables	–	–
Subtransmission other	0.06	3.9
Distribution lines (excluding LV)	2.07	197.1
Distribution cables (excluding LV)	0.12	6.9
Distribution other (excluding LV)	0.10	7.3

10(v): Fault Rate

	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Main equipment involved			
Subtransmission lines	153	969	15.80
Subtransmission cables	–	70	–
Subtransmission other	7		
Distribution lines (excluding LV)	3,411	10,124	33.69
Distribution cables (excluding LV)	20	716	2.79
Distribution other (excluding LV)	186		
Total	3,777		

Company Name	**Powerco Limited**
For Year Ended	**31 March 2017**
Network / Sub-network Name	**Eastern Region**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

10(i): Interruptions

	Number of interruptions
Interruptions by class	
Class A (planned interruptions by Transpower)	–
Class B (planned interruptions on the network)	885
Class C (unplanned interruptions on the network)	930
Class D (unplanned interruptions by Transpower)	2
Class E (unplanned interruptions of EDB owned generation)	–
Class F (unplanned interruptions of generation owned by others)	–
Class G (unplanned interruptions caused by another disclosing entity)	–
Class H (planned interruptions caused by another disclosing entity)	–
Class I (interruptions caused by parties not included above)	274
Total	2,091

Interruption restoration	≤3Hrs	>3hrs
Class C interruptions restored within	606	324

SAIFI and SAIDI by class	SAIFI	SAIDI
Class A (planned interruptions by Transpower)	–	–
Class B (planned interruptions on the network)	0.25	47.5
Class C (unplanned interruptions on the network)	2.00	142.6
Class D (unplanned interruptions by Transpower)	0.08	8.4
Class E (unplanned interruptions of EDB owned generation)	–	–
Class F (unplanned interruptions of generation owned by others)	–	–
Class G (unplanned interruptions caused by another disclosing entity)	–	–
Class H (planned interruptions caused by another disclosing entity)	–	–
Class I (interruptions caused by parties not included above)	0.07	15.0
Total	2.40	213.5

Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
Classes B & C (interruptions on the network)	2.25	190.1

Quality path normalised reliability limit	SAIFI reliability limit	SAIDI reliability limit
SAIFI and SAIDI limits applicable to disclosure year*	–	–

** not applicable to exempt EDBs*

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

Cause	SAIFI	SAIDI
Lightning	0.01	0.5
Vegetation	0.23	18.9
Adverse weather	0.11	5.0
Adverse environment	0.04	4.4
Third party interference	0.13	16.2
Wildlife	0.06	4.7
Human error	0.16	3.3
Defective equipment	0.67	50.6
Cause unknown	0.60	39.0

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.00	0.5
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.20	40.0
Distribution cables (excluding LV)	0.01	1.3
Distribution other (excluding LV)	0.04	5.7

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.52	40.0
Subtransmission cables	–	–
Subtransmission other	0.08	5.6
Distribution lines (excluding LV)	1.04	79.3
Distribution cables (excluding LV)	0.24	12.5
Distribution other (excluding LV)	0.12	5.3

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	46	544	8.45
Subtransmission cables	–	95	–
Subtransmission other	5		
Distribution lines (excluding LV)	1,098	4,695	23.39
Distribution cables (excluding LV)	57	1,303	4.37
Distribution other (excluding LV)	73		
Total	1,279		

Schedule 14: Mandatory Explanatory Notes

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).

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 12 of this schedule is part of the audited disclosure information, and so is subject to the assurance requirements specified in section 2.8.

Return on Investment (Schedule 2)

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

Our disclosed ROI under both a Vanilla and Post tax approach for 2017 is higher than 2016 primarily as a result of:

- Higher CPI in this regulatory year (2.17% in 2017 compared to 0.59% in 2016). This resulted in an increase in revaluations to $32.7m in 2017 from $8.6m in 2016.
- This was partially offset by reduction in operating surplus down to 171.3m in 2017 from $181.3m in 2016.

Regulatory Profit (Schedule 3)

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

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

Box 2: Explanatory comment on regulatory profit

Regulatory profit for the year to 31 March 2017 is $114.6m. This represents an increase of $13.6m over the previous year. This increase in profit is a result of higher revaluations in the current year, offset by an increase in disposals and depreciation.

Other regulated income is largely income received to reimburse Powerco's operational costs that arise from network damage caused by a third party (e.g. income received from insurers or directly from the third parties). This amount varies between years as Powerco has no control over the events that lead to this income.

During the regulatory period, insurance proceeds of $0.7m were received.

Costs related to the Customised Price-Quality Path application were incurred during the year. $0.4m of these may be able to be treated as recoverable costs in a future year if they are specified by the Commission in a CPP determination.

There have been no reclassified items.

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

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

- information on reclassified items in accordance with subclause 2.7.1(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

No merger and acquisition expenditure has been incurred during the disclosure year.

Value of the Regulatory Asset Base (Schedule 4)

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 Regulatory Asset Base (RAB) has increased by $64.5m during the year. This increase was higher than 2016 primarily due to a higher revaluation rate in 2017 compared to 2016.

Due to ongoing data quality checks and updates to asset category mapping there are reclassifications in the Asset category transfer line in Schedule 4(vii).

Details of the movements are detailed below.

Subtransmission lines ($000)	Subtransmission cables ($000)	Zone substations ($000)	Distribution and LV Lines ($000)	Distribution & LV cables ($000)	Distribution substations & transformers ($000)	Distribution Switchgear ($000)	Other network assets ($000)
($31)	($29)	($1,272)	$25	$32	$176	$1,298	($199)

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

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

- Income not included in regulatory profit / (loss) before tax but taxable;
- Expenditure or loss in regulatory profit / (loss) before tax but not deductible;
- Income included in regulatory profit / (loss) before tax but not taxable;
- Expenditure or loss deductible but not in regulatory profit / (loss) before tax.

Box 5: Regulatory tax allowance: permanent differences

There is $0.28m of expenditure in regulatory profit that is not deductible for tax. This is related to entertainment expenditure.

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

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

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

Temporary differences amount to $462k ($129k tax effect) and relate to—

- Employee related provisions $152k
- ACC provisions $131k
- Substation electricity consumption provisions $174k
- Other provisions $5k

Related party transactions: disclosure of related party transactions (Schedule 5b)

In the box below, provide descriptions of related party transactions beyond those disclosed on Schedule 5b including identification and descriptions as to the nature of directly attributable costs disclosed under subclause 2.3.6(1)(b).

Box 7: Related party transactions

There are no further related party transactions, other than those disclosed in schedule 5b.

Cost allocation (Schedule 5d)

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 8: Cost allocation

Powerco has adopted a fully distributed cost approach to allocate shared costs between Powerco's electricity and gas distribution businesses.

All operating costs except some specified systems operations and network support (SONS) costs and some specified business supports costs are directly attributable to the specific regulated businesses.

Directly attributable costs are primarily incurred in the functional areas of:

- SONS
- Customised Price-Quality Path related costs
- Network management and administration
- Customer related costs

Powerco has opted to use cost allocators that have been calculated under the ABAA (accounting based allocation approach) methodology type as defined in the Input Methodology determination, to allocate those operating costs that are not directly attributable.

The use of causal relationships has been utilised where the cost driver has led to the cost being incurred.

The use of proxy relationships has been utilised to allocate operating costs for which a causal relationship cannot be established. The rationale behind the use of each proxy allocator is based on an analysis of each financial statement item that is not directly attributable and the key cost driver as determined by Powerco's management team. This is based on a combination of experience and knowledge, an analysis of the costs and the comparative sizes of the regulated businesses.

The main reason why a causal relationship cannot be established is that for some functional areas there is not one key causal cost driver. The use of one causal allocator would unfairly effect the allocation of costs between regulated businesses.

SONS costs that are not directly attributable relate to network information services management costs and have been allocated based on a proxy fixed asset allocator (which is based on the carrying value of network fixed assets). The not directly attributable costs include the significant cost categories below:

- Personnel costs
- Professional services

Business support costs that are not directly attributable primarily arise in the functional areas of:

- Corporate services which has a proxy cost allocator of distribution line charge revenue
- Human resources which has a proxy cost allocator of employee numbers
- Regulatory management which has a causal allocation of managements estimate of staff time working on regulated and unregulated services and legal has a proxy fixed asset allocator
- Insurance which has causal allocators of indemnity values, vehicle allocations and employee numbers
- Facility costs which has a causal allocator of employee numbers and a proxy fixed assets allocator
- Information systems and projects which have a proxy fixed asset allocator.

The not directly attributable costs included in business support include the significant cost categories below:

- Personnel costs
- Professional services
- Information technology related expenses
- Building & insurance related costs
- Administration costs
- Communication & marketing costs.

Within each functional area across Powerco only one allocation methodology type has been used.

There have been no changes to the cost allocators applied in the current disclosure year.

Asset allocation (Schedule 5e)

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

Box 9: Commentary on asset allocation

Non-network assets have been allocated to the regulatory asset base based on the proxy allocator of fixed asset net book value.

The rationale behind the use of the proxy allocator is based on an analysis of the asset types that are not directly attributable and the key driver of each asset type as determined by management. This is based on a combination of managements experience and knowledge, an analysis of the assets and the comparative sizes of the regulated businesses.

There have been no reclassifications in the period reported.

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

- a description of the materiality threshold applied to identify material projects and programmes described in Schedule 6a;
- information on reclassified items in accordance with subclause 2.7.1(2).

Box 10: Explanation of capital expenditure for the disclosure year

Total capital expenditure (capex) during this period exceeded the 2016 Asset Management Plan (AMP) forecast by 4%. This reflects an ongoing focus on investing to enable growth, and an increasing focus on renewal related expenditure as an increasing proportion of assets reach the end of their service life.

The higher than anticipated connection numbers and volume growth in this disclosure period has necessitated increased investment levels and resulted in expenditure levels exceeding forecast.

<u>Materiality threshold</u>

In addition to the programmes outlined in previous AMPs, a material project is defined as any project where

- quality of supply projects where the value exceeds 5% of the category's total value
- asset relocations projects where the total value of the project exceeds $100k
- other reliability, safety and environment projects or programmes where expenditure exceeds $150k
- non-network expenditure programmes exceeding $300k.

<u>Reclassified items</u>

As part of the improvements intended to be achieved under the Customised Price-Quality Path (CPP), we

have introduced some changes to the manner in which network capital expenditure is categorised into the primary Commerce Commission expenditure categories. These changes have been reflected in the current Asset Management Plan and CPP forecasts. The change in approach has occurred as a result of reviewing the historical approach to the classification of projects. Historically projects which were primarily renewal in nature (as the asset required replacement in the near future) were, in some instances, being classified as growth or security projects. The changes to the categorisation of expenditure are required to better support our expenditure tracking by providing more consistency in how expenditure is categorised, and to remove unnecessary variability between years.

These changes have resulted in a change in classification from 2016. The overall result of these changes has no impact on total capital expenditure; however the allocation between the categories has changed. Details of these change are as follows:

a) The items reclassified predominantly relate to expenditure previously classified as reliability, safety and environment

b) The value of the items reclassified in the current year are ($000s):

- Asset relocations $725
- Asset replacement and renewal $7,544
- Consumer connection ($1,202)
- Reliability, safety and environment: Other ($8,037)
- Reliability, safety and environment: QoS ($2,830)
- System growth: $3,800

The value of the items in the previous year were ($000s):

- Asset replacement and renewal $4,845
- Reliability, safety and environment: Other ($5,521)
- Reliability, safety and environment: QoS ($2,949)
- System growth: $3,625

c) In the previous year this expenditure remained in its original capex category as per b) above. We have not restated previous years expenditure.

d) In the current year these items were classified as per b) above

The changes are required to better support our expenditure tracking by providing more consistency in how expenditure is categorised, and to remove unnecessary variability between years.

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

- Commentary on assets replaced or renewed with asset replacement and renewal operational expenditure, as reported in 6b(i) of Schedule 6b;
- Information on reclassified items in accordance with subclause 2.7.1(2);
- Commentary on any material atypical expenditure included in operational expenditure disclosed in Schedule 6b, including the value of the expenditure the purpose of the expenditure, and the operational expenditure categories the expenditure relates to.

Box 11: Explanation of operational expenditure for the disclosure year

Total operational expenditure (opex) was in line with Powerco's 2016 AMP.

Asset replacement and renewal opex is primarily driven by the need to maintain network asset integrity to maintain current security and quality of supply. This category includes the replacement of minor, low cost assets or asset components.

Further information regarding opex expenditure for the disclosure year is contained in box 12.

Reclassified items

No items have been reclassified during this disclosure year.

Atypical expenditure

There have been no material items of atypical expenditure.

Variance between forecast and actual expenditure (Schedule 7)

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

Box 12: Explanatory comment on variance in actual to forecast expenditure

Total expenditure for the period exceeded that forecast in Powerco's 2016 AMP by $6.2m (4%). The largest contributor to the increased expenditure was the higher than anticipated customer connection expenditure during the period.

Commentary is provided on each category where the forecast to actual variance is greater than 5% (subject to being material in dollar terms).

Consumer Connection

Consumer connection expenditure exceeded the forecast by $17.1m (80%). Large subdivisions continued to develop at record pace in the Eastern region, driven by unprecedented residential and commercial growth in Tauranga. In the Western region the delivery of the Mangamutu dairy factory project contributed to the increased cost.

The increase in expenditure on consumer connection is partially offset by a corresponding increase in capital contributions shown in schedule 6a(i) Expenditure on assets.

System Growth

System growth expenditure is less than forecast by $12.9m (27%). The delivery of the system growth programme was impacted by design, access and consent issues that persisted throughout the period. The challenges involved with the delivery of several large scale projects account for the majority of this forecast variance:

- the Papamoa substation project was forecast to incur $10.1m. Due to a combination of access issues and savings through technical design, the actual delivery was $6.8m for the year
- the Whangamata line was forecast to incur $1.8m. Due to design and access constraints this was unable to be started in FY17
- the Palmerston North CBD growth related projects have experienced significant delay as a result of design, consent and technical issues. This has created a variance of $3.2m between forecast and actual.

Asset Replacement and Renewal

Asset replacement and renewal expenditure exceeded the forecast by $5.0m (8%). During the period capex has increased due to an increased focus on:

- defective equipment as we respond to an increasing number of assets, particularly distribution overhead assets reaching the end of their service lives
- proactive replacement of end of life distribution and low voltage lines and feeders where the performance of these assets has deteriorated.

Asset Relocations

Capital expenditure was $0.4m (14%) lower due to the timelines for several large scale roading projects signalled by NZTA and Councils differing from that originally planned. Other roading and customer

generated projects requiring relocation of Powerco assets were fewer and of smaller scale than had been anticipated.

Other Reliability, Safety and Environment

Expenditure on Other reliability, safety and environment was $1.6m (108%) higher than forecast. This reflected a focus on ensuring reliability and safety improvement initiatives undertaken across the network. Three major projects accounted for the higher level of capex; Seismic strengthening of substations ($1.0m), LV fusing upgrades ($1.0m) and Whanganui cable duct replacements ($600k).

Quality of Supply

Expenditure on Quality of supply has exceeded forecast by $1.3m (34%). The $5.2m total comprised of $4.5m of Automation projects, which was higher than anticipated and the main driver of the overspend. Powerco also carried out several backfeed cable projects totalling $0.6m.

Non-network Capex

Expenditure on non-network assets was $5.5m (58%) under the forecast. The variance resulted primarily from the deferral of a planned upgrade of the Enterprise Asset Management System.

Operational Expenditure

Actual opex of $73.5m was within 2% ($1.6m) of forecast with lower expenditure driven primarily by lower than forecast expenditure in the non-network area.

Whilst network operational expenditure was in line with forecast, expenditure on service interruptions and emergencies was lower than forecast contributing to marginally lower than expected operational expenditure.

Commentary is provided for each category where the variance against target exceeds 5% (subject to the difference being material in dollar terms).

Service Interruptions and Emergencies

Service interruptions and emergencies expenditure was $865k (12%) less than forecast. This reflects the lower than average LV fault volumes observed for FY17. Despite this the year was punctuated with events impacting our HV and LV networks which contributed to SAIDI and SAIDI exceeding our targets, but remaining below our regulatory caps.

Asset Replacement and Renewal

Asset replacement and renewal expenditure was $0.5m (6%) more than forecast. A significant portion of this variance ($0.4m) is driven by the unforeseen requirement for a temporary OH 33kV line to be constructed in Palmerston North. This was constructed in order to maintain CBD supply while a more permanent solution was constructed.

Non-network Opex

Powerco's total non-network operational expenditure in the disclosure period was 2% below that forecast in the 2016 AMP.

Information relating to revenues and quantities for the disclosure year

In the box below provide-

- 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 13: Explanatory comment relating to revenue for the disclosure year

Powerco's revenue for FY17 was $377.1m, compared to the targeted revenue of $378.1m. Electricity revenue was lower than target due to lower than expected billable demands and volumes across the Western region. This was partially off-set by higher than expected revenue across the Eastern region due to a continuation of strong ICP growth resulting from new sub-division developments.

Network Reliability for the Disclosure Year (Schedule 10)

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

Box 14: Commentary on network reliability for the disclosure year

In FY17 Powerco's SAIDI and SAIFI (Class B and Class C) is relatively high with a Non-Normalised SAIDI result of 242 minutes and SAIFI of 2.68. What is notable about this result is that weather was not atypically worse than normal. The Powerco network experienced only one severe weather event during the period which coincided with interruptions to supply caused by the earthquake centred north of Kaikoura. Powerco's historical average is around three major storms per year.

This, and the growing number of faults on the network, supports Powerco's analysis in its customised price path (CPP) application[1] of underlying deterioration in the network.

As signalled in Powerco's 2016 Asset Management Plan[2], reliability performance at specific locations across our networks is deteriorating due to a combination of declining asset condition and reducing security headroom. The AMP 2016 signals the need to increase the level of investment in asset renewal and security upgrades described in the Asset Management Plan. Actual capital expenditure in these categories in FY17 is higher than originally forecast.

Calculating reliability results

Powerco has well developed processes to capture outage / interruption information and ensure the accuracy of these records. In utilising this data to complete schedule 10 the following key calculation steps are applied—

- To calculate SAIDI and SAIFI customer connection numbers ("ICPs") are calculated from the Geographic Information System ("GIS") for the transformers affected. ICPs are updated to the GIS daily from the Electricity Registry;
- The customer connection number used in the annual calculation of SAIDI and SAIFI is the average of customer numbers at the end of each month of the Assessment year. The sum of all customer minutes interrupted is divided by the average customer connection numbers to derive the annual SAIDI minutes and SAIFI value; and
- Calculation of the final year result is completed using the outage / interruption records in the Outage Management Database noting refinements to the data to correct for a number of practical delays affecting the recorded restoration time for many faults; these include SCADA polling delays, voice communication constraints and clock time coding discrepancies. Consistent with previous reporting periods, an adjustment of three minutes per interruption is made across all fault records to correct for these discrepancies. Powerco's CPP proposal includes investment planned to improve communication systems over the five year CPP period ending March 2023. It is expected the improved communications systems will see the communications adjustment phased out by the end of the CPP period.

The normalised results for Powerco

In Schedule 10 Powerco is required to report the reliability limits established under the 2015 Default Price-Quality Path Determination (DPP) for Powerco Limited. The comparative actual normalised results must apply the methodology contained in the Information Disclosure Determination.

The methodology for calculating SAIDI and SAIFI between the DPP and Information Disclosure Determinations is significantly different and the actual normalised results (row 37 of schedule 10) reported

[1] Powerco's CPP proposal is available from our website http://www.yourenergyfuture.co.nz/about/
[2] Powerco's full Asset Management Plan is available from our website www.Powerco.co.nz.

in this information disclosure should not be compared to the quality path normalised reliability limit reported in line 40 of schedule 10.

The Commerce Commission is aware of the inherent inconsistency in the Information Disclosure Determination and will consider this issue in future amendments to the Information Disclosure Determination.[3]

Powerco's normalised reliability results prepared on the same basis as the reliability limit for the quality path for 2016 are:

Measure	Actual Results	Limit
SAIDI	203.879	210.629
SAIFI	2.483	2.520

The normalised results for Powerco's sub-networks

When calculating the normalised SAIDI and SAIFI for the sub-networks for the purposes of Information Disclosure, Powerco has derived normalised datasets for each sub-network using boundary values calculated using the reference dataset (2005-2009 disclosure years) for each sub-network. This approach follows one of the two options provided by the Commerce Commission in its Issues Register for Electricity and Gas Information Disclosure[4]. Powerco has chosen this option as we consider it provides a more meaningful analysis of the actual performance of each sub-network than the alternative option of applying a Powerco wide network boundary value to the sub-networks.

Insurance cover

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

- The EDB's approaches and practices in regard to the insurance of assets used to provide electricity distribution services, including the level of insurance;
- In respect of any self insurance, the level of reserves, details of how reserves are managed and invested, and details of any reinsurance.

Box 15: Explanation of insurance cover

Powerco holds significant insurance cover relating to material damage and business interruption, targeted at key assets. This includes full cover for buildings and contents, substations and IS server equipment, and natural disaster cover for distribution transformers and SCADA equipment.

Powerco continues to prudently insure our network and other assets where it is economically feasible to do so, in line with good industry practice. Cover for poles, wires and pipes (commonly referred to as transmission and distribution cover) are, for all practical purposes, unavailable in NZ. Where it may be available in small amounts across our geographic region, the cost is considered to be uneconomic versus the risk, as there is a restricted retained limit and a premium cost of 10-15% of the sum insured.

To manage the immediate financial exposure to a catastrophic event affecting uninsured assets, the company maintains headroom in its debt facilities as explained below. The geographically diverse nature of Powerco's assets, and the resilience of those assets, also provides some practical mitigation of seismic risks.

Powerco maintains debt facilities, in excess of net (drawn) debt, that would be available for use should events occur which require extra funds to be made available quickly. This headroom amount is in excess of our day-to-day working capital requirements.

The value of this facility headroom, currently $70 million, is based primarily on an assessment of the uninsured damage to Powerco's network assets undertaken by Marsh Risk Consulting. This analysis

[3] Commerce commission's issues register for gas and electricity information disclosure, item number 447
[4] Commerce commission's issues register for gas and electricity information disclosure, item number 231

reviewed the catastrophic risk and expected loss from a catastrophic event, and was last assessed at $50-70 million.

Insurance costs are allocated to Powerco's separate businesses following Powerco's allocation policies discussed earlier in this document.

Amendments to previously disclosed information

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:

- a description of each error; and
- for each error, reference to the web address where the disclosure made in accordance with clause 2.12.1 is publicly disclosed.

Box 16: Disclosure of amendment to previously disclosed information

There have been no amendments to previously disclosed information.

Schedule 15 Voluntary Explanatory Notes

This section includes notes, which supplement the mandatory notes set out in Schedule 14, provide additional information to aid understanding of the required disclosure schedules.

Finance Schedules

Weighted average remaining useful life of assets (schedule 4)

The weighted average remaining useful life of assets has been calculated in accordance with Schedule 16 of the IDD which specifies the weighting be based on opening RAB values. Opening RAB is a depreciated value which skews the weighted average remaining useful life value towards the newer, and consequently, higher value longer remaining life assets. This measure is therefore not a true reflection of the age of Powerco's assets.

It is also important to note that asset age, particularly total average remaining asset life, is not a key driver of the need to replace network assets. Good asset management practice would suggest this is primarily driven by overall asset health – i.e. condition/performance/criticality. For this reason, Powerco's forecast investment profiles set out in the company's current Asset Management Plan are not directly linked to addressing specific movements in average asset age although this is one of a number of key considerations.

Overhead to underground conversion (schedule 6a)

Powerco does not collect information separately where the conversion from overhead line to underground cable forms part of a larger project. The capital expenditure for this metric reported in schedule 6a is for those projects that are only converting overheard distribution to underground.

Billed Quantities and Revenues (schedule 8)

Billed Quantities

Powerco operates an ICP (installation control point) pricing methodology for the Eastern region and a GXP (grid exit point) pricing methodology for the Western region. Schedule 8 requires the reporting of energy delivered to ICPs and also the billed quantities by price component.

Under the GXP pricing methodology, the actual energy delivered to ICPs differs from the chargeable kWh quantities detailed in the billed quantities section of Schedule 8, which is based on GXP quantities delivered.

Powerco's Western Region uses volumes reconciled at each GXP to determine billable charges. Consequently, Powerco does not hold information on the energy delivered to ICPs for the Western Region. Powerco has obtained retailer submission data from the Reconciliation Manager to complete this metric.

In FY17 Powerco revised demand charges for the commercial and industrial customers in our Western region. Historically these customers were charged demand charges based on the average of their twelve highest half hourly peaks (kVA) over the previous twelve months. Based on feedback from retailers and customers we have moved to a less complicated, more cost reflective and transparent methodology. This involves taking historical half hourly (kW) Anytime Maximum Demands (AMD) and On Peak Demands (OPD) from the previous year to determine chargeable quantities.

From 1 April 2016 we split the existing demand charge into two to allow us to separately apply a distribution charge and a transmission charge. The distribution charge will have the AMD quantity applied to it. The transmission charge will have the OPD quantity applied, similar to Transpower's current pricing methodology.

As the two new chargeable quantities have different prices and revenues associated with them we have separated out the two different demand quantities in schedule 8 of the Information Disclosure.

Consumer types

The IDD permits Powerco to define the appropriate consumer types that are typical of the consumers connected to our network.

Powerco has three major types of consumer groups:

- residential/ small commercial;
- commercial; and

- industrial.

The Industrial consumer group is further separated into those on standard and non-standard contracts.

Table one illustrates the application of these consumer groups to our pricing groups for the 2017 assessment period.

Table One: Price groups assigned to consumer groups

Consumer Group	Eastern Region Price Categories	Western Region Price Categories
Residential/Small Commercial	0-69 KVA (V05, V06, T05, T06 tariff groups)	<301 kVA (E1 tariff group)
Commercial	69-299 kVA (V24,V28,T22,T24,T41 tariff groups)	100-300 kVA (E100 tariff group)
Large Commercial/Industrial (standard)	≥300kVA (T43 tariff group)	>300kVA (E300 tariff group)
Large Commercial/Industrial (non-standard)	≥300kVA (T50, T60, V40, V60 tariff groups)	≥300kVA (Special)

ICP numbers

When reporting Powerco's ICPs, Powerco has included ready, inactive and active ICPs in the disclosed number.

Transmission line charge revenue

Transmission line charge revenue reflects Powerco's recovery, via prices, of recoverable costs and pass-through costs in FY17. Recoverable costs are mostly transmission costs. Pass-through costs include rates and levies. Further information on Powerco's recoverable and pass-through costs included in prices is available in the annual Electricity Default Price-Quality compliance statement available on Powerco's website.

Asset Information (schedules 9a-9c)

Powerco's network is made up of fifteen legacy lines networks that have been amalgamated over time. This diversity of networks has created on-going data and systems integration and improvement challenges for Powerco.

Powerco has invested in both systems and data cleansing programmes over the past decade to help align and cleanse the data, resulting in material and progressive improvements in the quality and completeness of our asset related data sets.

Whilst we believe that the quality of our data is now adequate for business purposes, and in line with the levels of quality available by other electricity distributors, there are some known limitations to our current data set as set out in schedules 9a and 9b; key points are noted as follows:

- The underlying GIS data comprises a comprehensive set of network information that is generally complete and consistently applied. However, a small proportion of the asset data is either internally conflicting or not wholly reliable and, for a small number of asset categories, there are also gaps in the attribute information.
- Ongoing programmes of work are underway to improve the completeness and accuracy of our asset data. This work may impact the future reporting of quantities reflected in the schedules.
- The asset age profile (Schedule 9b) includes some default ages in each asset class. For some asset classes (particularly poles and switches), an installation date estimate has been made at some time after the initial data capture. While based on the best information available, these estimates are likely to contain some inaccuracies.

- Data is extracted from our GIS system on 1 April each year. Each year there will be assets that are in use on the network but are not yet entered in the GIS system. We complete the extract at the same time each year for consistency in reporting and to provide sufficient time to analyse the disclosure results.

Asset Age

Powerco asset data modelling is applied to determine the most likely installation date where that information is not directly recorded. For example, conductor dates can be inferred from associated poles and adjacent conductor when conductor age is not directly recorded. As a result, the dataset does not contain assets in the age-unknown category.

Some date information is known to have been defaulted, and this is reported as such.

Network Asset Classification

The programmes we have put in place to ensure on-going improvement of asset data over time, as well as the process of clarification used by the Commission to ensure data is calculated on a consistent basis between companies, means that from time to time we re-categorise small numbers of assets to reflect the latest guidance and latest available data.

The only material change in the assessment period affects Ground Mounted Substation Housings, for which an inference has been applied to improve classification accuracy.

Asset Categorisation

Powerco operates network assets, as set out in table 2, which do not clearly fit in to a specified category. These assets have been included in the category that most closely relates to the asset type and function.

Table Two: asset categorisation

Asset Type	Included in	
	Asset category	Asset class
Ground mounted 33/66kV fuses	Zone substation switchgear	33kV switch (ground mounted)
Pole mounted 33/66kV fuses	Zone substation switchgear	33kV switch (pole mounted)
33kV reclosers	Zone substation switchgear	22/33kV CB(outdoor)
Reclosers in zone substations	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)
Ground mounted 3.3/6.6/11/22kv fuses	Distribution switchgear	3.3/6.6/11/22kv switch (ground mounted) except RMU
Pole mounted distribution conversion and SWER isolation transformers	Distribution transformer	Pole mounted transformer
Ground mounted distribution conversion and SWER isolation transformers	Distribution transformer	Ground mounted transformer
Ground mounted subtransmission switchgear(not in zone substations)	Zone substation switchgear	33kV switch (ground mounted)
Pole mounted subtransmission switchgear(not in zone substations)	Zone substation switchgear	33kV switch (pole mounted)

Asset Type	Included in	
	Asset category	Asset class
Protection system pilots	Not included[5]	Not included

Excluded assets

Assets are excluded from schedule 9a and schedule 9b if —

- They do not clearly fit into a specified category
- There is no category that closely relates to the asset type and function.

This approach follows the advice given by the Commerce Commission in its issues register.[6]

An example of an asset type excluded from schedules 9a and 9b is the small number of Remote Area Power Supply (RAPS) units Powerco has on the network. These are typically deployed in remote areas and provide a fully autonomous off-grid power solution. Each unit operates as a mini-AC grid managing the sources of generation, storage and loads across the connected loads. The RAPS unit is designed to typically use renewable PV generation and energy storage to meet consumer needs.

RAPS units do not fit into the categories specified in 9a and 9b and are excluded from the report. The costs associated with these assets however are included in the commissioned asset values in the RAB roll-forward.

Service Connections

Service connections are calculated for Schedules 9a and 9b based on the guidance provided by the Commerce Commission in their issues register for electricity and gas businesses.

For completeness we note that streetlight connections are not considered a service connection.

SCADA and Communications equipment operating as a single system

The entire Powerco network operates from a single SCADA and communications system.

An average installation date has been calculated in response to Commission's issues register item #443.

Low voltage circuit length

Powerco notes that low voltage circuit length has been calculated in accordance with disclosure information provided by the Commission. This updated definition requires low voltage service lines in transport corridors (other than road crossings) to be excluded from the calculation. For completeness Powerco considers that this definition understates the practical circuit length under management by Powerco.

Circuits in sensitive areas

Powerco does not record sensitive area geography. Therefore no circuit length is reported for this criterion.

Circuit length under vegetation management

Powerco's vegetation management approach applies to its entire overhead electricity network. Similar to previous years, in FY17 work mainly involved vegetation trimming and removal in high criticality areas. The development of our customised price-path proposal included a review and creation of a new vegetation strategy. FY17 work volumes were lower than those consistent with the new vegetation strategy that we intend to adopt at the beginning of the customised price-path.

[5] Commerce Commission's issues register for electricity and gas information disclosure 30 June 2016. Issue #28

[6] Commerce Commission's issues register for electricity and gas information disclosure 30 June 2016. Issue #440

Transformer capacity (schedule 9e)

Distribution transformer capacity

The disclosed Powerco owned distribution transformer capacity includes transformers that are recorded in the GIS as network connected. In accordance with Powerco's operational approach to ownership, transformers with no clear owner (where the GIS ownership field is null or unknown) are included as Powerco owned for disclosure purposes.

Assumptions have been made for operational distribution substations where installed capacity is not known.

Zone substation transformer capacity

Powerco owns transformers provided by various suppliers with ratings calculated at varying temperatures. The capacity reported in the information disclosure uses a standardised rating for continuous operation at 20^{o}C.

Amendments to formulae in the schedules

There have been no amendments to the templates provided by the Commerce Commission for the 2017 Information Disclosure.

Certificate for year-end disclosures

CERTIFICATE FOR YEAR-END DISCLOSURES

Pursuant to clause 2.9.2 of section 2.9

We, John Loughlin and Michael Bessell,

being directors of Powerco 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 Powerco Limited's accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained.

Director

Director

24th August 2017

Date

24th August 2017

Date

Deloitte.

INDEPENDENT AUDITOR'S REPORT
TO THE DIRECTORS OF POWERCO LIMITED AND THE COMMERCE COMMISSION

Report on the Disclosure Information prepared in accordance with the Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015)

We have been engaged by the Board of Directors of Powerco Limited ('the Company') to conduct a reasonable assurance engagement to provide an opinion on whether the information disclosed in Schedules 1, 2, 3, 4, 5a-5g, 6a, 6b, 7, the system average interruption duration index ('SAIDI') and system average interruption frequency index ('SAIFI') information disclosed in Schedule 10 and the explanatory notes disclosed in boxes 1 to 12 of Schedule 14 for the disclosure year ended 31 March 2017 ('the Disclosure Information'), have been prepared, in all material respects, in accordance with the Electricity Distribution Information Disclosure Determination 2012 (consolidated in 2015) ('the Determination').

Responsibilities of the Board of Directors for the Disclosure Information

The Board of Directors is responsible for the preparation of the Disclosure Information in accordance with the Determination. This responsibility includes the design, implementation and maintenance of internal control relevant to the Company's compliance with the Determination.

Auditor's responsibility

Our responsibility is to express an opinion on whether the Disclosure Information has been prepared, in all material respects, in accordance with the Determination.

We conducted our engagement in accordance with the International Standard on Assurance Engagements (New Zealand) 3000: *Assurance Engagements Other Than Audits or Reviews of Historical Financial Information* issued by the New Zealand Auditing and Assurance Standards Board and the Standard on Assurance Engagements 3100: *Compliance Engagements* issued by the External Reporting Board, to provide reasonable assurance that the Company has complied with the Determination. Our procedures included:

- reviewing the methodologies used in preparing the Disclosure Information and confirming that they are in accordance with the requirements set out in the Determination;
- identifying key inputs to the information;
- ensuring the information used in preparing the Disclosure Information has been properly extracted from the Company's accounting and other records, sourced from its financial and non-financial systems; and
- ensuring the calculations are mathematically correct.

These procedures have been undertaken to form an opinion as to whether the Disclosure Information has been prepared, in all material respects, in accordance with the Determination for the disclosure year ended 31 March 2017.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Inherent limitations

Because of the inherent limitations in internal control systems, it is possible that fraud, error or non-compliance may occur and not be detected. As the procedures performed for this engagement are not performed continuously throughout the disclosure year ended 31 March 2017 and the procedures performed in respect of the Company's compliance with the Determination in preparing the Disclosure Information are undertaken on a test basis, our assurance engagement cannot be relied on to detect all instances where the Company may not have complied with the Determination.

Our opinion has been formed on the above basis.

Deloitte.

Our Independence and Quality Control

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

Other than in our capacity as auditor and the provision of other assurance services in the audit of regulatory disclosure statements and trustee reporting, we have no relationship with or interests in the Company or any of its subsidiaries. These services have not impaired our independence as auditor of the Company.

The firm applies Professional and Ethical Standard 3 (Amended): *Quality Control for Firms that Perform Audits and Reviews of Financial Statements, and Other Assurance Engagements* issued by the New Zealand Auditing and Assurance Standards Board, 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.

Use of report

This report is provided solely for your exclusive use and solely for the purpose of providing you with independent audit assurance whether the Disclosure Information has been prepared, in all material respects, in accordance with the Determination. Our report is not to be used for any other purpose. We accept or assume no duty, responsibility or liability to any other party in connection with the report or this engagement, including without limitation, liability for negligence in relation to the opinion expressed in this report.

Opinion

This opinion has been formed on the basis of, and is subject to, the inherent limitations outlined elsewhere in this independent assurance report.

In our opinion:

- As far as appears from an examination of them, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the Company;
- As far as appears from an examination of the records, 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; and
- The Company has complied with the Determination, in all material respects, in preparing the Disclosure Information.

In forming our opinion we have obtained sufficient recorded evidence and all the explanations we have required.

Deloitte Limited

Chartered Accountants
24 August 2017
Wellington, New Zealand