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EA NETWORKS ASSET MANAGEMENT PLAN UPDATE 2017-27

ASSET MANAGEMENT PLAN UPDATE
FOR EA NETWORKS' ELECTRICITY NETWORK

Planning Period:	1 April 2017 to 31 March 2027
Disclosure Year:	2017-18
Disclosure Date:	31 March 2017
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As of November 2012, EA Networks is the trading name of Electricity Ashburton Limited. References to EA Networks in this document denote Electricity Ashburton Limited.

The owner and custodian of this document is the Network Division of EA Networks, Ashburton. All comments, queries and suggestions should be forwarded to the Network Manager.

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ASSET MANAGEMENT PLAN UPDATE

1 Scope of this Document

In particular disclosure years, the Commerce Commission's Electricity Information Disclosure Determination 2012 allows a distribution lines company to prepare and disclose an Asset Management Plan Update rather than a full Asset Management Plan. The 31 March 2017 disclosure date is one of these occasions when an update is permitted. EA Networks have chosen to issue an Asset Management Plan Update for the 31 March 2017 disclosure date.

This document is the EA Networks 2017-2027 electricity network Asset Management Plan Update. It presumes that the reader has examined the EA Networks 2016-26 Asset Management Plan and it provides incremental information from that plan.

The layout of the document headings follow clause 2.6.4 of the Disclosure Determination.

2 Changes to Network Development Plans

Subtransmission System

The previous AMP/disclosure forecast that the Montalto 66kV zone substation would be built in the 2021-22 financial year. A lack of anticipated load growth in the Montalto area has postponed the need for this development and it has been rescheduled for the 2023-2024 financial year. As a consequence of this delay, the final stages of the associated Mt Somers to Montalto 66kV line have been delayed until 2022-23. The subsequent security project which provided a second 66kV line to Montalto 66kV zone substation has also been delayed by two years and is now proposed to start in 2024 and finish in 2026.

The delay in Montalto 66kV Zone Substation construction had been anticipated but continuing prospects of gravity pressurised piped irrigation development which could not only postpone additional load but remove existing load, have made the situation quite dynamic. Additional nutrient discharge restrictions by ECAN have effectively suppressed irrigation development in the area.

The current Montalto 33kV substation is small and one or two additional large pumps could put it under pressure. In addition to irrigation load, there had been interest in utilising the existing irrigation race for generation and this would have necessitated Montalto 66kV Zone Substation for full development. This proposal has now been superseded by another proposal to build a 30,000,000m^3 water storage pond. The pond would have some prospect for hydro generation but the scale is currently unknown. When a final decision is made about piping some of the existing open race schemes and/or the pond development, one of several outcomes are likely:

(a) The pond and/or piping proceeds and no new load occurs and even reduces. Montalto 66kV Zone Substation does not proceed.

(b) The pond/piping proceeds with the need for hydro generation infeed and/or pumping. Montalto 66kV Zone Substation proceeds because of the new generation/pumping.

(c) The pond/piping does not proceed and existing load remains with additional load gradually connecting. Montalto 66kV Zone Substation proceeds at relatively long notice because of the slowly increasing irrigation loads.

The exact timetable for a storage pond and/or final gravity pressurised piping decision is not known.

The proposed 66kV line between Hackthorne and Lauriston is driven by a combination of load growth in the Methven area and additional security to Lauriston, Methven, Hackthorne and Mt Somers during 66kV line outages. Summer load has not increased in the Methven area but could still do so with at least one large-scale irrigation development still possible. It has been decided to delay the construction of the Hackthorne-Lauriston 66kV line and associated works by one to two years (now starting 2019, finishing 2020) until more certainty on additional future load is apparent.

Zone Substations

As mentioned above, the Montalto 66kV zone substation has been rescheduled for two years later than previously disclosed (now 2023-24). It is entirely possible that a further delay may occur if sufficient irrigation load does not eventuate.

The Mt Somers 33kV zone substation is adjacent to Montalto and it has also seen little load growth in the last year. As a consequence, it has been decided to delay the conversion of Mt Somers to 66kV operation by one year (now 2019-20).

The addition of a third 220/66kV transformer at the Transpower Ashburton GXP, has caused EA Networks' ripple injection facilities to provide close to the minimum acceptable signal level. The replacement of at least one ripple injection plant had been scheduled for the 2016-17 financial year to improve signal levels. With the prospect of demand control no longer being incentivised by Transpower's pricing, the decision has been made to delay the ripple plant replacement until 2020-21. The postponement allows time to continue research into viable alternatives to ripple technology as well as reducing the risk of asset stranding. The existing 33kV ripple plant has been scheduled for replacement in 2026. This plant would be a standby for the new 66kV plant should that be installed.

Distribution Network

The delay in Montalto zone substation (see above) causes downstream delays in two distribution projects. The first is the additional overhead and underground 22kV network needed to integrate the Montalto 66kV zone substation into the distribution network. The second is the conversion of the Montalto Hydro station to 22kV (from 33kV) as the 33kV circuit connecting it will be converted to 66kV. Both of these projects have been postponed by two years to coincide with Montalto zone substation construction.

The urban underground conversion programme has now been fully documented (project by project) by ranking pole condition assessments to determine appropriate project timing. The plan now contains projects that should remove every urban distribution (11kV or LV) power pole before 2027. These projects replace an assessed generic programme of underground conversion work.

The rural 11kV to 22kV conversion programme has now been documented to cover the entire planning period and, by 2027, very little rural 11kV network should remain. These projects replace an assessed generic programme of 11kV to 22kV conversion work.

The overhead distribution line rebuilding programme now has three years of specific projects documented based upon pole condition inspections. Data has been captured for additional years but has yet to be fully assessed for inclusion as specific projects. This will occur in future plans. The effect of this is to reduce the large unscheduled Replacement and Renewal programme for the first three years.

The Ashburton township core 11kV network programme has been documented generically based upon an assessment of expected resource demand and timing. Future plans will provide a sequence of specific projects. The core 11kV network programme aims to significantly increase capacity and reduce the count of consumers per urban 11kV feeder.

Proposed Rural Ring Main Unit (RMU) installations have now been individually identified and it is anticipated that within five years the programme will reduce to a much lower level.

Other Project and Programmes

A New Technology Contingency programme has been introduced which incorporates previously documented projects that were associated with either solar PV, grid-connected batteries, electric vehicle charging, or general contingencies for unknown assets. The total expenditure is similar to the discrete projects. The programme starts in 2022 and is shown until the end of the planning period. In a future plan specific projects will be created to identify the work.

A programme to cover Distribution Automation has been introduced to formalise the myriad of small projects that achieved this in previous plans. This retrospective automation programme runs from 2018 to 2025. By 2025 it is anticipated that most devices that can be remote controlled will be. When appropriate, new equipment will be automated as part of the project creating the asset.

The current SCADA system is adequate for the moment, but it is foreseen that it will be replaced at some stage within the next few years. The SCADA replacement project has been delayed by one year and now is scheduled for 2020.

3 Changes to Lifecycle Asset Management Plans

There have been no material changes to the methodologies applied to lifecycle management plans during the last year.

The identification of specific projects to replace end of life overhead lines (with either rebuilt overhead lines or underground cables) has provided a clearer picture of future expenditure and resource requirements.

The imminent introduction of a new work order management / asset management system will introduce new processes surrounding asset lifecycles.

4 Reasons for Material Changes to Disclosure Schedules 11a and 11b

There are only minor changes to the disclosure schedules which are generally caused by delays in projects caused by lower than expected load growth.

Forecast Capital Expenditure – Schedule 11a

In general, the forecast overall capital expenditure is similar to the previous disclosure.

The previous plan had several contingency projects in the latter half of the planning period as well as two new technology contingency projects. This caused a rather variable cash-flow year by year. This plan has taken the value of those projects and created a programme of work that spans the same period. This approach has changed the previously variable yearly values by providing the same yearly amount. Overall, the total value is the same.

The period 2018 to 2026 has forecasts which are contained in the previous plan and this plan. The total variation over this period is about +$15M out of a total of about $140M over nine years. This represents approximately +11%. There are several reasons for this variation:

(a) Overhead lines have now been individually assessed based upon pole inspection data for the first three years of the plan. The level of overhead line rebuilding during these three years is higher than previously estimated. The previously estimated levels of expenditure have been retained for the remainder for the planning period. This has added about $4.5M to the plan.

(b) A distribution automation programme has been introduced to capture a raft of minor projects that were previously being introduced each year. This programme has added approximately $2.8M to the plan.

(c) Some project costs have been reassessed and this has caused a small increase in costs.

(d) Some project work from 2016-17 has been delayed and approximately $2.2M has been allowed for in the 2017-18 year.

(e) A number of smaller new projects have been identified and collectively these are of the order of $0.5M.

(f) By delaying a group of projects these have been escalated by the relevant CPI values (about 2.1% per annum). This will have added up to 4% cost to the delayed projects.

(g) $2.8M is the intrinsic increase in value caused by CPI on the sequence of work.

Forecast Operational Expenditure – Schedule 11b

The overall operational expenditure is broadly in line with the previous disclosure. The future forecasts beyond the coming year show a rise in both categories of Non-Network expenditure which then plateau towards the end of the forecast period. This is a consequence of additional staff being employed to accommodate the workload, health and safety compliance, and succession planning (about half of the employees are over 50).

The AMP forecast has been prepared using ACAM. It is possible that the capital investment program may decrease slightly when the numbers are restated next year to take into account the removal of ACAM as a cost allocation method.

5 Changes to Asset Management Practices

There have been no material changes to asset management practices during the last year that would affect the disclosure of Schedule 13 contents.

As mentioned in section 3 above, a new work order management / asset management system is to be introduced during the coming year. In all likelihood, this system will change some of the methodologies used to manage the electricity assets. A future AMP will detail any changes that are introduced.

6 Disclosure Schedules 11a, 11b, 12a, 12b, 12c, 12d, 14a and 17

EA Networks have chosen not to disclose Schedule 13 as is permitted in the Disclosure Determination.

The disclosed schedules have been completed as at 31 January 2017 and, where necessary, forecasted/ scaled to reflect the full 2016-17 disclosure year.

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2017 – 31 March 2027**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8		for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10		Consumer connection	2,547	2,990	2,955	2,961	3,008	3,088	3,135	3,510	3,367	3,422	3,570
11		System growth	7,539	3,312	7,910	5,851	4,017	4,258	5,896	7,955	4,894	4,974	5,791
12		Asset replacement and renewal	5,541	10,399	7,457	7,608	7,308	7,638	7,459	5,083	1,999	2,031	2,119
13		Asset relocations	38	-	-	55	-	-	-	-	-	-	-
14		Reliability, safety and environment:											
15		Quality of supply	3,938	2,254	1,687	3,107	1,802	378	384	393	2,479	3,175	82
16		Legislative and regulatory	26	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	67	549	74	62	83	85	86	96	101	66	69
18		**Total reliability, safety and environment**	4,031	2,803	1,760	3,170	1,885	462	469	489	2,580	3,241	151
19		**Expenditure on network assets**	19,696	19,503	20,082	19,646	16,218	15,446	16,959	17,037	12,840	13,669	11,632
20		Expenditure on non-network assets	1,325	2,129	1,170	1,135	1,191	1,183	1,153	1,177	1,236	1,227	1,253
21		**Expenditure on assets**	21,021	21,632	21,252	20,781	17,409	16,630	18,111	18,214	14,076	14,896	12,884
22													
23	*plus*	Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less*	Value of capital contributions	860	770	657	733	732	825	831	849	867	885	903
25	*plus*	Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26													
27		**Capital expenditure forecast**	20,161	20,862	20,596	20,048	16,677	15,805	17,280	17,365	13,210	14,011	11,981
28													
29		Assets commissioned	20,161	20,862	20,596	20,048	16,677	15,805	17,280	17,365	13,210	14,011	11,981

30			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31		for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
32			**$000 (in constant prices)**										
33		Consumer connection	2,547	2,990	2,894	2,844	2,829	2,845	2,828	3,102	2,914	2,901	2,964
34		System growth	7,539	3,312	7,748	5,618	3,777	3,922	5,319	7,029	4,236	4,216	4,808
35		Asset replacement and renewal	5,541	10,399	7,304	7,306	6,873	7,036	6,729	4,492	1,730	1,722	1,759
36		Asset relocations	38	-	-	53	-	-	-	-	-	-	-
37		Reliability, safety and environment:											
38		Quality of supply	3,938	2,254	1,652	2,984	1,695	348	346	347	2,145	2,691	68
39		Legislative and regulatory	26	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	67	549	72	60	78	78	77	85	87	56	57
41		**Total reliability, safety and environment**	4,031	2,803	1,724	3,044	1,773	426	423	432	2,233	2,747	125
42		**Expenditure on network assets**	19,696	19,503	19,669	18,864	15,252	14,228	15,300	15,054	11,112	11,586	9,657
43		Expenditure on non-network assets	1,325	2,129	1,146	1,090	1,120	1,090	1,040	1,040	1,070	1,040	1,040
44		**Expenditure on assets**	21,021	21,632	20,815	19,954	16,372	15,318	16,340	16,094	12,182	12,626	10,697
45													
46	**Subcomponents of expenditure on assets (where known)**												
47		Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
48		Overhead to underground conversion	3,821	9,446	4,811	4,358	4,616	4,152	3,766	2,811	-	-	-
49		Research and development	-	-	-	-	-	-	-	-	-	-	-
50													

51			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
52		for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
53	**Difference between nominal and constant price forecasts**		**$000**										
54		Consumer connection	-	-	61	118	179	244	307	408	453	521	606
55		System growth	-	-	163	233	239	336	577	926	658	758	983
56		Asset replacement and renewal	-	-	153	303	435	602	730	592	269	309	360
57		Asset relocations	-	-	-	2	-	-	-	-	-	-	-
58		Reliability, safety and environment:											
59		Quality of supply	-	-	35	124	107	30	38	46	334	484	14
60		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61		Other reliability, safety and environment	-	-	2	2	5	7	8	11	14	10	12
62		**Total reliability, safety and environment**	-	-	36	126	112	36	46	57	347	494	26
63		**Expenditure on network assets**	-	-	413	781	965	1,218	1,659	1,983	1,728	2,082	1,975
64		Expenditure on non-network assets	-	-	24	45	71	93	113	137	166	187	213
65		**Expenditure on assets**	-	-	437	827	1,036	1,312	1,772	2,120	1,894	2,269	2,187
66													

67			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
		for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
68	**11a(ii): Consumer Connection**							
69		*Consumer types defined by EDB**	**$000 (in constant prices)**					
70		Urban LV	243	330	288	283	282	283
		Urban Transformer	39	99	97	96	95	96
		Urban Alteration for Safety	-	-	-	-	-	-
		Urban Capacity Alteration	-	6	6	6	6	6
		Rural LV	314	215	210	206	205	207
71		Rural Transformer	1,261	1,380	1,352	1,328	1,321	1,329
72		Rural Alteration for Safety	316	917	898	883	878	883
73		Rural Capacity Alteration	-	43	43	42	42	42
74		Other	373	-	-	-	-	-
75		**include additional rows if needed*						
76		**Consumer connection expenditure**	2,547	2,990	2,894	2,844	2,829	2,845
77	*less*	Capital contributions funding consumer connection	539	550	550	550	560	560
78		**Consumer connection less capital contributions**	2,009	2,440	2,344	2,294	2,269	2,285
79	**11a(iii): System Growth**							
80		Subtransmission	22	-	3,187	1,642	-	-
81		Zone substations	4,732	962	1,716	2,396	951	351
82		Distribution and LV lines	216	389	848	424	367	158
83		Distribution and LV cables	1,114	91	774	487	568	1,217
84		Distribution substations and transformers	1,423	380	1,114	17	1,852	1,590
85		Distribution switchgear	32	1,357	63	4	40	312
86		Other network assets	-	132	45	648	-	293
87		**System growth expenditure**	7,539	3,312	7,748	5,618	3,777	3,922
88	*less*	Capital contributions funding system growth	-	-	-	-	-	-
89		**System growth less capital contributions**	7,539	3,312	7,748	5,618	3,777	3,922
90								

91			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
92		for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
93	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
94		Subtransmission	554	3,221	-	-	990	934
95		Zone substations	480	20	-	-	-	-
96		Distribution and LV lines	1,756	2,492	2,957	2,930	1,248	1,243
97		Distribution and LV cables	1,414	3,934	3,807	3,450	3,630	3,773
98		Distribution substations and transformers	1,178	511	350	553	721	802
99		Distribution switchgear	86	214	189	372	284	284
100		Other network assets	72	6	-	-	-	-
101		**Asset replacement and renewal expenditure**	5,541	10,399	7,304	7,306	6,873	7,036
102	*less*	Capital contributions funding asset replacement and renewal	312	220	93	101	128	200
103		**Asset replacement and renewal less capital contributions**	5,229	10,179	7,211	7,205	6,745	6,836
104								

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2017 – 31 March 2027**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
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sch ref

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
107	**11a(v):Asset Relocations**						
108	*Project or programme**	**$000 (in constant prices)**					
109	11kV UG New - SH1 & Walnut Ave intersection re-design	-	-	-	53	-	-
110	NZTA Streetlights	4	-	-	-	-	-
111	Unplanned Relocation Requested by Customer	33	-	-	-	-	-
112		-	-	-	-	-	-
113		-	-	-	-	-	-
114	*include additional rows if needed*						
115	All other project or programmes - asset relocations	-	-	-	-	-	-
116	**Asset relocations expenditure**	38	-	-	53	-	-
117	*less* Capital contributions funding asset relocations	-	-	-	53	-	-
118	**Asset relocations less capital contributions**	38	-	-	-	-	-
119							

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
122	**11a(vi):Quality of Supply**						
123	*Project or programme**	**$000 (in constant prices)**					
124	SCADA - Distribution Automation Programme	-	276	276	277	281	283
	11kV Network Centres - Tinwald	-	422	-	-	223	-
	66/22kV OH New - River Piles Ashburton River North Branch	-	74	-	-	-	-
	ZSS - Synchrophasors - Stage 1 and Stage 2	-	75	-	-	-	-
	ZSS - Upgrading 110Vdc Supplies	-	73	-	-	-	-
	ZSS HTH - 22kV Switchboard Extension	99	87	-	-	-	-
	22kV UG New - Tinwald ZSS, Hinds Hwy, Fords Rd Tie Cable	-	212	-	-	-	-
	11kV Network Centres - Ashburton	-	-	441	440	439	-
125	Rural Ring Main Unit Installations	1,932	860	871	550	687	-
126	Cnr	-	-	-	1,430	-	-
127	Distribution Network - Self Healing Network - Phase 1-5	-	-	-	213	-	-
	Protection Relay Upgrading	4	-	-	-	-	-
	Rakaia 22kV Security. Railway Tce to Mackie St.	299	-	-	-	-	-
	11kV-22kV Conversion Programme	131	-	-	-	-	-
	ZSS MHT - Comms and SCADA	132	-	-	-	-	-
	22kV OH New - Hepburns Rd	59	-	-	-	-	-
	22kV OH Underbuilt - Gibsons Rd & Smalls Rd	68	-	-	-	-	-
	66kV OH New - FTN66 to Company Rd	166	-	-	-	-	-
	22kV OH New - Maronan Rd	59	-	-	-	-	-
	22kV OH New - Winslow Westerfield Rd	130	-	-	-	-	-
	ZSS CRW - 2nd 66/22kV Transformer	424	-	-	-	-	-
	ZSS TIN - 22/11kV Transformer & Switchgear	146	-	-	-	-	-
	22kV OH New - Rawles Crossing Rd	67	-	-	-	-	-
	Urban UG Programme	100	-	-	-	-	-
128		-	-	-	-	-	-
129	*include additional rows if needed*						
130	All other projects or programmes - quality of supply	121	175	64	74	65	65
131	**Quality of supply expenditure**	3,938	2,254	1,652	2,984	1,695	348
132	*less* Capital contributions funding quality of supply	-	-	-	-	-	-
133	**Quality of supply less capital contributions**	3,938	2,254	1,652	2,984	1,695	348
134							

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
136	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
137	**11a(vii): Legislative and Regulatory**						
138	*Project or programme**	**$000 (in constant prices)**					
139	ZSS EGN - Seal Road Frontage	26	-	-	-	-	-
140		-	-	-	-	-	-
141		-	-	-	-	-	-
142		-	-	-	-	-	-
143		-	-	-	-	-	-
144	*include additional rows if needed*						
145	All other projects or programmes - legislative and regulatory	-	-	-	-	-	-
146	**Legislative and regulatory expenditure**	26	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory	-	-	-	-	-	-
148	**Legislative and regulatory less capital contributions**	26	-	-	-	-	-
149							

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme**	**$000 (in constant prices)**					
153	ZSS - Substation Surveillance Programme	-	17	6	6	23	23
154	Earthing Upgrades	-	369	-	-	-	-
155	UG Conversion - Convert State Hwy OH crossings to UG	-	87	-	-	-	-
156	Longbeach Rd Streetlights	50	-	-	-	-	-
157		-	-	-	-	-	-
158	*include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment	17	76	66	54	55	55
160	**Other reliability, safety and environment expenditure**	67	549	72	60	78	78
161	*less* Capital contributions funding other reliability, safety and environment	10	-	-	-	-	-
162	**Other reliability, safety and environment less capital contributions**	57	549	72	60	78	78
163							

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
165	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme**	**$000 (in constant prices)**					
169	Routine Vehicles	133	299	180	180	180	180
170	Routine Building Work	-	50	50	50	50	50
171	Routine Plant	33	10	10	10	10	10
172	Routine Info Tech	148	100	100	100	100	100
173		-	-	-	-	-	-
174	*include additional rows if needed*						
175	All other projects or programmes - routine expenditure	-	50	50	50	50	50
176	**Routine expenditure**	314	509	390	390	390	390
177	**Atypical expenditure**						
178	*Project or programme**						
179	Atypical Info Tech	-	-	700	700	700	700
180	Software - ICP Management	232	320	-	-	-	-
	Software - ERP Development	413	150	-	-	-	-
	Software - Payroll Management System	122	-	-	-	-	-
	Software - Document Management System	43	105	-	-	-	-
181	Software - Data Warehouse	3	100	-	-	-	-
	Software - Outage Manager - Control Centre	-	212	-	-	-	-
	Software/Hardware - IT Field Mobility	40	70	-	-	-	-
182	Power Transformer Test Equipment	-	90	-	-	-	-
	ZSS MVN - Backup Control Room	16	107	-	-	-	-
	DMR Repeater Stations for Rakaia Gorge	-	60	-	-	-	-
	EV Charging Solution	74	-	-	-	-	-
	Building Work (Office and Stores)	63	-	-	-	-	-
183	Hardware (IT) - New and Upgraded	-	125	-	-	-	-
184	*include additional rows if needed*						
185	All other projects or programmes - atypical expenditure	6	281	56	-	30	-
186	**Atypical expenditure**	1,011	1,620	756	700	730	700
187							
188	**Expenditure on non-network assets**	1,325	2,129	1,146	1,090	1,120	1,090

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2017 – 31 March 2027**

SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
7		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	629	847	867	886	907	929	951	973	996	1,019	1,043
11	Vegetation management	595	611	625	639	655	670	686	702	718	735	753
12	Routine and corrective maintenance and inspection	834	811	830	849	869	889	910	932	954	976	999
13	Asset replacement and renewal	783	846	866	885	906	928	950	972	995	1,018	1,042
14	**Network Opex**	2,841	3,115	3,188	3,260	3,337	3,416	3,496	3,578	3,663	3,749	3,837
15	System operations and network support	3,156	3,424	3,505	3,584	3,668	3,755	3,843	3,934	4,026	4,121	4,218
16	Business support	4,264	5,188	5,310	5,430	5,558	5,689	5,823	5,960	6,101	6,244	6,391
17	**Non-network opex**	7,420	8,613	8,815	9,014	9,227	9,444	9,666	9,894	10,127	10,365	10,610
18	**Operational expenditure**	10,261	11,728	12,004	12,275	12,564	12,859	13,162	13,472	13,790	14,114	14,447

sch ref												
19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	629	847	849	851	853	856	858	860	862	864	866
23	Vegetation management	595	611	613	614	616	617	619	620	622	623	625
24	Routine and corrective maintenance and inspection	834	811	813	815	817	819	821	823	825	827	829
25	Asset replacement and renewal	783	846	848	850	852	854	857	859	861	863	865
26	**Network Opex**	2,841	3,115	3,123	3,131	3,138	3,146	3,154	3,162	3,170	3,178	3,186
27	System operations and network support	3,156	3,424	3,433	3,441	3,450	3,459	3,467	3,476	3,485	3,493	3,502
28	Business support	4,264	5,188	5,201	5,214	5,227	5,240	5,253	5,267	5,280	5,293	5,306
29	**Non-network opex**	7,420	8,613	8,634	8,656	8,677	8,699	8,721	8,743	8,764	8,786	8,808
30	**Operational expenditure**	10,261	11,728	11,757	11,786	11,816	11,845	11,875	11,905	11,934	11,964	11,994

sch ref												
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses	-	-	-	-	-	-	-	-	-	-	-
34	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
35	Research and Development	-	-	-	-	-	-	-	-	-	-	-
36	Insurance	-	-	-	-	-	-	-	-	-	-	-
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												

sch ref												
39		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	18	35	54	73	93	113	134	155	177
43	Vegetation management	-	-	13	25	39	53	67	82	97	112	128
44	Routine and corrective maintenance and inspection	-	-	17	34	52	70	89	108	128	149	170
45	Asset replacement and renewal	-	-	18	35	54	73	93	113	134	155	177
46	**Network Opex**	-	-	66	130	199	269	342	416	493	571	651
47	System operations and network support	-	-	72	143	218	296	376	458	542	628	716
48	Business support	-	-	109	216	331	449	570	694	821	951	1,085
49	**Non-network opex**	-	-	181	359	549	745	945	1,151	1,363	1,579	1,801
50	**Operational expenditure**	-	-	247	488	748	1,014	1,287	1,568	1,855	2,150	2,453

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2017 – 31 March 2027**

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

sch ref	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
7					**Asset condition at start of planning period (percentage of units by grade)**						
8											
9	**Voltage**	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	No.	2.49%	8.75%	76.89%	11.88%	-	2	6.86%
11	All	Overhead Line	Wood poles	No.	6.37%	4.52%	37.20%	51.91%	-	2	8.63%
12	All	Overhead Line	Other pole types	No.	-	-	-	100.00%	-	2	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	0.65%	2.62%	21.85%	74.88%	-	3	1.96%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	66.22%	33.78%	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-	N/A	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	N/A	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-	N/A	-
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.	-	-	4.55%	95.45%	-	2	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	N/A	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	65.00%	5.00%	30.00%	-	-	2	67.50%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	11.43%	8.57%	74.29%	5.71%	-	3	15.71%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	N/A	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	100.00%	-	2	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	6.47%	17.99%	75.54%	-	2	3.24%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	N/A	-
35											
36					**Asset condition at start of planning period (percentage of units by grade)**						
37											
38	**Voltage**	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	3.13%	9.38%	12.50%	75.00%	-	3	7.81%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3.82%	4.28%	40.42%	51.48%	-	3	5.96%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	N/A	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.23%	0.58%	22.70%	76.49%	-	3	0.52%
44	HV	Distribution Cable	Distribution UG PILC	km	4.66%	62.59%	32.74%	-	-	1	35.96%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	N/A	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	13.33%	10.00%	36.67%	40.00%	-	2	18.33%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	-	N/A	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2.49%	1.98%	12.23%	83.30%	-	2	3.49%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	N/A	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	0.43%	4.08%	29.83%	65.67%	-	3	2.47%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	9.50%	11.94%	19.89%	58.66%	-	3	15.47%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	4.57%	6.11%	15.99%	73.33%	-	3	7.62%
53	HV	Distribution Transformer	Voltage regulators	No.	-	100.00%	-	-	-	3	50.00%
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	0.43%	4.08%	29.83%	65.67%	-	2	2.47%
55	LV	LV Line	LV OH Conductor	km	31.02%	10.34%	41.39%	17.25%	-	3	36.19%
56	LV	LV Cable	LV UG Cable	km	1.59%	5.06%	35.50%	57.85%	-	3	4.12%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	2.31%	5.06%	38.22%	54.41%	-	2	4.84%
58	LV	Connections	OH/UG consumer service connections	No.	-	33.33%	33.33%	33.34%	-	3	16.67%
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	6.67%	13.33%	80.00%	-	2	3.33%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	100.00%	-	3	-
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	N/A	-
62	All	Load Control	Centralised plant	Lot	66.67%	33.33%	-	-	-	3	83.33%
63	All	Load Control	Relays	No.	-	-	-	-	100.00%	1	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	N/A	-

Company Name **Electricity Ashburton Limited**
AMP Planning Period **1 April 2017 – 31 March 2027**

SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
8										
9	Ashburton 33/11kV [ASH]	25	20	N-1 Switched	28	125%	-	-	No constraint within +5 years	Firm capacity limit is N-1 transformer capacity limit. 20 MVA hot stand-by available from ASH 66/11kV substation. Additional 11kV cables in Ashburton will increase fast transfer capacity from NTN.
10	Ashburton 66/11kV [ASH]	-	-	N-1 Switched	28	-	20	94%	No constraint within +5 years	Does not normally serve load. Within 2 years the ASH 33/11kV substation will be the ASH 66/11 kV substation. All load will be served from the 66kV network. A combination of a second 66/11kV transformer, steady state load transfer to NTN, and additional fast transfer switched capacity will ensure acceptable security.
11	Carew 66/22kV [CRW]	15	20	N-1	9	75%	20	64%	No constraint within +5 years	Second transformer is one of two system spares and provides 100% firm capacity. Transfer capacity increases with additional 22kV conversion.
12	Coldstream 66/22kV [CSM]	13	-	N	9	-	-	-	Transformer	Second Carew transformer provides an increase in transfer capacity. Future additional 22kV lines increases transfer capacity.
13	Dorie 66/22kV [DOR]	11	-	N	9	-	-	-	Transformer	Pendarves and a Overdale substations offer close to 100% of firm capacity via transfer on 22kV distribution network.
14	Eiffelton 66/11kV [EFN]	9	-	N	4	-	-	-	Transformer	Transfer capacity increases significantly with additional 22kV conversion. When operating at 66/22kV all load should be able to be backfed.
15	Fairton 33/11kV [FTN]	3	10	N-1 Switched	6	30%	-	-	No constraint within +5 years	Substation provides 100% firm capacity. 33/11kV substation to be decommissioned within 2 years. New 66/11-22kV substation replacing 33/11kV site. Significant switched transfer capacity from adjacent sites at 11kV and 22kV. 10 MVA of N-1 capacity limited by 22/11kV transformer.
16	Fairton 66/22/11kV [FTN]	4	20	N-1 Switched	11	20%	20	50%	No constraint within +5 years	New substation (2017) with 1x20MVA 66/22kV, 1x20MVA 66/11kV and 1x8MVA 22/11kV transformers. Station firm capacity is enhanced by adjacent switched transfer capacity at 22kV and 11kV.
17	Hackthorne 66/22kV [HTH]	15	-	N	9	-	-	-	Transformer	Second Carew transformer along with additional 22kV conversion provides extra transfer capacity. Future 66kV MSM and MON also significantly increase transfer capacity.
18	Highbank 66/11kV [HBK]	8	-	N	-	-	-	-	Subtransmission circuit	By agreement, EA Networks provide N 66kV subtransmission security.
19	Lagmhor 66/22kV [LGM]	7	-	N	6	-	-	-	Transformer	22kV transfer capacity increases with additional 22kV conversion, new 22kV lines, and Tinwald 11/22kV, 8MVA transformer.
20	Lauriston 66/22kV [LSN]	15	-	N	7	-	-	-	Transformer	OVD transformer, FTN commissioning, and MTV 22kV supply capability.
21	Methven 33/11kV [MVN]	-	-	N	4	-	-	-	No constraint within +5 years	Load transferred to Methven 66/11kV substation in 2016. Acting as hot standby for Methven 11kV load until 2020.
22	Methven 66/22/11kV [MTV]	5	-	N	4	-	-	-	Transformer	22/11kV transformer provides significant backfeed from LSN. 66/22kV, 66/11kV & 22/11kV transformers will provide 100% transfer capacity in 2020.
23	Methven 66/33kV [MTV]	5	-	N	5	-	-	-	No constraint within +5 years	Existing 33 load is converted to 66/11kV or 66/22kV alleviating constraint (2020).
24	Mt Somers 33/11kV [MSM]	3	-	N	3	-	-	-	Transformer	Additional conversion of surrounding distribution network to 22kV permits adequate switched transfer capacity. After conversion to 66/22kV (2019), two 66kV circuits provide N-1 subtransmission security (currently N subtransmission security).
25	Mt Hutt 33/11kV [MHT]	2	-	N	2	-	-	-	Transformer	Considered adequate. 33kV and 11kV lines share common poles. Possible 22kV conversion would increase switched transfer capacity.
26	Montalto 33/11kV [MON]	2	-	N	1	-	-	-	Transformer	Possible conversion to 66/22kV and surrounding distribution network 22kV conversion increases transfer capacity in 2022. May be N subtransmission security for some time.
	Northtown 66/11kV [NTN]	11	20	N-1	8	55%	20	93%	No constraint within +5 years	Currently seasonally constrained by subtransmission network. Fully resolved in 2019 with additional 66kV circuit. Additional 11kV cables in Ashburton increase fast transfer capacity from ASH.
	Overdale 66/22kV [OVD]	14	-	N	10	-	-	-	Transformer	adjacent substations ([PDS] & [LSN]) and increases further with additional 22kV conversion and Fairton 66/22kV construction (2016).
	Pendarves 66/22kV [PDS]	16	20	N-1	28	80%	20	80%	No constraint within +5 years	Firm capacity limit is N-1 transformer capacity limit. Second transformer is one of two system spares.
	Seafield 33/11kV [SFD33]	8	-	N-1 Switched	10	-	-	-	Transformer	A second transformer would provide 100% firm capacity. Negotiated security with sole industrial customer. In 2019 this substation will be decommissioned.
27	Seafield 66/11kV [SFD66]	8	-	N-1 Switched	10	-	-	-	Transformer	A second transformer would provide 100% firm capacity. Negotiated security with sole industrial customer. Remote-controlled change-over between 33/11kV and 66/11kV substations.
28	Wakanui 66/22kV [WNU]	13	-	N	10	-	-	-	Transformer	Elgin's 66/33kV transformer conversion to 66/22kV (2019) increases 22kV transfer capacity significantly.

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2017 – 31 March 2027**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

7 12c(i): Consumer Connections

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
8	*Number of ICPs connected in year by consumer type*		**Number of connections**					
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
11	*Consumer types defined by EDB**							
12	Urban LV		171	120	115	115	115	115
	Urban Transformer		2	2	2	2	2	2
	Urban Alteration for Safety		-	-	-	-	-	-
	Urban Capacity Alteration		-	-	-	-	-	-
	Rural LV		90	45	42	42	42	42
13	Rural Transformer		67	93	90	90	90	90
14	Rural Alteration for Safety		39	65	60	55	50	50
15	Rural Capacity Alteration		27	7	7	7	7	7
16	Other		-	-	-	-	-	-
17	**Connections total**		396	332	316	311	306	306
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		29	28	27	26	25	25
21	Capacity of distributed generation installed in year (MVA)		-	-	-	-	-	-

22 12c(ii) System Demand

sch ref				Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
23				*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24		**Maximum coincident system demand (MW)**	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
25		GXP demand		162	178	180	181	182	184
26	*plus*	Distributed generation output at HV and above		2	2	2	2	2	2
27		**Maximum coincident system demand**		163	180	181	183	184	185
28	*less*	Net transfers to (from) other EDBs at HV and above		0	0	0	0	0	0
29		**Demand on system for supply to consumers' connection points**		163	180	181	182	184	185
30		**Electricity volumes carried (GWh)**							
31		Electricity supplied from GXPs		478	498	509	519	530	540
32	*less*	Electricity exports to GXPs		2	-	-	-	-	-
33	*plus*	Electricity supplied from distributed generation		114	114	114	114	114	114
34	*less*	Net electricity supplied to (from) other EDBs		(0)	(0)	(0)	(0)	(0)	(0)
35		**Electricity entering system for supply to ICPs**		591	613	623	633	644	655
36	*less*	Total energy delivered to ICPs		548	569	578	588	598	608
37		**Losses**		42	44	45	46	46	47
38									
39		**Load factor**		41%	39%	39%	40%	40%	40%
40		**Loss ratio**		7.1%	7.2%	7.2%	7.2%	7.2%	7.2%

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2017 – 31 March 2027**
Network / Sub-network Name	**Electricity Ashburton Limited**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	93.0	95.5	95.1	94.0	93.0	92.0
12	Class C (unplanned interruptions on the network)	90.0	115.5	114.3	113.2	112.9	111.5
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.35	0.37	0.35	0.34	0.33	0.32
15	Class C (unplanned interruptions on the network)	1.21	1.25	1.24	1.23	1.22	1.21

Schedule 14a Mandatory Explanatory Notes on Forecast Information

1. This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.5.

2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

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

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

The difference is 0.0%. Costs have been prepared using 2017-18 values for labour, plant and materials. Years after 2017-18 have been escalated by the 2018 CPI Forecast by the New Zealand Government Treasury published on 8th December 2016. (http://www.treasury.govt.nz/budget/forecasts/hyefu2016)

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

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

The difference is 0.0%. Costs have been prepared using 2017-18 values for labour, plant and materials. Years after 2017-18 have been escalated by the 2018 CPI Forecast by the New Zealand Government Treasury published on 8th December 2016. (http://www.treasury.govt.nz/budget/forecasts/hyefu2016)

EA Networks considers the answers given for 3. and 4. represent the most prudent source of information available to EA Networks for the purpose of estimating future costs. A vast range of alternative algorithms can be proposed and defended but there is no authoritative judgement upon which is the most accurate and reliable. EA Networks do not have sufficient internal expertise to promote any particular theory or speculate on how future costs will trend. It is the opinion of EA Networks that the Treasury's CPI forecast is a reasonable indicator of future cost as it incorprates a range of factors that could influence the future cost of expenditure on the electricity network. Even with additional cost escalation data, EA Networks current future cost modelling is not sufficiently granular to take full advantage of the additional detail. The Treasury forecast extends to 2021. Beyond 2021, EA Networks have used the 2021 CPI value (2.1%) until 2027.

Schedule 17 Certification for Year-beginning Disclosures

Clause 2.9.1

We, Gary Richard Leech and Philip John McKendry being directors of Electricity Ashburton Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) the following attached information of Electricity Ashburton Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Electricity Ashburton Limited corporate vision and strategy and are documented in retained records.

Gary Richard Leech

Philip John McKendry

29 March 2017

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connecting our community