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EA NETWORKS ASSET MANAGEMENT PLAN UPDATE 2019-29

ASSET MANAGEMENT PLAN UPDATE
FOR EA NETWORKS' ELECTRICITY NETWORK

Planning Period:	1 April 2019 to 31 March 2029
Disclosure Year:	2019-20
Disclosure Date:	31 March 2019
Approved by Board:	27 February 2019

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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 2019 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 2019 disclosure date.

This document is the EA Networks 2019-2029 electricity network Asset Management Plan Update. It presumes that the reader has examined the EA Networks 2018-28 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 2024-25 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 2026-2027 financial year. The final stages of the associated Mt Somers to Montalto 66kV line have not been further delayed as the 33kV line this new line replaces is reaching the end of its useful life. The subsequent security project, which provided a second 66kV line to Montalto 66kV zone substation, has also been delayed by three years and is now proposed to start in 2028 and finish in 2029. These load-driven projects are looking less and less likely to proceed.

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 (and planned 22kV 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. The generation 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 to coincide with a second GXP (now starting 2028, finishing 2029) which provides a ring of 66kV from the new GXP. The immediate security concern about Lauriston and Overdale Zone Substations has been resolved with a short (3km) new 66kV circuit from Lauriston Zone

Substation to the Overdale-Methven 66kV line (a location now referred to as "Lauriston T"). This line will be constructed in 2019-20 and the 66kV line bay at Lauriston created in 2020-21.

The 33kV line from Elgin Zone Substation to Ashburton Zone Substation is still in the process of conversion to operate at 66kV. The key element is the urban 66kV cable being installed, and completion of this has been delayed into the 2019-20 year. This in turn has delayed the final portion of conversion of Ashburton 33/11kV substation to 66/11kV operation until 2019-20.

Zone Substations

As mentioned above, the Montalto 66kV zone substation has been rescheduled later than previously disclosed (now 2026-27). It is entirely possible that a further delay may occur if sufficient irrigation load does not eventuate.

It is intended to convert the existing Montalto 33/11kV Zone Substation to 22/11kV operation (2021) as well as converting the Montalto Hydro Power Station to 22kV (from 33kV). Over time, the surrounding 11kV distribution network will be progressively converted to 22kV. This will ultimately lead to the Montalto 22/11kV substation becoming redundant. Should the load increase sufficiently, it will trigger the development of the Montalto 66/22kV Zone Substation.

The Mt Somers 33kV zone substation will be converted to 66/22kV operation in 2019-20 as planned.

Ashburton 66/11kV Zone Substation will be completed in 2019-20 making the Ashburton 33/11kV Zone Substation redundant.

The Fairton 33/11kV Zone Substation will be dismantled in 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 reconfiguration of at least one ripple injection plant had been scheduled for the 2019-20 financial year to improve signal levels and provide some redundancy. With the prospect of demand control no longer being incentivised by Transpower's pricing, the decision has been made to remove the new 66kV ripple plant. The funds have been allocated for investment in an alternative signalling technology. Research and trials into viable alternatives to ripple technology will occur. Should the alternatives not prove to be viable, the new 66kV ripple plant could be reinstated using the same funds. 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. If an alternative signalling technology is introduced, the 33kV ripple plant replacement funds may be allocated to expand that alternative system.

Distribution Network

The delay in Montalto zone substation (see above) causes downstream delays in a distribution project - the additional overhead and underground 22kV network needed to integrate the Montalto 66kV zone substation into the distribution network. This project has been postponed by three years to coincide with Montalto zone substation construction. The conversion of the Montalto Hydro station to 22kV (from 33kV) will still proceed as planned as the 33kV circuit connecting it will be converted to 22kV.

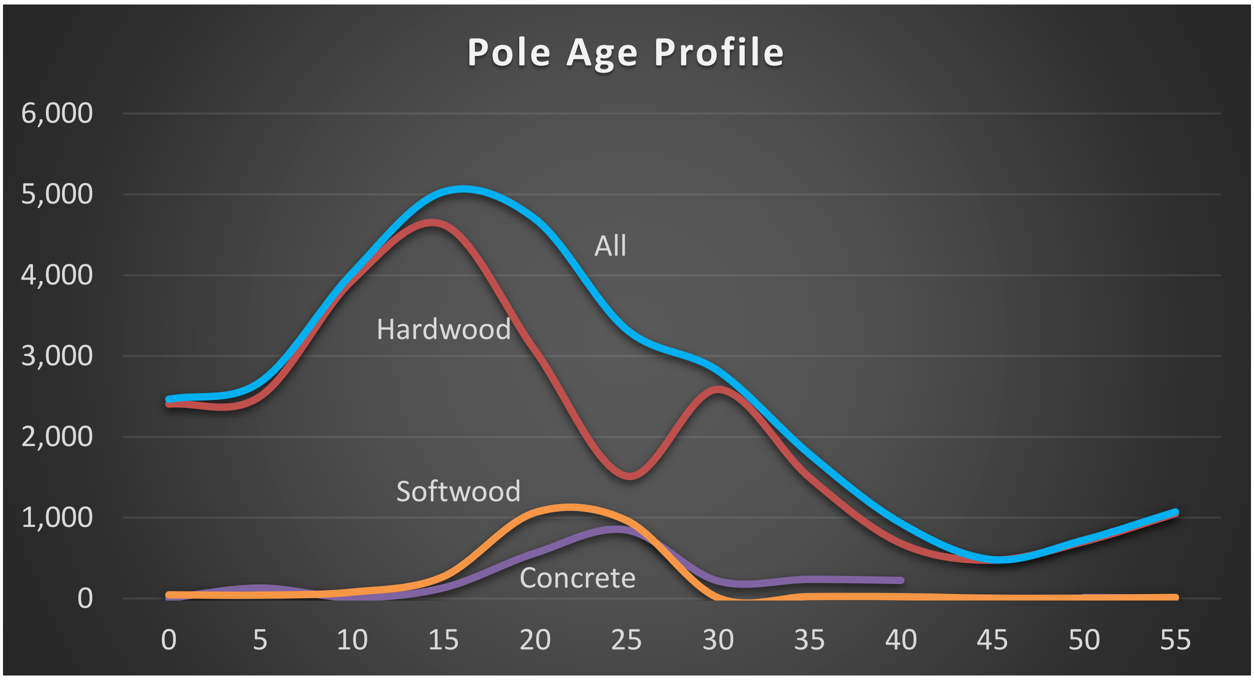
The urban underground conversion programme has now been fully documented (project by project) by ranking pole condition assessments to determine appropriate project timing. The plan now contains projects that should remove every urban distribution (11kV or LV) power pole before 2026. These projects replace an assessed generic programme of underground conversion work.

The urban underground conversion programme has been ambitious, and it has been re-examined considering both the internal and external resources available to complete the work. Each year some of the work has spilled over to the following year and this has accumulated to the point where almost two years work is planned in 2020-21. The decision has been made to push the programme completion back by one year to make it manageable. This decision does introduce the need to carefully manage the aged urban overhead line assets that the underground conversion programme replaces. Each conversion project (and the poles within it) will be carefully reassessed to determine a strict priority to minimise the risk of failure and, where that risk is seen to be too high, mitigation measures will be introduced to reduce risk to an acceptable level.

The rural 11kV to 22kV conversion programme has now been documented to cover the entire planning period and, by 2028, very little rural 11kV network should remain. The order of conversion may change as the priority for capacity and/or security is reassessed. These projects replace an assessed generic programme of 11kV to 22kV conversion work. There is no provision for the 22kV conversion programme in 2029.

The overhead distribution line rebuilding programme now has two/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.

Beyond the scheduled overhead rebuild projects, the allowance for rebuilding is fixed until 2026. It is then increased by 10% per annum until the end of the planning period as the impact of the aging pole population impacts condition-based rebuilding. The diagram below illustrates the issue (note that the poles over 50 years old are predominantly urban poles awaiting removal once underground conversion takes place).



Untreated hardwood pole lines can be expected to last between 40 and 50 years. Some of the "second growth" hardwood poles supplied during the 1980s are showing signs of premature decay. Not all poles are affected, and future pole inspections will reveal if the issue will cause a shift in rebuild cost timing. The use of concrete and treated softwood poles during the 1980s and 1990s will dampen the rebuild requirements as they have a longer life than the untreated hardwood poles. During the late 1990s and beyond the hardwood poles used were treated with preservative compounds that should increase their useful life beyond 40-50 years.

The Ashburton township core 11kV network programme has been documented to 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. The initial parts of this programme have been delayed by one year as research into switchgear and protection took longer than intended. These issues have now been resolved and the first network centres will be built in 2019-20.

Proposed Rural Ring Main Unit (RMU) installations have now been individually identified and beyond 2019-20 the programme will reduce to a much lower level.

Other Project and Programmes

The New/Smart Technology programme incorporate 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 2024 and is shown until the end of the planning period. In a future plan, specific projects will be created to identify the work.

The Distribution Automation programme formalises a myriad of small projects. This retrospective automation programme runs from 2020 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 will be replaced during 2019-20 with a much more sophisticated Distribution Management System of which SCADA is only one aspect. This new system has the potential to improve both reliability and customer responsiveness.

Corporate IT systems continue to develop, and an allowance has been made for ongoing improvements and integration.

3 Changes to Lifecycle Asset Management Plans

The introduction of a new work order management / asset management system has initiated some new processes surrounding asset lifecycles. The inspection and testing of certain assets have been scheduled in the new system and as the system matures and becomes better populated, the routine aspects of maintenance work will become more process driven.

There have been no material changes to the methodologies applied to lifecycle management plans during the last year. The previously manual process has now become more automated in some cases.

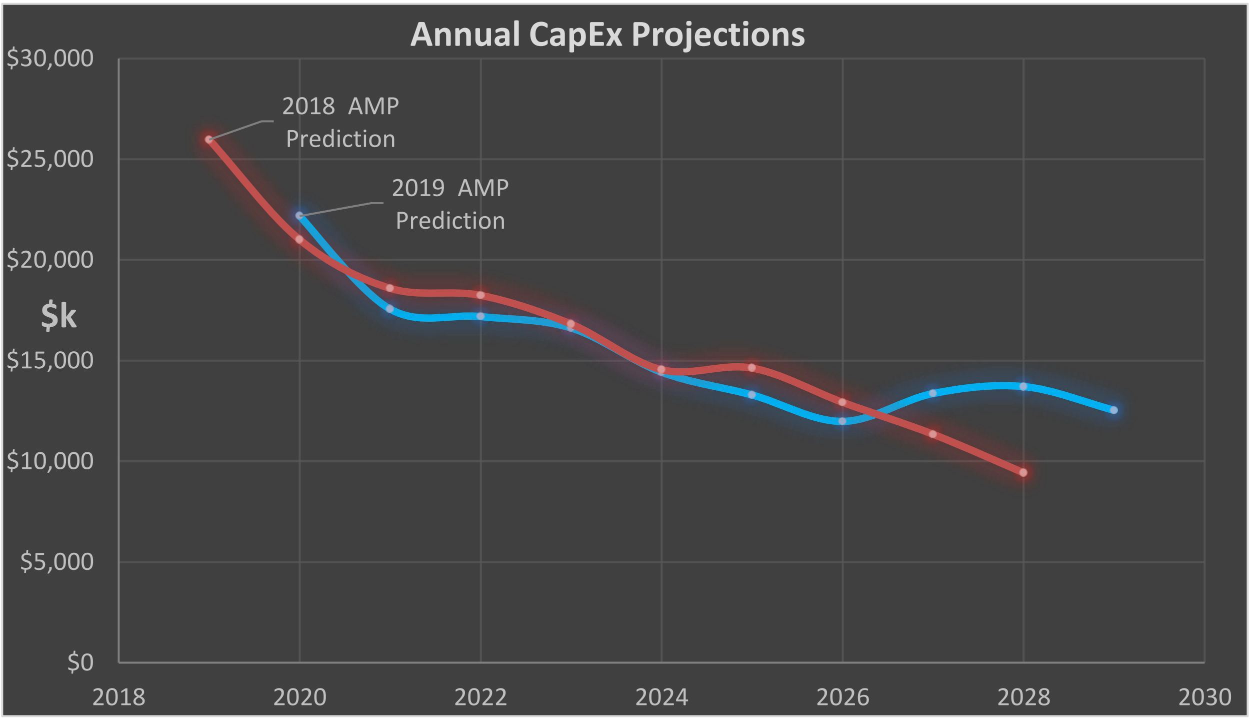
The identification of specific projects to replace end of life overhead lines (with either rebuilt overhead lines or underground cables) has provided a clearer picture of future expenditure and resource requirements. This assessment work will continue to expand and gather condition data over time.

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 for the same year.



Note that the costs are shown in 2019-20 dollars and include capitalised labour.

The graph shows that the expenditure predicted in the 2019-20 plan is close to the 2018-19 plan for the 2020-26 period. The key difference is at the end of the planning period (2027-29). The tail-end difference is caused by several factors:

- The 2018-19 year is likely to have some carry-over into the 2019-20 year. This could be up to $7M.
- For various reasons, a number of projects have been postponed from the 2019-20 and 2020-21 years to the middle of the planning period and this has lessened the impact of carry-overs on the 2019-20 year expenditure.
- Several projects have been postponed from the middle of the planning period until later in the planning period. These are all displaced due to uncertainty in them proceeding or lower than anticipated load growth.
- An increase in unscheduled overhead line rebuild costs has been introduced late in the planning period to allow for the pole age profile.
- The net effect is a shift/increase in expenditure towards the end of the planning period when compared to the previous plan.

The 10-year planning periods covered by the 2018-28 and 2019-29 plans have capital expenditure forecasts in them. A comparison of the forecasts shows the following:

Years	2018-28 Plan	2019-29 Plan
2019-29 (10y)	163.5M	152.8M
2020-28 (8y)	137.5M	140.3M

The overall (10y) comparison shows that, as predicted, the cumulative forecast is decreasing and will continue to do so.

The overlapping period (8y) has a variation between the two plans of about +$2.8M out of a total of about $140M. This represents approximately +2%. There are a few reasons for this variation:

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

(b) Some project work from 2018-19 has been delayed and a portion of this has been allowed for in the 2019-20 year.

Schedule 11a(iii) ~ System Growth ~ Distribution and LV Cables (sch ref [83]) is a small negative amount for the 2018-19 end-of-year assessment. This is the result of a minor allocation correction from the previous year and it is expected that this will become net positive after the final end-of-year costs have been collected.

Forecast Operational Expenditure – Schedule 11b

The overall operational expenditure forecast has increased markedly for 2019-20 and stays above the previous forecast for the whole planning period. The future forecasts show a step rise in both categories of Non-Network expenditure which then plateau or slightly decrease towards the end of the forecast period.

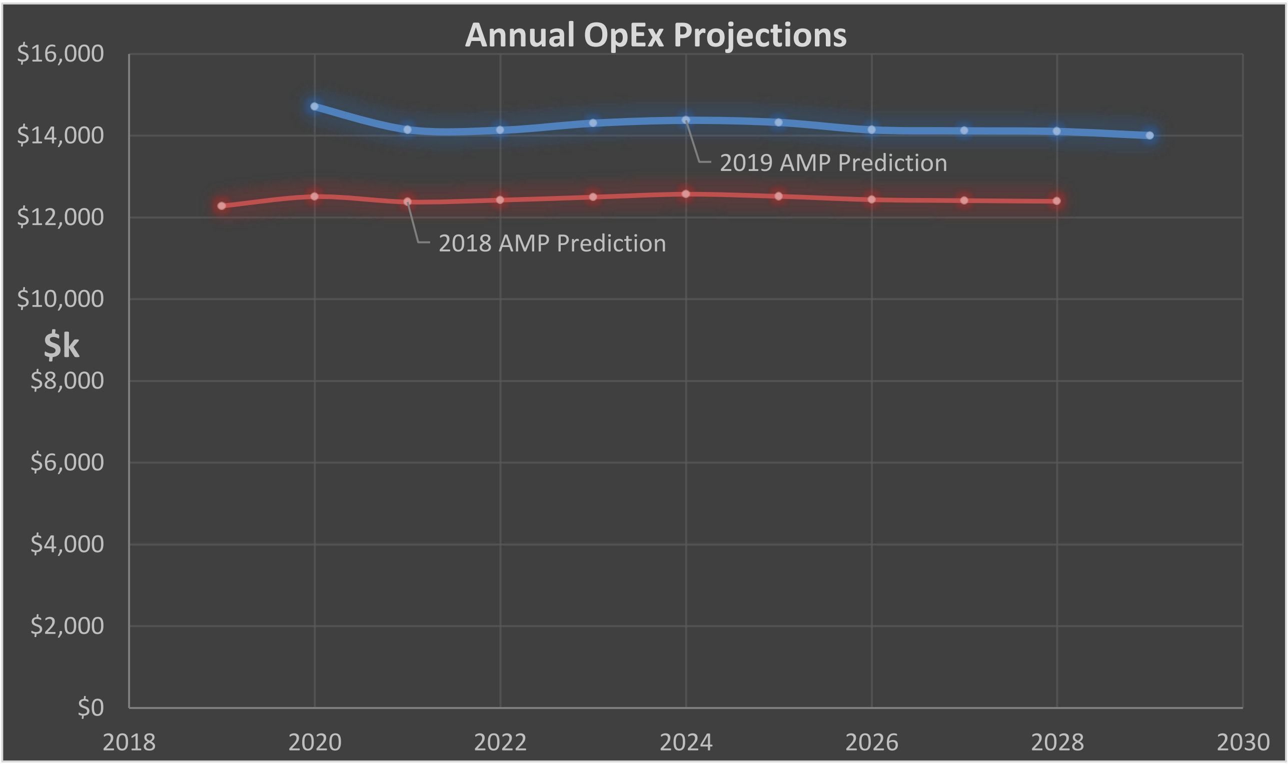
Business Support

Several key drivers have increased the forecast Business Support cost from the historical predictions:

1. An unforeseen project which is looking at electricity business opportunities for EA Networks.
2. Additional staff being employed to accommodate:
    - the base workload,
    - new systems which require support,
    - health and safety compliance,
    - succession planning (about half of EA Networks' employees are over 50 and many are over 60) which will entail employment of new staff to overlap the incumbents so that knowledge held can be passed on to new staff in an orderly manner,

- changing the pool of skills available for implementing and maintaining new technologies.

3. Software licensing costs have increased well above those anticipated in previous plans.



System Operations and Network Support

Similar drivers to Business Support have caused increases in forecast System Operations and Network Support:

1. A new Distribution Management System is being implemented. While progressing this project, it has been identified that there are key business processes that need to be significantly changed. Funding has been allowed for external assistance in completing this work as well as internal implementation costs.
2. Additional staff costs will also be incurred for similar reasons to those identified for Business Support.
3. Software licensing costs have increased well above those anticipated in previous plans.

The AMP forecast has been prepared using ABAA accounting standards.

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 has been introduced. This system is in its infancy but will change some of the methodologies used to manage the electricity assets. A future AMP will detail any material 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 2019 and, where necessary, forecasted/ scaled to reflect the full 2018-19 disclosure year.

	Company Name	Electricity Ashburton Limited
	AMP Planning Period	1 April 2019 – 31 March 2029

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 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	31 Mar 28	31 Mar 29
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	2,746	3,592	3,611	3,290	3,286	3,413	3,417	3,497	3,420	3,469	3,574
11	System growth	3,201	4,921	3,132	4,256	5,659	4,522	4,652	6,162	8,315	6,761	4,489
12	Asset replacement and renewal	7,450	8,024	8,321	8,123	7,123	6,169	4,956	2,152	2,281	2,531	2,847
13	Asset relocations	1	-	-	-	-	-	-	-	-	-	-
14	Reliability, safety and environment:											
15	Quality of supply	2,455	3,356	1,342	1,124	383	395	407	523	77	2,135	2,758
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	581	653	495	165	169	182	188	158	159	162	167
18	**Total reliability, safety and environment**	3,036	4,009	1,838	1,289	552	578	594	681	237	2,298	2,925
19	**Expenditure on network assets**	16,434	20,547	16,901	16,958	16,620	14,682	13,619	12,493	14,253	15,059	13,835
20	Expenditure on non-network assets	1,425	1,629	1,006	922	1,015	928	1,058	1,000	1,100	1,005	1,145
21	**Expenditure on assets**	17,859	22,175	17,907	17,881	17,635	15,610	14,676	13,493	15,354	16,064	14,980
22												
23	*plus* Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less* Value of capital contributions	907	546	288	360	228	225	160	160	160	160	160
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27	**Capital expenditure forecast**	16,952	21,629	17,619	17,521	17,407	15,385	14,516	13,333	15,194	15,904	14,820
28												
29	Assets commissioned	15,952	22,629	17,619	17,521	17,407	15,385	14,516	13,333	15,194	15,904	14,820

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
31	for year ended	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	31 Mar 28	31 Mar 29
32		**$000 (in constant prices)**										
33	Consumer connection	2,746	3,592	3,540	3,162	3,096	3,153	3,095	3,105	2,978	2,961	2,991
34	System growth	3,201	4,921	3,070	4,091	5,333	4,178	4,213	5,472	7,239	5,771	3,756
35	Asset replacement and renewal	7,450	8,024	8,157	7,808	6,712	5,699	4,488	1,911	1,986	2,160	2,382
36	Asset relocations	1	-	-	-	-	-	-	-	-	-	-
37	Reliability, safety and environment:											
38	Quality of supply	2,455	3,356	1,316	1,080	361	365	368	465	67	1,823	2,307
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	581	653	486	159	159	169	170	140	139	138	140
41	**Total reliability, safety and environment**	3,036	4,009	1,802	1,239	520	534	538	605	206	1,961	2,447
42	**Expenditure on network assets**	16,434	20,547	16,569	16,300	15,661	13,564	12,335	11,093	12,408	12,853	11,576
43	Expenditure on non-network assets	1,425	1,629	987	887	957	857	958	888	958	858	958
44	**Expenditure on assets**	17,859	22,175	17,556	17,186	16,618	14,421	13,293	11,982	13,366	13,710	12,534
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses	-	50	-	975	978	-	-	397	-	-	-
48	Overhead to underground conversion	7,361	4,578	3,944	4,155	3,581	3,825	2,598	-	-	-	-
49	Research and development	-	-	-	-	-	-	-	-	-	-	-
50												

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
52	for year ended	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	31 Mar 28	31 Mar 29
53	**Difference between nominal and constant price forecasts**	**$000**										
54	Consumer connection	-	-	71	128	190	260	322	392	443	508	583
55	System growth	-	-	61	165	326	344	439	690	1,076	991	733
56	Asset replacement and renewal	-	-	163	315	411	470	467	241	295	371	465
57	Asset relocations	-	-	-	-	-	-	-	-	-	-	-
58	Reliability, safety and environment:											
59	Quality of supply	-	-	26	44	22	30	38	59	10	313	450
60	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
61	Other reliability, safety and environment	-	-	10	6	10	14	18	18	21	24	27
62	**Total reliability, safety and environment**	-	-	36	50	32	44	56	76	31	337	477
63	**Expenditure on network assets**	-	-	331	659	959	1,118	1,284	1,400	1,845	2,206	2,258
64	Expenditure on non-network assets	-	-	20	36	59	71	100	112	142	147	187
65	**Expenditure on assets**	-	-	351	694	1,017	1,189	1,384	1,512	1,987	2,353	2,445
66												

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
68	**11a(ii): Consumer Connection**						
69	*Consumer types defined by EDB**	**$000 (in constant prices)**					
70	Urban LV	486	169	172	172	172	174
	Urban Transformer	265	158	161	161	161	163
	Urban Alteration for Safety (No new ICP created)	-	-	-	-	-	-
	Urban Capacity Alteration (No new ICP created)	-	2	2	2	2	2
	Rural LV	278	321	326	326	300	303
71	Rural Transformer	1,064	1,566	1,591	1,498	1,502	1,519
72	Rural Alteration for Safety (No new ICP created)	471	684	695	696	628	635
73	Rural Capacity Alteration (No new ICP created)	166	274	279	265	266	269
74	Other (including large subdivisions)	18	418	315	43	65	88
75	**include additional rows if needed*						
76	**Consumer connection expenditure**	2,746	3,592	3,540	3,162	3,096	3,153
77	*less* Capital contributions funding consumer connection	224	369	160	160	160	160
78	**Consumer connection less capital contributions**	2,522	3,224	3,380	3,002	2,936	2,993
79	**11a(iii): System Growth**						
80	Subtransmission	336	1,786	-	-	1,107	-
81	Zone substations	1,279	1,505	926	351	352	356
82	Distribution and LV lines	769	276	15	365	253	159
83	Distribution and LV cables	(47)	817	576	988	1,225	1,239
84	Distribution substations and transformers	835	358	1,522	1,763	1,790	1,810
85	Distribution switchgear	29	99	5	332	312	316
86	Other network assets	-	79	28	293	293	297
87	**System growth expenditure**	3,201	4,921	3,070	4,091	5,333	4,178
88	*less* Capital contributions funding system growth	198	-	-	-	-	-
89	**System growth less capital contributions**	3,003	4,921	3,070	4,091	5,333	4,178
90							

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
92	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
93	**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**					
94	Subtransmission	507	895	932	982	1,023	-
95	Zone substations	33	140	67	67	67	68
96	Distribution and LV lines	2,754	3,648	2,612	1,775	1,294	1,050
97	Distribution and LV cables	3,467	2,633	3,547	3,795	3,337	3,532
98	Distribution substations and transformers	609	455	624	865	701	713
99	Distribution switchgear	81	238	362	309	291	336
100	Other network assets	-	14	14	14	-	-
101	**Asset replacement and renewal expenditure**	7,450	8,024	8,157	7,808	6,712	5,699
102	*less* Capital contributions funding asset replacement and renewal	484	178	128	200	68	65
103	**Asset replacement and renewal less capital contributions**	6,966	7,847	8,029	7,608	6,644	5,634
104							

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2019 – 31 March 2029**

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 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
107	**11a(v): Asset Relocations**						
108	*Project or programme**	**$000 (in constant prices)**					
109	N/A	-	-	-	-	-	-
110	N/A	-	-	-	-	-	-
111	N/A	-	-	-	-	-	-
112	N/A	-	-	-	-	-	-
113	N/A	-	-	-	-	-	-
114	**include additional rows if needed*						
115	All other project or programmes - asset relocations	1	-	-	-	-	-
116	**Asset relocations expenditure**	1	-	-	-	-	-
117	*less* Capital contributions funding asset relocations	-	-	-	-	-	-
118	**Asset relocations less capital contributions**	1	-	-	-	-	-
119							

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
122	**11a(vi): Quality of Supply**						
123	*Project or programme**	**$000 (in constant prices)**					
124	SCADA - Distribution Automation Programme	254	289	294	294	295	298
125	Rural Ring Main Unit Installations	1,621	1,001	-	-	-	-
	UG Conversion - Methven Hwy (Farm Rd to Racecourse Rd)	406	-	-	-	-	-
	OH - Misc. completion work	43	-	-	-	-	-
	UG - Misc. completion work	16	-	-	-	-	-
	ZSS - Misc. completion work	12	-	-	-	-	-
	SCADA - Misc. completion work	14	-	-	-	-	-
126	11kV Core Network Centres	-	658	451	666	-	-
127	Distribution Transformers - Reliability, Safety & Environment	-	1,035	11	11	11	11
	ZSS - Upgrading 110V DC Supplies	77	97	-	-	-	-
	22kV Conversion - Mvn Hwy Sprgfld Rd to Mvn, AF to Nwtns Cnr	-	-	399	-	-	-
128	ZSS - Synchrophasors - Stage 1 and Stage 2	-	-	39	-	-	-
129	**include additional rows if needed*						
130	All other projects or programmes - quality of supply	13	277	122	110	55	56
131	**Quality of supply expenditure**	2,455	3,356	1,316	1,080	361	365
132	*less* Capital contributions funding quality of supply						
133	**Quality of supply less capital contributions**	2,455	3,356	1,316	1,080	361	365
134							

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
136	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
137	**11a(vii): Legislative and Regulatory**						
138	*Project or programme**	**$000 (in constant prices)**					
139	N/A	-	-	-	-	-	-
140	N/A	-	-	-	-	-	-
141	N/A	-	-	-	-	-	-
142	N/A	-	-	-	-	-	-
143	N/A	-	-	-	-	-	-
144	**include additional rows if needed*						
145	All other projects or programmes - legislative and regulatory	-	-	-	-	-	-
146	**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	*less* Capital contributions funding legislative and regulatory	-	-	-	-	-	-
148	**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
149							

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
151	**11a(viii): Other Reliability, Safety and Environment**						
152	*Project or programme**	**$000 (in constant prices)**					
153	Distribution Earthing Upgrades	86	388	394	80	80	81
154	UG Conversion - State Hwy Road Crossings	-	92	-	-	-	-
155	ZSS Security and Surveillance Programme	-	7	23	23	23	31
156	UG Conversion - Rakaia Hwy (Racecourse Rd to Golf Links Rd)	302	-	-	-	-	-
157	N/A	-	-	-	-	-	-
158	**include additional rows if needed*						
159	All other projects or programmes - other reliability, safety and environment	194	166	69	56	56	57
160	**Other reliability, safety and environment expenditure**	581	653	486	159	159	169
161	*less* Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
162	**Other reliability, safety and environment less capital contributions**	581	653	486	159	159	169
163							

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
165	for year ended	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
166	**11a(ix): Non-Network Assets**						
167	**Routine expenditure**						
168	*Project or programme**	**$000 (in constant prices)**					
169	Routine Vehicles	146	183	273	273	273	273
170	Routine Building Work	-	-	100	-	100	-
171	Software - GIS Development	55	53	53	54	54	54
172	ZSS ASH - Building Improvement	-	104	-	-	-	-
	Routine Plant	28	-	-	-	-	-
173	Routine Info Tech	-	647	520	520	520	520
174	**include additional rows if needed*						
175	All other projects or programmes - routine expenditure	14	11	10	10	10	10
176	**Routine expenditure**	243	997	957	857	957	857
177	**Atypical expenditure**						
178	*Project or programme**						
179	Non-Network - DMR Repeater Stations	-	163	-	-	-	-
180	Non-Network - Software - Distribution Management Software	918	411	-	-	-	-
181	Non-Network - Software - ERP Development	19	-	-	-	-	-
182	Non-Network - Software - Website Development	31	-	-	-	-	-
183	Non-Network - HR Management	107	-	-	-	-	-
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure	107	58	30	30	-	-
186	**Atypical expenditure**	1,182	632	30	30	-	-
187							
188	**Expenditure on non-network assets**	1,425	1,629	987	887	957	857

Company Name	Electricity Ashburton Limited
AMP Planning Period	1 April 2019 – 31 March 2029

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
8	for year ended	**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**	**31 Mar 28**	**31 Mar 29**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	704	1,113	1,135	1,158	1,181	1,205	1,229	1,253	1,278	1,304	1,330
11	Vegetation management	472	493	503	346	353	360	367	375	382	390	398
12	Routine and corrective maintenance and inspection	1,416	1,430	1,229	1,212	1,245	1,320	1,347	1,262	1,241	1,266	1,292
13	Asset replacement and renewal	1,145	1,157	1,133	1,147	1,133	1,183	1,149	1,191	1,234	1,241	1,265
14	**Network Opex**	3,737	4,193	4,000	3,864	3,912	4,068	4,092	4,081	4,136	4,201	4,285
15	System operations and network support	3,809	5,008	5,217	5,418	5,633	5,637	5,640	5,640	5,753	5,868	5,985
16	Business support	4,527	5,511	5,213	5,422	5,636	5,857	6,085	6,206	6,330	6,457	6,467
17	**Non-network opex**	8,336	10,519	10,431	10,840	11,269	11,494	11,724	11,846	12,083	12,325	12,452
18	**Operational expenditure**	12,073	14,712	14,431	14,704	15,181	15,562	15,816	15,927	16,219	16,525	16,736

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 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**	**31 Mar 28**	**31 Mar 29**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	704	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113	1,113
23	Vegetation management	472	493	493	333	333	333	333	333	333	333	333
24	Routine and corrective maintenance and inspection	1,416	1,430	1,205	1,165	1,173	1,220	1,220	1,120	1,081	1,081	1,081
25	Asset replacement and renewal	1,145	1,157	1,111	1,103	1,067	1,093	1,040	1,058	1,074	1,059	1,059
26	**Network Opex**	3,737	4,193	3,922	3,714	3,687	3,758	3,706	3,624	3,601	3,585	3,585
27	System operations and network support	3,809	5,008	5,115	5,208	5,308	5,208	5,108	5,008	5,008	5,008	5,008
28	Business support	4,527	5,511	5,111	5,211	5,311	5,411	5,511	5,511	5,511	5,511	5,411
29	**Non-network opex**	8,336	10,519	10,226	10,419	10,619	10,619	10,619	10,519	10,519	10,519	10,419
30	**Operational expenditure**	12,073	14,712	14,148	14,133	14,306	14,377	14,325	14,143	14,120	14,104	14,004
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	-	-	-	-	-	-	-
34	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
35	Research and Development	80	250	250	250	250	250	250	250	250	250	250
36	Insurance	180	182	182	182	182	182	182	182	182	182	182

37 * Direct billing expenditure by suppliers that direct bill the majority of their consumers

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 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**	**31 Mar 28**	**31 Mar 29**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	22	45	68	92	116	140	165	191	217
43	Vegetation management	-	-	10	13	20	27	35	42	49	57	65
44	Routine and corrective maintenance and inspection	-	-	24	47	72	101	127	141	161	186	211
45	Asset replacement and renewal	-	-	22	45	65	90	108	133	160	182	207
46	**Network Opex**	-	-	78	150	226	310	386	457	535	615	699
47	System operations and network support	-	-	102	210	325	429	532	632	745	860	977
48	Business support	-	-	102	211	325	446	574	695	819	946	1,056
49	**Non-network opex**	-	-	205	421	650	875	1,105	1,327	1,564	1,806	2,033
50	**Operational expenditure**	-	-	283	571	876	1,185	1,491	1,784	2,099	2,421	2,732

Company Name	Electricity Ashburton Limited
AMP Planning Period	1 April 2019 – 31 March 2029

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					Asset condition at start of planning period (percentage of units by grade)							
7–9	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	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.	-	1.73%	0.44%	51.67%	46.17%	-	2	1.73%
11	All	Overhead Line	Wood poles	No.	2.80%	3.79%	13.12%	34.14%	46.15%	-	2	6.60%
12	All	Overhead Line	Other pole types	No.	-	-	-	4.76%	95.24%	-	2	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	0.34%	1.01%	24.09%	74.56%	-	3	0.34%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	69.25%	30.75%	-	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%	36.36%	59.09%	-	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.	-	52.18%	17.39%	17.39%	13.04%	-	2	52.18%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	2.50%	28.33%	31.67%	37.50%	-	3	2.50%
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.	-	-	10.60%	60.61%	28.79%	-	2	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	5.85%	7.60%	86.55%	-	2	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	N/A	-

					Asset condition at start of planning period (percentage of units by grade)							
35–38	Voltage	Asset category	Asset class	Units	H1	H2	H3	H4	H5	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.	-	6.25%	9.38%	31.25%	53.13%	-	3	6.25%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.49%	2.20%	13.28%	38.63%	44.40%	-	3	3.69%
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	-	-	0.88%	22.95%	76.18%	-	3	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	4.06%	69.52%	26.42%	-	-	1	4.06%
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.	-	44.26%	4.92%	32.79%	18.03%	-	2	15.00%
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.	2.43%	1.87%	4.23%	26.50%	64.97%	-	2	4.30%
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.	4.12%	6.47%	11.76%	29.41%	48.24%	-	3	1.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.16%	7.85%	25.26%	21.77%	44.96%	-	3	5.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.09%	4.59%	16.43%	12.76%	66.13%	-	3	1.00%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	100.00%	-	-	-	3	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	1.00%	3.39%	9.98%	29.14%	56.49%	-	2	4.39%
55	LV	LV Line	LV OH Conductor	km	7.72%	17.07%	13.57%	48.52%	13.12%	-	3	24.79%
56	LV	LV Cable	LV UG Cable	km	0.02%	0.85%	6.90%	35.81%	56.41%	-	3	0.87%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	1.33%	3.53%	8.46%	38.87%	47.82%	-	2	4.86%
58	LV	Connections	OH/UG consumer service connections	No.	-	-	33.33%	33.33%	33.34%	-	3	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	3.63%	6.05%	90.32%	-	2	3.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	100.00%	-	-	3	25.00%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	-	N/A	-
62	All	Load Control	Centralised plant	Lot	-	66.67%	33.33%	-	-	-	3	66.67%
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 2019 – 31 March 2029**

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
9	Ashburton 33/11kV [ASH]	22	20	N-1 Switched	28	110%	-	-	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. Due to be decommissioned in 2020.
10	Ashburton 66/11kV [ASH]	-	-	N-1 Switched	28	-	20	94%	No constraint within +5 years	Does not currently serve load. Within 1 year 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	Elgin 66/22kV [EGN] (Future)	-	-	-	-	-	-	-	Transformer	Existing 66/33kV transformer to be converted to 66/22kV operation by 2021. Will unload 66kV circuits and provide secure backfeeds at 22kV to other sites. Load to be secured by switched capacity.
16	Fairton 33/11kV [FTN]	-	10	N-1 Switched	6	-	-	-	No constraint within +5 years	Substation provides redundant standby capacity. 33/11kV substation to be decommissioned in 2019-20. New 66/11-22kV substation has replaced 33/11kV site.
	Fairton 66/22/11kV [FTN]	4	20	N-1 Switched	11		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.
	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.
	Highbank 66/11kV [HBK]	8	-	N	-		-	-	Subtransmission circuit	Owned by Trustpower. Winter : generation. Summer : pump load. By agreement, EA Networks provide N 66kV subtransmission security.
	Lagmhor 66/22kV [LGM]	7	-	N	6		-	-	Transformer	22kV transfer capacity improved with additional 22kV conversion, new 22kV lines, and Tinwald 11/22kV, 8MVA transformer.
	Lauriston 66/22kV [LSN]	15	-	N	7		-	-	Transformer	Transfer capacity increased with additional 22kV conversion, larger OVD transformer, FTN commissioning, and MTV 22kV supply capability.
17	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 2021.
18	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 2021.
19	Methven 66/33kV [MTV]	5	-	N	5	-	-	-	No constraint within +5 years	Existing 33kV load is converted to 66/11kV or 66/22kV alleviating constraint (2020).
20	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 (2020 & 2021), two 66kV circuits provide N-1 subtransmission security (currently N subtransmission security).
21	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.
22	Montalto 33/11kV [MON]	2	-	N	1	-	-	-	Transformer	Possible conversion to 66/22kV (long term). Surrounding distribution network 22kV conversion increases transfer capacity in 2021 along with coversion to 22/11kV. Ultimately redundant at 22/11kV as 22kV conversion proceeds.
23	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 2020 with additional 66kV circuit. Additional 11kV cables in Ashburton increase fast transfer capacity from ASH.
24	Overdale 66/22kV [OVD]	14	-	N	10	-	-	-	Transformer	Transfer capacity has increased with larger 66/22kV transformers at adjacent substations ([PDS] & [LSN]) and with additional 22kV conversion and Fairton 66/22kV construction.
25	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.
26	Seafield 22/11kV [SFD22]	-	-	N	10	-	-	-	Transformer	Decommissioned as 33/11kV and converted to 22/11kV for 5MVA limited transfer back-up supply to SFD66 (several minutes for restoration). This site is now a distribution voltage level backup for a zone substation.
27	Seafield 66/11kV [SFD66]	8	-	N-1 Switched	5	-	-	-	Transformer	A second transformer and short length of 66kV line would provide 100% firm capacity. Negotiated security with sole industrial customer. Remote-controlled change-over between 22/11kV and 66/11kV substations.
28	Wakanui 66/22kV [WNU]	13	-	N	10	-	-	-	Transformer	Elgin's 66/33kV transformer conversion to 66/22kV (2019-20) 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 2019 – 31 March 2029

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 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
11	*Consumer types defined by EDB**						
12	Urban LV	133	120	120	120	120	120
	Urban Transformer	2	7	7	7	7	7
	Urban Alteration for Safety (No new ICP created)	-	-	-	-	-	-
	Urban Capacity Alteration (No new ICP created)	1	5	5	5	5	5
	Rural LV	66	60	60	60	55	55
13	Rural Transformer	79	85	85	80	80	80
14	Rural Alteration for Safety (No new ICP created)	53	50	50	50	45	45
15	Rural Capacity Alteration (No new ICP created)	44	40	40	38	38	38
16	Other	-	10	10	10	15	15
17	**Connections total**	378	377	377	370	365	365
18	**include additional rows if needed*						
19	**Distributed generation**						
20	Number of connections	43	45	48	52	55	60
21	Capacity of distributed generation installed in year (MVA)	0	0	0	0	0	0

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 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
25		GXP demand	149	181	183	185	187	189
26	*plus*	Distributed generation output at HV and above	2	2	2	2	2	2
27		**Maximum coincident system demand**	151	183	185	187	189	191
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**	151	183	185	187	189	191
30		**Electricity volumes carried (GWh)**						
31		Electricity supplied from GXPs	338	456	457	458	459	460
32	*less*	Electricity exports to GXPs	0	0	0	0	0	0
33	*plus*	Electricity supplied from distributed generation	164	164	164	164	164	164
34	*less*	Net electricity supplied to (from) other EDBs	(0)	(0)	(0)	(0)	(0)	(0)
35		**Electricity entering system for supply to ICPs**	502	620	621	622	623	624
36	*less*	Total energy delivered to ICPs	467	576	577	578	579	580
37		**Losses**	35	44	44	44	44	44
38								
39		**Load factor**	38%	39%	38%	38%	38%	37%
40		**Loss ratio**	7.1%	7.1%	7.1%	7.1%	7.1%	7.1%

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2019 – 31 March 2029**
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 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	125.0	100.0	95.0	85.0	85.0	80.0
12	Class C (unplanned interruptions on the network)	69.0	110.0	108.0	106.0	104.0	102.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.40	0.40	0.35	0.35	0.35	0.30
15	Class C (unplanned interruptions on the network)	0.95	1.25	1.25	1.25	1.25	1.25

Schedule 14a Mandatory Explanatory Notes on Forecast Information

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

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

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

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

The difference is 0.0% for 2019-20. Costs have been prepared using 2019-20 values for labour, plant and materials. Years after 2019-20 have been escalated by the 2020 CPI Forecast by the New Zealand Government Treasury published on 13th December 2018.
https://treasury.govt.nz/publications/efu/half-year-economic-and-fiscal-update-2018

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

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

The difference is 0.0% for 2019-20. Costs have been prepared using 2019-20 values for labour, plant and materials. Years after 2019-20 have been escalated by the 2020 CPI Forecast by the New Zealand Government Treasury published on 13th December 2018.
https://treasury.govt.nz/publications/efu/half-year-economic-and-fiscal-update-2018

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 incorporates 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 2023.
Beyond 2023, EA Networks have used the 2023 CPI value (2.0%) until 2029.

Schedule 17 Certification for Year-beginning Disclosures

Clause 2.9.1

We, Philip John McKendry and Paul Jason Munro 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.

P J McKendry

Philip McKendry

Paul Jason Munro

28 March 2019

EA networks
connecting our community