Regulatory Information Disclosure

Year End 31 March 2015

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for

Schedules 1–10

Company Name	The Lines Company Limited
Disclosure Date	31 March 2015
Disclosure Year (year ended)	31 March 2015

Templates for Schedules 1–10 excluding 5f–5g
Template Version 4.1. Prepared 24 March 2015

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**

SCHEDULE 1: ANALYTICAL RATIOS

This schedule calculates expenditure, revenue and service ratios from the information disclosed. The disclosed ratios may vary for reasons that are company specific and, as a result, must be interpreted with care. The Commerce Commission will publish a summary and analysis of information disclosed in accordance with the ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of the determination.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

1(i): Expenditure metrics

	Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
Operational expenditure	30,704	427	159,482	2,324	41,930
Network	9,896	138	51,401	749	13,514
Non-network	20,808	289	108,081	1,575	28,416
Expenditure on assets	32,394	450	168,264	2,452	44,238
Network	30,507	424	158,463	2,309	41,662
Non-network	1,887	26	9,801	143	2,577

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	117,352	1,631
Standard consumer line charge revenue	129,385	1,409
Non-standard consumer line charge revenue	73,909	404,151

1(iii): Service intensity measures

Demand density	15	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	76	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	5	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	13,896	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	10,062	26.17%
Pass-through and recoverable costs excluding financial incentives and wash-ups	7,451	19.38%
Total depreciation	9,265	24.09%
Total revaluations	147	0.38%
Regulatory tax allowance	3,236	8.42%
Regulatory profit/(loss) including financial incentives and wash-ups	8,586	22.33%
Total regulatory income	38,456	

1(v): Reliability

Interruption rate	33.16	*Interruptions per 100 circuit km*

Company Name	**The Lines Company Limited**
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SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).
EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
8		31 Mar 13	31 Mar 14	31 Mar 15
9	**ROI – comparable to a post tax WACC**	%	%	%
10	Reflecting all revenue earned	4.06%	4.99%	4.27%
11	Excluding revenue earned from financial incentives	4.06%	4.99%	4.27%
12	Excluding revenue earned from financial incentives and wash-ups	4.06%	4.99%	4.27%
13				
14	**Mid-point estimate of post tax WACC**	5.85%	5.43%	6.10%
15	25th percentile estimate	5.13%	4.71%	5.39%
16	75th percentile estimate	6.56%	6.14%	6.82%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	4.84%	5.68%	5.05%
21	Excluding revenue earned from financial incentives	4.84%	5.68%	5.05%
22	Excluding revenue earned from financial incentives and wash-ups	4.84%	5.68%	5.05%
23				
24	**WACC rate used to set regulatory price path**	8.77%	8.77%	8.77%
25				
26	**Mid-point estimate of vanilla WACC**	6.62%	6.11%	6.89%
27	25th percentile estimate	5.91%	5.39%	6.17%
28	75th percentile estimate	7.34%	6.83%	7.60%
29				

30	**2(ii): Information Supporting the ROI**		($000)	
31				
32	Total opening RAB value	175,959		
33	*plus* Opening deferred tax	(4,936)		
34	**Opening RIV**		171,023	
35				
36	**Line charge revenue**		38,458	
37				
38	Expenses cash outflow	17,513		
39	*add* Assets commissioned	10,691		
40	*less* Asset disposals	317		
41	*add* Tax payments	1,267		
42	*less* Other regulated income	(2)		
43	**Mid-year net cash outflows**		29,157	
44				
45	**Term credit spread differential allowance**		2	
46				
47	Total closing RAB value	177,215		
48	*less* Adjustment resulting from asset allocation	(0)		
49	*less* Lost and found assets adjustment	–		
50	*plus* Closing deferred tax	(6,905)		
51	**Closing RIV**		170,310	
52				
53	**ROI – comparable to a vanilla WACC**			5.05%
54				
55	Leverage (%)			44%
56	Cost of debt assumption (%)			6.36%
57	Corporate tax rate (%)			28%
58				
59	**ROI – comparable to a post tax WACC**			4.27%
60				

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).
EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).
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sch ref

2(iii): Information Supporting the Monthly ROI

Opening RIV — N/A

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

Tax payments — N/A

Term credit spread differential allowance — N/A

Closing RIV — N/A

Monthly ROI – comparable to a vanilla WACC — N/A

Monthly ROI – comparable to a post tax WACC — N/A

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

Year-end ROI – comparable to a vanilla WACC — 4.87%

Year-end ROI – comparable to a post tax WACC — 4.08%

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

2(v): Financial Incentives and Wash-Ups

Net recoverable costs allowed under incremental rolling incentive scheme	–	
Purchased assets – avoided transmission charge		
Energy efficiency and demand incentive allowance		
Quality incentive adjustment		
Other financial incentives		
Financial incentives		–

Impact of financial incentives on ROI — –

Input methodology claw-back		
Recoverable customised price-quality path costs		
Catastrophic event allowance		
Capex wash-up adjustment		
Transmission asset wash-up adjustment		
2013–2015 NPV wash-up allowance		
Reconsideration event allowance		
Other wash-ups		
Wash-up costs		–

Impact of wash-up costs on ROI — –

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

sch ref				
7	**3(i): Regulatory Profit**			**($000)**
8		**Income**		
9		Line charge revenue		38,458
10	*plus*	Gains / (losses) on asset disposals		(2)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		
12				
13		**Total regulatory income**		38,456
14		**Expenses**		
15	*less*	Operational expenditure		10,062
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		7,451
18				
19		**Operating surplus / (deficit)**		20,943
20				
21	*less*	Total depreciation		9,265
22				
23	*plus*	Total revaluations		147
24				
25		**Regulatory profit / (loss) before tax**		11,824
26				
27	*less*	Term credit spread differential allowance		2
28				
29	*less*	Regulatory tax allowance		3,236
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		8,586
32				
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**		**($000)**	
34		**Pass through costs**		
35		Rates	190	
36		Commerce Act levies	120	
37		Industry levies	71	
38		CPP specified pass through costs		
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	5,485	
41		Transpower new investment contract charges		
42		System operator services		
43		Distributed generation allowance	1,585	
44		Extended reserves allowance		
45		Other recoverable costs excluding financial incentives and wash-ups		
46		**Pass-through and recoverable costs excluding financial incentives and wash-ups**		7,451
47				

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SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).
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sch ref

3(iii): Incremental Rolling Incentive Scheme

($000)

	CY-1 31 Mar 14	CY 31 Mar 15
Allowed controllable opex		
Actual controllable opex		
Incremental change in year		

		Previous years' incremental change	Previous years' incremental change adjusted for inflation
CY-5	31 Mar 10		
CY-4	31 Mar 11		
CY-3	31 Mar 12		
CY-2	31 Mar 13		
CY-1	31 Mar 14		
Net incremental rolling incentive scheme			–
Net recoverable costs allowed under incremental rolling incentive scheme			–

3(iv): Merger and Acquisition Expenditure

	($000)
Merger and acquisition expenditure	

Provide commentary on the benefits of merger and acquisition expenditure to the electricity distribution business, including required disclosures in accordance with section 2.7, in Schedule 14 (Mandatory Explanatory Notes)

3(v): Other Disclosures

	($000)
Self-insurance allowance	

Company Name	**The Lines Company Limited**
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SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

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

sch ref

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

		for year ended	RAB 31 Mar 11 ($000)	RAB 31 Mar 12 ($000)	RAB 31 Mar 13 ($000)	RAB 31 Mar 14 ($000)	RAB 31 Mar 15 ($000)
10		**Total opening RAB value**	169,248	170,880	173,267	173,379	175,959
12	*less*	**Total depreciation**	9,101	9,103	9,343	8,968	9,265
14	*plus*	**Total revaluations**	4,080	2,679	1,484	2,655	147
16	*plus*	**Assets commissioned**	6,676	8,815	7,993	8,907	10,691
18	*less*	**Asset disposals**	23	4	22	14	317
20	*plus*	**Lost and found assets adjustment**	–	–	–	–	–
22	*plus*	**Adjustment resulting from asset allocation**	–	–	–	–	(0)
24		**Total closing RAB value**	170,880	173,267	173,379	175,959	177,215

4(ii): Unallocated Regulatory Asset Base

			Unallocated RAB * ($000)	Unallocated RAB ($000)	RAB ($000)	RAB ($000)
29		**Total opening RAB value**		176,268		175,959
31	*less*	**Total depreciation**		9,353		9,265
33	*plus*	**Total revaluations**		147		147
35	*plus*	Assets commissioned (other than below)	3,629		3,514	
36		Assets acquired from a regulated supplier				
37		Assets acquired from a related party	7,178		7,178	
38		**Assets commissioned**		10,807		10,691
40	*less*	Asset disposals (other than below)	317		317	
41		Asset disposals to a regulated supplier				
42		Asset disposals to a related party				
43		**Asset disposals**		317		317
45	*plus*	**Lost and found assets adjustment**				

Company Name	**The Lines Company Limited**
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SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

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

sch ref				
46				
47	*plus*	**Adjustment resulting from asset allocation**		(0)
48				
49		**Total closing RAB value**	177,553	177,215

** The 'unallocated RAB' is the total value of those assets used wholly or partially to provide electricity distribution services without any allowance being made for the allocation of costs to services provided by the supplier that are not electricity distribution services. The RAB value represents the value of these assets after applying this cost allocation. Neither value includes works under construction.*

50
51

4(iii): Calculation of Revaluation Rate and Revaluation of Assets

54		CPI_4	1,193
55		CPI_4^{-4}	1,192
56		Revaluation rate (%)	0.08%
57			

			Unallocated RAB *		RAB	
58			($000)	($000)	($000)	($000)
60		Total opening RAB value	176,268		175,959	
61	*less*	Opening value of fully depreciated, disposed and lost assets	699		692	
62						
63		Total opening RAB value subject to revaluation	175,570		175,267	
64		**Total revaluations**		147		147
65						

4(iv): Roll Forward of Works Under Construction

			Unallocated works under construction		Allocated works under construction	
67						
68		**Works under construction—preceding disclosure year**		1,093		1,098
69	*plus*	Capital expenditure	10,709		10,773	
70	*less*	Assets commissioned	10,807		10,691	
71	*plus*	Adjustment resulting from asset allocation				
72		**Works under construction - current disclosure year**		995		1,179
73						
74		Highest rate of capitalised finance applied				5.43%
75						

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

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

sch ref

4(v): Regulatory Depreciation

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Depreciation - standard	8,769		8,716	
Depreciation - no standard life assets	584		549	
Depreciation - modified life assets				
Depreciation - alternative depreciation in accordance with CPP				
Total depreciation		9,353		9,265

4(vi): Disclosure of Changes to Depreciation Profiles

($000 unless otherwise specified)

Asset or assets with changes to depreciation*	Reason for non-standard depreciation (text entry)	Depreciation charge for the period (RAB)	Closing RAB value under 'non-standard' depreciation	Closing RAB value under 'standard' depreciation

** include additional rows if needed*

4(vii): Disclosure by Asset Category

($000 unless otherwise specified)

		Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total	
	Total opening RAB value	18,130	303	15,583	55,580	19,544	28,881	13,563	22,968	1,407	175,959	
less	Total depreciation	893	11	758	2,756	1,286	1,392	887	733	549	9,265	
plus	Total revaluations	11	0	14	50	17	25	12	15	1	147	
plus	Assets commissioned	330	21	1,147	5,768	101	1,442	1,030	377	475	10,691	
less	Asset disposals	–	–	–	–	–	305	12	–	–	317	
plus	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–	
plus	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–	
plus	Asset category transfers	(4,556)	0	1,300	4,735	1,126	1,593	1,079	(5,276)	–	0	
	Total closing RAB value	13,022	313	17,286	63,377	19,503	30,244	14,785	17,350	1,334	177,215	
	Asset Life											
	Weighted average remaining asset life	27.1	39.8	29.1	36.0	34.6	29.3	30.0	36.2	3.9		(years)
	Weighted average expected total asset life	53.8	53.9	43.9	55.7	52.5	45.0	40.8	43.3	6.2		(years)

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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref					
7	**5a(i): Regulatory Tax Allowance**				**($000)**
8		**Regulatory profit / (loss) before tax**			11,824
9					
10	*plus*	Income not included in regulatory profit / (loss) before tax but taxable		*	
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible		*	
12		Amortisation of initial differences in asset values	4,085		
13		Amortisation of revaluations	438		
14					4,524
15					
16	*less*	Total revaluations	147		
17		Income included in regulatory profit / (loss) before tax but not taxable		*	
18		Discretionary discounts and customer rebates			
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax		*	
20		Notional deductible interest	4,643		
21					4,790
22					
23		**Regulatory taxable income**			11,558
24					
25	*less*	Utilised tax losses			
26		Regulatory net taxable income			11,558
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			3,236
30					
31	*	Workings to be provided in Schedule 14			
32	**5a(ii): Disclosure of Permanent Differences**				
33		In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i).			
34	**5a(iii): Amortisation of Initial Difference in Asset Values**				**($000)**
35					
36		Opening unamortised initial differences in asset values	104,388		
37	*less*	Amortisation of initial differences in asset values	4,085		
38	*plus*	Adjustment for unamortised initial differences in assets acquired			
39	*less*	Adjustment for unamortised initial differences in assets disposed			
40		Closing unamortised initial differences in asset values			100,302
41					
42		Opening weighted average remaining useful life of relevant assets (years)			26
43					

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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref				($000)
44	**5a(iv): Amortisation of Revaluations**			
45				
46		Opening sum of RAB values without revaluations	161,610	
47				
48		Adjusted depreciation	8,827	
49		Total depreciation	9,265	
50		Amortisation of revaluations		438
51				
52	**5a(v): Reconciliation of Tax Losses**			($000)
53				
54		**Opening tax losses**	–	
55	*plus*	Current period tax losses	–	
56	*less*	Utilised tax losses	–	
57		**Closing tax losses**		–
58	**5a(vi): Calculation of Deferred Tax Balance**			($000)
59				
60		**Opening deferred tax**	(4,936)	
61				
62	*plus*	Tax effect of adjusted depreciation	2,472	
63				
64	*less*	Tax effect of tax depreciation	1,164	
65				
66	*plus*	Tax effect of other temporary differences*	(2,221)	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	1,144	
69				
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year	–	
71				
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year	(89)	
73				
74	*plus*	Deferred tax cost allocation adjustment	0	
75				
76		**Closing deferred tax**		(6,905)
77				
78	**5a(vii): Disclosure of Temporary Differences**			
79		*In Schedule 14, Box 6, provide descriptions and workings of items recorded in the asterisked category in Schedule 5a(vi) (Tax effect of other temporary differences).*		
80				
81	**5a(viii): Regulatory Tax Asset Base Roll-Forward**			
82				($000)
83		**Opening sum of regulatory tax asset values**	41,902	
84	*less*	Tax depreciation	4,158	
85	*plus*	Regulatory tax asset value of assets commissioned	2,482	
86	*less*	Regulatory tax asset value of asset disposals	–	
87	*plus*	Lost and found assets adjustment		
88	*plus*	Adjustment resulting from asset allocation		
89	*plus*	Other adjustments to the RAB tax value		
90		**Closing sum of regulatory tax asset values**		40,226

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For Year Ended	**31 March 2015**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

This schedule provides information on the valuation of related party transactions, in accordance with section 2.3.6 and 2.3.7 of the ID determination.
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

5b(i): Summary—Related Party Transactions

	($000)
Total regulatory income	58
Operational expenditure	1,845
Capital expenditure	7,689
Market value of asset disposals	
Other related party transactions	

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

Name of related party	Related party relationship
TLC Contracting Services	Internal division of The Lines Company
John Deere Electrical Ltd	Wholly owned subsidiary
Clearwater Hydro Ltd	Wholly owned subsidiary
Speedys Road Hydro Ltd	Wholly owned subsidiary
Mangapehi Power	Internal division of The Lines Company

** include additional rows if needed*

5b(iii): Related Party Transactions

Name of related party	Related party transaction type	Description of transaction	Value of transaction ($000)	Basis for determining value
TLC Contracting Services	Opex	Supply of services to maintain the distribution system	1,802	ID clause 2.3.6(1)(b)
TLC Contracting Services	Capex	Supply of services to upgrade the distribution system	7,689	ID clause 2.3.6(1)(c)(ii)
John Deere Electical Ltd	Opex	Supply of services to maintain the distribution system other regulated property and equipment	43	ID clause 2.3.6(1)(c)(ii)
John Deere Electical Ltd	Sales	Line charge revenue	2	ID clause 2.3.7(2)(a)
Mangapehi Power	Sales	Line charge revenue	52	ID clause 2.3.7(2)(a)
Speedys Road Hydro Ltd	Sales	Line charge revenue	4	ID clause 2.3.7(2)(a)
	[Select one]			[Select one]
	[Select one]			[Select one]
	[Select one]			[Select one]
	[Select one]			[Select one]
	[Select one]			[Select one]
	[Select one]			[Select one]
	[Select one]			[Select one]
	[Select one]			[Select one]
	[Select one]			[Select one]

** include additional rows if needed*

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

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

Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Cost of executing an interest rate swap	Debt issue cost readjustment
North King Country Development Trust	7/5/1993	7/5/1993	Due on Wind Up	5.00%	2,000	2,000	3	–	(5)
Waitomo Energy Services Customer Trust	7/5/1993	1/4/2010	Due on Wind Up	7.62%	1,000	1,000	6	0	(3)
** include additional rows if needed*						3,000	9	0	(8)

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

Gross term credit spread differential		1
Total book value of interest bearing debt	52,200	
Leverage	44%	
Average opening and closing RAB values	176,587	
Attribution Rate (%)		149%
Term credit spread differential allowance		2

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(i): Operating Cost Allocations

	Value allocated ($000s)				
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
Service interruptions and emergencies					
Directly attributable		1,445			
Not directly attributable				–	
Total attributable to regulated service		1,445			
Vegetation management					
Directly attributable		826			
Not directly attributable				–	
Total attributable to regulated service		826			
Routine and corrective maintenance and inspection					
Directly attributable		783			
Not directly attributable				–	
Total attributable to regulated service		783			
Asset replacement and renewal					
Directly attributable		189			
Not directly attributable				–	
Total attributable to regulated service		189			
System operations and network support					
Directly attributable		2,045			
Not directly attributable				–	
Total attributable to regulated service		2,045			
Business support					
Directly attributable		2,791			
Not directly attributable		1,983	1,219	3,202	
Total attributable to regulated service		4,774			
Operating costs directly attributable		8,079			
Operating costs not directly attributable	–	1,983	1,219	3,202	–
Operational expenditure		10,062			

5d(ii): Other Cost Allocations

Pass through and recoverable costs	($000)
Pass through costs	
Directly attributable	346
Not directly attributable	
Total attributable to regulated service	346
Recoverable costs	
Directly attributable	7,070
Not directly attributable	
Total attributable to regulated service	7,070

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

Change in cost allocation 1

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

Change in cost allocation 2

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

Change in cost allocation 3

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

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

† include additional rows if needed

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	13,022
Not directly attributable	
Total attributable to regulated service	13,022
Subtransmission cables	
Directly attributable	313
Not directly attributable	
Total attributable to regulated service	313
Zone substations	
Directly attributable	17,286
Not directly attributable	
Total attributable to regulated service	17,286
Distribution and LV lines	
Directly attributable	63,377
Not directly attributable	
Total attributable to regulated service	63,377
Distribution and LV cables	
Directly attributable	19,503
Not directly attributable	
Total attributable to regulated service	19,503
Distribution substations and transformers	
Directly attributable	30,244
Not directly attributable	
Total attributable to regulated service	30,244
Distribution switchgear	
Directly attributable	14,785
Not directly attributable	
Total attributable to regulated service	14,785
Other network assets	
Directly attributable	17,350
Not directly attributable	
Total attributable to regulated service	17,350
Non-network assets	
Directly attributable	
Not directly attributable	1,334
Total attributable to regulated service	1,334
Regulated service asset value directly attributable	175,881
Regulated service asset value not directly attributable	1,334
Total closing RAB value	177,215

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

Change in asset value allocation 1

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

Change in asset value allocation 2

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

Change in asset value allocation 3

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

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

Company Name	**The Lines Company**
For Year Ended	**31 March 2015**

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

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

Have costs been allocated in aggregate using ACAM in accordance with clause 2.1.1(3) of the IM Determination? **No**

sch ref	Line Item*	Allocation methodology type	Cost allocator	Allocator type	Allocator Metric (%): Electricity distribution services	Allocator Metric (%): Non-electricity distribution services	Value allocated ($000): Arm's length deduction	Value allocated ($000): Electricity distribution services	Value allocated ($000): Non-electricity distribution services	Value allocated ($000): Total	OVABAA allocation increase ($000)
12	**Service interruptions and emergencies**										
13	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
14	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
15	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
16	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
17	**Not directly attributable**						-	-	-	-	-
18	**Vegetation management**										
19	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
20	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
21	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
22	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
23	**Not directly attributable**						-	-	-	-	-
24	**Routine and corrective maintenance and inspection**										
25	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
26	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
27	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
28	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
29	**Not directly attributable**						-	-	-	-	-
30	**Asset replacement and renewal**										
31	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
32	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
33	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
34	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
35	**Not directly attributable**						-	-	-	-	-
36											
37	**System operations and network support**										
38	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
39	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
40	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
41	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
42	**Not directly attributable**						-	-	-	-	-
43	**Business support**										
44	HR	ABAA	Headcount	Proxy	50.00%	50.00%		92	91	183	
45	Corporate, Finance, Public Relations, IT, Metering & Relays	ABAA	Asset utilisation	Proxy	62.83%	37.17%		1,854	1,096	2,950	
46	Corporate, Finance	ABAA	Specific analysis	Proxy	55.46%	44.54%		38	31	69	
47										-	
48	**Not directly attributable**						-	1,984	1,219	3,203	-
49											
50	**Operating costs not directly attributable**						-	1,984	1,219	3,203	-
51											
52	**Pass through and recoverable costs**										
53	**Pass through costs**										
54	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
55	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
56	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
57	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
58	**Not directly attributable**						-	-	-	-	-
59	**Recoverable costs**										
60	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
61	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
62	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
63	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
64	**Not directly attributable**						-	-	-	-	-
65	** include additional rows if needed*										

Company Name	**The Lines Company**
For Year Ended	**31 March 2015**

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

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

Have assets been allocated in aggregate using ACAM in accordance with clause 2.1.1(3) of the IM Determination? **No**

sch ref	Line Item*	Allocation methodology type	Allocator	Allocator type	Allocator Metric (%): Electricity distribution services	Allocator Metric (%): Non-electricity distribution services	Value allocated ($000): Arm's length deduction	Value allocated ($000): Electricity distribution services	Value allocated ($000): Non-electricity distribution services	Value allocated ($000): Total	OVABAA allocation increase ($000)
	Subtransmission lines										
	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
	Not directly attributable						-	-	-	-	-
	Subtransmission cables										
	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
	Not directly attributable						-	-	-	-	-
	Zone substations										
	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
	Not directly attributable						-	-	-	-	-
	Distribution and LV lines										
	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
	Not directly attributable						-	-	-	-	-
	Distribution and LV cables										
	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
	Not directly attributable						-	-	-	-	-
	Distribution substations and transformers										
	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
	Not directly attributable						-	-	-	-	-
	Distribution switchgear										
	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
	Not directly attributable						-	-	-	-	-
	Other network assets										
	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
	Not directly attributable						-	-	-	-	-
	Non-network assets										
	Non system fixed assets	ABAA	emises utilisation/S	Proxy	79.78%	20.2%		1,334	338	1,672	
	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
	Not directly attributable						-	1,334	338	1,672	-
	Regulated service asset value not directly attributable						-	1,334	338	1,672	-

** include additional rows if needed*

2

FINANCIAL INFORMATION FOR THE DISCLOSURE YEAR

		Page
Schedule 6a	Report on Capital Expenditure for the Disclosure Year	24
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Schedule 7	Comparison of Forecasts to Actual Expenditure	27

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**

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

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

sch ref

6a(i): Expenditure on Assets

			($000)	($000)
8		Consumer connection		365
9		System growth		569
10		Asset replacement and renewal		7,761
11		Asset relocations		–
12		Reliability, safety and environment:		
13		Quality of supply	181	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	1,121	
16		**Total reliability, safety and environment**		1,303
17		**Expenditure on network assets**		9,998
18		Expenditure on non-network assets		618
19				
20		**Expenditure on assets**		10,616
21	*plus*	Cost of financing		178
22	*less*	Value of capital contributions		21
23	*plus*	Value of vested assets		
24				
25		**Capital expenditure**		10,773

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

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

6a(iii): Consumer Connection

		*Consumer types defined by EDB**	($000)	($000)
32		Service Level A	102	
33		Service Level B	50	
34		Service Level C	73	
35		Service Level D	90	
		Service Level E	47	
36		Service Level F	4	
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		365
39				
40	*less*	Capital contributions funding consumer connection expenditure	–	
41		**Consumer connection less capital contributions**		365

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

			System Growth ($000)	Asset Replacement and Renewal ($000)
45		Subtransmission	–	300
46		Zone substations	186	192
47		Distribution and LV lines	61	5,658
48		Distribution and LV cables	–	166
49		Distribution substations and transformers	–	807
50		Distribution switchgear	317	350
51		Other network assets	4	288
52		**System growth and asset replacement and renewal expenditure**	569	7,761
53	*less*	Capital contributions funding system growth and asset replacement and renewal	–	21
54		**System growth and asset replacement and renewal less capital contributions**	569	7,740
55				

6a(v): Asset Relocations

		*Project or programme**	($000)	($000)
58		[Description of material project or programme]		
59		[Description of material project or programme]		
60		[Description of material project or programme]		
61		[Description of material project or programme]		
62		[Description of material project or programme]		
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations		
65		**Asset relocations expenditure**		–
66	*less*	Capital contributions funding asset relocations		
67		**Asset relocations less capital contributions**		–
68				

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**

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

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

sch ref

6a(vi): Quality of Supply

			($000)	($000)
		*Project or programme**		
		11kV Switch Automation	178	
		33kV Substations	3	
		[Description of material project or programme]		
		[Description of material project or programme]		
		[Description of material project or programme]		
		** include additional rows if needed*		
		All other projects programmes - quality of supply		
		Quality of supply expenditure		181
	less	Capital contributions funding quality of supply		
		Quality of supply less capital contributions		181

6a(vii): Legislative and Regulatory

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

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

			($000)	($000)
		*Project or programme**		
		11kV Feeder Safety Switchgear	228	
		33kV Substations	399	
		33kV Supply Points	84	
		Transformer 2 Pole Structures	222	
		Pillar Boxes	56	
		Ground Mount Transformers	133	
		** include additional rows if needed*		
		All other projects or programmes - other reliability, safety and environment		
		Other reliability, safety and environment expenditure		1,121
	less	Capital contributions funding other reliability, safety and environment		
		Other reliability, safety and environment less capital contributions		1,121

6a(ix): Non-Network Assets

Routine expenditure

			($000)	($000)
		*Project or programme**		
		Data Systems	348	
		Miscellaneous Equipment	5	
		Office Equipment	19	
		Vehicle Replacements	186	
		Furniture and Fittings	9	
		** include additional rows if needed*		
		All other projects or programmes - routine expenditure		
		Routine expenditure		567

Atypical expenditure

			($000)	($000)
		*Project or programme**		
		Miscellaneous Equipment	51	
		[Description of material project or programme]		
		[Description of material project or programme]		
		[Description of material project or programme]		
		[Description of material project or programme]		
		** include additional rows if needed*		
		All other projects or programmes - atypical expenditure		
		Atypical expenditure		51
		Expenditure on non-network assets		618

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**

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

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

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	1,445	
9	Vegetation management	826	
10	Routine and corrective maintenance and inspection	783	
11	Asset replacement and renewal	189	
12	**Network opex**		3,243
13	System operations and network support	2,045	
14	Business support	4,774	
15	**Non-network opex**		6,819
16			
17	**Operational expenditure**		10,062
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		634
20	Direct billing*		1,031
21	Research and development		–
22	Insurance		205
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

sch ref

		Target ($000) [1]	Actual ($000)	% variance
7	**7(i): Revenue**			
8	Line charge revenue	38,800	38,458	(1%)
		Forecast ($000) [2]	**Actual ($000)**	**% variance**
9	**7(ii): Expenditure on Assets**			
10	Consumer connection	618	365	(41%)
11	System growth	220	569	159%
12	Asset replacement and renewal	7,102	7,761	9%
13	Asset relocations	11	–	(100%)
14	Reliability, safety and environment:			
15	Quality of supply	812	181	(78%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	1,420	1,121	(21%)
18	**Total reliability, safety and environment**	2,232	1,303	(42%)
19	**Expenditure on network assets**	10,182	9,998	(2%)
20	Expenditure on non-network assets	3,105	618	(80%)
21	Expenditure on assets	13,288	10,616	(20%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,290	1,445	12%
24	Vegetation management	720	826	15%
25	Routine and corrective maintenance and inspection	1,053	783	(26%)
26	Asset replacement and renewal	113	189	67%
27	**Network opex**	3,176	3,243	2%
28	System operations and network support	2,797	2,045	(27%)
29	Business support	3,927	4,774	22%
30	**Non-network opex**	6,724	6,819	1%
31	**Operational expenditure**	9,900	10,062	2%
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses	–	–	–
34	Overhead to underground conversion	–	–	–
35	Research and development	–	–	–
36				
37	**7(v): Subcomponents of Operational Expenditure (where known)**			
38	Energy efficiency and demand side management, reduction of energy losses	346	634	83%
39	Direct billing	1,188	1,031	(13%)
40	Research and development	–	–	–
41	Insurance	190	205	8%
42				

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

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

3

PRICING AND RELATED INFORMATION

		Page
Schedule 8	Report on Billed Quantities and Line Charge Revenues (by Price Component)	31

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8(i): Billed Quantities by Price Component

Billed quantities by price component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Price component	Standard/Low User Transmission	Standard kW Load	Standard Low Voltage/High Density Network	Standard Low Voltage/Low Density Network	Standard High Voltage/High Density Network	Standard High Voltage/Low Density Network	Low User Low Voltage/High Density kW Load (FP__L)	Low User Low Voltage/Low Density kW Load (FP__LR)	Low User High Voltage/High Density kW Load (FP__LUT)	Low User High Voltage/Low Density kW Load (FP__LRT)	Low User Fixed Charge	Major Use Connection Transmission	Major Use Demand Transmission	Major Use Demand Coincidental Transmission	Major Use Standard Network	Major Use 33 kV Network	Major Use Stepped Network	Major Use Low Voltage Network	Billing Charge
					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kW of demand	kW of demand	kVA of capacity	kVA of capacity	kVA of capacity	kVA of capacity	kW of demand	kW of demand	kW of demand	kW of demand	Months	kVA of demand	kVA of demand	kVA of demand	kVA of capacity	kVA of capacity	kVA of capacity	kVA of capacity	Months
Hangatiki (HT)	Standard	Standard	8,941	85,938		28,835	25,346	20,749	5,140	12,645	10,436	2,988	197	283	21	2,015								
	Streetlights	Standard	–																					
	Generators	Non-standard	1	–																				
	Major Use - Standard	Standard	18	24,571													8,686	8,686	–	10,860	–	–	–	18
	Major Use - Non-standard	Non-standard	4	52,485													15,804	5,380	1,646	4,100	1,262	700	–	4
National Park (NP)	Standard	Standard	853	8,884		3,378	3,176	2,437	4,460	626	1,176	146	26	25	6	135								
	Streetlights	Standard																						
	Generators	Non-standard	–	–																				
	Major Use - Standard	Standard	2	2,767													680	680	–	1,300	–	–	–	2
	Major Use - Non-standard	Non-standard	1	3,156													2,299	–	685	–	–	–	–	1
Ohakune (OK)	Standard	Standard	1,946	15,124		7,041	6,375	9,937	33	1,383	–	184	–	83	–	382								
	Streetlights	Standard																						
	Generators	Non-standard	–	–																				
	Major Use - Standard	Standard	–	–													–	–	–	–	–	–	–	–
	Major Use - Non-standard	Non-standard	2	13,757													2,792	–	578	–	–	–	–	2
Ongarue (ON)	Standard	Standard	4,623	39,059		12,429	10,051	12,031	2,563	3,023	3,976	1,857	238	193	90	1,428								
	Streetlights	Standard																						
	Generators	Non-standard	2	–																				
	Major Use - Standard	Standard	2	1,241													382	382	–	660	–	–	240	2
	Major Use - Non-standard	Non-standard	–	–													–	–	–	–	–	–	–	–
Tokaanu (TK)	Standard	Standard	4,737	29,523		12,064	10,257	19,190	246	2,278	662	1,772	2	33	–	1,128								
	Streetlights	Standard																						
	Generators	Non-standard	1	–																				
	Major Use - Standard	Standard	5	2,650													635	635	–	1,627	–	–	–	5
	Major Use - Non-standard	Non-standard	1	1,688													370	370	–	975	–	–	–	1
Whakamaru (WK)	Standard	Standard	2,443	43,449		10,546	10,031	2,754	2,684	1,112	15,702	417	37	20	42	348								
	Streetlights	Standard																						
	Generators	Non-standard	–	–																				
	Major Use - Standard	Standard	1	3,421													1,027	1,027	–	1,000	–	–	–	1
	Major Use - Non-standard	Non-standard	1	–													–	–	–	–	–	–	–	–
Other/Unknown	Other	Standard	–	–		–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category codes as necessary																								
		Standard consumer totals	23,571	256,626		74,295	65,235	67,098	15,126	21,067	31,952	7,763	500	637	159	5,446	11,410	11,410	–	15,447	–	–	240	28
		Non-standard consumer totals	13	71,087		–	–	–	–	–	–	–	–	–	–	–	21,266	5,750	2,908	5,075	1,262	700	–	8
		Total for all consumers	23,584	327,713		74,295	65,235	67,098	15,126	21,067	31,952	7,763	500	637	159	5,446	32,676	17,160	2,908	20,522	1,262	700	240	36

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

Line charge revenues ($000) by price component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Price component	Standard/Low User Transmission	Standard kW Load	Standard Low Voltage/High Density Network	Standard Low Voltage/Low Density Network	Standard High Voltage/High Density Network	Standard High Voltage/Low Density Network	Low User Low Voltage/High Density kW Load (FP__L)	Low User Low Voltage/Low Density kW Load (FP__LR)	Low User High Voltage/High Density kW Load (FP__LUT)	Low User High Voltage/Low Density kW Load (FP__LRT)	Low User Fixed Charge	Major Use Connection Transmission	Major Use Demand Transmission	Major Use Demand Coincidental Transmission	Major Use Standard Network	Major Use 33 kV Network	Major Use Stepped Network	Major Use Low Voltage Network	Billing Charge
							Rate (eg, $ per day, $ per kWh, etc.)	$/kW	$/kW	$/kVA	$/kVA	$/kVA	$/kVA	$/kW	$/kW	$/kW	$/kW	$/month	$/kVA	$/kVA	$/kVA	$/kVA	$/kVA	$/kVA	$/kVA	$/month
Hangatiki (HT)	Standard	Standard	$1,588	$1,288	$9,297	$2,291		$1,291	$4,815	$830	$424	$253	$403	$770	$67	$61	$5	$119								
	Streetlights	Standard	$72	$8	$61	$11																				
	Generators	Non-standard	$72	$8	$72	–																				
	Major Use - Standard	Standard	$1,751	$195	$1,072	$679													$139	$540	–	$993	–	–	–	$26
	Major Use - Non-standard	Non-standard	$3,152	$350	$2,340	$812													$269	$154	$189	$403	$75	$51	–	$6
National Park (NP)	Standard	Standard	$1,699	$189	$1,342	$357		$357	$628	$126	$342	$15	$43	$41	$9	$8	$1	$7								
	Streetlights	Standard	–	–	–	–																				
	Generators	Non-standard	$0	$0	–	$0																				
	Major Use - Standard	Standard	$265	$29	$194	$71													$29	$41	–	$185	–	–	–	$3
	Major Use - Non-standard	Non-standard	$682	$76	$504	$178													$99	–	$79	–	–	–	–	$2
Ohakune (OK)	Standard	Standard	$2,241	$249	$1,744	$496		$498	$994	$429	$3	$28	–	$131	–	$15	–	$21								
	Streetlights	Standard	–	–	–	–																				
	Generators	Non-standard	–	–	–	–																				
	Major Use - Standard	Standard	–	–	–	–													–	–	–	–	–	–	–	–
	Major Use - Non-standard	Non-standard	$603	$67	$498	$103													$37	–	$66	–	–	–	–	$3
Ongarue (ON)	Standard	Standard	$5,394	$599	$4,267	$1,127		$1,127	$2,006	$519	$213	$61	$157	$497	$83	$44	$23	$75								
	Streetlights	Standard	$74	$8	$63	$11																				
	Generators	Non-standard	$114	$13	$84	$30																				
	Major Use - Standard	Standard	$142	$16	$104	$38													$9	$29	–	$73	–	–	$25	$3
	Major Use - Non-standard	Non-standard	–	–	–	–													–	–	–	–	–	–	–	–
Tokaanu (TK)	Standard	Standard	$4,239	$471	$3,491	$747		$747	$1,861	$827	$20	$46	$26	$442	$1	$7	–	$59								
	Streetlights	Standard	–	–	–	–																				
	Generators	Non-standard	$4	$0	–	$4																				
	Major Use - Standard	Standard	$232	$26	$194	$38													$5	$33	–	$174	–	–	–	$8
	Major Use - Non-standard	Non-standard	$199	$22	$177	$22													$3	$19	–	$104	–	–	–	$2
Whakamaru (WK)	Standard	Standard	$4,508	$501	$4,317	$190		$190	$2,590	$118	$205	$22	$569	$134	$14	$6	$13	$18								
	Streetlights	Standard	$16	$2	$11	$5																				
	Generators	Non-standard	–	–	–	–																				
	Major Use - Standard	Standard	$211	$23	$192	$19													–	$19	–	$185	–	–	–	$2
	Major Use - Non-standard	Non-standard	$429	$48	$429	–													–	–	–	–	–	–	–	–
Other/Unknown	Other	Standard	$773	$86	$773	–		–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Add extra rows for additional consumer groups or price category codes as necessary																										
		Standard consumer totals	$33,204	$3,689	$27,123	$6,081		$5,209	$12,904	$2,909	$1,206	$425	$1,203	$2,014	$174	$138	$42	$287	$183	$662	–	$1,609	–	–	$25	$41
		Non-standard consumer totals	$5,254	$584	$4,105	$1,149		–	–	–	–	–	–	–	–	–	–	–	$408	$373	$334	$504	$75	$51	–	$12
		Total for all consumers	$38,458	$4,273	$31,228	$7,230		$5,209	$12,904	$2,909	$1,206	$425	$1,203	$2,014	$174	$138	$42	$287	$590	$1,035	$334	$2,114	$75	$51	$25	$53

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	23,584	**Check** OK

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
Hangatiki (HT)	Standard	Standard	8,941	85,938
	Streetlights	Standard		
	Generators	Non-standard	1	–
	Major Use - Standard	Standard	18	24,571
	Major Use - Non-standard	Non-standard	4	52,485
National Park (NP)	Standard	Standard	853	8,884
	Streetlights	Standard		
	Generators	Non-standard	–	–
	Major Use - Standard	Standard	2	2,767
	Major Use - Non-standard	Non-standard	1	3,156
Ohakune (OK)	Standard	Standard	1,946	15,124
	Streetlights	Standard		
	Generators	Non-standard	–	–
	Major Use - Standard	Standard	–	–
	Major Use - Non-standard	Non-standard	2	13,757
Ongarue (ON)	Standard	Standard	4,623	39,059
	Streetlights	Standard		
	Generators	Non-standard	2	–
	Major Use - Standard	Standard	2	1,241
	Major Use - Non-standard	Non-standard	–	–
Tokaanu (TK)	Standard	Standard	4,737	29,523
	Streetlights	Standard		
	Generators	Non-standard	1	–
	Major Use - Standard	Standard	5	2,650
	Major Use - Non-standard	Non-standard	1	1,688
Whakamaru (WK)	Standard	Standard	2,443	43,449
	Streetlights	Standard		
	Generators	Non-standard	–	–
	Major Use - Standard	Standard	1	3,421
	Major Use - Non-standard	Non-standard	1	–
Other/Unknown	Other	Standard		
Add extra rows for additional consumer groups or price category codes as necessary				
		Standard consumer totals	23,571	256,626
		Non-standard consumer totals	13	71,087
		Total for all consumers	23,584	327,713

Price component	Transformer 5 kVA	Transformer 10 kVA	Transformer 15 kVA	Transformer 25 kVA	Transformer 30 kVA	Transformer 50 kVA	Transformer 75 kVA	Transformer 100 kVA	Transformer 200 kVA	Transformer 300 kVA	Transformer 500 kVA	Transformer 750 kVA	Transformer 1000 kVA	Other Dedicated Asset Charges	Load Control Fee	Generation Transpower injection Overhead	Streetlight Mounting Service	Network - Streetlights	Transmission Demand - Streetlights
Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	Months	Months	Months	Months	Months	Months	Months	Months	Months	Months	Months	Months	Months	Months	Months	Years	Months	kVA of capacity	kW of demand
	1,550	465	726	–	87	88	38	18	4	1	–	–	–	–	6,034				
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		866	188	188
	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–			
	–	–	–	–	–	–	–	1	2	4	9	3	1	–	1				
	–	–	–	–	–	–	–	–	–	–	2	5	1	4	–				
	88	16	86	–	4	13	6	–	1	–	–	–	–	–	514				
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1			
	–	–	–	–	–	–	–	–	3	–	–	–	–	–	1				
	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–				
	104	17	58	–	13	3	2	1	–	1	–	–	–	–	1,422				
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–				
	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–				
	626	140	382	–	19	9	5	2	2	2	–	–	–	–	3,399				
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		959	165	165
	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	1			
	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–				
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			
	93	22	83	–	9	4	1	3	7	–	–	–	–	–	3,767				
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1			
	–	–	–	–	–	–	–	1	–	1	3	–	–	–	–				
	1	–	1	1	2	2	–	–	1	–	1	–	–	1	–				
	527	174	301	–	53	66	45	20	6	1	1	2	–	–	1,670				
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	76	76
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			
	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–				
	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–				
	2,988	834	1,634	–	185	183	97	46	25	10	16	5	1	–	16,808	–	1,825	429	429
	1	–	1	1	2	2	–	–	1	–	3	5	1	11	–	3	–	–	–
	2,989	834	1,635	1	187	185	97	46	26	10	19	10	2	11	16,808	3	1,825	429	429

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)
Hangatiki (HT)	Standard	Standard	$11,588	$1,288
	Streetlights	Standard	$72	$8
	Generators	Non-standard	$72	$8
	Major Use - Standard	Standard	$1,751	$195
	Major Use - Non-standard	Non-standard	$3,152	$350
National Park (NP)	Standard	Standard	$1,699	$189
	Streetlights	Standard	–	–
	Generators	Non-standard	$0	$0
	Major Use - Standard	Standard	$265	$29
	Major Use - Non-standard	Non-standard	$682	$76
Ohakune (OK)	Standard	Standard	$2,241	$249
	Streetlights	Standard	–	–
	Generators	Non-standard	–	–
	Major Use - Standard	Standard	–	–
	Major Use - Non-standard	Non-standard	$603	$67
Ongarue (ON)	Standard	Standard	$5,394	$599
	Streetlights	Standard	$74	$8
	Generators	Non-standard	$114	$13
	Major Use - Standard	Standard	$142	$16
	Major Use - Non-standard	Non-standard	–	–
Tokaanu (TK)	Standard	Standard	$4,239	$471
	Streetlights	Standard	–	–
	Generators	Non-standard	$4	$0
	Major Use - Standard	Standard	$232	$26
	Major Use - Non-standard	Non-standard	$199	$22
Whakamaru (WK)	Standard	Standard	$4,508	$501
	Streetlights	Standard	$16	$2
	Generators	Non-standard	–	–
	Major Use - Standard	Standard	$211	$23
	Major Use - Non-standard	Non-standard	$429	$48
Other/Unknown	Other	Standard	$773	$86
Add extra rows for additional consumer groups or price category codes as necessary				
		Standard consumer totals	$33,204	$3,689
		Non-standard consumer totals	$5,254	$584
		Total for all consumers	$38,458	$4,273

Total distribution line charge revenue	Total transmission line charge revenue (if available)
$9,297	$2,291
$61	$11
$72	–
$1,072	$679
$2,340	$812
$1,342	$357
–	–
–	$0
$194	$71
$504	$178
$1,744	$496
–	–
–	–
–	–
$498	$103
$4,267	$1,127
$63	$11
$84	$30
$104	$38
–	–
$3,491	$747
–	–
–	$4
$194	$38
$177	$22
$4,317	$190
$11	$5
–	–
$192	$19
$429	–
$773	–
$27,123	$6,081
$4,105	$1,149
$31,228	$7,230

Price component	Transformer 5 kVA	Transformer 10 kVA	Transformer 15 kVA	Transformer 25 kVA	Transformer 30 kVA	Transformer 50 kVA	Transformer 75 kVA	Transformer 100 kVA	Transformer 200 kVA	Transformer 300 kVA	Transformer 500 kVA	Transformer 750 kVA	Transformer 1000 kVA	Other Dedicated Asset Charges	Load Control Fee	Generation Transpower injection Overhead	Streetlight Mounting Service	Network - Streetlights	Transmission Demand - Streetlights
Rate (eg, $ per day, $ per kWh, etc.)	$/month	$/month	$/month	$/month	$/month	$/month	$/month	$/month	$/month	$/month	$/month	$/month	$/month	$/month	$/month	$/annum	$/month	$/kVA	$/kW
	$413	$206	$440	–	$70	$78	$41	$22	$8	$3	–	–	–	–	$106				
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		$38	$12	$8
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	$72	–			
	–	–	–	–	–	–	–	$1	$4	$10	$25	$11	$2	–	–				
	–	–	–	–	–	–	–	–	–	–	$6	$18	$4	$1,781	–				
	$23	$7	$52	–	$3	$12	$7	–	$2	–	–	–	–	–	$9				
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	$0			
	–	–	–	–	–	–	–	–	$6	–	–	–	–	–	–				
	–	–	–	–	–	–	–	–	–	–	–	–	–	$502	–				
	$28	$8	$35	–	$10	$3	$2	$1	–	$3	–	–	–	–	$25				
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–				
	–	–	–	–	–	–	–	–	–	–	–	–	–	$495	–				
	$167	$62	$231	–	$15	$8	$5	$2	$4	$5	–	–	–	–	$60				
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		$49	$9	$9
	–	–	–	–	–	–	–	–	–	–	–	–	–	$84	–	$10			
	–	–	–	–	–	–	–	–	–	–	$3	–	–	–	–				
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–				
	$25	$10	$49	–	$7	$4	$1	$4	$15	–	–	–	–	–	$66				
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	–	–
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	$4			
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		$2	$1	$1
	–	–	–	–	–	–	–	$1	–	$3	$9	–	–	–	–				
	$0	–	$1	$1	$2	$2	–	–	$2	–	$3	–	–	$61	–				
	$140	$77	$182	–	$43	$59	$49	$24	$13	$3	$3	$7	–	–	$29				
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	$7	$3
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			
	–	–	–	–	–	–	–	–	–	–	$6	–	–	–	–				
	–	–	–	–	–	–	–	–	–	–	–	–	–	$429	–				
	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	$796	$369	$990	–	$148	$163	$105	$56	$52	$25	$46	$18	$2	–	$294	–	$87	$34	$20
	$0	–	$1	$1	$2	$2	–	–	$2	–	$9	$18	$4	$3,424	–	$35	–	–	–
	$797	$369	$990	$1	$150	$164	$105	$56	$54	$25	$55	$35	$6	$3,424	$294	$35	$87	$34	$20

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	23,584

Check OK

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Price component	Transmission Connection - Streetlights	Load Plant Operation	Streetlight Assets	De-energisation/Re-energisation 1A	De-energisation/Re-energisation 1B	De-energisation/Re-energisation 1C	De-energisation/Re-energisation 1D	De-energisation/Re-energisation 2A	De-energisation/Re-energisation 2B	De-energisation/Re-energisation 2C	De-energisation/Re-energisation 3A	De-energisation/Re-energisation 3B	De-energisation/Re-energisation 3C	De-energisation/Re-energisation 4A	De-energisation/Re-energisation 4B	De-energisation/Re-energisation 4C	De-energisation/Re-energisation 5A	De-energisation/Re-energisation 5B	De-energisation/Re-energisation 7A
					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kW of demand	Units	Years	Units	Units	Units	Units	Units	Units	Units	Units	Units	Units	Units	Units	Units	Units	Units	Units
Hangatiki (HT)	Standard	Standard	8,941	85,938					161	114	164	39	87	47	70	100	42	45	30	10	12	1	–	–
	Streetlights	Standard				177	2,590	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Generators	Non-standard	1	–					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Standard	Standard	18	24,571					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Non-standard	Non-standard	4	52,485					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
National Park (NP)	Standard	Standard	853	8,884					1	3	23	–	–	1	8	1	2	6	–	–	3	–	–	–
	Streetlights	Standard				–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Generators	Non-standard	–	–					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Standard	Standard	2	2,767					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Non-standard	Non-standard	1	3,156					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Ohakune (OK)	Standard	Standard	1,946	15,124					103	6	1	8	35	1	1	33	1	–	8	1	–	–	–	–
	Streetlights	Standard				–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Generators	Non-standard	–	–					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Standard	Standard	–	–					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Non-standard	Non-standard	2	13,757					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Ongarue (ON)	Standard	Standard	4,623	39,059					120	15	43	13	63	6	9	75	6	7	18	3	1	–	–	–
	Streetlights	Standard				165	2,190	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Generators	Non-standard	2	–					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Standard	Standard	2	1,241					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Non-standard	Non-standard	–	–					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Tokaanu (TK)	Standard	Standard	4,737	29,523					120	31	4	10	64	12	2	75	7	1	18	1	1	–	1	–
	Streetlights	Standard				–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Generators	Non-standard	1	–					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Standard	Standard	5	2,650					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Non-standard	Non-standard	1	1,688					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Whakamaru (WK)	Standard	Standard	2,443	43,449					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Streetlights	Standard				76	1,460	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Generators	Non-standard	–	–					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Standard	Standard	1	3,421					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Non-standard	Non-standard	1	–					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Other/Unknown	Other	Standard						4	372	94	91	4	51	17	25	149	27	39	36	3	12	–	–	5

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

Standard consumer totals	23,571	256,626	418	6,240	4	877	263	326	74	300	84	115	433	85	98	110	18	29	1	1	5
Non-standard consumer totals	13	71,087	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Total for all consumers	23,584	327,713	418	6,240	4	877	263	326	74	300	84	115	433	85	98	110	18	29	1	1	5

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Price component	Transmission Connection - Streetlights	Load Plant Operation	Streetlight Assets	De-energisation/Re-energisation 1A	De-energisation/Re-energisation 1B	De-energisation/Re-energisation 1C	De-energisation/Re-energisation 1D	De-energisation/Re-energisation 2A	De-energisation/Re-energisation 2B	De-energisation/Re-energisation 2C	De-energisation/Re-energisation 3A	De-energisation/Re-energisation 3B	De-energisation/Re-energisation 3C	De-energisation/Re-energisation 4A	De-energisation/Re-energisation 4B	De-energisation/Re-energisation 4C	De-energisation/Re-energisation 5A	De-energisation/Re-energisation 5B	De-energisation/Re-energisation 7A
							Rate (eg, $ per day, $ per kWh, etc.)	$/kW	$/unit	$/annum	$/unit	$/unit	$/unit	$/unit	$/unit	$/unit	$/unit	$/unit	$/unit	$/unit	$/unit	$/unit	$/unit	$/unit	Units	$/unit	$/unit
Hangatiki (HT)	Standard	Standard	$1,588	$1,288	$9,297	$2,291					$7	$7	$29	$2	$5	$3	$14	$7	$3	$12	$3	$2	$4	$0	–	–
	Streetlights	Standard	$72	$8	$61	$11		$3	$6	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Generators	Non-standard	$72	$8	$72	–					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Standard	Standard	$1,751	$195	$1,072	$679					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Non-standard	Non-standard	$3,152	$350	$2,340	$812					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
National Park (NP)	Standard	Standard	$1,699	$189	$1,342	$357					$0	$0	$4	–	–	$0	$2	$0	$0	$2	–	–	$1	–	–	–
	Streetlights	Standard	–	–	–	–					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Generators	Non-standard	$0	$0	–	$0		–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Standard	Standard	$265	$29	$194	$71					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Non-standard	Non-standard	$682	$76	$504	$178					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Ohakune (OK)	Standard	Standard	$2,241	$249	$1,744	$496					$5	$0	$0	$0	$2	$0	$0	$2	$0	–	$1	$0	–	–	–	–
	Streetlights	Standard	–	–	–	–		–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Generators	Non-standard	–	–	–	–					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Standard	Standard	–	–	–	–					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Non-standard	Non-standard	$602	$67	$498	$103					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Ongarue (ON)	Standard	Standard	$5,394	$599	$4,267	$1,127					$6	$1	$7	$1	$3	$0	$2	$5	$0	$2	$2	$1	$0	–	–	–
	Streetlights	Standard	$74	$8	$63	$11		$2	$6	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Generators	Non-standard	$114	$13	$84	$30					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Standard	Standard	$142	$16	$104	$38					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Non-standard	Non-standard	–	–	–	–					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Tokaanu (TK)	Standard	Standard	$4,239	$471	$3,491	$747					$6	$2	$1	$1	$3	$1	$0	$5	$1	$0	$2	$0	$0	–	$0	–
	Streetlights	Standard	–	–	–	–		–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Generators	Non-standard	$4	$0	–	$4					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Standard	Standard	$232	$26	$194	$38					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Non-standard	Non-standard	$199	$22	$177	$22					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Whakamaru (WK)	Standard	Standard	$4,508	$501	$4,317	$190					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Streetlights	Standard	$16	$2	$11	$5		$2	$4	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Generators	Non-standard	–	–	–	–					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Standard	Standard	$211	$23	$192	$19					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Major Use - Non-standard	Non-standard	$429	$48	$429	–					–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Other/Unknown	Other	Standard	$773	$86	$773	–		–	–	$495	$17	$5	$16	$0	$3	$1	$5	$10	$2	$10	$4	$1	$4	–	–	$0

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

Standard consumer totals	$33,204	$3,689	$27,123	$6,081		$7	$15	$495	$41	$15	$57	$4	$16	$5	$23	$30	$7	$26	$13	$3	$10	$0	$0	$0
Non-standard consumer totals	$5,254	$584	$4,105	$1,149		–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Total for all consumers	$38,458	$4,273	$31,228	$7,230		$7	$15	$495	$41	$15	$57	$4	$16	$5	$23	$30	$7	$26	$13	$3	$10	$0	$0	$0

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	23,584	**Check**	**OK**

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**
Network / Sub-Network Name	

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

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8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	De-energisation/Re-energisation 7B	De-energisation/Re-energisation 7C	Discount Not Taken Up by Consumers	To balance Schedule 8 and Financial Accounts
Price component								
Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)					Units	Units	Years	Years
Hangatiki (HT)	Standard	Standard	8,941	85,938	–	–		
	Streetlights	Standard			–	–		
	Generators	Non-standard	1	–	–	–		
	Major Use - Standard	Standard	18	24,571	–	–		
	Major Use - Non-standard	Non-standard	4	52,485	–	–		
National Park (NP)	Standard	Standard	853	8,884	–	–		
	Streetlights	Standard			–	–		
	Generators	Non-standard	–	–	–	–		
	Major Use - Standard	Standard	2	2,767	–	–		
	Major Use - Non-standard	Non-standard	1	3,156	–	–		
Ohakune (OK)	Standard	Standard	1,946	15,124	–	–		
	Streetlights	Standard			–	–		
	Generators	Non-standard	–	–	–	–		
	Major Use - Standard	Standard	–	–	–	–		
	Major Use - Non-standard	Non-standard	2	13,757	–	–		
Ongarue (ON)	Standard	Standard	4,623	39,059	–	–		
	Streetlights	Standard			–	–		
	Generators	Non-standard	2	–	–	–		
	Major Use - Standard	Standard	2	1,241	–	–		
	Major Use - Non-standard	Non-standard	–	–	–	–		
Tokaanu (TK)	Standard	Standard	4,737	29,523	–	–		
	Streetlights	Standard			–	–		
	Generators	Non-standard	1	–	–	–		
	Major Use - Standard	Standard	5	2,650	–	–		
	Major Use - Non-standard	Non-standard	1	1,688	–	–		
Whakamaru (WK)	Standard	Standard	2,443	43,449	–	–		
	Streetlights	Standard			–	–		
	Generators	Non-standard	–	–	–	–		
	Major Use - Standard	Standard	1	3,421	–	–		
	Major Use - Non-standard	Non-standard	1	–	–	–		
Other/Unknown	Other	Standard			3	4	1	1
Add extra rows for additional consumer groups or price category codes as necessary								
		Standard consumer totals	23,571	256,626	3	4	1	1
		Non-standard consumer totals	13	71,087	–	–	–	–
		Total for all consumers	23,584	327,713	3	4	1	1

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

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	De-energisation/Re-energisation 7B	De-energisation/Re-energisation 7C	Discount Not Taken Up by Consumers	To balance Schedule 8 to Financial Accounts
Price component										
Rate (eg, $ per day, $ per kWh, etc.)							$/unit	$/unit	$/annum	$/annum
Hangatiki (HT)	Standard	Standard	$1,588	$1,288	$9,297	$2,291	–	–		
	Streetlights	Standard	$72	$8	$61	$11	–	–		
	Generators	Non-standard	$72	$8	$72	–	–	–		
	Major Use - Standard	Standard	$1,751	$195	$1,072	$679	–	–		
	Major Use - Non-standard	Non-standard	$3,152	$350	$2,340	$812	–	–		
National Park (NP)	Standard	Standard	$1,699	$189	$1,342	$357	–	–		
	Streetlights	Standard	–	–	–	–	–	–		
	Generators	Non-standard	$0	$0	–	$0	–	–		
	Major Use - Standard	Standard	$265	$29	$194	$71	–	–		
	Major Use - Non-standard	Non-standard	$682	$76	$504	$178	–	–		
Ohakune (OK)	Standard	Standard	$2,241	$249	$1,744	$496	–	–		
	Streetlights	Standard	–	–	–	–	–	–		
	Generators	Non-standard	–	–	–	–	–	–		
	Major Use - Standard	Standard	–	–	–	–	–	–		
	Major Use - Non-standard	Non-standard	$602	$67	$498	$103	–	–		
Ongarue (ON)	Standard	Standard	$5,394	$599	$4,267	$1,127	–	–		
	Streetlights	Standard	$74	$8	$63	$11	–	–		
	Generators	Non-standard	$114	$13	$84	$30	–	–		
	Major Use - Standard	Standard	$142	$16	$104	$38	–	–		
	Major Use - Non-standard	Non-standard	–	–	–	–	–	–		
Tokaanu (TK)	Standard	Standard	$4,239	$471	$3,491	$747	–	–		
	Streetlights	Standard	–	–	–	–	–	–		
	Generators	Non-standard	$4	$0	–	$4	–	–		
	Major Use - Standard	Standard	$232	$26	$194	$38	–	–		
	Major Use - Non-standard	Non-standard	$199	$22	$177	$22	–	–		
Whakamaru (WK)	Standard	Standard	$4,508	$501	$4,317	$190	–	–		
	Streetlights	Standard	$16	$2	$11	$5	–	–		
	Generators	Non-standard	–	–	–	–	–	–		
	Major Use - Standard	Standard	$211	$23	$192	$19	–	–		
	Major Use - Non-standard	Non-standard	$429	$48	$429	–	–	–		
Other/Unknown	Other	Standard	$773	$86	$773	–	$0	$1	$413	($216)
Add extra rows for additional consumer groups or price category codes as necessary										
		Standard consumer totals	$33,204	$3,689	$27,123	$6,081	$0	$1	$413	($216)
		Non-standard consumer totals	$5,254	$584	$4,105	$1,149	–	–	–	–
		Total for all consumers	$38,458	$4,273	$31,228	$7,230	$0	$1	$413	($216)

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

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	23,584	**Check** OK

4

NON-FINANCIAL INFORMATION RELATING TO NETWORK ASSETS

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Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**
Network / Sub-network Name	

SCHEDULE 9a: ASSET REGISTER

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

sch ref	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	20,880	21,177	297	2
10	All	Overhead Line	Wood poles	No.	14,584	14,118	(466)	2
11	All	Overhead Line	Other pole types	No.	7	–	(7)	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	490	499	9	2
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	2	2	0	2
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	8	9	1	3
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	N/A
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	201	192	(9)	3
29	HV	Zone substation switchgear	33kV RMU	No.	8	–	(8)	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	52	57	5	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	80	73	(7)	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	81	82	1	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	37	40	3	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,227	2,218	(9)	2
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	3	–	(3)	N/A
37	HV	Distribution Line	SWER conductor	km	860	888	27	2
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	120	121	1	2
39	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	N/A
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	206	214	8	2
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	3	3	–	3
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	7,291	7,438	147	2
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	18	13	(5)	2
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	231	254	23	2
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,945	4,893	(52)	2
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	516	545	29	3
48	HV	Distribution Transformer	Voltage regulators	No.	90	36	(54)	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	7	8	1	2
50	LV	LV Line	LV OH Conductor	km	410	420	10	2
51	LV	LV Cable	LV UG Cable	km	130	179	48	2
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	172	172	–	2
53	LV	Connections	OH/UG consumer service connections	No.	4,038	4,054	16	2
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	275	273	(2)	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	714	783	69	3
56	All	Capacitor Banks	Capacitors including controls	No	5	3	(2)	4
57	All	Load Control	Centralised plant	Lot	14	15	1	3
58	All	Load Control	Relays	No	17,138	16,808	(330)	3
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**
Network / Sub-network Name	

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 **Disclosure Year (year ended)** 31 March 2015

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	No. with age unknown	Items at end of year	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	8	589	3,316	3,883	3,671	5,475	717	55	98	66	29	71	48	147	166	38	232	344	355	385	596	353	535	–	21,177	13,430	2
11	All	Overhead Line	Wood poles	No.	1	208	1,595	2,625	2,025	4,811	1,099	126	115	33	47	20	146	56	127	27	136	156	104	110	155	146	250	–	14,118	9,514	2
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	148	59	197	52	3	1	2	–	4	0	7	5	8	1	2	1	–	0	0	0	–	9	499	349	2
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	0	–	0	–	0	–	–	–	–	–	–	–	1	–	–	0	–	0	0	–	2	1	2
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.	–	–	–	3	4	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	9	–	3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	24	37	20	12	20	–	4	5	2	8	4	8	12	2	7	3	4	5	–	11	4	–	192	93	3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	1	2	5	–	4	–	–	4	–	2	–	–	3	5	4	7	7	4	3	2	4	–	57	12	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	11	25	1	13	–	–	–	2	–	1	–	2	–	2	1	–	9	–	6	–	–	73	39	3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	9	11	3	7	–	–	13	2	10	12	–	1	–	–	1	1	–	1	10	1	–	82	34	3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	2	11	3	3	4	–	–	4	2	1	–	–	2	–	1	4	–	1	1	–	1	–	40	22	3
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1	60	317	664	374	508	131	12	16	2	0	7	22	10	42	7	37	1	0	3	1	1	4	–	2,218	1,564	2
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
38	HV	Distribution Line	SWER conductor	km	0	38	303	258	108	110	50	4	5	3	0	1	0	0	2	0	0	–	0	–	1	2	1	–	888	660	2
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	1	2	26	19	20	–	–	–	–	24	1	4	3	8	8	0	1	1	1	1	0	–	121	51	2
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	8	61	21	24	12	–	–	–	–	7	5	1	4	–	3	10	2	13	17	16	10	–	214	95	2
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	3	–	–	–	–	3	–	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	5	194	864	1,206	2,133	738	42	102	141	136	89	51	32	32	72	206	100	165	195	291	307	337	–	7,438	4,171	2
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	3	–	–	–	–	–	–	1	–	–	–	–	1	–	1	1	–	3	3	–	13	2	2
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	4	18	59	3	–	–	–	–	–	–	10	10	21	22	17	10	22	20	25	13	–	254	63	2
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	25	129	656	1,544	686	31	102	117	129	98	67	71	73	99	246	169	178	124	106	124	119	–	4,893	2,564	2
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	12	72	132	36	2	8	11	14	6	9	10	11	14	47	38	66	18	16	11	12	–	545	215	3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	1	3	–	1	1	2	–	–	–	1	2	2	4	1	2	2	2	4	3	1	4	–	36	6	3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	–	1	–	–	–	–	–	–	–	–	3	–	–	–	1	1	–	1	1	–	8	1	2
51	LV	LV Line	LV OH Conductor	km	–	11	41	52	90	159	8	0	1	0	1	0	0	4	2	1	2	4	6	5	12	9	14	–	420	272	2
52	LV	LV Cable	LV UG Cable	km	–	–	3	5	64	32	7	–	–	–	–	–	3	4	3	2	5	0	0	0	1	0	0	48	179	83	2
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	172	172	–	2
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	82	3,627	–	–	–	–	–	–	–	–	–	–	3	57	67	42	69	64	43	–	4,054	2,782	2
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	2	27	74	5	71	–	–	38	22	8	9	2	7	3	–	–	–	–	5	–	–	–	273	179	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	3	3	177	7	83	9	17	109	100	109	46	3	12	17	4	–	–	16	68	–	783	224	3
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	3	–	–	3	–	4
58	All	Load Control	Centralised plant	Lot	–	–	–	5	1	–	3	–	–	–	–	–	–	–	–	–	3	1	1	–	–	–	1	–	15	7	3
59	All	Load Control	Relays	No	–	–	–	–	–	18	60	6	6	12	–	18	12	6	6	–	12	12	13	–	9	73	–	16,545	16,808	77	3
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**
Network / Sub-network Name	

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref				
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	–	–	–
12	50kV & 66kV	–	–	–
13	33kV	499	2	502
14	SWER (all SWER voltages)	888	–	888
15	22kV (other than SWER)	–	–	–
16	6.6kV to 11kV (inclusive—other than SWER)	2,221	121	2,342
17	Low voltage (< 1kV)	421	179	600
18	**Total circuit length (for supply)**	4,028	302	4,330
19				
20	Dedicated street lighting circuit length (km)	94	78	172
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			697
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	491	12%	
25	Rural	2,913	72%	
26	Remote only	225	6%	
27	Rugged only	302	8%	
28	Remote and rugged	84	2%	
29	Unallocated overhead lines	13	0%	
30	**Total overhead length**	4,028	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	265	6%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	416	10%	

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref

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

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

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

9e(i): Consumer Connections

Number of ICPs connected in year by consumer type

*Consumer types defined by EDB**	Number of connections (ICPs)
Urban A	22
Rural B	3
Rural C	20
Rural D	20
Remote Rural E	3
Remote Rural F	3

** include additional rows if needed*

Connections total 71

Distributed generation

Number of connections made in year	4	**connections**
Capacity of distributed generation installed in year	0.01	**MVA**

9e(ii): System Demand

		Demand at time of maximum coincident demand (MW)	
	Maximum coincident system demand		
	GXP demand	55	
plus	Distributed generation output at HV and above	8	
	Maximum coincident system demand	63	
less	Net transfers to (from) other EDBs at HV and above	–	
	Demand on system for supply to consumers' connection points	63	

		Energy (GWh)	
	Electricity volumes carried		
	Electricity supplied from GXPs	288	
less	Electricity exports to GXPs	4	
plus	Electricity supplied from distributed generation	66	
less	Net electricity supplied to (from) other EDBs	(11)	
	Electricity entering system for supply to consumers' connection points	361	
less	Total energy delivered to ICPs	328	
	Electricity losses (loss ratio)	33	9.2%
	Load factor	0.65	

9e(iii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	240
Distribution transformer capacity (Non-EDB owned, estimated)	10
Total distribution transformer capacity	250
Zone substation transformer capacity	153

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

10(i): Interruptions

	Interruptions by class	Number of interruptions
10	Class A (planned interruptions by Transpower)	1
11	Class B (planned interruptions on the network)	338
12	Class C (unplanned interruptions on the network)	667
13	Class D (unplanned interruptions by Transpower)	3
14	Class E (unplanned interruptions of EDB owned generation)	–
15	Class F (unplanned interruptions of generation owned by others)	–
16	Class G (unplanned interruptions caused by another disclosing entity)	–
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	427
19	**Total**	1,436

	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	432	235

	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.42	75.07
27	Class C (unplanned interruptions on the network)	3.64	203.94
28	Class D (unplanned interruptions by Transpower)	0.40	1.84
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	0.04	19.05
34	**Total**	4.50	299.91

	Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
37	Classes B & C (interruptions on the network)	3.74	233.54

	Quality path normalised reliability limit	SAIFI reliability limit	SAIDI reliability limit
40	SAIFI and SAIDI limits applicable to disclosure year*	4.15	307.69

41 ** not applicable to exempt EDBs*

Company Name	**The Lines Company Limited**
For Year Ended	**31 March 2015**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

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

Cause	SAIFI	SAIDI
Lightning	0.12	7.95
Vegetation	0.59	51.96
Adverse weather	0.66	30.03
Adverse environment	0.00	0.83
Third party interference	0.14	16.17
Wildlife	0.12	4.17
Human error	0.03	0.15
Defective equipment	1.46	86.32
Cause unknown	0.51	6.35

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.00	0.01
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.39	71.95
Distribution cables (excluding LV)	0.04	3.12
Distribution other (excluding LV)	–	–

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	1.19	14.22
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	2.38	184.59
Distribution cables (excluding LV)	0.07	5.14
Distribution other (excluding LV)	–	–

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	42	499	8.41
Subtransmission cables	–	2	–
Subtransmission other	–		
Distribution lines (excluding LV)	1,383	3,108	44.50
Distribution cables (excluding LV)	11	121	9.10
Distribution other (excluding LV)	–		
Total	1,436		

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FORECAST INFORMATION

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Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

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 15	31 Mar 16	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
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10		Consumer connection	633	3,255	3,312	1,093	673	687	702	1,190	734	750	766
11		System growth	225	368	1,133	1,887	1,877	1,007	1,607	1,270	1,035	1,502	1,419
12		Asset replacement and renewal	7,273	7,532	8,052	8,145	8,453	8,893	8,657	9,031	9,594	7,894	8,440
13		Asset relocations	11	11	11	11	11	12	12	12	12	13	13
14		Reliability, safety and environment:											
15		Quality of supply	832	326	187	201	177	432	260	248	217	253	208
16		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17		Other reliability, safety and environment	1,454	918	528	580	413	497	1,118	1,008	502	1,013	718
18		**Total reliability, safety and environment**	2,286	1,243	714	781	590	929	1,378	1,256	720	1,266	926
19		**Expenditure on network assets**	10,427	12,408	13,222	11,917	11,605	11,527	12,356	12,760	12,094	11,425	11,564
20		Expenditure on non-network assets	3,105	4,497	4,565	1,753	208	212	217	221	226	231	236
21		**Expenditure on assets**	13,532	16,905	17,787	13,670	11,813	11,739	12,573	12,982	12,321	11,656	11,800
22													
23	*plus*	Cost of financing	223	236	251	226	220	219	235	242	230	217	220
24	*less*	Value of capital contributions	165	30	35	38	40	45	50	52	55	59	63
25	*plus*	Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26													
27		**Capital expenditure forecast**	13,590	17,111	18,003	13,859	11,993	11,913	12,758	13,172	12,495	11,814	11,957
28													
29		Assets commissioned	10,427	12,408	13,222	11,917	11,605	11,527	12,356	12,760	12,094	11,425	11,564

			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 15	31 Mar 16	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
32			**$000 (in constant prices)**										
33		Consumer connection	618	3,255	3,263	1,058	638	638	638	1,058	638	638	638
34		System growth	220	368	1,116	1,827	1,780	935	1,460	1,129	900	1,278	1,181
35		Asset replacement and renewal	7,102	7,532	7,932	7,884	8,014	8,253	7,861	8,024	8,340	6,715	7,025
36		Asset relocations	11	11	11	11	11	11	11	11	11	11	11
37		Reliability, safety and environment:											
38		Quality of supply	812	326	184	194	210	401	236	221	189	215	173
39		Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40		Other reliability, safety and environment	1,420	918	520	562	392	461	1,015	896	437	862	597
41		**Total reliability, safety and environment**	2,232	1,243	704	756	602	862	1,252	1,116	626	1,077	771
42		**Expenditure on network assets**	10,182	12,408	13,025	11,536	11,044	10,698	11,220	11,337	10,515	9,719	9,625
43		Expenditure on non-network assets	3,032	4,497	4,539	1,746	197	197	197	197	197	197	197
44		**Expenditure on assets**	13,215	16,905	17,564	13,282	11,240	10,895	11,417	11,534	10,711	9,916	9,822
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											
49		Research and development											
50													

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

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*
		for year ended	**31 Mar 15**	**31 Mar 16**	**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**
	Difference between nominal and constant price forecasts		**$000**										
	Consumer connection		15	-	49	35	35	49	65	133	96	112	128
	System growth		5	-	17	60	98	72	148	142	135	224	238
	Asset replacement and renewal		171	-	120	261	440	640	796	1,007	1,253	1,179	1,415
	Asset relocations		0	-	0	0	1	1	1	1	2	2	2
	Reliability, safety and environment:												
	Quality of supply		20	-	3	6	(33)	31	24	28	28	38	35
	Legislative and regulatory		-	-	-	-	-	-	-	-	-	-	-
	Other reliability, safety and environment		34	-	8	19	21	36	103	112	66	151	120
	Total reliability, safety and environment		54	-	11	25	(11)	67	127	140	94	189	155
	Expenditure on network assets		244	-	197	381	562	830	1,136	1,423	1,580	1,706	1,939
	Expenditure on non-network assets		73	0	26	6	11	15	20	25	30	35	40
	Expenditure on assets		317	0	223	388	572	845	1,156	1,447	1,609	1,741	1,978

			Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
	11a(ii): Consumer Connection							
	*Consumer types defined by EDB**		**$000 (in constant prices)**					
	Urban A		168	138	172	592	172	172
	Rural B		69	57	71	71	71	71
	Rural C		125	103	129	129	129	129
	Rural D		209	2,919	2,841	216	216	216
	Remote Rural E		24	20	25	25	25	25
	Remote Rural F		24	19	24	24	24	24
	**include additional rows if needed*							
	Consumer connection expenditure		618	3,255	3,263	1,058	638	638
less	Capital contributions funding consumer connection							
	Consumer connection less capital contributions		618	3,255	3,263	1,058	638	638
	11a(iii): System Growth							
	Subtransmission		-	-	299	-	-	-
	Zone substations		-	-	-	1,575	903	725
	Distribution and LV lines		-	-	-	-	-	-
	Distribution and LV cables		-	-	-	-	-	-
	Distribution substations and transformers		-	263	712	147	772	105
	Distribution switchgear		220	-	-	-	-	-
	Other network assets		-	105	105	105	105	105
	System growth expenditure		220	368	1,116	1,827	1,780	935
less	Capital contributions funding system growth							
	System growth less capital contributions		220	368	1,116	1,827	1,780	935

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

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
92		for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
93	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
94	Subtransmission		602	498	702	1,050	1,237	2,102
95	Zone substations		147	253	714	-	164	-
96	Distribution and LV lines		5,277	5,069	4,654	6,032	5,758	5,270
97	Distribution and LV cables		-	-	-	-	-	-
98	Distribution substations and transformers		355	128	124	130	162	130
99	Distribution switchgear		95	95	670	53	95	47
100	Other network assets		626	1,489	1,069	620	599	703
101	**Asset replacement and renewal expenditure**		7,102	7,532	7,932	7,884	8,014	8,253
102	*less* Capital contributions funding asset replacement and renewal							
103	**Asset replacement and renewal less capital contributions**		7,102	7,532	7,932	7,884	8,014	8,253
104								

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106		for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
107	**11a(v):Asset Relocations**							
108	*Project or programme**		**$000 (in constant prices)**					
109	Miscellaneous		11	11	11	11	11	11
110	[Description of material project or programme]							
111	[Description of material project or programme]							
112	[Description of material project or programme]							
113	[Description of material project or programme]							
114	*include additional rows if needed							
115	All other project or programmes - asset relocations							
116	**Asset relocations expenditure**		11	11	11	11	11	11
117	*less* Capital contributions funding asset relocations							
118	**Asset relocations less capital contributions**		11	11	11	11	11	11
119								

			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
121		for year ended	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
122	**11a(vi):Quality of Supply**							
123	*Project or programme**		**$000 (in constant prices)**					
124	11kV Fdr Dev - Switch Automation		234	273	184	194	210	184
125	Sub & 33 Dev - Substations		-	53	-	-	-	217
126	Sub & 33 Dev - Supply Points		579	-	-	-	-	-
127	[Description of material project or programme]							
128	[Description of material project or programme]							
129	*include additional rows if needed							
130	All other projects or programmes - quality of supply							
131	**Quality of supply expenditure**		812	326	184	194	210	401
132	*less* Capital contributions funding quality of supply							
133	**Quality of supply less capital contributions**		812	326	184	194	210	401
134								

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

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*
		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
	11a(vii): Legislative and Regulatory							
	*Project or programme**		**$000 (in constant prices)**					
	[Description of material project or programme]							
	[Description of material project or programme]							
	[Description of material project or programme]							
	[Description of material project or programme]							
	[Description of material project or programme]							
	*include additional rows if needed							
	All other projects or programmes - legislative and regulatory							
	Legislative and regulatory expenditure		-	-	-	-	-	-
less	Capital contributions funding legislative and regulatory							
	Legislative and regulatory less capital contributions		-	-	-	-	-	-

			Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
		for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
	11a(viii): Other Reliability, Safety and Environment							
	*Project or programme**		**$000 (in constant prices)**					
	11kV Fdr Dev - Switchgear for Safety		412	53	53	147	53	53
	Sub & 33 Dev - 33kV Lines		-	-	-	-	-	-
	Sub & 33 Dev - Substations		380	445	49	47	18	-
	Tx & Service Boxes - 2 Pole Structures		363	212	253	222	216	264
	Tx & Service Boxes - Capital Pillar Boxes		111	66	-	-	-	-
	Tx & Service Boxes - GMT		153	142	165	146	105	145
	*include additional rows if needed							
	All other projects or programmes - other reliability, safety and environment							
	Other reliability, safety and environment expenditure		1,420	918	520	562	392	461
less	Capital contributions funding other reliability, safety and environment							
	Other reliability, safety and environment less capital contributions		1,420	918	520	562	392	461

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

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*
	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
	11a(ix): Non-Network Assets						
	Routine expenditure						
	*Project or programme**	**$000 (in constant prices)**					
	Eng & Asset Capital - Data Systems	95	96	96	96	96	96
	Eng & Asset Capital - Metering	2,310	2,800	2,842	1,550	-	-
	Eng & Asset Capital - Misc Equip	11	11	11	11	11	11
	Eng & Asset Capital - Office Area	21	21	21	21	21	21
	Eng & Asset Capital - Vehicle Replacements	71	68	68	68	68	68
	*include additional rows if needed						
	All other projects or programmes - routine expenditure						
	Routine expenditure	2,507	2,997	3,039	1,746	197	197
	Atypical expenditure						
	*Project or programme**						
	Eng & Asset Capital - Building Re-structure	525	1,500	1,500			
	[Description of material project or programme]						
	[Description of material project or programme]						
	[Description of material project or programme]						
	[Description of material project or programme]						
	*include additional rows if needed						
	All other projects or programmes - atypical expenditure						
	Atypical expenditure	525	1,500	1,500	-	-	-
	Expenditure on non-network assets	3,032	4,497	4,539	1,746	197	197

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

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												
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 15**	**31 Mar 16**	**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**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,354	1,262	1,281	1,304	1,331	1,360	1,390	1,420	1,452	1,484	1,516
11	Vegetation management	756	851	864	879	898	917	937	958	979	1,001	1,023
12	Routine and corrective maintenance and inspection	1,105	1,062	1,078	1,097	1,120	1,144	1,169	1,195	1,222	1,248	1,276
13	Asset replacement and renewal	119	302	307	312	319	325	333	340	347	355	363
14	**Network Opex**	3,334	3,477	3,530	3,592	3,668	3,747	3,829	3,914	4,000	4,088	4,178
15	System operations and network support	2,936	3,114	3,189	3,265	3,344	3,424	3,506	3,590	3,676	3,765	3,855
16	Business support	4,122	3,787	3,878	3,971	4,066	4,164	4,264	4,366	4,471	4,578	4,688
17	**Non-network opex**	7,058	6,901	7,067	7,236	7,410	7,588	7,770	7,956	8,147	8,343	8,543
18	**Operational expenditure**	10,392	10,378	10,596	10,828	11,078	11,335	11,599	11,870	12,147	12,430	12,721
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 15**	**31 Mar 16**	**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**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,290	1,262	1,262	1,262	1,262	1,262	1,262	1,262	1,262	1,262	1,262
23	Vegetation management	720	851	851	851	851	851	851	851	851	851	851
24	Routine and corrective maintenance and inspection	1,053	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062	1,062
25	Asset replacement and renewal	113	302	302	302	302	302	302	302	302	302	302
26	**Network Opex**	3,176	3,477	3,477	3,477	3,477	3,477	3,477	3,477	3,477	3,477	3,477
27	System operations and network support	2,797	3,114	3,114	3,114	3,114	3,114	3,114	3,114	3,114	3,114	3,114
28	Business support	3,927	3,787	3,787	3,787	3,787	3,787	3,787	3,787	3,787	3,787	3,787
29	**Non-network opex**	6,724	6,901	6,901	6,901	6,901	6,901	6,901	6,901	6,901	6,901	6,901
30	**Operational expenditure**	9,900	10,378	10,378	10,378	10,378	10,378	10,378	10,378	10,378	10,378	10,378
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses	346	346	346	346	346	346	346	346	346	346	346
34	Direct billing*	1,188	1,187	1,161	1,134	1,133	1,161	1,190	1,219	1,249	1,280	1,262
35	Research and Development	-	-	-	-	-	-	-	-	-	-	-
36	Insurance	190	212	212	212	212	212	212	212	212	212	212
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
38												
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 15**	**31 Mar 16**	**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**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	64	-	19	42	69	98	128	158	190	222	254
43	Vegetation management	36	-	13	28	47	66	86	107	128	149	171
44	Routine and corrective maintenance and inspection	52	-	16	35	58	82	108	133	160	186	214
45	Asset replacement and renewal	6	-	5	10	17	23	31	38	45	53	61
46	**Network Opex**	158	-	53	115	191	270	352	436	522	610	700
47	System operations and network support	139	-	75	151	230	310	392	476	562	651	741
48	Business support	195	-	91	184	279	377	477	579	684	791	901
49	**Non-network opex**	334	-	166	335	509	687	869	1,055	1,246	1,442	1,642
50	**Operational expenditure**	492	-	218	450	700	956	1,221	1,492	1,769	2,052	2,342

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

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)						
	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.	0.62%	0.90%	62.00%	10.66%	25.82%	2	6.35%
11	All	Overhead Line	Wood poles	No.	2.26%	2.80%	35.77%	5.06%	54.11%	2	6.35%
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	N/A	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	12.80%	65.98%	0.41%	20.81%	2	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	41.18%	22.67%	36.15%	2	-
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.	-	-	88.89%	11.11%	-	3	-
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.	-	10.71%	35.71%	48.21%	5.37%	3	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	7.73%	77.32%	12.89%	2.06%	3	-
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.	-	-	-	-	-	N/A	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	13.89%	63.89%	22.22%	-	3	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	11.54%	71.79%	16.67%	-	3	-

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

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)						
36												
37	**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**
38												
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	5.26%	76.32%	18.42%	-	3	-
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	15.81%	62.57%	0.25%	21.37%	2	1.41%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	-	21.69%	39.29%	0.38%	38.64%	2	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	6.45%	4.30%	89.25%	2	-
44	HV	Distribution Cable	Distribution UG PILC	km	-	-	-	-	-	N/A	-
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.	-	6.09%	42.13%	24.37%	27.41%	2	7.11%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	100.00%	-	3	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	0.03%	0.69%	77.76%	15.79%	5.73%	2	0.07%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	50.00%	50.00%	-	2	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	62.03%	37.97%	-	2	5.06%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.06%	0.11%	63.80%	16.03%	20.00%	2	0.36%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	1.63%	2.65%	67.21%	28.51%	-	3	6.52%
53	HV	Distribution Transformer	Voltage regulators	No.	-	3.06%	64.29%	32.65%	-	3	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	50.00%	50.00%	-	2	-
55	LV	LV Line	LV OH Conductor	km	-	4.81%	53.07%	0.71%	41.41%	2	-
56	LV	LV Cable	LV UG Cable	km	-	-	3.67%	1.94%	94.39%	2	-
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	-	2.81%	43.11%	0.19%	53.89%	2	-
58	LV	Connections	OH/UG consumer service connections	No.	-	-	62.82%	27.40%	9.78%	2	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	99.26%	0.74%	-	3	-
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	9.26%	7.41%	74.07%	9.26%	-	3	-
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	100.00%	-	4	-
62	All	Load Control	Centralised plant	Lot	-	7.14%	50.00%	42.86%	-	3	-
63	All	Load Control	Relays	No.	-	-	82.54%	17.46%	-	3	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	N/A	-

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

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

12b(i): System Growth - Zone Substations

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
Arohena	2	-	N	1	-	-	-	No constraint within +5 years	0
Atiamuri	10	-	N	-	-	-	-	No constraint within +5 years	New point of supply will alleviate transformer constraint.
Awamate Road	1	-	N	1	-	-	-	No constraint within +5 years	0
Borough	8	5	N - 1	3	157%	5	165%	No constraint within +5 years	0
Gadsby Rd	3	-	N	6	-	-	-	No constraint within +5 years	0
Hangatiki	4	-	N	1	-	-	-	No constraint within +5 years	0
Kaahu Tee	2	-	N	1	-	-	-	No constraint within +5 years	0
Kiko Rd	1	-	N	0	-	-	-	No constraint within +5 years	0
Kuratau	2	2	N-1	0	165%	2	169%	No constraint within +5 years	0
Mahoenui	1	-	N	0	-	-	-	No constraint within +5 years	0
Manunui	2	-	N	1	-	-	-	No constraint within +5 years	0
Maraetai	4	-	N	0	-	-	-	No constraint within +5 years	0
Marotiri	2	-	N	1	-	-	-	No constraint within +5 years	0
Mokai	4	-	N	1	-	-	-	No constraint within +5 years	0
National Park	2	-	N	1	-	-	-	No constraint within +5 years	0
Nihoniho	1	-	N	1	-	-	-	No constraint within +5 years	0
Oparure	2	-	N	1	-	-	-	No constraint within +5 years	0
Otukou	0	-	N	-	-	-	-	No constraint within +5 years	0
Taharoa	11	10	N - 1	-	114%	15	153%	Transformer	Upgrade of transformers is planned for 2016 to provide additional capacity.
Tawhai	4	-	N	1	-	-	-	No constraint within +5 years	0
Te Anga	2	-	N	-	-	-	-	No constraint within +5 years	0
Te Waireka Rd	11	10	N - 1	2	113%	10	120%	No constraint within +5 years	0
Tokaanu	0	-	N	-	-	-	-	No constraint within +5 years	0
Tuhua	1	-	N	1	-	-	-	No constraint within +5 years	0
Turangi	5	5	N - 1	2	92%	5	83%	No constraint within +5 years	0
Waiotaka	1	-	N	1	-	-	-	No constraint within +5 years	0
Wairere	3	3	N - 1	1	122%	3	129%	No constraint within +5 years	0
Waitete	9	10	N - 1	4	93%	10	78%	No constraint within +5 years	0

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

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**

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

12c(i): Consumer Connections

Number of ICPs connected in year by consumer type

		Number of connections					
		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
	*Consumer types defined by EDB**						
	Urban A	29	32	32	32	32	32
	Rural B	4	5	5	5	5	5
	Rural C	13	20	20	20	20	20
	Rural D	52	55	55	55	55	55
	Remote Rural E	4	6	6	6	6	6
	Remote Rural F	-	4	4	4	4	4
	Connections total	102	122	122	122	122	122

**include additional rows if needed*

Distributed generation

	Number of connections	4	4	4	4	4	4
	Capacity of distributed generation installed in year (MVA)	0	0	0	0	0	0

12c(ii) System Demand

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
	Maximum coincident system demand (MW)						
	GXP demand	57	58	58	59	60	61
plus	Distributed generation output at HV and above	8	8	8	8	9	9
	Maximum coincident system demand	65	66	67	68	69	70
less	Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
	Demand on system for supply to consumers' connection points	65	66	67	68	69	70
	Electricity volumes carried (GWh)						
	Electricity supplied from GXPs	287	291	295	299	303	308
less	Electricity exports to GXPs	4	4	4	4	4	4
plus	Electricity supplied from distributed generation	58	59	59	60	61	62
less	Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
	Electricity entering system for supply to ICPs	341	345	350	355	360	365
less	Total energy delivered to ICPs	311	315	320	324	329	333
	Losses	30	30	30	31	31	32
	Load factor	60%	60%	60%	60%	60%	60%
	Loss ratio	8.7%	8.7%	8.7%	8.7%	8.7%	8.7%

Company Name	**The Lines Company**
AMP Planning Period	**1 April 2015 – 31 March 2025**
Network / Sub-network Name	**The Lines Company**

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							
8		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9	for year ended	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	90.7	58.9	58.9	58.9	58.9	58.9
12	Class C (unplanned interruptions on the network)	217.0	149.9	149.9	149.9	149.9	149.9
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.70	0.45	0.45	0.45	0.45	0.45
15	Class C (unplanned interruptions on the network)	3.45	2.62	2.62	2.62	2.62	2.62

6

EXPLANATORY NOTES TO DISCLOSED INFORMATION

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Schedule 15	Voluntary Explanatory Notes	69

Company Name	The Lines Company
For Year Ended	31st March 2015

Schedule 14 Mandatory Explanatory Notes

1. This schedule requires EDBs to provide explanatory notes to information provided in accordance with clauses 2.3.1, 2.4.21, 2.4.22, and subclauses 2.5.1(1)(f),and 2.5.2(1)(e).

2. This schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. Information provided in boxes 1 to 12 of this schedule is part of the audited disclosure information, and so is subject to the assurance requirements specified in section 2.8.

3. Schedule 15 (Voluntary Explanatory Notes to Schedules) provides for EDBs to give additional explanation of disclosed information should they elect to do so.

Return on Investment (Schedule 2)

4. In the box below, comment on return on investment as disclosed in Schedule 2. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 1: Explanatory comment on return on investment
No further commentary required.

Regulatory Profit (Schedule 3)

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

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

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

Box 2: Explanatory comment on regulatory profit

TLC regulatory profit has reduced by 14.2% on 2014 to $9m, due to:

- A decrease in RAB revaluation
- A higher RAB depreciation

Operational surplus shows an 8% increase of $1.6m on 2014. This increase is attributable to:

- Increased lines charges (net of increased Transpower charges and ACOT) resulting predominately from increases in unit prices
- This was partially offset by increased business support expense relating to regulatory compliance, IT upgrades and personnel costs.

Line charge revenue of $38.5m includes $0.3m from meter relay charges and $0.3m from disconnection/reconnection charges.

Other regulatory income is nil in 2015.

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

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

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

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

Box 3: Explanatory comment on merger and acquisition expenditure

Not applicable

Value of the Regulatory Asset Base (Schedule 4)

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

Box 4: Explanatory comment on the value of the regulatory asset based (rolled forward)

Schedule 4 RAB Value (Rolled Forward)

- The RAB asset register is held in TLC asset database 'Basix'. Upgrades to this software and data entry errors have historically led to a small variance between previously disclosed RAB values and the RAB values that the Basix asset database holds. The software issues are now resolved and the figures presented have been extracted from the system.

Schedule 4 (vii) – Disclosure by Asset Category

- Included within the closing RAB value in the disclosure category "Other Network Assets" are bundled assets which historically were unable to be accurately allocated. Extensive work has been done, and will continue to be done, on refining this information to improve reporting ability. This is reflected in the asset category transfers in Schedule 4 (vii). This process has resulted in revision of some of the asset category transfers made in 2014.

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

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

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

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

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

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

Box 5: Regulatory tax allowance: permanent differences

Not applicable

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

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

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

Negative Temporary Differences (Gross values):

- Opening accrued annual leave accrual - $374k
- Opening long service leave accrual - $12k
- Opening bonus provision accrual - $137k
- Opening bad debt provision - $601k
- Opening general provision - Nil
- Closing unrecognised capital contributions - $219k
- Lines renewal R&M deduction - $7,708k
- Total Negative Temporary Differences - $9,051

Positive Temporary Differences (Gross values):

- Closing accrued annual leave accrual - $311k
- Closing long service leave accrual - $12k
- Closing bonus provision accrual - $119k
- Closing bad debt provision - $422k
- Closing general provision – Nil
- Opening unrecognised capital contributions - $254k
- Total Positive Temporary Differences - $1,118k

Net NEGATIVE temporary differences is $7,933k, tax effect $2,221k

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

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

Box 7: Related party transactions

TLC operates a division ("Contracting") which provides both internal and external electrical lines contracting services. This division performs the majority of work on the TLC distribution infrastructure lines maintenance and capital programmes. The Contracting division revenue is predominately (80%) related to services provided to TLC Network.

The TLC Network is charged on fully costed basis for labour, materials usage, plant/equipment usage and project management costs. External services organised by the Contracting Division are on-charged at cost. A significant amount of materials is sourced directly by the TLC Network. The total margin earned by the Contracting Division on services provided is less than the 17.2% allowable which is evident in earnings reported by the Contracting Division in TLC annual accounts.

Cost allocation (Schedule 5d)

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

Box 8: Cost allocation

Directly attributable costs include, for each TLC division or part thereof which has any regulatory business transactions, each general ledger cost code which is allocated 100% to the regulatory business. Directly attributable costs are primarily incurred in the functional areas of 1) Network operations and support, 2) IT, 3) Billing Services, 4) Regulatory and 5) Disconnections/Reconnections services. Costs are analysed by each relevant category.

TLC has opted to apply ABAA (Accounting based allocation approach) to allocate those operating costs not directly attributable to the regulatory business. The Business support costs, not directly attributable are identified as any general ledger cost, for each TLC division or part thereof that has any regulatory business transactions, which is allocated at less than 100%. The actual percentage allocated to the regulatory business is applied. Business Support costs have been allocated to regulated and unregulated services using proxy cost allocators such as; Management's estimate of percentage of staff time working on regulated and unregulated services. Further use of causal relationships has been utilised to allocate costs to regulated and unregulated services, where the cost driver has led to the cost being incurred. The most important causal relationship used to allocate costs to the regulatory business is the percentage of regulatory assets to total TLC group assets. For the TLC Group, regulatory assets accounts for over 85% of total Group assets.

Not directly attributable costs primarily arise in the functional support areas of 1) office of CEO/Directors, 2) finance, 3) Human Resources, 4) Public Relations and include the following significant costs:

- Personnel costs
- Property costs
- Professional services fees
- Customer related expenses

Professional services fees are evaluated on individual basis and apportioned to the Network as appropriate to services provided.

Non EDB services are the percentage not allocated to the regulatory business on the general ledger codes identified for the 'not attributable costs' above.

Asset allocation (Schedule 5e)

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

Box 9: Commentary on asset allocation

Directly attributable assets are those assets used wholly and solely in the conveyance of electricity or management of the electricity network.

Not directly attributable assets are non system assets which include the following:

- Buildings
- Plant/Vehicles/Equipment
- Office Equipment & Furniture
- IT Equipment and Software
- Intangibles (leaseholds, easements, etc.)

Not directly attributable assets have been determined to be 80% related to the regulatory business having regards to asset utilisation

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

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

Box 10: Explanation of capital expenditure for the disclosure year

System Assets

Nothing further to disclose.

Non Systems Assets

Nothing further to disclose.

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

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

14.2 Information on reclassified items in accordance with subclause 2.7.1(2);

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

Box 11: Explanation of operational expenditure for the disclosure year

Network Opex

With respect to Network opex incurred, nothing of note requires further disclosure. Expenditure is consistent in type with respect to routine systems and network maintenance carried out. Resource limitations impacted maintenance schedules.

Systems Operations and Network Support

Nothing further to disclose.

Business Support

Nothing further to disclose.

Variance between forecast and actual expenditure (Schedule 7)

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

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

Revenues

Consistent with target reflecting planned price increase and growth.

Expenditure on Assets

Forecast data is extracted from the relevant AMP. Expenditure on assets continues to trend below AMP forecasts due largely to resource constraints. Key overview comments:

Customer Connections

- Economic factors limited connection demand.

System growth

- Borough Zone Substation capacitor bank project and Wharepapa feeder regulator project carry overs from 2014 financial year impacted current year actuals.

Quality of supply

- Mokai backup transformer project was put on hold for further investigation of options.

Non-network assets

- Included provision for office premise expansion which has been delayed.
- The published AMP forecast figures included $2.3m for the Network Metering rollout whilst the actual does not.

Operational Expenditure

The forecast target figures are extracted from the relevant AMP. In total the actual costs are comparable to budget:

- Network opex – is comparable to budget.
- Systems operations and network support – exceeded budget by $0.7m.
- Business support – cost down $0.8m on forecast. This can be attributed to $0.3m for bad debts on customer billings. $0.1m for regulatory costs of meter reading and compliance. $0.1m for IT systems upgrades and support. $0.1m for telecommunications. $0.1m for corporate professional fees.

Direct billing is $0.2m down on forecast. This decrease can be attributed to a reduction of bad debts on customer billings.

Information relating to revenues and quantities for the disclosure year

16. In the box below provide-

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

    16.2 explanatory comment on reasons for any material differences between target revenue and total billed line charge revenue.

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

Forecast revenue of 38,800 is as per 2014 Pricing Methodology. Revenue was within 1% of forecast.

Preparation Note This schedule has been prepared using quantities from February 2015. The quantities have been multiplied by the disclosed prices in the tariff schedule making note that TLC changed its prices in June 2014. TLC bills its customers directly and the quantity for an individual customer does not alter throughout the disclosure year. However, there may be a small variance, as, upon application, some customers may get a form of relief with a reduced quantity; and new connections on the network may be billed after the commencement of the disclosure year.

For these reasons, billed quantities and line charge revenue in this schedule may not match exactly what has been recorded and audited through the financial accounts. There is a balancing total in line charge revenue to ensure reconciliation between line charge revenue in this schedule and line charge revenue in the audited financial accounts.

In addition, it has not been possible to accurately determine which of our customers have chosen to take up the billed prompt payment discount offered by TLC. In this schedule, the customers who have not taken the discount are shown as a lump sum.

Network Reliability for the Disclosure Year (Schedule 10)

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

Box 14: Commentary on network reliability for the disclosure year

TLC uses the BASIX computer programme which has a connectivity model for outage and performance recording and reporting. This includes SAIDI and SAIFI reports. The module connects various assets together and then runs a calculation that produces the regulatory performance indicators. Customer numbers are transferred automatically from the billing system on a regular basis. The use of BASIX outage calculator has allowed TLC to collect more accurate outage data. The company is reliant on third parties to notify it of outages. This is consistent with industry practice.

Insurance cover

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

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

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

Box 15: Explanation of insurance cover

TLC has an insurance programme in place for selected network and non-network assets. This insurance programme is placed with a reputable insurer(s) organised by an independent broker. The insured assets covered under material damage, business interruption and machinery breakdown policies include:

- ground mounted substations and transformers
- plant & equipment
- vehicles
- buildings
- office equipment

The sum insured of assets is $63m (excluding buildings). Aggregate annual cover capped at $5m, and $1m per event for machinery breakdown losses.

All other assets are not insured.

TLC has a number of liability insurance policies to cover: Public liability, statutory liability, fidelity/theft, Professional indemnity and Directors & Officers liability

Amendments to previously disclosed information

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

    19.1 a description of each error; and

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

Box 16: Disclosure of amendment to previously disclosed information

Schedule 11a (ix) Non-Network Assets:

- The data published in the TLC 2015 AMP contains a transposition of data in the above schedule between the project/programme name and the sited forecast figures. The data has been correctly aligned in this disclosure document.
- The disclosed TLC 2015 AMP web address is as follows: www.thelinescompany.co.nz/disclosures/disclosures/asset-management-plans

Company Name	The Lines Company
For Year Ended	31st March 2015

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.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts
With respect to the disclosure year, the difference relates to a 2.5% inflation factor, as disclosed in our AMP.

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

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

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts
With respect to the disclosure year, the difference relates to a 2.5% inflation factor, as disclosed in our AMP.

Company Name	The Lines Company
For Year Ended	31st March 2015

Schedule 15 Voluntary Explanatory Notes

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

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

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

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

3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Schedule 9a & 9b – Asset Registers

- Default dates - To allow for data inaccuracies, assets with default dates are estimated at 75% of assets with installation dates prior to 2004. Zone substation buildings are exempted.
- Continuing improvements to data and standardizing of data extraction processes has seen changes to some asset counts and is especially notable in conductor lengths by installation date figures.
- Voltage Regulators – Disclosure figures reflect Regulator installation sites only. Prior figures related to tanks and were inclusive of Tap Changers.
- OH/UG consumer service connections - Due to data limitations and for consistency with prior year reporting, figures for OH/UG consumer service connections is limited to pillar box installations.

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CERTIFICATES

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Schedule 18 Certification for Year-end Disclosures

Clause 2.9.2 of section 2.9

We, Angus Malcolm DON and Peter John TILL, being directors of The Lines Company Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) The information prepared for the purposes of clauses 2.3.1 and 2.3.2; and clauses 2.1.21 and 2.4.22; clauses 2.5.1 and 2.5.2; and clauses 2.7.1 and 2.7.2 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination; and

b) The historical information used in the preparation of Schedules 8,9a,9b, 9c, 9d, 94, 10, 14a and 14b has been properly extracted from The Lines Company Limited's accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate record have been retained; and

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

In respect of related party costs and revenues recorded in accordance with clauses 2.3.6(1) (when valued in accordance with clause 2.2.11(5)(h)(ii) of the Electricity Distribution Services Input Methodologies Determination 2010), 2.3.6.(2)(f) and 2.3.7(2)(b), we certify that, having made all reasonable enquiry, including enquiries of our related parties, we are satisfied that to the best of our knowledge and belief the costs and revenues recorded for related party transactions reasonably reflect the price or prices that would have been paid or received had these transactions been at arm's-length.

In respect of outages, the company is reliant on third parties, in some situations, to notify it of outages. This is consistent with industry practice.

Signature

Angus Malcolm DON

Signature

Peter John TILL

19 AUGUST 2015

DATE

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AUDITOR'S REPORT

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Independent Auditors' Report

To the Directors of The Lines Company Limited and to the Commerce Commission

The Auditor-General is the auditor of The Lines Company Limited (the company). The Auditor-General has appointed me, Matthew White, using the staff and resources of PricewaterhouseCoopers, to provide an opinion, on her behalf, on whether Schedules 1 to 4, 5a to 5g, 6a and 6b, 7, the SAIDI and SAIFI information disclosed in Schedule 10 and the explanatory notes in boxes 1 to 12 in Schedule 14 ('the Disclosure Information') for the disclosure year ended 31 March 2015, have been prepared, in all material respects, in accordance with the Electricity Distribution Disclosure Information Determination 2012 (the 'Determination').

Directors' responsibility for the Disclosure Information

The directors of the company are responsible for preparation of the Disclosure Information in accordance with the Determination, and for such internal control as the directors determine is necessary to enable the preparation of the Disclosure Information that is free from material misstatement.

Auditor's responsibility for the Disclosure Information

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

We conducted our engagement in accordance with the International Standard on Assurance Engagements (New Zealand) 3000: *Assurance Engagements Other Than Audits or Reviews of Historical Financial Information* issued by the External Reporting Board and the Standard on Assurance Engagements 3100: *Compliance Engagements* issued by the External Reporting Board.

These standards require that we comply with ethical requirements and plan and perform our audit to provide reasonable assurance (which is also referred to as 'audit' assurance) about whether the Disclosure Information has been prepared in all material respects in accordance with the Determination.

An audit involves performing procedures to obtain evidence about the amounts and disclosures in the Disclosure Information. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the Disclosure Information, whether due to fraud or error or non-compliance with the Determination. In making those risk assessments, the auditor considers internal control relevant to the company's preparation of the Disclosure Information in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the company's internal control.

An audit also involves evaluating:

- The appropriateness of assumptions used and whether they have been consistently applied; and
- The reasonableness of the significant judgements made by the directors of the company.

Independent Auditors' Report

To the Directors of The Lines Company Limited and to the Commerce Commission

Use of this report

This independent auditor's report has been prepared for the directors of the company and for the Commerce Commission for the purpose of providing those parties with independent audit assurance about whether the Disclosure Information has been prepared, in all material respects, in accordance with the Determination. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the company or the Commerce Commission, or for any other purpose than that for which it was prepared.

Scope and inherent limitations

Because of the inherent limitations of an audit engagement, and the test basis of the procedures performed, it is possible that fraud, error or non-compliance may occur and not be detected.

We did not examine every transaction, adjustment or event underlying the Disclosure Information nor do we guarantee complete accuracy of the Disclosure Information. Also we did not evaluate the security and controls over the electronic publication of the Disclosure Information.

The opinion expressed in this independent auditor's report has been formed on the above basis.

Independence

When carrying out the engagement we followed the independence requirements of the Auditor-General, which incorporate the independence requirements of the External Reporting Board. We also complied with the independent auditor requirements specified in the Determination.

The Auditor-General, and her employees, and PricewaterhouseCoopers and its Partners and employees may deal with the company on normal terms within the ordinary course of trading activities of the company. Other than any dealings on normal terms within the ordinary course of business, this engagement, Default Price-Quality Path Compliance audit, other 53ZD request audits, and other accounting and regulatory advice which are compatible with those independence requirements and the annual audit of the company's financial statements, we have no relationship with or interests in the company.

Basis for Qualified Opinion on Schedules 10(i) to 10 (iv)

As described in Box 14 of Schedule 14, there are inherent limitations in the ability of the company to collect and record the network reliability information required to be disclosed in Schedules 10(i) to 10(iv). Consequently there is no independent evidence available to support the completeness and accuracy of recorded faults, and control over the completeness and accuracy of interconnection point ('ICP') data included in the SAIDI and SAIFI calculations is limited throughout the year.

There are no practical audit procedures that we could adopt to confirm independently that all the faults and ICP data was properly recorded for the purposes of inclusion in the amounts relating to quality measures set out in Schedules 10(i) to 10(iv). Because of the potential effect of the limitations described above, we are unable to form an opinion as the completeness and accuracy of the data that forms the basis of the compilation of Schedules 10(i) to 10(iv).

In these respects alone we have not obtained all the recorded evidence and explanations that we have required.

Independent Auditors' Report

To the Directors of The Lines Company Limited and to the Commerce Commission

Qualified Opinion

In our opinion, except for the matters described in the Basis for Qualified Opinion paragraph above:

- As far as appears from an examination of them, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the company;
- The information used in the preparation of the Disclosure Information has been properly extracted from the company's accounting and other records and has been sourced, where appropriate, from the company's financial and non-financial systems; and
- The company has complied with the Determination, in all material respects, in preparing the Disclosure Information.

Matthew White
On behalf of the Auditor-General
Hamilton, New Zealand
19 August 2015

PricewaterhouseCoopers