OtagoNet Joint Venture

INFORMATION DISCLOSURE PREPARED IN ACCORDANCE WITH ELECTRICITY INFORMATION DISCLOSURE DETERMINATION UNDER PART 4 OF THE COMMERCE ACT 1986

FOR THE YEAR ENDED 31 MARCH 2015

CONTENTS

1. INTRODUCTION

These Information Disclosure documents are submitted by OtagoNet Joint Venture pursuant to Part 4 of the Commerce Act 1986 in accordance with:

- The Electricity Information Disclosure Determination 2012, (Consolidated in 2015), issued 24 March 2015,
- The Electricity Distribution Services Input Methodologies Determination 2012 (Consolidated in 2014), issued 30 March 2015.

2. INFORMATION DISCLOSURE DISCLAIMER

The information disclosed in this Information Disclosure package issued by OtagoNet Joint Venture has been prepared in accordance with the Determination listed above.

The Determination requires the information to be disclosed in the manner it is presented.

The information should not be used for any other purposes than that intended under the Determination.

The financial information presented is for the electricity distribution business as described within the Determination.

Due to rounding and automatic calculations in the spreadsheets there may be minor summing variances.

3. SCHEDULES

Company Name	**OtagoNet Joint Venture**
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

7 **1(i): Expenditure metrics**

sch ref		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)
8						
9	**Operational expenditure**	19,632	542	129,625	1,731	44,982
10	Network	8,300	229	54,804	732	19,018
11	Non-network	11,332	313	74,821	999	25,964
12						
13	**Expenditure on assets**	32,917	909	217,347	2,902	75,423
14	Network	32,196	889	212,586	2,838	73,771
15	Non-network	721	20	4,760	64	1,652
16						

17 **1(ii): Revenue metrics**

sch ref		Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
18			
19	**Total consumer line charge revenue**	86,050	2,375
20	Standard consumer line charge revenue	153,242	2,110
21	Non-standard consumer line charge revenue	19,199	1,308,741
22			

23 **1(iii): Service intensity measures**

sch ref			
24			
25	Demand density	13	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	88	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
27	Connection point density	3	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
28	Energy intensity	27,600	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*
29			

30 **1(iv): Composition of regulatory income**

sch ref		($000)	% of revenue
31			
32	Operational expenditure	8,009	22.38%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	8,243	23.04%
34	Total depreciation	6,858	19.17%
35	Total revaluations	123	0.34%
36	Regulatory tax allowance	2,902	8.11%
37	Regulatory profit/(loss) including financial incentives and wash-ups	9,892	27.65%
38	**Total regulatory income**	35,782	
39			

40 **1(v): Reliability**

sch ref			
41			
42	Interruption rate	14.02	*Interruptions per 100 circuit km*

Company Name	OtagoNet Joint Venture
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).

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	6.77%	6.73%	5.81%
11	Excluding revenue earned from financial incentives	6.77%	6.73%	5.81%
12	Excluding revenue earned from financial incentives and wash-ups	6.77%	6.73%	5.81%
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%
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	7.55%	7.42%	6.59%
21	Excluding revenue earned from financial incentives	7.55%	7.42%	6.59%
22	Excluding revenue earned from financial incentives and wash-ups	7.55%	7.42%	6.59%
24	**WACC rate used to set regulatory price path**	8.77%	8.77%	8.77%
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%

sch ref				($000)	
30		**2(ii): Information Supporting the ROI**			
32		Total opening RAB value	147,443		
33	*plus*	Opening deferred tax	(3,035)		
34		**Opening RIV**		144,408	
36		**Line charge revenue**		35,105	
38		Expenses cash outflow	16,252		
39	*add*	Assets commissioned	23,814		
40	*less*	Asset disposals	880		
41	*add*	Tax payments	1,420		
42	*less*	Other regulated income	676		
43		**Mid-year net cash outflows**		39,930	
45		**Term credit spread differential allowance**		–	
47		Total closing RAB value	163,642		
48	*less*	Adjustment resulting from asset allocation	(0)		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(4,517)		
51		**Closing RIV**		159,125	
53		**ROI – comparable to a vanilla WACC**			6.59%
55		Leverage (%)			44%
56		Cost of debt assumption (%)			6.36%
57		Corporate tax rate (%)			28%
59		**ROI – comparable to a post tax WACC**			5.81%

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	6.33%
Year-end ROI – comparable to a post tax WACC	5.54%

** 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	**OtagoNet Joint Venture**
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

sch ref			($000)
7		**3(i): Regulatory Profit**	**($000)**
8		**Income**	
9		Line charge revenue	35,105
10	*plus*	Gains / (losses) on asset disposals	3
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	674
12			
13		**Total regulatory income**	35,782
14		**Expenses**	
15	*less*	Operational expenditure	8,009
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	8,243
18			
19		**Operating surplus / (deficit)**	19,530
20			
21	*less*	Total depreciation	6,858
22			
23	*plus*	Total revaluations	123
24			
25		**Regulatory profit / (loss) before tax**	12,795
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	2,902
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	9,892
32			

sch ref		($000)	
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34	**Pass through costs**		
35	Rates	104	
36	Commerce Act levies	70	
37	Industry levies	79	
38	CPP specified pass through costs	–	
39	**Recoverable costs excluding financial incentives and wash-ups**		
40	Electricity lines service charge payable to Transpower	7,923	
41	Transpower new investment contract charges	66	
42	System operator services	–	
43	Distributed generation allowance	–	
44	Extended reserves allowance	–	
45	Other recoverable costs excluding financial incentives and wash-ups	–	
46	**Pass-through and recoverable costs excluding financial incentives and wash-ups**		8,243
47			

sch ref				
48	**3(iii): Incremental Rolling Incentive Scheme**		**($000)**	
49			**CY-1**	**CY**
50			**31 Mar 14**	**0 Jan 00**
51	Allowed controllable opex		–	–
52	Actual controllable opex		–	–
53				
54	Incremental change in year			–
55				
56			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
57	CY-5	31 Mar 10	–	–
58	CY-4	31 Mar 11	–	–
59	CY-3	31 Mar 12	–	–
60	CY-2	31 Mar 13	–	–
61	CY-1	31 Mar 14	–	–
62	**Net incremental rolling incentive scheme**			–
63				
64	**Net recoverable costs allowed under incremental rolling incentive scheme**			–

sch ref		
65	**3(iv): Merger and Acquisition Expenditure**	
70		**($000)**
66	Merger and acquisition expenditure	–
67		
68	*Provide commentary on the benefits of merger and acquisition expenditure to the electricity distribution business, including required disclosures in accordance with section 2.7, in Schedule 14 (Mandatory Explanatory Notes)*	
69	**3(v): Other Disclosures**	
70		**($000)**
71	Self-insurance allowance	–

Company Name	OtagoNet Joint Venture
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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)

	RAB	RAB	RAB	RAB	RAB
for year ended	31 Mar 11	31 Mar 12	31 Mar 13	31 Mar 14	31 Mar 15
	($000)	($000)	($000)	($000)	($000)
Total opening RAB value	133,333	137,890	139,704	144,589	147,443
less **Total depreciation**	5,918	6,172	6,395	6,607	6,858
plus **Total revaluations**	3,195	2,141	1,188	2,195	123
plus **Assets commissioned**	7,321	6,030	10,102	7,285	23,814
less **Asset disposals**	41	184	10	19	880
plus **Lost and found assets adjustment**	–	–	–	–	–
plus **Adjustment resulting from asset allocation**	–	–	–	0	(0)
Total closing RAB value	137,890	139,704	144,589	147,443	163,642

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Total opening RAB value		147,443		147,443
less				
Total depreciation		6,858		6,858
plus				
Total revaluations		123		123
plus				
Assets commissioned (other than below)	8,081		8,081	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	15,734		15,734	
Assets commissioned		23,814		23,814
less				
Asset disposals (other than below)	14		14	
Asset disposals to a regulated supplier	–		–	
Asset disposals to a related party	866		866	
Asset disposals		880		880
plus **Lost and found assets adjustment**		–		–
plus **Adjustment resulting from asset allocation**				(0)
Total closing RAB value		163,642		163,642

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

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

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

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Total opening RAB value	147,443		147,443	
less Opening value of fully depreciated, disposed and lost assets	1,060		1,060	
Total opening RAB value subject to revaluation	146,383		146,383	
Total revaluations		123		123

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction		Allocated works under construction	
Works under construction—preceding disclosure year		5,896		5,896
plus Capital expenditure	11,393		11,393	
plus Assets acquired through amalgamation of another entity	9,398		9,398	
less Assets commissioned	23,814		23,814	
plus Adjustment resulting from asset allocation			–	
Works under construction - current disclosure year		2,872		2,872

Highest rate of capitalised finance applied	–

4(v): Regulatory Depreciation

	Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
Depreciation - standard	6,731		6,731	
Depreciation - no standard life assets	127		127	
Depreciation - modified life assets	–		–	
Depreciation - alternative depreciation in accordance with CPP	–		–	
Total depreciation		6,858		6,858

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	17,533	180	24,439	75,497	2,587	17,715	5,746	1,543	2,204	147,443
less	Total depreciation	1,003	4	1,280	3,197	103	662	322	129	158	6,858
plus	Total revaluations	14	0	21	63	2	14	5	1	2	123
plus	Assets commissioned	3,045	967	4,958	6,813	4,076	2,374	900	387	294	23,814
less	Asset disposals	–	–	–	–	–	14	–	–	866	880
plus	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
plus	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
plus	Asset category transfers	–	–	–	–	–	–	–	–	–	–
	Total closing RAB value	19,589	1,143	28,138	79,175	6,562	19,428	6,329	1,802	1,476	163,642
	Asset Life										
	Weighted average remaining asset life	22.4	53.4	32.3	26.3	47.2	29.1	20.2	23.4	27.9	(years)
	Weighted average expected total asset life	52.1	54.2	45.8	54.5	50.3	50.0	38.0	32.4	53.9	(years)

Company Name	**OtagoNet Joint Venture**
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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**		12,795	
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	1		*
12		Amortisation of initial differences in asset values	1,366		
13		Amortisation of revaluations	245		
14				1,612	
15					
16	*less*	Total revaluations	123		
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	3,918		
21				4,041	
22					
23		**Regulatory taxable income**		10,365	
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income		10,365	
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		2,902	
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	35,517		
37	*less*	Amortisation of initial differences in asset values	1,366		
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		34,151	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		26	
43					

5a(iv): Amortisation of Revaluations

			($000)
	Opening sum of RAB values without revaluations	138,724	
	Adjusted depreciation	6,613	
	Total depreciation	6,858	
	Amortisation of revaluations		245

5a(v): Reconciliation of Tax Losses

			($000)
	Opening tax losses	–	
plus	Current period tax losses	–	
less	Utilised tax losses	–	
	Closing tax losses		–

5a(vi): Calculation of Deferred Tax Balance

			($000)
	Opening deferred tax	(3,035)	
plus	Tax effect of adjusted depreciation	1,852	
less	Tax effect of tax depreciation	3,114	
plus	Tax effect of other temporary differences*	179	
less	Tax effect of amortisation of initial differences in asset values	382	
plus	Deferred tax balance relating to assets acquired in the disclosure year	–	
less	Deferred tax balance relating to assets disposed in the disclosure year	17	
plus	Deferred tax cost allocation adjustment	0	
	Closing deferred tax		(4,517)

5a(vii): Disclosure of Temporary Differences

In Schedule 14, Box 6, provide descriptions and workings of items recorded in the asterisked category in Schedule 5a(vi) (Tax effect of other temporary differences).

5a(viii): Regulatory Tax Asset Base Roll-Forward

			($000)
	Opening sum of regulatory tax asset values	90,598	
less	Tax depreciation	11,121	
plus	Regulatory tax asset value of assets commissioned	23,390	
less	Regulatory tax asset value of asset disposals	700	
plus	Lost and found assets adjustment	–	
plus	Adjustment resulting from asset allocation	–	
plus	Other adjustments to the RAB tax value	–	
	Closing sum of regulatory tax asset values		102,167

Company Name	**OtagoNet Joint Venture**
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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

7 5b(i): Summary—Related Party Transactions

sch ref		($000)
8	Total regulatory income	–
9	Operational expenditure	6,482
10	Capital expenditure	5,672
11	Market value of asset disposals	128
12	Other related party transactions	9,523

13 5b(ii): Entities Involved in Related Party Transactions

14	Name of related party	Related party relationship
15	Otago Power Services Limited	Same ownership as OtagoNet until 30 March 2015
16	PowerNet Limited	Common Ownership varied from 49% to 100% during the year
17	Marlborough Lines Limited	51% Ownership of OtagoNet until 30 September 2014
18	Electricity Southland Limited	Same ownership as OtagoNet at 31 March 2015
19		

20 ** include additional rows if needed*

21 5b(iii): Related Party Transactions

22	Name of related party	Related party transaction type	Description of transaction	Value of transaction ($000)	Basis for determining value
23	Otago Power Services Limited	Opex	Maintenance provided to OtagoNet	3,386	ID clause 2.3.6(1)(f)
24	Otago Power Services Limited	Capex	Construction provided to OtagoNet	5,672	IM clause 2.2.11(5)(h)
25	PowerNet Limited	Opex	Business support and system control	2,505	ID clause 2.3.6(1)(f)
26	Marlborough Lines Limited	Opex	Engineering Services	209	ID clause 2.3.6(1)(f)
27	PowerNet Limited	Sales	Rent	10	ID clause 2.3.7(2)(a)
28	PowerNet Limited	Capex	Asset disposals	128	ID clause 2.3.7(2)(a)
29	Otago Power Services Limited	Sales	Rent	88	ID clause 2.3.7(2)(a)
30	PowerNet Limited	Sales	Engineerng Services	27	ID clause 2.3.6(1)(f)
31	Electricity Southland Limited	Other	Assets commissioned from Electricity Southland Limited	9,398	ID clause 2.3.6(1)(a)
32	PowerNet Limited	Opex	System Control services provdied	381	ID clause 2.3.6(1)(a)
33		[Select one]			[Select one]
34		[Select one]			[Select one]
35		[Select one]			[Select one]
36		[Select one]			[Select one]
37		[Select one]			[Select one]

38 ** include additional rows if needed*

Company Name	**OtagoNet Joint Venture**
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)

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

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

sch ref			
20	**Gross term credit spread differential**		–
22	Total book value of interest bearing debt	–	
23	Leverage	44%	
24	Average opening and closing RAB values	–	
25	**Attribution Rate (%)**		–
27	**Term credit spread differential allowance**		–

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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

7 5d(i): Operating Cost Allocations

sch ref		Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
8		Value allocated ($000s)				
10	**Service interruptions and emergencies**					
11	Directly attributable		1,209			
12	Not directly attributable	–	–	–	–	–
13	**Total attributable to regulated service**		1,209			
14	**Vegetation management**					
15	Directly attributable		1,192			
16	Not directly attributable	–	–	–	–	–
17	**Total attributable to regulated service**		1,192			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		880			
20	Not directly attributable	–	–	–	–	–
21	**Total attributable to regulated service**		880			
22	**Asset replacement and renewal**					
23	Directly attributable		105			
24	Not directly attributable	–	–	–	–	–
25	**Total attributable to regulated service**		105			
26	**System operations and network support**					
27	Directly attributable		3,008			
28	Not directly attributable	–	–	–	–	–
29	**Total attributable to regulated service**		3,008			
30	**Business support**					
31	Directly attributable		1,615			
32	Not directly attributable	–	–	–	–	–
33	**Total attributable to regulated service**		1,615			
35	**Operating costs directly attributable**		8,009			
36	**Operating costs not directly attributable**	–	–	–	–	–
37	**Operational expenditure**		8,009			

39 5d(ii): Other Cost Allocations

sch ref		($000)
40	**Pass through and recoverable costs**	
41	**Pass through costs**	
42	Directly attributable	254
43	Not directly attributable	–
44	**Total attributable to regulated service**	254
45	**Recoverable costs**	
46	Directly attributable	7,989
47	Not directly attributable	–
48	**Total attributable to regulated service**	7,989

50 5d(iii): Changes in Cost Allocations* †

sch ref				($000) CY-1	Current Year (CY)
52	**Change in cost allocation 1**				
53	Cost category		Original allocation		
54	Original allocator or line items		New allocation		
55	New allocator or line items		Difference	–	–
57	Rationale for change				
61	**Change in cost allocation 2**				
62	Cost category		Original allocation		
63	Original allocator or line items		New allocation		
64	New allocator or line items		Difference	–	–
66	Rationale for change				
70	**Change in cost allocation 3**				
71	Cost category		Original allocation		
72	Original allocator or line items		New allocation		
73	New allocator or line items		Difference	–	–
75	Rationale for change				

78 ** 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.*
79 *† include additional rows if needed*

Company Name	**OtagoNet Joint Venture**
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	19,589
Not directly attributable	–
Total attributable to regulated service	19,589
Subtransmission cables	
Directly attributable	1,143
Not directly attributable	–
Total attributable to regulated service	1,143
Zone substations	
Directly attributable	28,138
Not directly attributable	–
Total attributable to regulated service	28,138
Distribution and LV lines	
Directly attributable	79,175
Not directly attributable	–
Total attributable to regulated service	79,175
Distribution and LV cables	
Directly attributable	6,562
Not directly attributable	–
Total attributable to regulated service	6,562
Distribution substations and transformers	
Directly attributable	19,428
Not directly attributable	–
Total attributable to regulated service	19,428
Distribution switchgear	
Directly attributable	6,329
Not directly attributable	–
Total attributable to regulated service	6,329
Other network assets	
Directly attributable	1,802
Not directly attributable	–
Total attributable to regulated service	1,802
Non-network assets	
Directly attributable	1,476
Not directly attributable	–
Total attributable to regulated service	1,476
Regulated service asset value directly attributable	163,642
Regulated service asset value not directly attributable	–
Total closing RAB value	163,642

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

			($000) CY-1	Current Year (CY)
Change in asset value allocation 1				
Asset category	Distribution and LV Lines Closing RAB	Original allocation	76,249	–
Original allocator or line items	Distribution and LV Lines	New allocation	75,497	–
New allocator or line items	Distribution and LV Cables	Difference	752	–
Rationale for change	One line item of cables was included in the Disribution Lines total - now transferred to Distribution Cables			

			($000) CY-1	Current Year (CY)
Change in asset value allocation 2				
Asset category	Distribution and LV Cables Closing RAB	Original allocation	1,835	–
Original allocator or line items	Distribution and LV Cables	New allocation	2,587	–
New allocator or line items	Distribution and LV Lines	Difference	(752)	–
Rationale for change	One line item of cables was included in the Disribution Lines total - now transferred from Distribution Lines			

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

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

Company Name	**OtagoNet Joint Venture**
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				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		2,838
9		System growth		2,063
10		Asset replacement and renewal		5,890
11		Asset relocations		152
12		Reliability, safety and environment:		
13		Quality of supply	–	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	2,192	
16		**Total reliability, safety and environment**		2,192
17		**Expenditure on network assets**		13,135
18		Expenditure on non-network assets		294
19				
20		**Expenditure on assets**		13,429
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		2,036
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		11,393
26		**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		35
29		Research and development		–
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Consumer Connections < 20 kVa	627	
33		Consumer Connections 21-99 kVa	1,057	
34		Consumer Connections > 100 kVa	1,154	
35		[EDB consumer type]	–	
36		[EDB consumer type]	–	
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		2,838
39				
40	*less*	Capital contributions funding consumer connection expenditure	1,675	
41		**Consumer connection less capital contributions**		1,163
42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement**
43			**System Growth**	**and Renewal**
44			**($000)**	**($000)**
45		Subtransmission	644	623
46		Zone substations	91	274
47		Distribution and LV lines	1,253	4,799
48		Distribution and LV cables	–	–
49		Distribution substations and transformers	–	35
50		Distribution switchgear	63	158
51		Other network assets	11	–
52		**System growth and asset replacement and renewal expenditure**	2,063	5,890
53	*less*	Capital contributions funding system growth and asset replacement and renewal	–	15
54		**System growth and asset replacement and renewal less capital contributions**	2,063	5,875
55				
56		**6a(v): Asset Relocations**		
57		*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	152	
65		**Asset relocations expenditure**		152
66	*less*	Capital contributions funding asset relocations	346	
67		**Asset relocations less capital contributions**		(194)

6a(vi): Quality of Supply

	Project or programme*	($000)	($000)
	[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 programmes - quality of supply	–	
	Quality of supply expenditure		–
less	Capital contributions funding quality of supply	–	
	Quality of supply less capital contributions		–

6a(vii): Legislative and Regulatory

	Project or programme*	($000)	($000)
	[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

	Project or programme*	($000)	($000)
	Transpower Palmerston and 110kV line purchase	1,231	
	[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 - other reliability, safety and environment	961	
	Other reliability, safety and environment expenditure		2,192
less	Capital contributions funding other reliability, safety and environment	–	
	Other reliability, safety and environment less capital contributions		2,192

6a(ix): Non-Network Assets

Routine expenditure

Project or programme*	($000)	($000)
Plant	243	
[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 - routine expenditure	51	
Routine expenditure		294

Atypical expenditure

Project or programme*	($000)	($000)
[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 - atypical expenditure	–	
Atypical expenditure		–
Expenditure on non-network assets		294

Company Name	**OtagoNet Joint Venture**
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	1,209	
9	Vegetation management	1,192	
10	Routine and corrective maintenance and inspection	880	
11	Asset replacement and renewal	105	
12	**Network opex**		3,386
13	System operations and network support	3,008	
14	Business support	1,615	
15	**Non-network opex**		4,623
16			
17	**Operational expenditure**		8,009
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		–
20	Direct billing*		–
21	Research and development		–
22	Insurance		196
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**OtagoNet Joint Venture**
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				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	35,127	35,105	(0%)
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	1,000	2,838	184%
11	System growth	1,779	2,063	16%
12	Asset replacement and renewal	4,520	5,890	30%
13	Asset relocations	1,405	152	(89%)
14	Reliability, safety and environment:			
15	Quality of supply	600	–	(100%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	2,090	2,192	5%
18	**Total reliability, safety and environment**	2,690	2,192	(19%)
19	**Expenditure on network assets**	11,394	13,135	15%
20	Expenditure on non-network assets	–	294	–
21	Expenditure on assets	11,394	13,429	18%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,658	1,209	(27%)
24	Vegetation management	850	1,192	40%
25	Routine and corrective maintenance and inspection	1,094	880	(20%)
26	Asset replacement and renewal	616	105	(83%)
27	**Network opex**	4,218	3,386	(20%)
28	System operations and network support	2,025	3,008	49%
29	Business support	1,507	1,615	7%
30	**Non-network opex**	3,532	4,623	31%
31	**Operational expenditure**	7,750	8,009	3%
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	–
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	–	–	–
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	–	196	–
42				

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

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

Company Name	**OtagoNet Joint Venture**
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					
				Price component	Variable day energy sales	Variable night energy sales	Variable day energy purchases	Variable night energy purchases		
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)** / **Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)**	kWh	Kwh	kwh	kwh	kw of Demand	Kva of Capacity
1	Residential	Standard	7,505	49,039	–	–	39,952,387	14,877,011	–	–
2	Commerical	Standard	3,380	61,542	–	–	50,138,754	18,670,093	–	–
3	Commerical	Standard	45	20,164	14,845,065	5,319,324	–	–	85,296	156,860
4	Commerical	Standard	28	53,780	7,314,668	–	–	–	–	–
5	unmetered	Standard	95	10	–	–	8,468	3,153	–	–
6	Street lights	Standard	9	98	–	–	79,939	29,767	–	–
7 & 8	Low user	Standard	3,717	18,830	14,122,291	4,707,430	–	–	–	–
Non Standard	Commerical	Non-standard	3	204,499	–	–	–	–	–	–
		[Select one]	–	–	–	–	–	–	–	–
		[Select one]	–	–	–	–	–	–	–	–
		Standard consumer totals	14,778	203,464	36,282,025	10,026,754	90,179,549	33,580,024	85,296	156,860
		Non-standard consumer totals	3	204,499	–	–	–	–	–	–
		Total for all consumers	14,781	407,962	36,282,025	10,026,754	90,179,549	33,580,024	85,296	156,860

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

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)	Line charge revenues ($000) by price component					
						Price component	Fixed	Variable - Day	Variable Night	Max Demand	Kva	
						Rate (eg, $ per day, $ per kWh, etc.)	$/Day	$/kwh	$/kWh	$/MD	4/kVa	
1	Residential	Standard	$10,125	–	$8,666	$1,459	$4,535	$5,359	$231	–	–	
2	Commerical	Standard	$12,905	–	$11,035	$1,870	$5,891	$6,725	$289	–	–	
3	Commerical	Standard	$1,929	–	$1,644	$285	–	$958	$37	$295	$639	
4	Commerical	Standard	$2,264	–	$804	$1,460	$1,943	$321	–	–	–	
5	unmetered	Standard	$33	–	$28	$5	$32	$1	$0	–	–	
6	Street lights	Standard	$134	–	$114	$20	$123	$11	$0	–	–	
7 & 8	Low user	Standard	$3,444	–	$2,936	$509	$208	$3,120	$117	–	–	
Non Standard	Commerical	Non-standard	$3,926	–	$577	$3,349	$3,926	–	–	–	–	
Generation		Standard	$346	–	$346	–	$346	–	–	–	–	
		[Select one]	–	–	–	–	–	–	–	–	–	
Add extra rows for additional consumer groups or price category codes as necessary												
		Standard consumer totals	$31,179	–	$25,572	$5,607	$13,076	$16,495	$674	$295	$639	–
		Non-standard consumer totals	$3,926	–	$577	$3,349	$3,926	–	–	–	–	–
		Total for all consumers	$35,105	–	$26,149	$8,956	$17,003	$16,495	$674	$295	$639	–

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

Check OK

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	

Company Name: OtagoNet Joint Venture
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

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	31,317	37,093	5,776	3
10	All	Overhead Line	Wood poles	No.	16,634	11,470	(5,164)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	614	614	0	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	93	94	0	3
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	2	8	6	4
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.	35	42	7	3
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	1	1	–	3
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	8	8	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	171	170	(1)	3
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	7	7	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	27	28	1	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	35	43	8	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	69	70	1	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	42	47	5	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,340	2,381	41	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	931	921	(9)	3
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	25	49	24	3
39	HV	Distribution Cable	Distribution UG PILC	km	2	4	2	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	12	14	2	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	N/A
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	5,702	5,746	44	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	2	2	N/A
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	8	27	19	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,059	4,081	22	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	151	188	37	3
48	HV	Distribution Transformer	Voltage regulators	No.	24	33	9	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	17	17	N/A
50	LV	LV Line	LV OH Conductor	km	508	515	7	2
51	LV	LV Cable	LV UG Cable	km	30	42	12	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	19	76	57	3
53	LV	Connections	OH/UG consumer service connections	No.	15,629	16,070	441	2
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	184	192	8	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	2	1	4
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	4	4	–	4
58	All	Load Control	Relays	No	–	–	–	1
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	**OtagoNet Joint Venture**
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 (quantity)**	**No. with default dates**	**Data accuracy (1–4)**
10	All	Overhead Line	Concrete poles / steel structure	No.	261	803	4,869	4,180	4,917	6,683	5,105	548	933	567	621	232	116	40	42	185	934	992	1,066	991	830	828	317	1,033	37,093	–	3
11	All	Overhead Line	Wood poles	No.	29	444	2,517	1,642	978	860	853	51	89	84	212	145	518	602	820	655	219	32	8	10	15	83	21	583	11,470	–	3
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	26	71	160	117	83	67	0	4	3	19	3	–	1	2	–	2	2	–	50	1	1	–	2	614	–	3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	47	–	47	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	94	–	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	0	–	0	–	0	–	–	–	0	1	–	–	1	–	6	–	–	–	–	–	–	0	8	–	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	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.	–	–	2	10	9	5	6	–	–	–	–	–	–	1	1	2	1	–	1	–	1	–	–	3	42	–	3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–		–	–	–	–	–	–	–	1	–	3
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	7	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	8	–	4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	11	21	18	51	23	–	1	1	8	–	6	2	3	9	–	3	5	6	–	2	–	–	170	–	3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	–	–	–	–	–	–	–	7	–	4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	2	1	11	6	–	–	–	–	–	–	1	1	–	–	–	2	2	1	–	1	–	28	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	2	–	–	10	–	–	–	–	–	3	8	2	–	–	9	–	–	9	–	–	–	43	–	4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	1	11	14	30	–	1	–	–	2	4	1	–	–	3	1	–	–	–	2	–	–	70	–	4
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	5	8	7	7	2	–	–	–	–	–	–	6	3	1	–	1	–	2	3	2	–	–	47	–	4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	4	35	184	236	271	331	356	80	96	55	43	26	50	35	65	60	69	104	50	64	80	27	12	48	2,381	–	3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
38	HV	Distribution Line	SWER conductor	km	–	–	214	124	100	160	118	4	2	3	12	2	5	20	3	10	20	11	49	37	7	15	1	4	921	–	3
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	0	0	2	0	3	1	0	1	1	3	2	1	2	1	5	1	1	1	4	6	–	16	49	–	3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	1	–	–	–	–	–	–	–	–	0	0	–	–	0	–	–	1	–	2	–	1	4	–	3
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	1	2	–	–	–	–	–	–	–	3	1	2	–	3	–	–	–	1	1	–	14	–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	34	785	876	1,112	633	577	37	127	109	86	85	133	137	149	144	140	132	103	100	59	73	31	84	5,746	–	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	2	–	N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	–	–	3	–	1	–	2	–	–	1	–	1	6	3	–	–	3	7	–	–	27	–	4
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	33	770	632	608	441	483	28	87	79	58	57	90	92	112	103	87	81	65	59	43	49	24	–	4,081	–	3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	5	34	7	25	2	3	1	4	1	8	5	13	13	12	10	4	15	9	14	3	–	188	–	3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	3	–	1	1	4	–	–	–	1	2	2	–	–	1	2	2	–	2	2	4	6	–	33	–	4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	4	2	–	–	3	7	–	–	17	–	N/A
51	LV	LV Line	LV OH Conductor	km	1	5	159	35	41	11	6	0	1	4	2	1	3	3	4	2	1	2	2	2	2	2	1	225	515	–	2
52	LV	LV Cable	LV UG Cable	km	–	–	0	1	4	2	0	–	0	0	1	2	2	1	6	2	1	1	3	1	1	5	0	7	42	–	3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	0	0	–	–	–	–	–	–	–	–	–	0	0	1	–	0	0	0	–	–	–	74	76	–	3
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	11,264	935	110	102	499	556	546	528	452	222	142	108	110	96	118	205	77	–	16,070	9,229	2
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	12	37	42	–	6	–	1	7	4	13	9	16	7	15	3	2	14	1	2	1	192	–	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	2	–	4
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	2	–	1	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	4	–	4
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A

Company Name	**OtagoNet Joint Venture**
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	94	–	94
12	50kV & 66kV	74	–	74
13	33kV	540	8	547
14	SWER (all SWER voltages)	921	3	924
15	22kV (other than SWER)	–	17	17
16	6.6kV to 11kV (inclusive—other than SWER)	2,381	34	2,414
17	Low voltage (< 1kV)	515	42	557
18	**Total circuit length (for supply)**	4,525	103	4,628
19				
20	Dedicated street lighting circuit length (km)	76	1	76
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			–
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	341	8%	
25	Rural	1,132	25%	
26	Remote only	713	16%	
27	Rugged only	1,779	39%	
28	Remote and rugged	560	12%	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	4,525	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	985	21%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	721	16%	

Company Name	**OtagoNet Joint Venture**
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	**OtagoNet Joint Venture**
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

sch ref				
8	**9e(i): Consumer Connections**			
9	*Number of ICPs connected in year by consumer type*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11	Residential		62	
12	Commercial		37	
13	[EDB consumer type]		–	
14	[EDB consumer type]		–	
15	[EDB consumer type]		–	
16	** include additional rows if needed*			
17	**Connections total**		99	
18				
19	**Distributed generation**			
20	Number of connections made in year		47	**connections**
21	Capacity of distributed generation installed in year		0.17	**MVA**

sch ref				
22	**9e(ii): System Demand**			
23				
24			**Demand at time of maximum coincident demand (MW)**	
25	**Maximum coincident system demand**			
26		GXP demand	54	
27	*plus*	Distributed generation output at HV and above	7	
28		**Maximum coincident system demand**	62	
29	*less*	Net transfers to (from) other EDBs at HV and above	–	
30		**Demand on system for supply to consumers' connection points**	62	
31	**Electricity volumes carried**		**Energy (GWh)**	
32		Electricity supplied from GXPs	330	
33	*less*	Electricity exports to GXPs	–	
34	*plus*	Electricity supplied from distributed generation	96	
35	*less*	Net electricity supplied to (from) other EDBs	–	
36		**Electricity entering system for supply to consumers' connection points**	426	
37	*less*	Total energy delivered to ICPs	408	
38		**Electricity losses (loss ratio)**	18	4.2%
39				
40		**Load factor**	0.79	

sch ref		
41	**9e(iii): Transformer Capacity - Engineering / Commercial**	
42		**(MVA)**
43	Distribution transformer capacity (EDB owned)	178
44	Distribution transformer capacity (Non-EDB owned, estimated)	42
45	**Total distribution transformer capacity**	220
46		
47	**Zone substation transformer capacity**	170

Company Name	**OtagoNet Joint Venture**
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(i): Interruptions

sch ref		Number of interruptions
8	**10(i): Interruptions**	
9	**Interruptions by class**	
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	422
12	Class C (unplanned interruptions on the network)	226
13	Class D (unplanned interruptions by Transpower)	1
14	Class E (unplanned interruptions of EDB owned generation)	–
15	Class F (unplanned interruptions of generation owned by others)	–
16	Class G (unplanned interruptions caused by another disclosing entity)	–
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	–
19	**Total**	649
20		

sch ref		≤3Hrs	>3hrs
21	**Interruption restoration**		
22	Class C interruptions restored within	142	84
23			

sch ref		SAIFI	SAIDI
24	**SAIFI and SAIDI by class**		
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.50	133.1
27	Class C (unplanned interruptions on the network)	2.77	222.9
28	Class D (unplanned interruptions by Transpower)	0.11	1.7
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)	–	–
34	**Total**	3.39	357.7
35			

sch ref		Normalised SAIFI	Normalised SAIDI
36	**Normalised SAIFI and SAIDI**		
37	Classes B & C (interruptions on the network)	3.27	353.2
38			

sch ref		SAIFI reliability limit	SAIDI reliability limit
39	**Quality path normalised reliability limit**		
40	SAIFI and SAIDI limits applicable to disclosure year*	3.11	361.1
41	** not applicable to exempt EDBs*		

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

sch ref		SAIFI	SAIDI
42	**10(ii): Class C Interruptions and Duration by Cause**		
43			
44	**Cause**		
45	Lightning	0.11	10.5
46	Vegetation	0.30	26.5
47	Adverse weather	0.45	43.7
48	Adverse environment	0.03	3.9
49	Third party interference	0.22	37.8
50	Wildlife	–	–
51	Human error	0.25	6.0
52	Defective equipment	1.00	81.1
53	Cause unknown	0.52	15.2
54			

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

sch ref		SAIFI	SAIDI
55	**10(iii): Class B Interruptions and Duration by Main Equipment Involved**		
56			
57	**Main equipment involved**		
58	Subtransmission lines	0.00	0.0
59	Subtransmission cables	–	–
60	Subtransmission other	–	–
61	Distribution lines (excluding LV)	0.45	119.0
62	Distribution cables (excluding LV)	0.00	0.7
63	Distribution other (excluding LV)	0.05	13.3

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

sch ref		SAIFI	SAIDI
64	**10(iv): Class C Interruptions and Duration by Main Equipment Involved**		
65			
66	**Main equipment involved**		
67	Subtransmission lines	1.02	56.1
68	Subtransmission cables	–	–
69	Subtransmission other	0.00	0.2
70	Distribution lines (excluding LV)	1.48	157.9
71	Distribution cables (excluding LV)	0.00	0.0
72	Distribution other (excluding LV)	0.26	8.7

10(v): Fault Rate

sch ref		Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
73	**10(v): Fault Rate**			
74	**Main equipment involved**			
75	Subtransmission lines	17	625	2.72
76	Subtransmission cables	–	1	–
77	Subtransmission other	1		
78	Distribution lines (excluding LV)	187	3,203	5.84
79	Distribution cables (excluding LV)	1	12	8.33
80	Distribution other (excluding LV)	20		
81	**Total**	226		

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

OtagoNet achieved a post-tax WACC of 5.81% below the 75th percentile estimate of post-tax WACC of 6.82% and 6.59% vanilla WACC below the 75th percentile estimate of vanilla WACC of 7.60%.

No items were reclassified.

Regulatory Profit (Schedule 3)

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

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

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

Box 2: Explanatory comment on regulatory profit

Included in other regulated income is an amount of $457k for TransPower Losses and Constraints.

No items were reclassified in the disclosure year.

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

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

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

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

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

Value of the Regulatory Asset Base (Schedule 4)

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

Box 4: Explanatory comment on the value of the regulatory asset based (rolled forward)
The calculation of the Regulatory Asset Base used the 31 March 2014 figure as the starting point with inflationary indexing over the year to 31 March 2015 plus additions less disposals. Additions included the acquired assets of Electricity Southland Limited. These assets were brought in at their book value as at 31 March 2015. Because no separate row existed to bring these assets in, they have been included as assets from a related party. The opening RAB also included a number of non-network assets that have been identified as not line assets and these have been removed. The value of these assets was $701k.

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
An amount of $1k relates to legal expenses not tax deductible. No other permanent differences were added or deducted.

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

	'000
2015 Payroll Provisions	$ 93
Capital Contributions:	$ 548
	$ 641
Tax Rate:	28%
Temporary Differences	$ 179

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

The OtagoNet Joint Venture comprises :

Marlborough Lines Ltd	0%,	51% until 30 September 2014
Electricity Invercargill Ltd	24.9%	24.5% until 30 September 2014
The Power Company	75.1%	24.5% until 30 September 2014

Otago Power Services Limited owned 50/50 by The Power Company Limited and Electricity Invercargill Limited, previously (until 30 March 2015) had the same ownership as OtagoNet Joint Venture. Otago Power Services Limited undertakes contracting services to maintain and develop the OtagoNet electrical network.

PowerNet Limited is owned 50/50 by Electricity Invercargill Limited and The Power Company Limited who together own 100% of OtagoNet Joint Venture (previously 49% of OtagoNet Joint Venture). PowerNet Limited provides network management, project management, system control, finance, regulatory, commercial, corporate services, IT management and software services to OtagoNet Joint Venture.

Marlborough Lines Limited until 30 September 2014 owned 51% of OtagoNet Joint Venture. Marlborough Lines Limited provided engineering services to OtagoNet Joint Venture.

Electricity Southland Limited has the same ownership as OtagoNet (75.1% owned by The Power Company Limited and 24.9% owned by Electricity Invercargill Limited). The Assets of Electricity Southland Limited were incorporated into the OtagoNet Joint Venture on 31 March 2015.

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
All disclosed costs were directly attributable to the operations of OtagoNet Joint Venture.

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
All assets were directly attributable to the operations of OtagoNet. An error in the allocation of a group of cable assets into lines distribution in previous years was identified and adjusted by correctly allocating the assets in the Opening RAB of schedule 4 (vii). Non-line assets, previously included in the RAB have now been excluded.

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
No material programmes or projects were identified during the disclosure year other than OtagoNet purchased some further assets related to the Halfway Bush to Palmerston 110 kVA lines and Palmerston substation from Transpower. The Electricity Southland Limited assets, as mentioned in box 4, have now been incorporated into the RAB. No items were reclassified during the disclosure year.

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 operating 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
Reactive and minor maintenance is performed on OtagoNet transformers and lines that are classified as refurbishment and renewal maintenance when the work performed is not material in relation to the overall value of the asset. No items were reclassified during the disclosure year. There was no material atypical expenditure disclosed in Schedule 6b.

Variance between forecast and actual expenditure (Schedule 7)

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

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

Capital Expenditure on Assets:

The actual expenditure on assets was 18% over budget.
Consumer connection:

- 184% overspend was attributed to an unexpected increase in dairy conversions and large irrigation projects in the Maniototo area.

System Growth:

- 16% overspend was a consequence of the increased connections above and the unexpected line reinforcements required.

Asset replacement and renewal:

- 30% overspend resulting from advanced condition assessment resulting in line and pole replacements as well as some projects carried over from the previous year.

Asset Relocations:

- Only 11% of the budget spent as a result of Council initiated undergrounding projects being delayed for a year.

Reliability, Safety and environment:

- 19% overspent due to higher priority line renewal work resulting from the condition survey.

Non-network Assets:

- There was no allowance made for non-network asset expenditure in the Asset Management Plan.

Operational Expenditure:

Network opex was 20% below budget. Overall opex was 3% overspent.

Service interruptions and emergencies:

- 27% underspent as a result of fewer faults This could be partly attributed to the increased pole and replacement work done during the year.

Vegetation management:

- 40% overspent mainly due to the increased cost of employing outside contractors with heavy machinery to clear large areas of trees.

Routine and corrective maintenance and inspection:

- 20% underspent due to re-categorised line condition survey work.

Asset replacement and renewal:

- 83% underspent due to some line and pole replacement work being categorised as capex work.

System Operations and Network Support:

- 49% overspent as a result of increased engineering staffing.

Business Support:

- 7% overspent

Information relating to revenue and quantities for the disclosure year

16. In the box below provide-

16.1 a comparison of the targ

et 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

Target revenue and actual revenue very close.

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

Continued investment in the network in excess of depreciation has assisted in maintaining levels of network reliability. As a result planned work continues to account for a significant portion of the SAIDI minutes for the year.

OtagoNet has not exceeded the SAIDI reliability limit but has exceeded the SAIFI reliability limit. The exceedance is discussed in depth in OtagoNet Joint Venture's default price-quality path compliance statement.

In summary, the exceedance of the SAIFI would not have occurred apart from the purchase of the Palmerston Grid Exit Point and dual circuit 110kV lines to Halfway Bush from Transpower on 31 March 2014. An outage occurred on those assets on 9 March 2015 which was correctly regarded as an OtagoNet Joint Venture outage. However the Commerce Act (Electricity Distribution Default Price-Quality Path) Determination 2012 that applies for the 2014/15 year is silent on an increased SAIDI and SAIFI allowance being provided for owning those assets. (The 2010 and 2015 Determinations that apply to the years either side of 2014/15 do provide for an allowance).

The 9 March 2015 outage contributed a minimal 0.4 minutes to OtagoNet Joint Venture's assessed SAIDI, but a significant 0.21 times to assessed SAIFI. Reassessment of the Reliability Limits to reflect the outage history of the ex-Transpower assets would have increased the SAIDI Limit by 10.4 minutes and the SAIFI Limit 0.41 times. With an increased allowance the SAIFI reliability limit would not have been exceeded. Equally if there was no purchase of the Transpower assets the SAIFI on OtagoNet Joint Venture's existing assets did not exceed the SAIFI limit.

Box 14: Commentary on network reliability for the disclosure year - continued

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

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

OtagoNet insures its substations, network equipment and buildings.

- Substations and network equipment are insured for $41.0 million.
- Buildings are insured for $17.5 million.

Lines and cables are un-insured; the cost of covering this risk through insurance is regarded as too expensive relative to the risk. This is particularly so in the context that an EDB can possibly recover prudent costs including rectifying for catastrophic events through the customised price path and claw back mechanisms.

OtagoNet does not self-insure and does not recognise the cost of self-insurance.

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

As mentioned previously, some non-line (property) assets were identified as having previously being incorporated into the RAB. These assets have now been removed. A small value of costs relating to these property assets had also been included in previous years. These costs have not been included this year.

An error in the allocation of a group of Distribution and LV cable assets into Distribution and LV lines in previous years was identified and adjusted by correctly allocating the assets in the Opening RAB of schedule 4 (vii).

Assets from Electricity Southland Limited incorporated into the OJV RAB have had to be added as an additional row in the Work Under Construction calculation (schedule 4(iv)). This is because these assets did not, and never will, go through capex, so need to be added as an additional line item as if they had gone through capex. (This approach was discussed and agreed with Simon Wakefield, Commerce Commission on 20 August 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

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

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

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

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

Nominal Prices are based on economic assumptions provided by Electricity Networks Association (ENA) on March 2014 as follows

	2015	**2016**	**2017**	**2018**	**2019**
Inflator (CAPEX)	4.2%	8.4%	6.2%	4.4%	3.1%
Inflator (OPEX)	3.3%	3.5%	3.6%	3.8%	3.8%

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

SCHEDULE 15 VOLUNTARY EXPLANATORY NOTES

1. This Schedule enable 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
None.

6. AUDITORS' REPORT

Independent Auditor's Report

To the Directors of OtagoNet JV Limited and the Commerce Commission as a recipient of the Report

Assurance Report Pursuant to Electricity Distribution Information Disclosure Determination 2012

We have completed our assurance engagement of OtagoNet JV Limited's (the 'Company') compliance with the Electricity Distribution Disclosure Information Determination 2012 (the 'Determination') in preparing 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 Schedules') for the disclosure year ended 31 March 2015.

Directors' Responsibilities

The Directors are responsible for preparation of the Schedules in accordance with the Determination and ensuring the Company keeps records to enable the preparation of the Schedules that are free from material misstatement.

Auditors' Responsibilities

Our responsibility is to express an opinion on whether the Company has complied, in all material respects, with the Determination in the preparation of the Schedules for the year ended 31 March 2015 and report our opinion to you.

Our engagement has been conducted in accordance with ISAE (NZ) 3000, Assurance Engagements Other than Audits or Reviews of Historical Financial Information and SAE 3100 Compliance Engagements to obtain reasonable assurance that the Company has complied, in all material respects, with the Determination in the preparation of the Schedules for the year ended 31 March 2015.

The procedures we performed were based on our professional judgment, including assessment of the risks of material misstatement in the Schedules, whether due to fraud or error. In making those risk assessments, we considered internal controls relevant to the Company's preparation of the Schedules to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Our procedures included analytical procedures, evaluating the appropriateness of assumptions used and whether they have been consistently applied, and agreement of the Schedules to, or reconciling with, source systems and underlying records. We included an assessment of the significant judgements made by the Company in the preparation of the disclosure information and also evaluated the overall adequacy of the presentation of supporting information and explanations.

Use of this report

This report has been prepared for the Directors of the Company in accordance with clause 2.8.1(1) of the Determination and is provided solely to assist you in establishing that compliance requirements have been met. We acknowledge that the Directors will provide the report to the Commerce Commission in accordance with clause 2.8.1(1)(a) of the Determination.

The report has been prepared in accordance with the scope and terms of our letter of engagement with the Company dated 14 April 2015. The terms and conditions are attached and form part of this report and are applicable to the Commerce Commission. Our report should not be used for any other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility for any reliance on this report to anyone other than the Directors, or for any purpose other than that for which it was prepared.

Inherent Limitations

Because of the inherent limitations in evidence gathering procedures, it is possible that fraud, error or non-compliance may occur and not be detected. As the procedures performed for this engagement are not performed continuously throughout the year and the procedures performed in respect of the Company's compliance with the Determination are undertaken on a test basis, our engagement cannot be relied on to detect all instances where the Company may not have complied with the Determination. The opinion expressed in this report has been formed on the above basis.

Independence

Other than this engagement, the annual audit of the Company's financial statements and an assignment providing assurance over compliance with the Commerce Act (Electricity Distribution Default Price-Quality Path) Determination 2012, we have no relationship with or interests in the Company or any of its subsidiaries. We are not aware of any relationship between our firm and OtagoNet JV Limited that, in our professional judgment, may reasonably be thought to impair our independence.

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

As described in Box 14 of Schedule 14, there are inherent limitations in 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 outage statistics is limited throughout the year.

There are no practical audit procedures that we could adopt to confirm independently that all the outage and ICP data was properly recorded for the purposes of inclusion in the amounts relating to SAIDI and SAIFI outage statistics 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 to 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.

Qualified Opinion

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

- As far as appears from our examination, proper records have been kept by the Company to enable the complete and accurate compilation of the Schedules;
- The information used in the preparation of the Schedules 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, in all material respects, with the Determination in preparing the Schedules.

Report on Other Matters

In forming our opinion we have, except for the matters described in the Basis of Qualified Opinion paragraph above, obtained sufficient recorded evidence and all the information and explanations that we have required.

PricewaterhouseCoopers

Chartered Accountants
28 August 2015

Christchurch, New Zealand

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7. DIRECTORS' CERTIFICATES

Schedule 18: Certification for Year-End Disclosures

Clause 2.9.2

We, Alan Bertram Harper and Neil Douglas Boniface, being governing committee members of OtagoNet Joint Venture certify that, having made all reasonable enquiry, to the best of our knowledge-

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

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

In respect of related party costs and revenues recorded in accordance with subclauses 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(1)(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.

Neil Douglas Boniface **Alan Bertram Harper**

26 August 2015