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 2016

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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 2016**

SCHEDULE 1: ANALYTICAL RATIOS

This schedule calculates expenditure, revenue and service ratios from the information disclosed. The disclosed ratios may vary for reasons that are company specific and, as a result, must be interpreted with care. The Commerce Commission will publish a summary and analysis of information disclosed in accordance with the ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of the determination.

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

1(i): Expenditure metrics

	Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
Operational expenditure	15,287	428	97,680	1,417	36,168
Network	10,374	291	66,291	962	24,545
Non-network	4,912	138	31,389	455	11,622
Expenditure on assets	29,680	831	189,651	2,751	70,221
Network	29,680	831	189,651	2,751	70,221
Non-network	–	–	–	–	–

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	80,381	2,251
Standard consumer line charge revenue	137,988	2,020
Non-standard consumer line charge revenue	17,307	1,190,682

1(iii): Service intensity measures

Demand density	15	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	93	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	3	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	28,003	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	6,609	18.74%
Pass-through and recoverable costs excluding financial incentives and wash-ups	9,103	25.82%
Total depreciation	7,291	20.68%
Total revaluations	960	2.72%
Regulatory tax allowance	2,805	7.95%
Regulatory profit/(loss) including financial incentives and wash-ups	10,411	29.53%
Total regulatory income	35,259	

1(v): Reliability

Interruption rate	10.70	*Interruptions per 100 circuit km*

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2016**

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 14	31 Mar 15	31 Mar 16
9	**ROI – comparable to a post tax WACC**	%	%	%
10	Reflecting all revenue earned	6.73%	5.81%	5.93%
11	Excluding revenue earned from financial incentives	6.73%	5.81%	5.93%
12	Excluding revenue earned from financial incentives and wash-ups	6.73%	5.81%	5.93%
13				
14	**Mid-point estimate of post tax WACC**	5.43%	6.10%	5.37%
15	25th percentile estimate	4.71%	5.39%	4.66%
16	75th percentile estimate	6.14%	6.82%	6.09%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	7.42%	6.59%	6.58%
21	Excluding revenue earned from financial incentives	7.42%	6.59%	6.58%
22	Excluding revenue earned from financial incentives and wash-ups	7.42%	6.59%	6.58%
23				
24	**WACC rate used to set regulatory price path**	8.77%	8.77%	7.19%
25				
26	**Mid-point estimate of vanilla WACC**	6.11%	6.89%	6.02%
27	25th percentile estimate	5.39%	6.17%	5.30%
28	75th percentile estimate	6.83%	7.60%	6.74%
29				

sch ref				($000)	
30		**2(ii): Information Supporting the ROI**			
31					
32		Total opening RAB value	163,642		
33	*plus*	Opening deferred tax	(4,517)		
34		**Opening RIV**		159,125	
35					
36		**Line charge revenue**		34,753	
37					
38		Expenses cash outflow	15,712		
39	*add*	Assets commissioned	11,027		
40	*less*	Asset disposals	65		
41	*add*	Tax payments	72		
42	*less*	Other regulated income	506		
43		**Mid-year net cash outflows**		26,241	
44					
45		**Term credit spread differential allowance**		–	
46					
47		Total closing RAB value	168,273		
48	*less*	Adjustment resulting from asset allocation	0		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(7,249)		
51		**Closing RIV**		161,023	
52					
53		**ROI – comparable to a vanilla WACC**			6.58%
54					
55		Leverage (%)			44%
56		Cost of debt assumption (%)			5.26%
57		Corporate tax rate (%)			28%
58					
59		**ROI – comparable to a post tax WACC**			5.93%
60					

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	6.32%
Year-end ROI – comparable to a post tax WACC	5.68%

** 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 2016**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

sch ref				
7		**3(i): Regulatory Profit**		**($000)**
8		**Income**		
9		Line charge revenue		34,753
10	*plus*	Gains / (losses) on asset disposals		(62)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		568
12				
13		**Total regulatory income**		35,259
14		**Expenses**		
15	*less*	Operational expenditure		6,609
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		9,103
18				
19		**Operating surplus / (deficit)**		19,547
20				
21	*less*	Total depreciation		7,291
22				
23	*plus*	Total revaluations		960
24				
25		**Regulatory profit / (loss) before tax**		13,216
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		2,805
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		10,411
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	119	
36		Commerce Act levies	56	
37		Industry levies	75	
38		CPP specified pass through costs	–	
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	7,218	
41		Transpower new investment contract charges	224	
42		System operator services	–	
43		Distributed generation allowance	1,411	
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**		9,103
47				
48		**3(iii): Incremental Rolling Incentive Scheme**	**($000)**	
49			**CY-1**	**CY**
50			**31 Mar 15**	**31 Mar 16**
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 11	–	–
58		CY-4 31 Mar 12	–	–
59		CY-3 31 Mar 13	–	–
60		CY-2 31 Mar 14	–	–
61		CY-1 31 Mar 15	–	–
62		**Net incremental rolling incentive scheme**		–
63				
64		**Net recoverable costs allowed under incremental rolling incentive scheme**		–
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
For Year Ended: 31 March 2016

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

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

sch ref

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

for year ended	RAB 31 Mar 12 ($000)	RAB 31 Mar 13 ($000)	RAB 31 Mar 14 ($000)	RAB 31 Mar 15 ($000)	RAB 31 Mar 16 ($000)
Total opening RAB value	137,890	139,704	144,589	147,443	163,642
less Total depreciation	6,172	6,395	6,607	6,858	7,291
plus Total revaluations	2,141	1,188	2,195	123	960
plus Assets commissioned	6,030	10,102	7,285	23,814	11,027
less Asset disposals	184	10	19	880	65
plus Lost and found assets adjustment	–	–	–	–	–
plus Adjustment resulting from asset allocation	–	–	0	(0)	0
Total closing RAB value	139,704	144,589	147,443	163,642	168,273

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
Total opening RAB value		163,642		163,642
less				
Total depreciation		7,291		7,291
plus				
Total revaluations		960		960
plus				
Assets commissioned (other than below)	–		–	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	11,027		11,027	
Assets commissioned		11,027		11,027
less				
Asset disposals (other than below)	65		65	
Asset disposals to a regulated supplier	–		–	
Asset disposals to a related party	–		–	
Asset disposals		65		65
plus Lost and found assets adjustment		–		–
plus Adjustment resulting from asset allocation				0
Total closing RAB value		168,273		168,273

* *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	1,200
CPI_4^{-4}	1,193
Revaluation rate (%)	0.59%

	Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
Total opening RAB value	163,642		163,642	
less Opening value of fully depreciated, disposed and lost assets	115		115	
Total opening RAB value subject to revaluation	163,528		163,528	
Total revaluations		960		960

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction		Allocated works under construction	
Works under construction—preceding disclosure year		2,872		2,872
plus Capital expenditure	11,469		11,469	
less Assets commissioned	11,027		11,027	
plus Adjustment resulting from asset allocation			–	
Works under construction - current disclosure year		3,314		3,314
Highest rate of capitalised finance applied				–

4(v): Regulatory Depreciation

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Depreciation - standard	7,291		7,291	
Depreciation - no standard life assets	–		–	
Depreciation - modified life assets	–		–	
Depreciation - alternative depreciation in accordance with CPP	–		–	
Total depreciation		7,291		7,291

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	19,589	1,143	28,138	79,175	6,562	19,428	6,329	1,802	1,476	163,642
less	Total depreciation	1,070	22	1,378	3,311	178	708	346	132	146	7,291
plus	Total revaluations	132	5	184	455	35	98	29	14	8	960
plus	Assets commissioned	2,352	79	1,631	4,686	13	912	877	464	14	11,027
less	Asset disposals	–	–	26	–	–	39	–	–	–	65
plus	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
plus	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
plus	Asset category transfers	–	–	–	–	–	–	–	–	–	–
	Total closing RAB value	21,003	1,205	28,549	81,005	6,432	19,691	6,889	2,148	1,352	168,273
	Asset Life										
	Weighted average remaining asset life	25.4	52.9	33.5	26.9	46.7	28.5	21.8	24.5	28.3	(years)
	Weighted average expected total asset life	52.4	54.3	46.2	54.6	50.3	50.0	38.3	32.2	53.9	(years)

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2016**

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

5a(i): Regulatory Tax Allowance

				($000)
	Regulatory profit / (loss) before tax			13,216
plus	Income not included in regulatory profit / (loss) before tax but taxable	–	*	
	Expenditure or loss in regulatory profit / (loss) before tax but not deductible	–	*	
	Amortisation of initial differences in asset values	1,366		
	Amortisation of revaluations	228		
				1,594
less	Total revaluations	960		
	Income included in regulatory profit / (loss) before tax but not taxable	–	*	
	Discretionary discounts and customer rebates	–		
	Expenditure or loss deductible but not in regulatory profit / (loss) before tax	244	*	
	Notional deductible interest	3,590		
				4,793
	Regulatory taxable income			10,017
less	Utilised tax losses	–		
	Regulatory net taxable income			10,017
	Corporate tax rate (%)	28%		
	Regulatory tax allowance			2,805

* Workings to be provided in Schedule 14

5a(ii): Disclosure of Permanent Differences

In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i).

5a(iii): Amortisation of Initial Difference in Asset Values

			($000)
	Opening unamortised initial differences in asset values	34,151	
less	Amortisation of initial differences in asset values	1,366	
plus	Adjustment for unamortised initial differences in assets acquired	–	
less	Adjustment for unamortised initial differences in assets disposed	37	
	Closing unamortised initial differences in asset values		32,748
	Opening weighted average remaining useful life of relevant assets (years)		25

5a(iv): Amortisation of Revaluations

			($000)
	Opening sum of RAB values without revaluations	155,883	
	Adjusted depreciation	7,063	
	Total depreciation	7,291	
	Amortisation of revaluations		228

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	(4,517)	
plus	Tax effect of adjusted depreciation	1,978	
less	Tax effect of tax depreciation	4,515	
plus	Tax effect of other temporary differences*	201	
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	13	
plus	Deferred tax cost allocation adjustment	(0)	
	Closing deferred tax		(7,249)

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	102,167	
less	Tax depreciation	16,126	
plus	Regulatory tax asset value of assets commissioned	12,767	
less	Regulatory tax asset value of asset disposals	107	
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		98,701

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2016

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	6,000
10	Capital expenditure	12,832
11	Market value of asset disposals	–
12	Other related party transactions	109

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

sch ref	Name of related party	Related party relationship
14		
15	Otago Power Services Limited	100% Common Ownership
16	PowerNet Limited	100% Common Ownership
17	Peak Power Services Limited	51% Common Ownership
18		
19		

20 ** include additional rows if needed*

21 5b(iii): Related Party Transactions

sch ref	Name of related party	Related party transaction type	Description of transaction	Value of transaction ($000)	Basis for determining value
22					
23	PowerNet Limited	Capex	Builds network capex on behalf of line business	10,167	IM clause 2.2.11(5)(h)
24	PowerNet Limited	Opex	Completes maintenance on behalf of line business	4,374	ID clause 2.3.6(1)(f)
25	PowerNet Limited	Opex	Business support and system control (agency costs)	1,514	ID clause 2.3.6(1)(f)
26	PowerNet Limited	Sales	Rent	21	ID clause 2.3.7(2)(a)
27	Otago Power Services Limited	Sales	Rent	88	ID clause 2.3.7(2)(a)
28	Peak Power Services Limited	Capex	Builds network capex on behalf of line business	2,665	IM clause 2.2.11(5)(h)
29	Peak Power Services Limited	Opex	Completes maintenance on behalf of line business	112	ID clause 2.3.6(1)(f)
30		[Select one]			[Select one]
31		[Select one]			[Select one]
32		[Select one]			[Select one]
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 2016**

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

7

8 **5c(i): Qualifying Debt (may be Commission only)**

9

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*						–	–	–	–

17

18 **5c(ii): Attribution of Term Credit Spread Differential**

19

sch ref			
20	**Gross term credit spread differential**		–
21			
22	Total book value of interest bearing debt		
23	Leverage	44%	
24	Average opening and closing RAB values		
25	**Attribution Rate (%)**		–
26			
27	**Term credit spread differential allowance**		–

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2016

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(i): Operating Cost Allocations

	Value allocated ($000s)				
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
Service interruptions and emergencies					
Directly attributable		1,972			
Not directly attributable				–	
Total attributable to regulated service		1,972			
Vegetation management					
Directly attributable		1,250			
Not directly attributable				–	
Total attributable to regulated service		1,250			
Routine and corrective maintenance and inspection					
Directly attributable		639			
Not directly attributable				–	
Total attributable to regulated service		639			
Asset replacement and renewal					
Directly attributable		624			
Not directly attributable				–	
Total attributable to regulated service		624			
System operations and network support					
Directly attributable		587			
Not directly attributable		–		–	
Total attributable to regulated service		587			
Business support					
Directly attributable		1,537			
Not directly attributable				–	
Total attributable to regulated service		1,537			
Operating costs directly attributable		6,609			
Operating costs not directly attributable	–	–	–	–	–
Operational expenditure		6,609			

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	250
Not directly attributable	–
Total attributable to regulated service	250
Recoverable costs	
Directly attributable	8,853
Not directly attributable	–
Total attributable to regulated service	8,853

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

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

Change in cost allocation 2			($000) CY-1	Current Year (CY)
Cost category		Original allocation	–	–
Original allocator or line items		New allocation	–	–
New allocator or line items		Difference	–	–
Rationale for change				

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

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

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2016**

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

7 ### 5e(i): Regulated Service Asset Values

sch ref		Value allocated ($000s) Electricity distribution services
10	**Subtransmission lines**	
11	Directly attributable	21,003
12	Not directly attributable	–
13	**Total attributable to regulated service**	21,003
14	**Subtransmission cables**	
15	Directly attributable	1,205
16	Not directly attributable	–
17	**Total attributable to regulated service**	1,205
18	**Zone substations**	
19	Directly attributable	28,549
20	Not directly attributable	–
21	**Total attributable to regulated service**	28,549
22	**Distribution and LV lines**	
23	Directly attributable	81,005
24	Not directly attributable	–
25	**Total attributable to regulated service**	81,005
26	**Distribution and LV cables**	
27	Directly attributable	6,432
28	Not directly attributable	–
29	**Total attributable to regulated service**	6,432
30	**Distribution substations and transformers**	
31	Directly attributable	19,691
32	Not directly attributable	–
33	**Total attributable to regulated service**	19,691
34	**Distribution switchgear**	
35	Directly attributable	6,889
36	Not directly attributable	–
37	**Total attributable to regulated service**	6,889
38	**Other network assets**	
39	Directly attributable	2,148
40	Not directly attributable	–
41	**Total attributable to regulated service**	2,148
42	**Non-network assets**	
43	Directly attributable	1,352
44	Not directly attributable	–
45	**Total attributable to regulated service**	1,352
46		
47	**Regulated service asset value directly attributable**	168,273
48	**Regulated service asset value not directly attributable**	–
49	**Total closing RAB value**	168,273

51 ### 5e(ii): Changes in Asset Allocations* †

sch ref				($000) CY-1	Current Year (CY)
53	**Change in asset value allocation 1**				
54	Asset category		Original allocation		
55	Original allocator or line items		New allocation		
56	New allocator or line items		Difference	–	–
58	Rationale for change				
62	**Change in asset value allocation 2**				
63	Asset category		Original allocation		
64	Original allocator or line items		New allocation		
65	New allocator or line items		Difference	–	–
67	Rationale for change				
71	**Change in asset value allocation 3**				
72	Asset category		Original allocation		
73	Original allocator or line items		New allocation		
74	New allocator or line items		Difference	–	–
76	Rationale for change				

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

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2016**

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		2,036
9	System growth		5,812
10	Asset replacement and renewal		3,031
11	Asset relocations		1,184
12	Reliability, safety and environment:		
13	Quality of supply	213	
14	Legislative and regulatory	–	
15	Other reliability, safety and environment	556	
16	**Total reliability, safety and environment**		770
17	**Expenditure on network assets**		12,832
18	Expenditure on non-network assets		–
19			
20	**Expenditure on assets**		12,832
21	*plus* Cost of financing		–
22	*less* Value of capital contributions		1,363
23	*plus* Value of vested assets		–
24			
25	**Capital expenditure**		11,469
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		1,184
29	Research and development		–
30	**6a(iii): Consumer Connection**		
31	*Consumer types defined by EDB**	**($000)**	**($000)**
32	Consumer Connections < 20 kVa	490	
33	Consumer Connections 21-99 kVa	699	
34	Consumer Connections > 100 kVa	847	
35	[EDB consumer type]	–	
36	[EDB consumer type]	–	
37	** include additional rows if needed*		
38	**Consumer connection expenditure**		2,036
39			
40	*less* Capital contributions funding consumer connection expenditure	1,067	
41	**Consumer connection less capital contributions**		969
42	**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement**
43		**System Growth**	**and Renewal**
44		**($000)**	**($000)**
45	Subtransmission	918	552
46	Zone substations	424	863
47	Distribution and LV lines	1,372	1,615
48	Distribution and LV cables	1,524	–
49	Distribution substations and transformers	509	–
50	Distribution switchgear	1,031	–
51	Other network assets	34	–
52	**System growth and asset replacement and renewal expenditure**	5,812	3,031
53	*less* Capital contributions funding system growth and asset replacement and renewal	–	–
54	**System growth and asset replacement and renewal less capital contributions**	5,812	3,031
55			
56	**6a(v): Asset Relocations**		
57	*Project or programme**	**($000)**	**($000)**
58	Balcutha main street undergrounding	1,184	
59	[Description of material project or programme]	–	
60	[Description of material project or programme]	–	
61	[Description of material project or programme]	–	
62	[Description of material project or programme]	–	
63	** include additional rows if needed*		
64	All other projects or programmes - asset relocations	–	
65	**Asset relocations expenditure**		1,184
66	*less* Capital contributions funding asset relocations	297	
67	**Asset relocations less capital contributions**		888

6a(vi): Quality of Supply

		($000)	($000)
	*Project or programme**		
	SCADA upgrade	213	
	[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		213
less	Capital contributions funding quality of supply	–	
	Quality of supply less capital contributions		213

6a(vii): Legislative and Regulatory

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

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

		($000)	($000)
	*Project or programme**		
	Substation Safety	470	
	[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	87	
	Other reliability, safety and environment expenditure		556
less	Capital contributions funding other reliability, safety and environment	–	
	Other reliability, safety and environment less capital contributions		556

6a(ix): Non-Network Assets

Routine expenditure

	($000)	($000)
*Project or programme**		
[Description of material project or programme]	–	
[Description of material project or programme]	–	
[Description of material project or programme]	–	
[Description of material project or programme]	–	
[Description of material project or programme]	–	
** include additional rows if needed*		
All other projects or programmes - routine expenditure	–	
Routine expenditure		–

Atypical expenditure

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

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2016

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	1,972	
9	Vegetation management	1,250	
10	Routine and corrective maintenance and inspection	639	
11	Asset replacement and renewal	624	
12	**Network opex**		4,485
13	System operations and network support	587	
14	Business support	1,537	
15	**Non-network opex**		2,124
16			
17	**Operational expenditure**		6,609
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		143
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2016**

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	34,149	34,753	2%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	1,288	2,036	58%
11	System growth	4,165	5,812	40%
12	Asset replacement and renewal	4,625	3,031	(34%)
13	Asset relocations	1,098	1,184	8%
14	Reliability, safety and environment:			
15	Quality of supply	404	213	(47%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	1,436	556	(61%)
18	**Total reliability, safety and environment**	1,840	770	(58%)
19	**Expenditure on network assets**	13,016	12,832	(1%)
20	Expenditure on non-network assets	–	–	–
21	Expenditure on assets	13,016	12,832	(1%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,612	1,972	22%
24	Vegetation management	972	1,250	29%
25	Routine and corrective maintenance and inspection	632	639	1%
26	Asset replacement and renewal	660	624	(5%)
27	**Network opex**	3,876	4,485	16%
28	System operations and network support	608	587	(4%)
29	Business support	1,573	1,537	(2%)
30	**Non-network opex**	2,181	2,124	(3%)
31	**Operational expenditure**	6,057	6,609	9%
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	–	1,184	–
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	168	143	(15%)
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 2016**
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 **8(i): Billed Quantities by Price Component**

sch ref	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)	Billed quantities by price component					
12					Price component	Variable day energy sales	Variable night energy sales	Variable day energy purchases	Variable night energy purchases	Variable energy sales	
13					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	Kwh	kwh	kwh	kwh	
15	1	Domestic	Standard	6,876	52,478	–	–	41,613,548	15,828,506		
16	2	Commerical	Standard	3,354	58,804	–	–	46,630,310	17,736,726		
18	4	Major Customers	Standard	82	79,194	56,477,631		–	–		
19	5	Unmetered	Standard	94	119	–	–	85,883	32,667		
20	6	Street lights	Standard	9	147	–	–	106,444	40,488		
21	7 & 8	Low user	Standard	4,448	21,926	16,445,047	5,481,682				
22	Non Standard	Commerical	Non-standard	3	206,389	–	–				
23	LLNW	Domestic	Standard	363	1,427					1,427	
24	LLNW	Non Domestic	Standard	204	6,425						
25	LLNW	Half Hour	Standard	7	5,454						
26											
27											
29			Standard consumer totals	15,437	225,972	72,922,678	5,481,682	88,436,185	33,638,387	1,427	–
30			Non-standard consumer totals	3	206,389	–	–	–	–	–	–
31			Total for all consumers	15,440	432,361	72,922,678	5,481,682	88,436,185	33,638,387	1,427	–

28 *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)
1	Domestic	Standard	$10,092	–	$8,824	$1,269
2	Commerical	Standard	$11,700	–	$10,229	$1,471
4	Major Customers	Standard	$3,849	–	$2,495	$1,354
5	Unmetered	Standard	$35	–	$31	$4
6	Street lights	Standard	$138	–	$121	$17
7 & 8	Low user	Standard	$4,036	–	$3,529	$507
Non Standard	Commerical	Non-standard	$3,572	–	$479	$3,093
Generation		Standard	$368	–	$368	
LLNW	Domestic	Standard	$165	–	$117	$47
LLNW	Non Domestic	Standard	$485	–	$346	$139
LLNW	Half Hour	Standard	$313	–	$175	$138
			–			
			–			
Add extra rows for additional consumer groups or price category codes as necessary						
		Standard consumer totals	$31,181	–	$26,235	$4,947
		Non-standard consumer totals	$3,572	–	$479	$3,093
		Total for all consumers	$34,753	–	$26,714	$8,040

Line charge revenues ($000) by price component

Consumer group name or price category code	Fixed	Variable - Day	Variable Night	Kva	Fixed	Variable
Rate (eg, $ per day, $ per kWh, etc.)	$/Day	$/kwh	$/kWh	Per/kVa	$/kW	$/kWh
1		$5,581	$245	$4,265		
2		$6,219	$275	$5,206		
4	$2,780	$1,070	–			
5	$23	$12	$1			
6	$123	$14	$1			
7 & 8	$235	$3,665	$136			
Non Standard	$3,572	–	–			
Generation	$368					
LLNW	$13					$151
LLNW	$220				$265	
LLNW	$313					
Standard consumer totals	$4,075	$16,561	$657	$9,471	$265	$151
Non-standard consumer totals	$3,572	–	–	–	–	–
Total for all consumers	$7,647	$16,561	$657	$9,471	$265	$151

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	1

Company Name: OtagoNet Joint Venture
For Year Ended: 31 March 2016
Network / Sub-network Name:

SCHEDULE 9a: ASSET REGISTER

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

sch ref

	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	37,093	37,266	173	3
10	All	Overhead Line	Wood poles	No.	11,470	11,443	(27)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	614	661	46	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	94	47	(47)	3
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	8	10	3	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.	42	44	2	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.	170	198	28	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.	28	28	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	43	43	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	70	72	2	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	47	48	1	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,381	2,379	(2)	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	921	936	15	3
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	49	57	8	3
39	HV	Distribution Cable	Distribution UG PILC	km	4	5	1	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.	14	16	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.	5,746	5,758	12	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	N/A
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	27	39	12	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,081	4,089	8	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	188	199	11	3
48	HV	Distribution Transformer	Voltage regulators	No.	33	37	4	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	17	17	–	3
50	LV	LV Line	LV OH Conductor	km	515	518	2	2
51	LV	LV Cable	LV UG Cable	km	42	51	10	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	76	81	5	3
53	LV	Connections	OH/UG consumer service connections	No.	16,070	16,242	172	2
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	192	198	6	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	2	2	–	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	–	–	–	N/A
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name OtagoNet Joint Venture
For Year Ended 31 March 2016
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 2016

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	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.	259	799	4,823	4,183	5,033	6,636	4,905	531	899	528	578	234	126	50	48	196	946	1,006	1,079	1,070	876	884	729	100	748	37,266	–	3
11	All	Overhead Line	Wood poles	No.	29	444	2,425	1,864	1,012	861	929	65	121	110	253	162	517	596	813	655	220	33	9	12	18	83	34	12	166	11,443	–	3
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	26	71	158	117	85	67	0	4	3	18	1	–	1	2	–	2	2	–	52	1	–	0	–	49	661	–	3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	47	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	47	–	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	0	–	0	–	0	–	–	–	0	1	–	–	1	–	6	–	–	–	0	–	2	–	0	10	–	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	8	5	7	–	–	–	–	–	–	1	1	2	1	–	1	–	1	–	–	–	5	44	–	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	24	18	62	29	–	1	1	9	–	6	3	3	10	–	3	5	5	–	2	5	1	–	198	–	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	1	1	–	1	1	–	28	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	–	–	10	–	–	–	–	–	3	10	2	–	–	9	–	–	9	–	–	–	–	43	–	4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	3	11	14	31	–	1	–	–	2	3	1	–	–	3	1	–	–	–	2	–	–	–	72	–	4
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	5	8	7	7	2	–	–	–	–	–	–	6	3	1	–	1	–	2	3	2	–	1	–	48	–	4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	4	34	181	236	266	328	351	80	94	55	43	26	50	34	63	60	69	104	50	61	73	29	23	5	59	2,379	–	3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
38	HV	Distribution Line	SWER conductor	km	–	–	213	124	99	162	118	4	2	3	12	2	5	20	3	10	20	11	49	39	19	15	2	–	4	936	–	3
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	0	0	2	0	2	1	0	1	1	2	2	3	2	2	10	2	2	3	5	6	9	1	1	57	–	3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	1	–	–	–	–	–	–	–	–	0	0	–	0	0	–	–	1	–	2	0	–	–	5	–	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.	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	2	–	3	–	–	–	1	7	1	–	16	–	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.	–	31	768	860	1,097	631	565	37	123	108	84	84	132	134	146	144	140	131	103	100	58	77	104	13	88	5,758	–	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	–	–	3	–	1	1	2	–	–	–	–	1	6	3	1	–	3	7	11	–	–	39	–	4
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	30	754	616	599	442	476	28	85	79	56	57	89	90	109	103	88	79	65	59	42	53	83	7	–	4,089	–	3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	3	34	7	24	2	3	1	4	1	8	5	13	12	12	10	4	14	9	14	16	3	–	199	–	3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	3	–	1	1	4	–	–	–	1	2	2	–	–	1	2	2	–	2	2	2	12	–	–	37	–	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	157	35	41	11	6	0	1	4	2	1	3	3	4	2	1	2	2	2	2	2	2	0	228	518	–	2
52	LV	LV Cable	LV UG Cable	km	–	–	0	1	4	2	0	–	0	0	1	2	2	1	6	2	2	1	3	1	3	7	5	3	3	51	–	3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	0	0	–	–	–	–	–	–	–	–	–	0	0	1	–	0	0	0	–	0	3	2	75	81	–	3
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	11,135	927	109	101	490	552	532	519	447	218	140	106	110	94	118	194	361	88	1	16,242	9,121	2
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	12	36	41	–	6	–	1	7	4	9	9	16	7	15	3	2	14	1	11	3	1	198	–	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 2016
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	47	–	47
12	50kV & 66kV	75	–	75
13	33kV	586	10	596
14	SWER (all SWER voltages)	936	3	939
15	22kV (other than SWER)	–	26	26
16	6.6kV to 11kV (inclusive—other than SWER)	2,379	34	2,412
17	Low voltage (< 1kV)	518	51	569
18	**Total circuit length (for supply)**	4,540	124	4,664
19				
20	Dedicated street lighting circuit length (km)	76	5	81
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	340	7%	
25	Rural	1,139	25%	
26	Remote only	721	16%	
27	Rugged only	1,779	39%	
28	Remote and rugged	562	12%	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	4,540	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,119	24%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	811	18%	

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2016**

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	None		
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 2016**
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				
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		Domestic	223	
12		Commercial	52	
13		Major Customers	2	
14		Half Hour - LLNW	2	
15				
16		** include additional rows if needed*		
17		**Connections total**	279	
18				
19		**Distributed generation**		
20		Number of connections made in year	17	**connections**
21		Capacity of distributed generation installed in year	0.08	**MVA**
22		**9e(ii): System Demand**		
23				
24				
25		**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
26		GXP demand	49	
27	*plus*	Distributed generation output at HV and above	19	
28		**Maximum coincident system demand**	68	
29	*less*	Net transfers to (from) other EDBs at HV and above	–	
30		**Demand on system for supply to consumers' connection points**	68	
31		**Electricity volumes carried**	**Energy (GWh)**	
32		Electricity supplied from GXPs	354	
33	*less*	Electricity exports to GXPs		
34	*plus*	Electricity supplied from distributed generation	98	
35	*less*	Net electricity supplied to (from) other EDBs		
36		**Electricity entering system for supply to consumers' connection points**	452	
37	*less*	Total energy delivered to ICPs	432	
38		**Electricity losses (loss ratio)**	20	4.4%
39				
40		**Load factor**	0.76	
41		**9e(iii): Transformer Capacity**		
42			**(MVA)**	
43		Distribution transformer capacity (EDB owned)	183	
44		Distribution transformer capacity (Non-EDB owned, estimated)	42	
45		**Total distribution transformer capacity**	225	
46				
47		**Zone substation transformer capacity**	175	

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2016
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)	–	
11	Class B (planned interruptions on the network)	250	
12	Class C (unplanned interruptions on the network)	248	
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**	499	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	149	99
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.33	80.9
27	Class C (unplanned interruptions on the network)	3.03	283.0
28	Class D (unplanned interruptions by Transpower)	0.21	7.0
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**	3.57	370.9
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	2.94	278.1
38			
39	**Quality path normalised reliability limit**	**SAIFI reliability limit**	**SAIDI reliability limit**
40	SAIFI and SAIDI limits applicable to disclosure year*	2.93	254.9
41	** not applicable to exempt EDBs*		

42	**10(ii): Class C Interruptions and Duration by Cause**		
43			
44	**Cause**	**SAIFI**	**SAIDI**
45	Lightning	0.05	6.8
46	Vegetation	0.33	53.7
47	Adverse weather	0.77	104.6
48	Adverse environment	–	0.0
49	Third party interference	0.42	12.9
50	Wildlife	–	–
51	Human error	–	–
52	Defective equipment	1.09	92.8
53	Cause unknown	0.38	12.3
54			
55	**10(iii): Class B Interruptions and Duration by Main Equipment Involved**		
56			
57	**Main equipment involved**	**SAIFI**	**SAIDI**
58	Subtransmission lines	–	0.0
59	Subtransmission cables	0.00	0.7
60	Subtransmission other	–	–
61	Distribution lines (excluding LV)	0.27	68.3
62	Distribution cables (excluding LV)	0.00	1.1
63	Distribution other (excluding LV)	0.06	10.8
64	**10(iv): Class C Interruptions and Duration by Main Equipment Involved**		
65			
66	**Main equipment involved**	**SAIFI**	**SAIDI**
67	Subtransmission lines	1.62	95.1
68	Subtransmission cables	–	–
69	Subtransmission other	0.08	12.2
70	Distribution lines (excluding LV)	1.18	161.7
71	Distribution cables (excluding LV)	0.00	0.2
72	Distribution other (excluding LV)	0.14	13.8

73	**10(v): Fault Rate**			
74	**Main equipment involved**	**Number of Faults**	**Circuit length (km)**	**Fault rate (faults per 100km)**
75	Subtransmission lines	31	625	4.96
76	Subtransmission cables	–	1	–
77	Subtransmission other	2		
78	Distribution lines (excluding LV)	197	3,203	6.15
79	Distribution cables (excluding LV)	1	12	8.33
80	Distribution other (excluding LV)	17		
81	**Total**	248		

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 5.93% slightly below the 75th percentile estimate of post-tax WACC of 6.09% and 6.58% vanilla WACC slightly below the 75th percentile estimate of vanilla WACC of 6.74%.

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 $528k 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 was stated using the 31 March 2015 closing figure as a starting point with inflationary indexing over the year to 31 March 2016 plus additions less disposals. No items were reclassified.

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
The expenditure deductible but not in regulatory profit is the $244k cost of easements which is a tax deductible expense. Income included in regulatory profit / (loss) before tax but not taxable is the $960k revaluations for the year. There are no other permanent differences

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)

Capital Contributions:	$	716
	$	716
Tax Rate:		28%
Temporary Differences	$	201

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 Information Discolosures comprises of the OtagoNet Joint Venture and Electricity Southland Limited which are each owned 24.9% by Electricity Invercargill Limited and 75.1% by The Power Company Limited.

PowerNet Limited is a profit oriented limited liability company owned 50% by The Power Company Limited and 50% by Electricity Invercargill Limited. PowerNet Limited carries out project management and asset construction to develop OtagoNet Joint Venture's electricity network.

Peak Power Services Limited is 51.7% owned by PowerNet Limited and undertakes contracting services to maintain and develop the Electricity Southland Limited Network.

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 costs are directly attributable as all costs were either passed through by PowerNet Limited as agent or were invoiced to 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 network assets are directly attributable.

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
The materiality threshold applied to identify programmes or projects during the disclosure year was $100k. 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 1% below budget.

Consumer connection:

- 58% overspend attributed to increases in new customer connections including rapid growth in the Frankton area.

System Growth:

- 40% overspent due to a major line rebuild carrying over from the previous year, additional line reinforcement work required, and rapid growth in the Frankton area.

Asset replacement and renewal:

- Only 66% of the budget spent due to line replacement and renewal work being deferred in favour of customer driven work in the System Growth and Customer Connections categories.

Asset Relocations:

- 8% overspend as a result of Council initiated undergrounding projects being carried over from the previous year.

Reliability, Safety and environment:

- Only 42% of the budget spent as a result of the deferment of projects and the concentration of resources on System Growth and Customer Connections.

Non-network Assets:

- 1% underspent which is a minor variation.

Operational Expenditure:

Network opex was 16% above budget. Overall opex was 9% above budget.

Service interruptions and emergencies:

- 22% overspent due to a larger amount and higher cost of distribution faults than planned, and additional substation maintenance work carried out to repair a Ranfurly power transformer tap changer failure.

Vegetation management:

- 29% overspent due to a higher proportion of network funded vegetation control work being carried out than chargeable customer work.

Routine and corrective maintenance and inspection:

- 1% overspent which is a minor variation.

Asset replacement and renewal:

- 5% underspent due to resources being diverted to customer driven CAPEX work.

System Operations and Network Support:

- 4% underspent which is a minor variation representing $21k less operation expenditure during the year.

Business Support:

- 2% underspent which is a minor variation

Information relating to revenue and quantities for the disclosure year

16. In the box below provide-

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

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

Box 13: Explanatory comment relating to revenue for the disclosure year
Target revenue for the 2015-16 year was $34,149k. The total billed revenue for the 2015-16 year was $34,753k, a 2% variation. This is because the 2015 winter was a colder winter than the previous 2 winters, this resulted in additional variable line charge revenue due to the increased consumption over this period.

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

The SAIDI assessed value for 2015/16 at 223.1 was well below the applicable Commerce Commission Limit of 254.9, and slightly below the Commerce Commission Target level (224.6) that represents the average performance of the network over the last ten years.
The SAIFI assessed value for 2015/16 at 2.82 was below the applicable Commerce Commission Limit of 2.93, and above the Commerce Commission Target level of 2.52.
Two wind storm events (in early October 2015 and in March 2016) contributed significantly to the assessed SAIFI value exceeding the Target level and to the SAIDI level approaching the Target level.

However in accordance with the Issues Register for Electricity and Gas Information Disclosure issues 447 and 458, OJV has disclosed normalised SAIDI/SAIFI calculated according to the 2012 EDB ID while disclosing limits calculated according to the 2015 DPP.
The difference in methodology between the calculation of normalised SAIDI (278.1) and the calculation of the SAIDI limit (254.9) creates the misleading impression that OJV has exceeded its SAIDI limit. However as described above there is no exceedance when normalised SAIDI is calculated according to the 2015 DPP, so as to be consistent with the SAIDI limit.

Similarly, normalised SAIFI calculated according to the 2012 EDB ID (2.94) appears to exceed the SAIFI limit (2.93), but there is no exceedance when the normalised SAIFI is calculated consistently with the limit.

Network reliability is compliant with quality requirements under the default price-quality path, however there are inherent limitations in the ability of 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 $52.8 million.
- Buildings are insured for $20.5 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

No amendments were disclosed.

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

	2016	2017	2018	2019	2020
Inflator (CAPEX)	2.1%	2.2%	2.4%	2.4%	1.5%
Inflator (OPEX)	3.1%	2.7%	2.3%	2.3%	1.9%

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 Joint Venture and the Commerce Commission

Assurance Report Pursuant to Electricity Distribution Information Disclosure Determination 2012

We have completed our assurance engagement of OtagoNet Joint Venture (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 2016.

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.

Our Independence and Quality Control

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

The firm applies Professional and Ethical Standard 3 (Amended) and accordingly maintains a comprehensive system of quality control including documented policies and procedures regarding compliance with ethical requirements, professional standards, and applicable legal and regulatory requirements.

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 2016 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 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 27 May 2016. 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, assignments in the areas of compliance with other regulatory requirements of the Commerce Act 1986 and in the provision of other professional advisory services, 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 Joint Venture 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.

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

25 August 2016

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 Boniface

Neil Douglas Boniface **Alan Bertram Harper**

24 August 2016