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 2021
(Restated)

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 2018), issued 3 April 2018,
- 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 2021**

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	20,070	499	134,550	1,926	40,038
Network	11,756	292	78,814	1,128	23,452
Non-network	8,314	207	55,736	798	16,585
Expenditure on assets	37,009	920	248,106	3,551	73,828
Network	37,009	920	248,106	3,551	73,828
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	76,502	1,903
Standard consumer line charge revenue	122,749	1,707
Non-standard consumer line charge revenue	17,899	1,167,785

1(iii): Service intensity measures

Demand density	14	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	96	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	4	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	24,871	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	8,906	26.25%
Pass-through and recoverable costs excluding financial incentives and wash-ups	8,213	24.20%
Total depreciation	8,588	25.31%
Total revaluations	3,202	9.44%
Regulatory tax allowance	2,267	6.68%
Regulatory profit/(loss) including financial incentives and wash-ups	9,161	27.00%
Total regulatory income	33,933	

1(v): Reliability

Interruption rate	13.84	*Interruptions per 100 circuit km*

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2021**

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 19	31 Mar 20	31 Mar 21
9	**ROI – comparable to a post tax WACC**	%	%	%
10	Reflecting all revenue earned	6.46%	6.57%	4.38%
11	Excluding revenue earned from financial incentives	6.12%	6.63%	4.41%
12	Excluding revenue earned from financial incentives and wash-ups	5.54%	6.04%	4.41%
13				
14	**Mid-point estimate of post tax WACC**	4.75%	4.27%	3.72%
15	25th percentile estimate	4.07%	3.59%	3.04%
16	75th percentile estimate	5.43%	4.95%	4.40%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	6.96%	6.99%	4.71%
21	Excluding revenue earned from financial incentives	6.63%	7.06%	4.74%
22	Excluding revenue earned from financial incentives and wash-ups	6.05%	6.47%	4.74%
23				
24	**WACC rate used to set regulatory price path**	7.19%	7.19%	4.57%
25				
26	**Mid-point estimate of vanilla WACC**	5.26%	4.69%	4.05%
27	25th percentile estimate	4.58%	4.01%	3.37%
28	75th percentile estimate	5.94%	5.37%	4.73%
29				

sch ref				($000)	
30	**2(ii): Information Supporting the ROI**				
31					
32		Total opening RAB value	210,599		
33	*plus*	Opening deferred tax	(17,118)		
34	**Opening RIV**			193,481	
35					
36	**Line charge revenue**			33,948	
37					
38		Expenses cash outflow	17,119		
39	*add*	Assets commissioned	12,425		
40	*less*	Asset disposals	30		
41	*add*	Tax payments	(37)		
42	*less*	Other regulated income	(15)		
43	**Mid-year net cash outflows**			29,492	
44					
45	**Term credit spread differential allowance**			–	
46					
47		Total closing RAB value	217,607		
48	*less*	Adjustment resulting from asset allocation	(0)		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(19,422)		
51	**Closing RIV**			198,186	
52					
53	**ROI – comparable to a vanilla WACC**				4.71%
54					
55		Leverage (%)			42%
56		Cost of debt assumption (%)			2.82%
57		Corporate tax rate (%)			28%
58					
59	**ROI – comparable to a post tax WACC**				4.38%
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	4.62%
Year-end ROI – comparable to a post tax WACC	4.29%

** 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	(73)	
Other financial incentives	–	
Financial incentives		(73)
Impact of financial incentives on ROI		–0.03%
Input methodology claw-back	–	
CPP application recoverable costs	–	
Catastrophic event allowance	–	
Capex wash-up adjustment	–	
Transmission asset wash-up adjustment	–	
2013–15 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**
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SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).
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	33,948
10	*plus*	Gains / (losses) on asset disposals	(29)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	14
12			
13		**Total regulatory income**	33,933
14		**Expenses**	
15	*less*	Operational expenditure	8,906
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	8,213
18			
19		**Operating surplus / (deficit)**	16,814
20			
21	*less*	Total depreciation	8,588
22			
23	*plus*	Total revaluations	3,202
24			
25		**Regulatory profit / (loss) before tax**	11,428
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	2,267
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	9,161
32			

sch ref			
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34	**Pass through costs**		
35	Rates	152	
36	Commerce Act levies	67	
37	Industry levies	89	
38	CPP specified pass through costs	–	
39	**Recoverable costs excluding financial incentives and wash-ups**		
40	Electricity lines service charge payable to Transpower	6,379	
41	Transpower new investment contract charges	267	
42	System operator services	–	
43	Distributed generation allowance	1,259	
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**		8,213
47			

sch ref				
48	**3(iii): Incremental Rolling Incentive Scheme**		**($000)**	
49			**CY-1**	**CY**
50			**31 Mar 20**	**31 Mar 21**
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 16	–	–
58	CY-4	31 Mar 17	–	–
59	CY-3	31 Mar 18	–	–
60	CY-2	31 Mar 19	–	–
61	CY-1	31 Mar 20	–	–
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	–

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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			RAB	RAB	RAB	RAB	RAB
7	**4(i): Regulatory Asset Base Value (Rolled Forward)**						
8		for year ended	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21
9			($000)	($000)	($000)	($000)	($000)
10	**Total opening RAB value**		168,273	179,022	186,531	194,442	210,599
11							
12	*less* **Total depreciation**		7,496	6,647	7,712	7,994	8,588
13							
14	*plus* **Total revaluations**		3,641	1,967	2,766	4,923	3,202
15							
16	*plus* **Assets commissioned**		14,776	12,346	12,937	19,339	12,425
17							
18	*less* **Asset disposals**		173	157	80	111	30
19							
20	*plus* **Lost and found assets adjustment**		–	–	–	–	–
21							
22	*plus* **Adjustment resulting from asset allocation**		(0)	(0)	(0)	(0)	(0)
23							
24	**Total closing RAB value**		179,022	186,531	194,442	210,599	217,607
25							

		Unallocated RAB *		RAB	
26	**4(ii): Unallocated Regulatory Asset Base**				
27		Unallocated RAB *		RAB	
28		($000)	($000)	($000)	($000)
29	**Total opening RAB value**		210,599		210,599
30	*less*				
31	**Total depreciation**		8,588		8,588
32	*plus*				
33	**Total revaluations**		3,202		3,202
34	*plus*				
35	Assets commissioned (other than below)	–		–	
36	Assets acquired from a regulated supplier	–		–	
37	Assets acquired from a related party	12,425		12,425	
38	**Assets commissioned**		12,425		12,425
39	*less*				
40	Asset disposals (other than below)	30		30	
41	Asset disposals to a regulated supplier	–		–	
42	Asset disposals to a related party	–		–	
43	**Asset disposals**		30		30
44					
45	*plus* **Lost and found assets adjustment**		–		–
46					
47	*plus* **Adjustment resulting from asset allocation**				(0)
48					
49	**Total closing RAB value**		217,608		217,607

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

50					
51					
52	**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**				
53					
54	CPI_4				1,068
55	CPI_4^{-4}				1,052
56	Revaluation rate (%)				1.52%
57					
58		Unallocated RAB *		RAB	
59		($000)	($000)	($000)	($000)
60	Total opening RAB value	210,599		210,599	
61	*less* Opening value of fully depreciated, disposed and lost assets	93		93	
62					
63	Total opening RAB value subject to revaluation	210,505		210,505	
64	**Total revaluations**		3,202		3,202
65					
66	**4(iv): Roll Forward of Works Under Construction**				
67		Unallocated works under construction		Allocated works under construction	
68	**Works under construction—preceding disclosure year**		2,796		2,796
69	*plus* Capital expenditure	15,067		15,067	
70	*less* Assets commissioned	12,425		12,425	
71	*plus* Adjustment resulting from asset allocation				
72	**Works under construction - current disclosure year**		5,437		5,437
73					
74	Highest rate of capitalised finance applied				–

4(v): Regulatory Depreciation

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Depreciation - standard	8,588		8,588	
Depreciation - no standard life assets	–		–	
Depreciation - modified life assets	–		–	
Depreciation - alternative depreciation in accordance with CPP	–		–	
Total depreciation		8,588		8,588

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	25,231	2,834	35,341	98,010	11,159	22,175	11,108	3,588	1,153	210,599
less	Total depreciation	1,260	61	1,571	3,968	264	805	528	118	11	8,588
plus	Total revaluations	398	41	514	1,474	179	335	182	61	17	3,202
plus	Assets commissioned	2,607	–	862	4,933	959	1,202	1,498	364	–	12,425
less	Asset disposals	–	–	–	–	–	30	–	–	–	30
plus	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
plus	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
plus	Asset category transfers	–	–	–	–	–	–	–	–	–	–
	Total closing RAB value	26,977	2,815	35,145	100,448	12,033	22,877	12,260	3,894	1,159	217,607
	Asset Life										
	Weighted average remaining asset life	32.0	46.3	37.9	30.5	43.1	29.0	26.0	29.4	20.8	(years)
	Weighted average expected total asset life	55.2	49.1	50.6	56.8	49.1	49.9	38.9	40.3	33.3	(years)

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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref

5a(i): Regulatory Tax Allowance

				($000)
	Regulatory profit / (loss) before tax			11,428
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	1,338		
	Amortisation of revaluations	886		
				2,223
less	Total revaluations	3,202		
	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	94	*	
	Notional deductible interest	2,260		
				5,556
	Regulatory taxable income			8,095
less	Utilised tax losses	–		
	Regulatory net taxable income			8,095
	Corporate tax rate (%)	28%		
	Regulatory tax allowance			2,267

* 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	26,753	
less	Amortisation of initial differences in asset values	1,338	
plus	Adjustment for unamortised initial differences in assets acquired	–	
less	Adjustment for unamortised initial differences in assets disposed	19	
	Closing unamortised initial differences in asset values		25,396
	Opening weighted average remaining useful life of relevant assets (years)		20

5a(iv): Amortisation of Revaluations

			($000)
	Opening sum of RAB values without revaluations	190,808	
	Adjusted depreciation	7,702	
	Total depreciation	8,588	
	Amortisation of revaluations		886

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	(17,118)	
plus	Tax effect of adjusted depreciation	2,157	
less	Tax effect of tax depreciation	4,369	
plus	Tax effect of other temporary differences*	286	
less	Tax effect of amortisation of initial differences in asset values	375	
plus	Deferred tax balance relating to assets acquired in the disclosure year	–	
less	Deferred tax balance relating to assets disposed in the disclosure year	3	
plus	Deferred tax cost allocation adjustment	0	
	Closing deferred tax		(19,422)

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	97,948	
less	Tax depreciation	15,603	
plus	Regulatory tax asset value of assets commissioned	13,630	
less	Regulatory tax asset value of asset disposals	36	
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		95,939

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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 clause 2.3.6 of the ID determination.
This information is part of audited disclosure information (as defined in clause 1.4 of the ID determination), and so is subject to the assurance report required by clause 2.8.

sch ref

7	**5b(i): Summary—Related Party Transactions**	**($000)**	**($000)**
8	**Total regulatory income**		–
9			
10	**Market value of asset disposals**		–
11			
12	Service interruptions and emergencies	1,827	
13	Vegetation management	1,270	
14	Routine and corrective maintenance and inspection	1,914	
15	Asset replacement and renewal (opex)	206	
16	**Network opex**		5,217
17	Business support	1,735	
18	System operations and network support	1,010	
19	**Operational expenditure**		7,962
20	Consumer connection	7,398	
21	System growth	46	
22	Asset replacement and renewal (capex)	7,631	
23	Asset relocations	610	
24	Quality of supply	464	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	274	
27	**Expenditure on non-network assets**		–
28	**Expenditure on assets**		16,423
29	Cost of financing		–
30	Value of capital contributions		–
31	Value of vested assets		–
32	**Capital Expenditure**		16,423
33	**Total expenditure**		24,385
34			
35	**Other related party transactions**		–

36 5b(iii): Total Opex and Capex Related Party Transactions

37	**Name of related party**	**Nature of opex or capex service provided**	**Total value of transactions ($000)**
38	PowerNet Limited	Service interruptions and emergencies	1,827
39	PowerNet Limited	Vegetation management	1,270
40	PowerNet Limited	Routine and corrective maintenance and inspection	1,914
41	PowerNet Limited	Asset replacement and renewal (opex)	206
42	PowerNet Limited	System operations and network support	950
43	PowerNet Limited	Business support	1,735
44	PowerNet Limited	Consumer connection	7,398
45	PowerNet Limited	System growth	46
46	PowerNet Limited	Asset replacement and renewal (capex)	7,631
47	PowerNet Limited	Asset relocations	610
48	PowerNet Limited	Quality of supply	464
49	PowerNet Limited	Other reliability, safety and environment	274
50	The Power Company Limited	System operations and network support	60
51			
52			
53	**Total value of related party transactions**		24,385
54	** include additional rows if needed*		
55			

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Company Name	OtagoNet Joint Venture
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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	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	42%	
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

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		1,827			
Not directly attributable		–		–	
Total attributable to regulated service		1,827			
Vegetation management					
Directly attributable		1,270			
Not directly attributable		–		–	
Total attributable to regulated service		1,270			
Routine and corrective maintenance and inspection					
Directly attributable		1,914			
Not directly attributable		–		–	
Total attributable to regulated service		1,914			
Asset replacement and renewal					
Directly attributable		206			
Not directly attributable		–		–	
Total attributable to regulated service		206			
System operations and network support					
Directly attributable		1,293			
Not directly attributable		–		–	
Total attributable to regulated service		1,293			
Business support					
Directly attributable		2,396			
Not directly attributable		–		–	
Total attributable to regulated service		2,396			
Operating costs directly attributable		8,906			
Operating costs not directly attributable	–	–	–	–	–
Operational expenditure		8,906			

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	308
Not directly attributable	–
Total attributable to regulated service	308
Recoverable costs	
Directly attributable	7,905
Not directly attributable	–
Total attributable to regulated service	7,905

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

			($000)	
Change in cost allocation 1			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				

			($000)	
Change in cost allocation 2			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				

			($000)	
Change in cost allocation 3			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 2021

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	26,977
Not directly attributable	–
Total attributable to regulated service	26,977
Subtransmission cables	
Directly attributable	2,815
Not directly attributable	–
Total attributable to regulated service	2,815
Zone substations	
Directly attributable	35,145
Not directly attributable	–
Total attributable to regulated service	35,145
Distribution and LV lines	
Directly attributable	100,448
Not directly attributable	–
Total attributable to regulated service	100,448
Distribution and LV cables	
Directly attributable	12,033
Not directly attributable	–
Total attributable to regulated service	12,033
Distribution substations and transformers	
Directly attributable	22,877
Not directly attributable	–
Total attributable to regulated service	22,877
Distribution switchgear	
Directly attributable	12,260
Not directly attributable	–
Total attributable to regulated service	12,260
Other network assets	
Directly attributable	3,894
Not directly attributable	–
Total attributable to regulated service	3,894
Non-network assets	
Directly attributable	1,159
Not directly attributable	–
Total attributable to regulated service	1,159
Regulated service asset value directly attributable	217,607
Regulated service asset value not directly attributable	–
Total closing RAB value	217,607

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

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

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

			($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 2021**

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			($000)	($000)
7		**6a(i): Expenditure on Assets**		
8		Consumer connection		7,398
9		System growth		46
10		Asset replacement and renewal		7,631
11		Asset relocations		610
12		Reliability, safety and environment:		
13		Quality of supply	464	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	274	
16		**Total reliability, safety and environment**		738
17		**Expenditure on network assets**		16,423
18		Expenditure on non-network assets		–
19				
20		**Expenditure on assets**		16,423
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		1,356
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		15,067
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		610
29		Research and development		–
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	($000)	($000)
32		Customer Connections < 20 kVA	805	
33		Customer Connections 21 - 99 kVA	172	
34		Customer Connections > 100 kVA	758	
35		New Subdivisions	5,663	
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		7,398
39				
40	*less*	Capital contributions funding consumer connection expenditure	864	
41		**Consumer connection less capital contributions**		6,534
42		**6a(iv): System Growth and Asset Replacement and Renewal**		Asset Replacement
43			System Growth	and Renewal
44			($000)	($000)
45		Subtransmission	–	2,567
46		Zone substations	2	373
47		Distribution and LV lines	–	4,226
48		Distribution and LV cables	44	–
49		Distribution substations and transformers	–	239
50		Distribution switchgear	–	206
51		Other network assets	–	21
52		**System growth and asset replacement and renewal expenditure**	46	7,631
53	*less*	Capital contributions funding system growth and asset replacement and renewal	–	5
54		**System growth and asset replacement and renewal less capital contributions**	46	7,626
55				
56		**6a(v): Asset Relocations**		
57		*Project or programme**	($000)	($000)
58		Undergrounding of 11kV lines In Maniototo for Transpower	610	
59				
60				
61				
62				
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	–	
65		**Asset relocations expenditure**		610
66	*less*	Capital contributions funding asset relocations	486	
67		**Asset relocations less capital contributions**		123
68				

			($000)	($000)
69		**6a(vi): Quality of Supply**		
70		*Project or programme**	($000)	($000)
71		Finegand 33kV Smart Network Automation	410	
72		Mobile substation Site Made Ready	9	
73				
74				
75				
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply	45	
78		**Quality of supply expenditure**		464
79	*less*	Capital contributions funding quality of supply		
80		**Quality of supply less capital contributions**		464
81		**6a(vii): Legislative and Regulatory**		
82		*Project or programme**	($000)	($000)
83				
84				
85				
86				
87				
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory		
90		**Legislative and regulatory expenditure**		–
91	*less*	Capital contributions funding legislative and regulatory		
92		**Legislative and regulatory less capital contributions**		–
93		**6a(viii): Other Reliability, Safety and Environment**		
94		*Project or programme**	($000)	($000)
95		Substation NER`s and 33kV Transformer Circuit Breakers	24	
96		Clydevale 33 kV Ring Rebuild and Protection	28	
97				
98				
99				
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment	222	
102		**Other reliability, safety and environment expenditure**		274
103	*less*	Capital contributions funding other reliability, safety and environment		
104		**Other reliability, safety and environment less capital contributions**		274
105				
106		**6a(ix): Non-Network Assets**		
107		**Routine expenditure**		
108		*Project or programme**	($000)	($000)
109				
110				
111				
112				
113				
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure		
116		**Routine expenditure**		–
117		**Atypical expenditure**		
118		*Project or programme**	($000)	($000)
119				
120				
121				
122				
123				
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure	–	
126		**Atypical expenditure**		–
127				
128		**Expenditure on non-network assets**		–

Company Name **OtagoNet Joint Venture**
For Year Ended **31 March 2021**

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	1,827	
9	Vegetation management	1,270	
10	Routine and corrective maintenance and inspection	1,914	
11	Asset replacement and renewal	206	
12	**Network opex**		5,217
13	System operations and network support	1,293	
14	Business support	2,396	
15	**Non-network opex**		3,689
16			
17	**Operational expenditure**		8,906
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		171
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2021**

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	33,418	33,948	2%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	6,566	7,398	13%
11	System growth	246	46	(81%)
12	Asset replacement and renewal	7,565	7,631	1%
13	Asset relocations	79	610	672%
14	Reliability, safety and environment:			
15	Quality of supply	456	464	2%
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	858	274	(68%)
18	**Total reliability, safety and environment**	1,314	738	(44%)
19	**Expenditure on network assets**	15,770	16,423	4%
20	Expenditure on non-network assets	–	–	–
21	Expenditure on assets	15,770	16,423	4%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,617	1,827	13%
24	Vegetation management	1,118	1,270	14%
25	Routine and corrective maintenance and inspection	1,835	1,914	4%
26	Asset replacement and renewal	217	206	(5%)
27	**Network opex**	4,787	5,217	9%
28	System operations and network support	1,224	1,293	6%
29	Business support	2,328	2,396	3%
30	**Non-network opex**	3,552	3,689	4%
31	**Operational expenditure**	8,339	8,906	7%
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	–	610	–
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	187	171	(8%)
42				
43	*1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of this determination*			
44	*2 From the CY+1 nominal dollar expenditure forecasts disclosed in accordance with clause 2.6.6 for the forecast period starting at the beginning of the disclosure year (the second to last disclosure of Schedules 11a and 11b)*			

Company Name: OtagoNet Joint Venture
For Year Ended: 31 March 2021
Network / Sub-Network Name: OtagoNet Network

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 — 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	6,486	46,231			36,767,940	13,792,216		
16	2	Commerical	Standard	3,305	54,448			43,302,384	16,243,386		
17	4	Major Customers	Standard	104	85,020	59,594,208					
18	5	Unmetered	Standard	77	144			114,631	43,000		
19	6	Streetlights	Standard	10	710			564,267	211,665		
20	7 & 8	Low user	Standard	5,257	28,580	21,434,887	7,144,962				
21	Non Standard	Commerical	Non-standard	3	195,729	130,057,846					
22	LLNW	Domestic	Standard	2,210	14,959					14,958,907	
23	LLNW	Non Domestic	Standard	381	9,965						
24	LLNW	Half Hour	Standard	9	7,963						
25	*Add extra rows for additional consumer groups or price category codes as necessary*										
26			Standard consumer totals	17,839	248,020	81,029,095	7,144,962	80,749,222	30,290,268	14,958,907	–
27			Non-standard consumer totals	3	195,729	130,057,846	–	–	–	–	–
28			Total for all consumers	17,842	443,749	211,086,941	7,144,962	80,749,222	30,290,268	14,958,907	–

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

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

Line charge revenues ($000) by price component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Fixed	Variable - Day	Variable Night	Kva	Fixed	Variable
						Rate (eg, $ per day, $ per kWh, etc.)	$/Day	$/kwh	$/kWh	Per/kVa	$/kW	$/kWh
1	Domestic	Standard	$8,896		$7,997	$898		$4,761	$206	$3,929		
2	Commerical	Standard	$9,455		$8,500	$954		$5,607	$242	$3,606		
4	Major Customers	Standard	$3,225		$1,533	$1,692	$2,373	$852				
5	Unmetered	Standard	$35		$32	$4	$20	$15	$1			
6	Street lights	Standard	$146		$127	$19	$70	$73	$3			
7 & 8	Low user	Standard	$5,138		$4,624	$514	$288	$4,666	$183			
Non Standard	Commerical	Non-standard	$3,503		$459	$3,044	$3,503					
Generation		Standard	$341		$340	$0	$341					
LLNW	Domestic	Standard	$1,745		$1,415	$330.22	$120					$1,625
LLNW	Non Domestic	Standard	$968		$770	$198.13	$472				$496	
LLNW	Half Hour	Standard	$497		$250	$246	$497					
		Standard consumer totals	$30,444	–	$25,588	$4,856	$4,179	$15,974	$635	$7,534	$496	$1,625
		Non-standard consumer totals	$3,503	–	$459	$3,044	$3,503	–	–	–	–	–
		Total for all consumers	$33,948	–	$26,048	$7,900	$7,683	$15,974	$635	$7,534	$496	$1,625

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

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

8(iii): Number of ICPs directly billed

Check: OK

Number of directly billed ICPs at year end: 1

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2021**
Network / Sub-Network Name	**Otago Sub-Network**

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 — 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	6,486	46,231			36,767,940	13,792,216		
16	2	Commerical	Standard	3,305	54,448			43,302,384	16,243,386		
17	4	Major Customers	Standard	104	85,020	59,594,208					
18	5	Unmetered	Standard	77	144			114,631	43,000		
19	6	Street lights	Standard	10	710			564,267	211,665		
20	7 & 8	Low user	Standard	5,257	28,580	21,434,887	7,144,962				
21	Non Standard	Commerical	Non-standard	3	195,729	130,057,846					
22											
23											
24											
25	*Add extra rows for additional consumer groups or price category codes as necessary*										
26			Standard consumer totals	15,239	215,133	81,029,095	7,144,962	80,749,222	30,290,268	–	–
27			Non-standard consumer totals	3	195,729	130,057,846	–	–	–	–	–
28			Total for all consumers	15,242	410,862	211,086,941	7,144,962	80,749,222	30,290,268	–	–

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

31 **8(ii): Line Charge Revenues ($000) by Price Component**

33 Line charge revenues ($000) by price component

Row	Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Price component	Fixed	Variable - Day	Variable Night	Kva	Fixed	Variable
34								Rate (eg, $ per day, $ per kWh, etc.)	$/Day	$/kwh	$/kWh	Per/kVa	$/kW	$/kWh
35														
36														
37	1	Domestic	Standard	$8,896		$7,997	$898			$4,761	$206	$3,929		
38	2	Commerical	Standard	$9,455		$8,500	$954			$5,607	$242	$3,606		
	4	Major Customers	Standard	$3,225		$1,533	$1,692		$2,373	$852				
39	5	Unmetered	Standard	$35		$32	$4		$20	$15	$1			
40	6	Street lights	Standard	$146		$127	$19		$70	$73	$3			
41	7 & 8	Low user	Standard	$5,138		$4,624	$514		$288	$4,666	$183			
42	Non Standard	Major Customers	Non-standard	$3,503		$459	$3,044		$3,503					
43	Generation	Generation	Standard	$341		$340	$0		$341					
44				–										
45				–										
46				–										
47	*Add extra rows for additional consumer groups or price category codes as necessary*													
48			Standard consumer totals	$27,235	–	$23,153	$4,081		$3,092	$15,974	$635	$7,534	–	–
49			Non-standard consumer totals	$3,503	–	$459	$3,044		$3,503	–	–	–	–	–
50			Total for all consumers	$30,738	–	$23,613	$7,125		$6,595	$15,974	$635	$7,534	–	–

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

52 **8(iii): Number of ICPs directly billed**

Check: OK

53 Number of directly billed ICPs at year end: 1

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2021**
Network / Sub-Network Name	**Lakeland Frankton Sub-Network**

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)
15	LLNW	Domestic	Standard	1,922	13,565
16	LLNW	Non Domestic	Standard	362	9,698
17	LLNW	Half Hour	Standard	9	7,963
18					
19					
20					
21					
22					
23					
24					
25	*Add extra rows for additional consumer groups or price category codes as necessary*				
26			**Standard consumer totals**	2,293	31,226
27			**Non-standard consumer totals**	–	–
28			**Total for all consumers**	2,293	31,226

Billed quantities by price component

sch ref							
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						13,564,594	
16							
17							
18							
19							
20							
21							
22							
23							
24							
26	**Standard consumer totals**	–	–	–	–	13,564,594	–
27	**Non-standard consumer totals**	–	–	–	–	–	–
28	**Total for all consumers**	–	–	–	–	13,564,594	–

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

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

Line charge revenues ($000) by price component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Price component: Fixed	Variable - Day	Variable Night	Kva	Fixed	Variable
						Rate (eg, $ per day, $ per kWh, etc.)	$/Day	$/kwh	$/kWh	Per/kVa	$/kW	$/kWh
LLNW	Domestic	Standard	$1,585		$1,254	$330.22	$104					$1,480
LLNW	Non Domestic	Standard	$949		$751	$198.13	$463				$486	
LLNW	Half Hour	Standard	$497		$250	$246	$497					
			–									
			–									
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		Standard consumer totals	$3,030	–	$2,256	$775	$1,064	–	–	–	$486	$1,480
		Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	$3,030	–	$2,256	$775	$1,064	–	–	–	$486	$1,480

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

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 2021
Network / Sub-network Name	OtagoNet Network

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.	34,501	34,997	496	3
10	All	Overhead Line	Wood poles	No.	15,139	15,129	(10)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	659	697	38	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	47	–	(47)	3
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	17	18	1	3
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.	45	46	1	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	7	(1)	3
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	182	215	33	2
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	7	7	–	3
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	32	35	3	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	116	116	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	3	3	–	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	45	44	(1)	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,343	2,340	(3)	2
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	912	902	(10)	2
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	76	85	9	1
39	HV	Distribution Cable	Distribution UG PILC	km	5	4	(1)	1
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.	29	32	3	2
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.	4,862	5,058	196	1
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.	86	90	4	2
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,021	4,024	3	1
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	326	339	13	2
48	HV	Distribution Transformer	Voltage regulators	No.	43	42	(1)	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	16	16	–	3
50	LV	LV Line	LV OH Conductor	km	468	468	0	1
51	LV	LV Cable	LV UG Cable	km	97	114	18	1
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	89	101	12	1
53	LV	Connections	OH/UG consumer service connections	No.	18,433	19,153	720	1
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	243	244	1	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	2	2	–	3
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	5	5	–	3
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 2021
Network / Sub-network Name	Otago Sub-Network

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.	34,501	34,997	496	3
10	All	Overhead Line	Wood poles	No.	15,139	15,129	(10)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	659	697	38	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	47	–	(47)	3
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	11	11	1	3
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.	44	45	1	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	7	(1)	3
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	182	215	33	2
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	7	7	–	3
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	32	35	3	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	106	106	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	3	3	–	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	43	42	(1)	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,343	2,340	(3)	2
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	912	902	(10)	2
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	32	36	4	1
39	HV	Distribution Cable	Distribution UG PILC	km	4	3	(1)	1
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.	29	32	3	2
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.	4,862	5,058	196	1
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.	9	10	1	2
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,021	4,024	3	1
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	254	263	9	2
48	HV	Distribution Transformer	Voltage regulators	No.	43	42	(1)	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	16	16	–	3
50	LV	LV Line	LV OH Conductor	km	468	468	0	1
51	LV	LV Cable	LV UG Cable	km	45	48	3	1
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	77	78	2	1
53	LV	Connections	OH/UG consumer service connections	No.	15,983	16,117	134	1
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	233	234	1	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	3
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	5	5	–	3
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 2021**
Network / Sub-network Name	**Lakeland Frankton Sub-Network**

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.	–	–	–	N/A
10	All	Overhead Line	Wood poles	No.	–	–	–	N/A
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	–	N/A
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	6	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.	1	1	–	3
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	N/A
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	N/A
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	N/A
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	10	10	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	N/A
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	2	2	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	–	–	–	N/A
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	–	–	–	N/A
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	43	47	5	2
39	HV	Distribution Cable	Distribution UG PILC	km	1	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.	–	–	–	N/A
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.	–	–	–	N/A
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.	69	71	2	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	–	N/A
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	67	67	–	2
48	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	N/A
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	N/A
50	LV	LV Line	LV OH Conductor	km	0	0	–	2
51	LV	LV Cable	LV UG Cable	km	48	60	12	2
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	12	23	10	4
53	LV	Connections	OH/UG consumer service connections	No.	2,193	2,651	458	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	10	10	–	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	3
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	–	–	–	N/A
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 2021
Network / Sub-network Name: OtagoNet Network

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 2021

Number of assets at disclosure year end by installation date

sch ref	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	2017	2018	2019	2020	2021	2022	2023	2024	2025	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.	256	765	4,447	3,895	4,847	6,472	1,926	136	235	63	270	120	124	47	47	195	947	1,007	1,085	1,058	873	910	888	633	970	690	447	550	16	–	–	–	–	1,078	34,997	–	3
11	All	Overhead Line	Wood poles	No.	21	283	1,745	1,338	786	726	3,602	409	738	527	522	268	507	574	798	650	220	34	10	16	22	90	62	53	64	60	42	135	1	–	–	–	–	826	15,129	–	3
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	13	63	157	116	87	67	0	4	3	18	1	–	1	2	–	2	2	–	49	1	–	13	2	–	–	0	0	–	–	–	–	–	96	697	–	3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	0	–	0	0	1	–	–	–	–	–	1	–	6	–	–	–	1	–	1	0	–	–	0	8	–	–	–	–	–	0	18	–	3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	2	10	7	5	7	–	–	–	–	–	–	1	1	2	1	–	1	–	1	–	–	3	–	–	–	–	–	–	–	–	–	5	46	–	3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	6	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	3
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	15	24	23	49	28	–	1	1	10	2	5	2	3	7	–	3	2	7	1	2	4	2	1	3	7	8	1	–	–	–	–	4	215	–	3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	3
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	2	1	11	6	–	–	–	–	–	–	1	1	–	–	–	2	1	1	–	1	2	2	3	1	–	–	–	–	–	–	–	35	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	3	9	8	41	–	1	–	–	2	6	11	2	–	1	10	–	–	9	1	–	8	2	–	–	2	–	–	–	–	–	–	116	–	3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	3	–	3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	2	8	6	7	2	–	–	–	–	–	–	6	2	1	–	1	–	2	2	2	–	1	1	–	–	1	–	–	–	–	–	–	44	–	3
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	4	31	158	223	253	312	338	78	94	45	42	25	50	33	63	58	67	101	50	61	76	34	41	22	18	4	5	14	–	–	–	–	–	41	2,340	–	2
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
38	HV	Distribution Line	SWER conductor	km	–	–	192	113	97	155	105	4	1	3	8	3	5	20	3	11	20	11	44	41	16	15	2	0	3	23	1	2	–	–	–	–	–	4	902	–	2
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	0	0	0	0	2	1	0	0	1	2	2	1	2	2	10	2	2	2	5	6	12	5	11	5	3	3	–	–	–	–	–	5	85	–	1
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	1	–	–	–	–	–	–	–	0	0	0	–	0	0	–	–	1	–	0	–	0	–	–	0	–	–	–	–	–	–	–	4	–	1
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	–	–	–	–	7	3	2	6	5	2	1	–	–	–	–	–	32	–	2
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.	–	25	688	713	791	536	500	25	92	87	67	64	95	102	116	110	106	111	81	84	53	73	103	69	67	92	60	65	11	–	–	–	–	72	5,058	–	1
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.	–	–	–	–	–	–	4	–	–	1	2	–	–	–	–	1	5	3	1	–	3	9	11	10	7	13	11	8	1	–	–	–	–	–	90	–	2
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	25	683	560	561	418	455	24	77	73	53	52	79	80	98	98	77	79	60	56	36	52	80	48	49	66	40	38	6	–	–	–	–	1	4,024	–	1
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	2	32	7	21	4	9	5	4	3	14	11	15	13	18	11	6	14	10	16	20	21	15	13	23	26	4	–	–	–	–	2	339	–	2
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	1	4	–	–	–	1	2	2	–	–	1	2	2	–	2	2	2	11	3	2	2	1	2	–	–	–	–	–	–	42	–	3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	7	–	3	–	–	–	–	–	–	–	1	–	1	2	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	16	–	3
51	LV	LV Line	LV OH Conductor	km	1	5	157	49	66	37	30	2	4	6	5	2	4	4	4	3	2	3	2	2	2	2	3	2	1	2	2	2	1	–	–	–	–	64	468	–	1
52	LV	LV Cable	LV UG Cable	km	–	–	0	1	4	3	1	0	0	0	1	2	2	2	6	2	2	1	2	1	3	8	7	11	13	11	7	3	0	–	–	–	–	18	114	–	1
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	0	0	1	–	–	–	–	–	–	–	–	0	0	1	–	0	0	–	1	0	5	3	4	2	2	2	1	–	–	–	–	80	101	–	1
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	10,960	920	107	101	482	546	517	510	443	216	139	104	106	92	113	191	336	381	453	689	617	800	117	–	–	–	–	213	19,153	–	1
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	9	33	37	–	4	–	1	7	4	9	7	15	6	13	3	2	14	1	11	18	7	13	20	8	2	–	–	–	–	–	244	–	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	3
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	1	–	1	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	1	–	–	–	–	–	–	5	–	3
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 2021
Network / Sub-network Name	Otago Sub-Network

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 2021

Number of assets at disclosure year end by installation date

sch ref	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	2017	2018	2019	2020	2021	2022	2023	2024	2025	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.	256	765	4,447	3,895	4,847	6,472	1,926	136	235	63	270	120	124	47	47	195	947	1,007	1,085	1,058	873	910	888	633	970	690	447	550	16	–	–	–	–	1,078	34,997	–	3
11	All	Overhead Line	Wood poles	No.	21	283	1,745	1,338	786	726	3,602	409	738	527	522	268	507	574	798	650	220	34	10	16	22	90	62	53	64	60	42	135	1	–	–	–	–	826	15,129	–	3
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	13	63	157	116	87	67	0	4	3	18	1	–	1	2	–	2	2	–	49	1	–	13	2	–	–	0	0	–	–	–	–	–	96	697	–	3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	0	–	0	–	–	–	0	1	–	–	1	–	0	–	–	–	1	–	1	0	–	–	0	8	–	–	–	–	–	0	11	–	3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	2	10	7	5	7	–	–	–	–	–	–	–	1	2	1	–	1	–	1	–	–	3	–	–	–	–	–	–	–	–	–	5	45	–	3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	6	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	3
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	15	24	23	49	28	–	1	1	10	2	5	2	3	7	–	3	2	7	1	2	4	2	1	3	7	8	1	–	–	–	–	4	215	–	3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	3
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	2	1	11	6	–	–	–	–	–	–	1	1	–	–	–	2	1	1	–	1	2	2	3	1	–	–	–	–	–	–	–	35	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	3	9	8	41	–	1	–	–	2	6	1	2	–	1	10	–	–	9	1	–	8	2	–	–	2	–	–	–	–	–	–	106	–	3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–		3	–	3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	2	8	6	7	2	–	–	–	–	–	–	4	2	1	–	1	–	2	2	2	–	1	1	–	–	1	–	–	–	–	–	–	42	–	3
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	4	31	158	223	253	312	338	78	94	45	42	25	50	33	63	58	67	101	50	61	76	34	41	22	18	4	5	14	–	–	–	–	–	41	2,340	–	2
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
38	HV	Distribution Line	SWER conductor	km	–	–	192	113	97	155	105	4	1	3	8	3	5	20	3	11	20	11	44	41	16	15	2	0	3	23	1	2	–	–	–	–	–	4	902	–	2
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km			0	0	0	0	2	1	0	0	1	2	1	1	2	2	1	1	2	2	1	3	6	1	3	0	0	2	–	–	–	–	–	0	36	–	1
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	1	–	–	–	–	–	–	–	–	0	0	–	–	0	–	–	1	–	0	–	0	–	–	0	–	–	–	–	–	–	–	3	–	1
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	–	–	–	–	7	3	2	6	5	2	1	–	–	–	–	–	32	–	2
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.	–	25	688	713	791	536	500	25	92	87	67	64	95	102	116	110	106	111	81	84	53	73	103	69	67	92	60	65	11	–	–	–	–	72	5,058	–	1
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.	–	–	–	–	–	–	4	–	–	–	2	–	–	–	–	1	–	1	–	–	–	–	–	1	–	–	–	–	1	–	–	–	–		10	–	2
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	25	683	560	561	418	455	24	77	73	53	52	79	80	98	98	77	79	60	56	36	52	80	48	49	66	40	38	6	–	–	–	–	1	4,024	–	1
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	2	32	7	21	4	9	5	4	3	13	11	14	12	11	8	6	14	7	10	9	14	6	5	13	20	1	–	–	–	–	2	263	–	2
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	1	4	–	–	–	1	2	2	–	–	1	2	2	–	2	2	2	11	3	2	2	1	2	–	–	–	–	–	–	42	–	3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	7	–	3	–	–	–	–	–	–	–	1	–	1	2	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	16	–	3
51	LV	LV Line	LV OH Conductor	km	1	5	157	49	66	37	30	2	4	6	5	2	4	4	4	3	2	3	2	2	2	2	3	2	1	2	2	2	1	–	–	–	–	64	468	–	1
52	LV	LV Cable	LV UG Cable	km	–	–	0	1	4	3	1	0	0	0	1	1	2	2	6	2	1	1	2	1	2	1	2	2	3	2	1	2	0	–	–	–	–	4	48	–	1
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	0	0	1	–	–	–	–	–	–	–	–	0	0	1	–	0	0	–	–	–	1	0	1	1	0	1	1	–	–	–	–	71	78	–	1
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	10,960	920	107	101	470	535	489	477	401	196	134	90	100	87	73	96	126	85	104	122	148	156	36	–	–	–	–	104	16,117	–	1
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	9	33	37	–	4	–	1	7	4	5	3	15	4	13	3	2	14	1	11	18	7	13	20	8	2	–	–	–	–	–	234	–	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	3
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	1	–	1	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	1	–	–	–	–	–	–	5	–	3
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 2021
Network / Sub-network Name: Lakeland Frankton Sub-Network

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 2021

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	2017	2018	2019	2020	2021	2022	2023	2024	2025	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.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
11	All	Overhead Line	Wood poles	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	6	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–	–	6	–	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.	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	10	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	10	–	3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
38	HV	Distribution Line	SWER conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	–	–	–	–	–	–	–	–	–	–	1	0	0	–	9	1	0	–	4	3	7	4	7	5	2	1	–	–	–	–	–	5	47	–	2
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	–	–	–	–	–	–	–	–	0	0	–	–	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	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.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
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.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
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.	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	5	2	1	–	3	8	11	8	6	12	8	6	–	–	–	–	–	–	71	–	3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	–	–	–	–	–	–	–	–	–	1	–	1	1	7	2	–	–	3	6	11	7	7	8	8	3	2	–	–	–	–	–	67	–	2
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
51	LV	LV Line	LV OH Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	0	–	2
52	LV	LV Cable	LV UG Cable	km	–	–	–	–	–	–	–	–	–	–	–	1	0	0	0	0	0	0	–	–	2	7	5	10	7	8	4	1	–	–	–	–	–	13	60	–	2
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–	–	–	1	0	3	3	3	1	2	1	–	–	–	–	–	9	23	–	4
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	–	–	–	–	12	11	28	33	42	20	5	14	6	5	40	95	210	296	325	463	363	530	62	–	–	–	–	91	2,651	–	3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	4	4	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	10	–	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	3
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
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 2021**
Network / Sub-network Name	**OtagoNet Network**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	–	–	–
12	50kV & 66kV	75	–	75
13	33kV	623	10	633
14	SWER (all SWER voltages)	902	4	906
15	22kV (other than SWER)	0	43	43
16	6.6kV to 11kV (inclusive—other than SWER)	2,340	46	2,386
17	Low voltage (< 1kV)	468	114	583
18	**Total circuit length (for supply)**	4,408	217	4,624
19				
20	Dedicated street lighting circuit length (km)	75	26	101
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	329	7%	
25	Rural	893	20%	
26	Remote only	587	13%	
27	Rugged only	1,808	41%	
28	Remote and rugged	676	15%	
29	Unallocated overhead lines	114	3%	
30	**Total overhead length**	4,408	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	640	15%	

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Otago Sub-Network**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	–	–	–
12	50kV & 66kV	75	–	75
13	33kV	623	4	626
14	SWER (all SWER voltages)	902	4	906
15	22kV (other than SWER)	0	–	0
16	6.6kV to 11kV (inclusive—other than SWER)	2,340	39	2,379
17	Low voltage (< 1kV)	468	48	516
18	**Total circuit length (for supply)**	4,407	95	4,502
19				
20	Dedicated street lighting circuit length (km)	75	3	78
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	329	7%	
25	Rural	893	20%	
26	Remote only	587	13%	
27	Rugged only	1,808	41%	
28	Remote and rugged	676	15%	
29	Unallocated overhead lines	114	3%	
30	**Total overhead length**	4,407	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	25%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	640	15%	

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Lakeland Frankton Sub-Network**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	–	–	–
12	50kV & 66kV	–	–	–
13	33kV	–	6	6
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	–	43	43
16	6.6kV to 11kV (inclusive—other than SWER)	–	5	5
17	Low voltage (< 1kV)	0	60	60
18	**Total circuit length (for supply)**	0	114	114
19				
20	Dedicated street lighting circuit length (km)	–	23	23
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	–	–	
25	Rural	–	–	
26	Remote only	–	–	
27	Rugged only	0	100%	
28	Remote and rugged	–	–	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	0	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	–	–	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	–	–	

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2021**

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	Lakeland Wanaka GXP NLK0111 [used Average ICP Count as per Schedule 8(i)]	307	179
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 2021**
Network / Sub-network Name	**OtagoNet Network**

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	700	
12		Half Hour Individual	3	
13		Non Domestic	80	
14		Streetlights	1	
15		Unmetered	5	
16		** include additional rows if needed*		
17		**Connections total**	789	
18				
19		**Distributed generation**		
20		Number of connections made in year	42	**connections**
21		Capacity of distributed generation installed in year	0.28	**MVA**
22		**9e(ii): System Demand**		
23				
24			**Demand at time of maximum coincident demand (MW)**	
25		**Maximum coincident system demand**		
26		GXP demand	55	
27	*plus*	Distributed generation output at HV and above	11	
28		**Maximum coincident system demand**	66	
29	*less*	Net transfers to (from) other EDBs at HV and above	–	
30		**Demand on system for supply to consumers' connection points**	66	
31		**Electricity volumes carried**	**Energy (GWh)**	
32		Electricity supplied from GXPs	386	
33	*less*	Electricity exports to GXPs	–	
34	*plus*	Electricity supplied from distributed generation	77	
35	*less*	Net electricity supplied to (from) other EDBs	(2)	
36		**Electricity entering system for supply to consumers' connection points**	465	
37	*less*	Total energy delivered to ICPs	444	
38		**Electricity losses (loss ratio)**	21	4.6%
39				
40		**Load factor**	0.80	
41		**9e(iii): Transformer Capacity**		
42			**(MVA)**	
43		Distribution transformer capacity (EDB owned)	222	
44		Distribution transformer capacity (Non-EDB owned, estimated)	42	
45		**Total distribution transformer capacity**	264	
46				
47		**Zone substation transformer capacity**	162	

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Otago Sub-Network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

9e(i): Consumer Connections

Number of ICPs connected in year by consumer type

*Consumer types defined by EDB**	Number of connections (ICPs)
Domestic	130
Half Hour Individual	3
Non Domestic	37
Unmetered	5
Street lights	1

** include additional rows if needed*

Connections total	176	
Distributed generation		
Number of connections made in year	28	**connections**
Capacity of distributed generation installed in year	0.20	**MVA**

9e(ii): System Demand

		Demand at time of maximum coincident demand (MW)
	Maximum coincident system demand	
	GXP demand	52
plus	Distributed generation output at HV and above	11
	Maximum coincident system demand	62
less	Net transfers to (from) other EDBs at HV and above	–
	Demand on system for supply to consumers' connection points	62

		Energy (GWh)	
	Electricity volumes carried		
	Electricity supplied from GXPs	354	
less	Electricity exports to GXPs	–	
plus	Electricity supplied from distributed generation	77	
less	Net electricity supplied to (from) other EDBs	–	
	Electricity entering system for supply to consumers' connection points	431	
less	Total energy delivered to ICPs	411	
	Electricity losses (loss ratio)	20	4.7%
	Load factor	0.79	

9e(iii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	192
Distribution transformer capacity (Non-EDB owned, estimated)	42
Total distribution transformer capacity	234
Zone substation transformer capacity	137

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2021
Network / Sub-network Name	Lakeland Frankton Sub-Network

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	Domestic	455	
12	Half Hour Individual	–	
13	Non Domestic	39	
14			
15			
16	** include additional rows if needed*		
17	**Connections total**	494	
18			
19	**Distributed generation**		
20	Number of connections made in year	10	**connections**
21	Capacity of distributed generation installed in year	0.06	**MVA**
22	**9e(ii): System Demand**		
23			
24		**Demand at time of maximum coincident demand (MW)**	
25	**Maximum coincident system demand**		
26	GXP demand	4	
27	*plus* Distributed generation output at HV and above	–	
28	**Maximum coincident system demand**	4	
29	*less* Net transfers to (from) other EDBs at HV and above		
30	**Demand on system for supply to consumers' connection points**	4	
31	**Electricity volumes carried**	**Energy (GWh)**	
32	Electricity supplied from GXPs	32	
33	*less* Electricity exports to GXPs	–	
34	*plus* Electricity supplied from distributed generation	–	
35	*less* Net electricity supplied to (from) other EDBs	–	
36	**Electricity entering system for supply to consumers' connection points**	32	
37	*less* Total energy delivered to ICPs	31	
38	**Electricity losses (loss ratio)**	1	2.7%
39			
40	**Load factor**	0.96	
41	**9e(iii): Transformer Capacity**		
42		**(MVA)**	
43	Distribution transformer capacity (EDB owned)	29	
44	Distribution transformer capacity (Non-EDB owned, estimated)	–	
45	**Total distribution transformer capacity**	29	
46			
47	**Zone substation transformer capacity**	25	

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2021
Network / Sub-network Name	OtagoNet Network

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**

sch ref		Number of interruptions
9	**Interruptions by class**	
10	Class A (planned interruptions by Transpower)	4
11	Class B (planned interruptions on the network)	317
12	Class C (unplanned interruptions on the network)	318
13	Class D (unplanned interruptions by Transpower)	–
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)	1
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	–
19	**Total**	640
20		

sch ref		≤3Hrs	>3hrs
21	**Interruption restoration**		
22	Class C interruptions restored within	230	88
23			

sch ref		SAIFI	SAIDI
24	**SAIFI and SAIDI by class**		
25	Class A (planned interruptions by Transpower)	0.04	14.56
26	Class B (planned interruptions on the network)	0.72	192.85
27	Class C (unplanned interruptions on the network)	1.94	133.20
28	Class D (unplanned interruptions by Transpower)	–	–
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)	0.06	0.79
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	2.76	341.4
35			

sch ref		Normalised SAIFI	Normalised SAIDI
36	**Normalised SAIFI and SAIDI**		
37	Classes B & C (interruptions on the network)	2.66	323.39
38			

39 **10(ii): Class C Interruptions and Duration by Cause**

40

sch ref		SAIFI	SAIDI
41	**Cause**		
42	Lightning	0.02	2.93
43	Vegetation	0.16	10.82
44	Adverse weather	0.16	11.31
45	Adverse environment	0.00	0.06
46	Third party interference	0.26	19.67
47	Wildlife	0.07	5.11
48	Human error	0.16	3.21
49	Defective equipment	0.76	59.63
50	Cause unknown	0.35	20.46
51			

52 **10(iii): Class B Interruptions and Duration by Main Equipment Involved**

53

sch ref		SAIFI	SAIDI
54	**Main equipment involved**		
55	Subtransmission lines	0.12	43.51
56	Subtransmission cables	–	–
57	Subtransmission other	0.04	4.07
58	Distribution lines (excluding LV)	0.47	132.45
69	Distribution cables (excluding LV)	0.03	5.51
60	Distribution other (excluding LV)	0.05	7.32

61 **10(iv): Class C Interruptions and Duration by Main Equipment Involved**

62

sch ref		SAIFI	SAIDI
63	**Main equipment involved**		
64	Subtransmission lines	0.39	16.50
65	Subtransmission cables	–	–
66	Subtransmission other	0.23	4.40
67	Distribution lines (excluding LV)	1.07	92.76
68	Distribution cables (excluding LV)	0.05	9.39
69	Distribution other (excluding LV)	0.20	10.14

70 **10(v): Fault Rate**

sch ref		Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
71	**Main equipment involved**			
72	Subtransmission lines	16	697	2.29
73	Subtransmission cables	–	10	–
74	Subtransmission other	3		
75	Distribution lines (excluding LV)	244	3,242	7.53
76	Distribution cables (excluding LV)	5	93	5.38
77	Distribution other (excluding LV)	50		
78	**Total**	318		

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Otago Sub-Network**

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)	4	
11	Class B (planned interruptions on the network)	308	
12	Class C (unplanned interruptions on the network)	315	
13	Class D (unplanned interruptions by Transpower)	–	
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)	1	
17	Class H (planned interruptions caused by another disclosing entity)	–	
18	Class I (interruptions caused by parties not included above)	–	
19	**Total**	628	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	229	86
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	0.04	17.06
26	Class B (planned interruptions on the network)	0.68	218.06
27	Class C (unplanned interruptions on the network)	1.90	145.91
28	Class D (unplanned interruptions by Transpower)	–	–
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)	0.06	0.92
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	2.68	381.95
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	n/a	n/a
38			

39	**10(ii): Class C Interruptions and Duration by Cause**		
40			
41	**Cause**	**SAIFI**	**SAIDI**
42	Lightning	0.02	3.47
43	Vegetation	0.16	12.68
44	Adverse weather	0.16	13.23
45	Adverse environment	0.00	0.07
46	Third party interference	0.26	23.04
47	Wildlife	0.07	6.01
48	Human error	0.16	3.74
49	Defective equipment	0.73	62.29
50	Cause unknown	0.34	21.38
51			
52	**10(iii): Class B Interruptions and Duration by Main Equipment Involved**		
53			
54	**Main equipment involved**	**SAIFI**	**SAIDI**
55	Subtransmission lines	0.12	51.09
56	Subtransmission cables	–	–
57	Subtransmission other	0.04	4.81
58	Distribution lines (excluding LV)	0.47	154.98
69	Distribution cables (excluding LV)	–	–
60	Distribution other (excluding LV)	0.05	7.18
61	**10(iv): Class C Interruptions and Duration by Main Equipment Involved**		
62			
63	**Main equipment involved**	**SAIFI**	**SAIDI**
64	Subtransmission lines	0.39	19.32
65	Subtransmission cables	–	–
66	Subtransmission other	0.23	5.15
67	Distribution lines (excluding LV)	1.07	108.59
68	Distribution cables (excluding LV)	0.01	1.02
69	Distribution other (excluding LV)	0.20	11.83

70	**10(v): Fault Rate**			
71	**Main equipment involved**	**Number of Faults**	**Circuit length (km)**	**Fault rate (faults per 100km)**
72	Subtransmission lines	16	697	2.29
73	Subtransmission cables	–	4	–
74	Subtransmission other	3		
75	Distribution lines (excluding LV)	244	3,242	7.53
76	Distribution cables (excluding LV)	2	43	4.65
77	Distribution other (excluding LV)	50		
78	**Total**	315		

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2021**
Network / Sub-network Name	**Lakeland Frankton Sub-Network**

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**

sch ref		Number of interruptions
9	**Interruptions by class**	
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	6
12	Class C (unplanned interruptions on the network)	–
13	Class D (unplanned interruptions by Transpower)	–
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**	6
20		

sch ref		≤3Hrs	>3hrs
21	**Interruption restoration**		
22	Class C interruptions restored within	–	–
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)	0.23	24.20
27	Class C (unplanned interruptions on the network)	–	–
28	Class D (unplanned interruptions by Transpower)	–	–
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**	0.23	24.20
35			

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

39 **10(ii): Class C Interruptions and Duration by Cause**

40

sch ref		SAIFI	SAIDI
41	**Cause**		
42	Lightning	–	–
43	Vegetation	–	–
44	Adverse weather	–	–
45	Adverse environment	–	–
46	Third party interference	–	–
47	Wildlife	–	–
48	Human error	–	–
49	Defective equipment	–	–
50	Cause unknown	–	–
51			

52 **10(iii): Class B Interruptions and Duration by Main Equipment Involved**

53

sch ref		SAIFI	SAIDI
54	**Main equipment involved**		
55	Subtransmission lines	–	–
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	–	–
69	Distribution cables (excluding LV)	0.18	16.17
60	Distribution other (excluding LV)	0.05	8.03

61 **10(iv): Class C Interruptions and Duration by Main Equipment Involved**

62

sch ref		SAIFI	SAIDI
63	**Main equipment involved**		
64	Subtransmission lines	–	–
65	Subtransmission cables	–	–
66	Subtransmission other	–	–
67	Distribution lines (excluding LV)	–	–
68	Distribution cables (excluding LV)	–	–
69	Distribution other (excluding LV)	–	–

70 **10(v): Fault Rate**

sch ref		Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
71	**Main equipment involved**			
72	Subtransmission lines	–	–	–
73	Subtransmission cables	–	6	–
74	Subtransmission other	–		
75	Distribution lines (excluding LV)	–	–	–
76	Distribution cables (excluding LV)	–	48	–
77	Distribution other (excluding LV)	–		
78	**Total**	–		

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 11 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 ROI of 4.38% which is below the 75th percentile estimate of post-tax WACC of 4.40% and 4.71% vanilla ROI which is below the 75th percentile estimate of vanilla WACC of 4.73%.

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

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 (RAB) was stated using the 31 March 2020 closing figure of $210,599k as a starting point with inflationary indexing over the year to 31 March 2021 plus additions less disposals resulting to a $217,607k RAB closing balance. 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 $94k cost of easements which is a tax deductible expense. 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)

Taxable Capital Contributions:	$ 1,020
	$ 1,020
Tax Rate:	28%
Temporary Differences	$ 286

Cost allocation (Schedule 5d)

10. 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 7: 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.

No items were reclassified.

Asset allocation (Schedule 5e)

11. 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 8: Commentary on asset allocation

All network assets are directly attributable.

No items were reclassified.

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

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

Box 9: Explanation of capital expenditure for the disclosure year

The materiality threshold applied to identify programmes or projects during the disclosure year was $100k. Lower value projects with defined scope were included in the list for specific identification within categories.

No items were reclassified during the disclosure year.

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

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

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

    13.3 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 10: 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)

14. 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 11: Explanatory comment on variance in actual to forecast expenditure

No items were reclassified during the disclosure year. Refer to each classification under point 12 and 13 above.

Capital Expenditure on Assets:

The actual expenditure on network assets was 4% above budget.

Consumer connection:

- 13% overspent attributed to increased customer demand for subdivision reticulation and large commercial connections.

System Growth:

- Only 19% of the budget was spent due to less than expected new cabling installed for load growth.

Asset replacement and renewal:

- 1% overspent mainly due to a larger quantity of substation minor equipment replacement work than planned for.

Asset Relocations:

- Budget overspent by a large margin due to unforeseen works undergounding power lines for a third party.

Quality of supply:

- 2% overspend due to increased automation project design costs, which were partly offset by a mobile sub site project being delayed.

Other reliability, safety and environment:

- Only 32% of the budget was spent due to the planned Remarkables communications link being found to be cost prohibitive and an alternative plan being selected; a mobile substation site project delaying a dependent NER installation project; and resources being diverted to consumer connections work.

<u>Operational Expenditure:</u>

Network opex was 9% above budget. Overall opex was 7% above budget.

Service interruptions and emergencies:

- 13% overspent due to a larger amount of distribution and technical faults than allowed for.

Vegetation management:

- 14% overspend due to utilisation of additional resources to provide power outages, so vegetation trimming could be accomplished safely.

Routine and corrective maintenance and inspection:

- 4% overspent due to additional routine maintenance activity.

Asset replacement and renewal:

- 5% underspent, mainly due to a lower level of distribution refurbishment work resulting from inspections.

System Operations and Network Support:

- 6% overspent which is a minor variation representing $69k additional cost mainly due to interconnection costs (Aurora NSP charges) incurred in the period.

Business Support:

- 3% overspent mainly due to higher customer compensation claims partially offset by savings in other operating expenditure.

Information relating to revenue and quantities for the disclosure year

15. In the box below provide-

15.1 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

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

Box 12: Explanatory comment relating to revenue for the disclosure year

Target revenue for the 2020-21 year was $33.418 million. The total billed revenue for the 2020-21 year was $33.948 million, which is $530k (2%) above.

The increase in revenue is attributable to the higher chargeable volumes than forecast in Otago region (Mass Market consumption exceeding budget) slightly offset by lower revenue in Lakeland region. The Electricity Southland Limited network continued to grow in Frankton and Wanaka with an additional 200 ICPs during the year, however electricity consumption declined due to COVID-19 reducing visitor numbers in the area.

Network Reliability for the Disclosure Year (Schedule 10)

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

Box 13: Commentary on network reliability for the disclosure year

In accordance with the Issues Register for Electricity and Gas Information Disclosure (ID), issues 447 and 458, OtagoNet Joint Venture (OJV) has calculated and disclosed normalised SAIDI and SAIFI consistent with the 2012 Electricity Distribution Business (EDB) ID Determination.

OJV has disclosed a normalised SAIDI at 323.39 and normalised SAIFI at 2.66 for 2020/21.

This compares with the 2019/20 year OJV published ID Determination values for normalised SAIDI of 339.6 and normalised SAIFI of 2.66 for the 2019/20 year – meaning very similar SAIFI performance and a slight decline in SAIDI performance compared with last year.

The total number of power interruptions in 2020/21 on the total OJV network is similar to 2019/20 – however there were significantly more Class C unplanned interruptions, and less Class B planned interruptions.

For Class B interruptions in 2020/21 SAIFI was lower and SAIDI was slightly higher, indicating less frequent planned interruptions of longer duration.

SAIDI for Class C interruptions was lower in 2020/21, indicating shorter duration interruptions affecting less customers. The cause of Class C interruptions was generally consistent with 2019/20, with the greatest number of unplanned interruptions being the result of defective equipment and third party interference showing a relatively significant increase.

Distribution lines and distribution other were the main equipment involved with Class C interruptions, with both increasing from 2019/20 to 2020/21.

These results were reflective of interruptions occuring predominatly on the Otago sub-network.

Insurance cover

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

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

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

Box 14: Explanation of insurance cover
OtagoNet insures its substations and network equipment. • Substations and network equipment are insured for $68.6 million. Lines and cables are not insured. OtagoNet therefore "self-insures" its lines and cables but does not recognise the cost of self-insurance.

Amendments to previously disclosed information

18. 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:

    18.1 a description of each error; and

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

Box 15: Disclosure of amendment to previously disclosed information
An error has been identified in the 2020/21 disclosure year relating to the incorrect inclusion of the Charlotte Street, Balclutha commercial building development in the non-network assets commissioned. The new development is tenanted to other parties, some related and should not have been construed as a non-network asset as the assets are not related to the provision of electricity line services for the OtagoNet Joint Venture (OJV). The corrected treatment is consistent with the Ranfurly and Palmerston commercial buildings owned by the OJV which are not included in the Regulatory Asset Base (RAB). There have been several amendments to previously disclosed information for the 2020/21 year. • Schedule 4: RAB Value (Rolled Forward) • Schedule 5a: Regulatory Tax Allowance • Schedule 5b: Related Party Transactions • Schedule 5e: Asset Allocations • Schedule 1: Analytical Ratios • Schedule 2: Return on Investment • Schedule 3: Regulatory Profit • Schedule 6a: Actual Expenditure Capex • Schedule 7: Actual vs Forecast

Box 15: Disclosure of amendment to previously disclosed information (*continued*)

Schedule 4: RAB Value

Non-network assets commissioned of $8,491k were overstated and are now removed. This overstated the RAB balance at the end of the 2021 year by $8,491k.

This adjustment is flowing through to roll forward of works under construction and Schedule 5e (Asset Allocations).

Schedule 3: Regulatory Profit

Due to the above, the accompanying rental amounting to $405k was removed from the other regulated income.

Schedule 5b: Related Party Transactions

Expenditure on non-network assets amounting to $115k and rental income of $405k were removed to the related party transactions.

Schedule 6a: Actual Expenditure Capex

The $4,705k of actual expenditure during 2021 previously classified under non-network assets category has been removed. No adjustment has been made for prior years non-network assets expenditure in Schedule 6a as it does not change opening balances or have any material impact on other schedules.

Due to above restatements Schedules 1 (Analytical Ratios), 2 (Return on Investments), 5a (Regulatory Tax Allowance) and 7 (Actual vs Forecast) have been recalculated.

For full details of the above adjustments, refer to Appendix D.

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 current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

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

Nominal Prices are based on publicly available New Zealand Treasury's economic forecast indicated in the Half Year Economic and Fiscal Update (HYEFU) 2019 report released in December 2019:

	2021	2022	2023	2024	2025
Inflator (CAPEX & OPEX)	2.0%	2.0%	2.0%	2.2%	2.2%

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

Schedule 3
Excluded from other regulated income is an amount of $735k for Transpower Losses and Constraints.

Schedule 5f – 5g (Cost and Asset Allocation Support)
No disclosure made on these schedules with no shared assets and minimal shared costs relating to rental properties.

Schedule 10
Network reliability is compliant with quality requirements under DPP3, however there are inherent limitations in the ability of OJV to collect and record the network reliability information required to be disclosed in Schedule 10 (i) to 10 (iv). Consequently there is no independent evidence available to support the accuracy of recorded faults and control over the accuracy of installation control point (ICP) data included in the SAIDI and SAIFI calculations is limited throughout the year.

The information has been prepared on a basis consistent with the previous year's disclosure and OJV has recorded successive interruptions, originating from the same cause, as single interruptions.

APPENDICES

APPENDIX A:

Related Party Transactions:

Additional Information Disclosures

1. INTRODUCTION

For the purpose of meeting the 2021 Related Party Transaction reporting requirements, in accordance with section 2.3.6 of the Electricity Information Disclosure Determination 2012, (Consolidated in 2018), issued 3 April 2018, the following information is provided in support of:

- **OtagoNet Joint Venture's Information Disclosure**, for the year ended 31 March 2021 - Schedule 5(b) Related party Transactions

2. INFORMATION DISCLOSURE REQUIREMENTS

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

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.

3. RELATED PARTY RELATIONSHIPS

In accordance with Input Methodology rules, a Related Party Transaction occurs when a regulated supplier transacts with an entity which is related to it by common shareholding or other common control.

The OJV Regulated Network is comprised of OtagoNet Joint Venture (OJV) and Electricity Southland Limited (ESL). The OJV Regulated Network and the network management company PowerNet Limited (PowerNet), are all 100% wholly owned by Electricity Invercargill Limited (EIL) and The Power Company Limited (TPCL), through their respective wholly owned subsidiary companies Pylon Limited and Last Tango Limited.

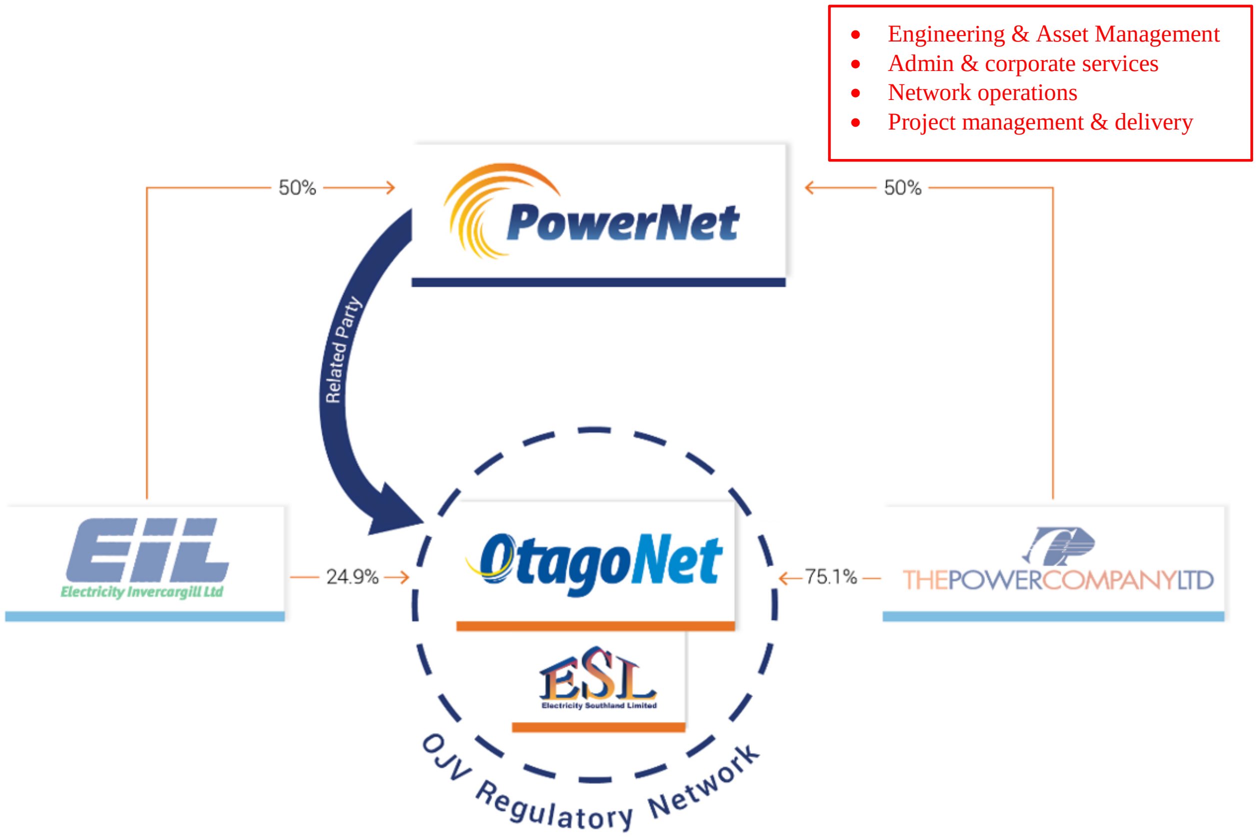
During the year ending 31 March 2021, OJV Regulated Network had related party transactions with the following entities:

- Goods and services provided by – PowerNet Limited;

Ownership Structure

The parties to the OtagoNet Joint Venture consist of EIL and TPCL. PowerNet is a related party, due to its ownership by EIL and TPCL. The regulated OJV network also includes the ESL network, which has the same ownership as OJV. The following diagram illustrates the OJV Regulated Network's transactions with PowerNet, and the nature of related party transaction work undertaken.

ID Determination reference: 2.3.8



a. **PowerNet Limited**

EIL and TPCL jointly hold a 100% interest in electricity network management company PowerNet Limited, and the regulated OJV network (OJV and ESL). PowerNet provides a range of field contracting, asset management, system control and finance and commercial services to the regulated OJV network. The value of the related party transactions for the year ended 31 March 2021 is categorised as follows:

		($000)
Operating Expenditure:		
i.	Service interruptions and emergencies	1,827
ii.	Vegetation management	1,270
iii.	Routine and corrective maintenance and inspection	1,914
iv.	Asset replacement and renewal (opex)	206
v.	System operations and network support	950
vi.	Business support	1,735
Capital Expenditure:		
vii.	Consumer connection	7,398
viii.	System growth	46
ix.	Asset replacement and renewal (capex)	7,631
x.	Asset relocations	610
xi.	Quality of supply	464
xii.	Other reliability, safety and environment	274
	Total Related Party expenditure from PowerNet	**24,325**

In the year to 31 March 2021, PowerNet provided 100% of the OJV and ESL Lines Business Capital Expenditure, and 89% of all Operating Expenditure. The high percentage of related party transactions relative to total expenditure is due to PowerNet operating under a Network Management Agreement (NMA) with OJV and ESL, in the form of an “agency agreement”.

Services provided under the agreement include:

- Electricity distribution field services
- System control services
- Project management of capital and maintenance work
- Faults restoration and stand by (on call) arrangements
- Asset management for EDB and meters,
- Heath, Safety and Environment management
- Business support, IT support and human resources
- Corporate, finance and commercial services

b. The Power Company Limited

TPCL holds a 75.1% ownership of OtagoNet JV and ESL. The value of the related party transaction with TPCL during the year ended 31 March 2021, relates to the use of specialised equipment, categorised as follows:

		($’000)
Operating Expenditure:		
i.	System operations and network support	60
	Total Related Party expenditure from TPCL	**60**

Network Management Agreement ('Agency Agreement')

OJV (including ESL) incurs 100% of its capital expenditure and the majority of operating costs from PowerNet, for operating its electricity distribution businesses. PowerNet operates in accordance with the explicit terms and conditions of a Network Management Agreement (NMA).

While OJV & ESL own the Network distribution assets and provide electricity distribution services through their respective electricity networks in the Clutha and Central Otago region, under the NMA agreement PowerNet manages the maintenance, replacement or development activity associated with network assets, in accordance with an approved annual Capital and Maintenance Works programme. PowerNet has the exclusive right to provide Line Function Services, and also provide the business administration services on behalf of OJV and ESL.

PowerNet was established in 1994 to extract operational efficiencies from the merger of field work management, asset management and office based functions performed by TPCL and EIL. In 1993, there were two autonomous Lines Companies in Southland (TPCL and EIL). Each had a separate staff, management and Board of Directors, and each had a different ownership structure. Directors of both companies recognised there would be significant economies of scale benefits if there were a single Lines company covering the area. Due to different ownership a single Lines company was not possible, however a single network management entity was a viable option.

The ongoing drive for efficiency by merging operations and achieving scale was recently identified by the Government Pricing Review and the terms of reference required investigation into the "PowerNet model" as the review looked at how other EDBs could potentially do the same.

PowerNet charges Agency Fees to the EDB's network and metering businesses it manages under the NMA's. These charges recover costs incurred in the performance of the system control services, asset management, corporate, finance and commercial services.

These costs are charged to customers based on a cost allocation methodology applied within PowerNet. The allocation is based on various allocation drivers, including field operating orders, staff numbers, EDB asset size, EDB customers and a departmental assessment of indirect labour time splits. The allocation forms the basis of costs recovered from:

- the agency fee to be charged to the EDB's and metering businesses; and
- the capital mark-up to recover costs allocated to EDB and meter capital projects

An independent review in 2018 of the allocation methodology ensured all parties that are charged agency and other fees by PowerNet are treated consistently and appropriately for each party.

4. PROCUREMENT POLICY

ID Determination 2.3.10 & 2.3.11

Under the Network Management Agreement (NMA), OJV and ESL have contracted PowerNet to manage the operational functions, maintain the network assets, implement the Asset Management Plan, and provide business management services, and hence, act on behalf of OJV and ESL when project managing and purchasing required goods and services in the course of carrying out the responsibilities of the Agreement. Due to the special relationship with OJV and ESL, the PowerNet **Procurement Policy** (including the **Procurement Strategy**), is implied as also being the procurement practices followed by OJV and ESL. Therefore, the Procurement Policy and Procurement Strategy provided for the purpose of this information disclosure, are as provided by PowerNet.

The **Procurement Policy**, sets the procurement principles for staff to follow when engaging suppliers or sourcing goods and services. The PowerNet **Procurement Strategy** provides guidance on practices and processes for the business to follow when engaging with the suppliers of goods and services, and anywhere the business commits to a purchase obligation.

These documents are to ensure appropriate practices and controls are followed, and to make sure the best value and quality is achieved for the business and stakeholders.

Procurement Policy (FNPO-035-Policy)

PowerNet Limited (PowerNet) aims to obtain the best long-term value for money across all its spend categories. In doing so, PowerNet's procurement processes will be guided by the following general principles:

- ✓ Plan and manage for the best outcome
- ✓ Be fair to all suppliers
- ✓ Choose the right supplier
- ✓ Adhere to the rules

Asset 'whole-of-life' cost focus

- The lowest lifecycle (whole-of-life) cost shall be sought.
- Consideration must be given in regard to the Capital versus Maintenance expenditure trade-offs for network assets and equipment.

Sourcing of labour

- Necessary skills, equipment and availability will be considered when resourcing labour – whether using internal or external sources. External contractors must comply with PowerNet health and safety and operating certification requirements.
- PowerNet recognises that the across the Southland-Otago region there is a limited pool of line mechanic and technical contractors, and accordingly relies heavily on its own internal field crews.
- Large specific network projects should be competitively tendered where possible, both to ensure that the lowest price has been obtained, and also to provide cost comparison information for PowerNet.

Sourcing of materials and equipment

- Routine supply of materials shall be through the Corys Electrical Agreement, which includes various mechanisms to ensure prices are efficient.
- Supply of non-routine materials or specialist equipment shall be competitive. The formality of the process shall be commensurate with the value of the purchase.

External party works

- Activities for which PowerNet has a statutory responsibility, but is not required to perform the function (e.g. vegetation management or new connections) will be made clear to those external parties (or customers). Communications with those consumers shall include a list of optional accredited external contractors who they can choose to undertake their work.

The above guidelines must be applied by all staff at PowerNet. Further detail is available within associated internal procurement process and procedure standards.

5. APPLICATION OF PROCUREMENT POLICY

ID Determination 2.3.12 (1)

As noted above, the procurement policy and processes adopted by OJV and ESL are based on the PowerNet Procurement Policy and Strategy (FNPO-035). PowerNet is responsible for sourcing all materials and services required to maintain the OJV and ESL network assets and project manage the replacement or development of new assets. PowerNet recovers this expenditure through charging OJV and ESL for capital and maintenance work, and through applying an agency fee for recovering a share of the associated business services costs.

The **Procurement Policy** puts emphasis on making decisions in the interest of an asset's lifecycle cost – in particular, capital versus maintenance decisions; considerations when sourcing labour, materials and equipment, and engaging customers for external party works.

The **Procurement Strategy** document covers in detail the applicable processes and practices of purchasing goods and services.

While PowerNet is a related party of OJV (including ESL) for reporting purposes, they are structured as separate legal entities, operating on an 'arms-length' basis.

Planning

Adequate planning is an important part of the Network's procurement process. Each year the PowerNet Network Asset Engineers prepare the OJV & ESL Asset Management Plan (AMP), a strategic, long-term view of the Network capabilities and constraints. The AMP provides an internal asset management framework for OJV's regulated network, including the Annual Works Programme (AWP), detailing the capital and operation expenditure (asset maintenance, replacement and/or development) required. The AMP is reviewed and approved by the OJV Governing Committee and ESL Board, prior to the PowerNet Engineers' and Project Managers' developing the AWP, as a key part of the annual business planning process. The AWP translates projects identified in the AMP into categorised work streams with detailed assumptions regarding the timing, materials and resources needed to complete the work, resulting in a more refined cost estimate, for Project Managers' to apply. The AMP is a 10 year view, whilst the AWP focuses on the upcoming 12 month period. In certain cases with large forecasted spend, a project business case is required in advance, for separate Board consideration and approval. The finalised AWP expenditure is included within the OJV & ESL annual business plan approval process.

Project Manager's are assigned to implement the identified projects, within the guidelines of the project budget, and are responsible for managing the resources and making sure the project is completed to required standard.

Where required for high cost projects, or if specialised skills or equipment are required, a 'Request for Tender' process may be undertaken, to provide an indication of market supplier interest and greater certainty of project costs. The PowerNet Tendering Policy provides the steps that are to be followed when work is tendered. The decision to undertake a Tender process will be determined during the project planning phase.

Goods and services will be procured within approved budgets, with any exceptions requiring approval from a Senior Leader or Chief Executive Officer, in line with the financial authority limits. Written cost estimates or quotes are required from Suppliers depending on the value or nature of the job to manage cost expectations.

Resourcing

Having the combined network management of TPCL, EIL, OJV and ESL, gives PowerNet a stronger position to negotiation more favourable competitive prices for goods and services, through the greater purchasing volumes and activity, than would otherwise be possible by OJV and ESL alone. A supplier agreement with Corys Electrical makes it possible to source the required specialised electrical materials at market competitive prices, and the volume of work enables priority response and competitively low prices from many external service providers.

The market of available suppliers of high voltage electrical work in Southland & Otago is very small, and in some cases for specialised tasks, non-existent. PowerNet has learnt over the past 25 years through different operating models (from operating with internal field crews, to operating with fully outsourced labour arrangements), the most effective, efficient and reliable outcome for getting OJV & ESL's Works Programme projects completed in a timely manner, to the required standard, is to secure required skills internally, and to apply these staff as needed, across the different networks PowerNet manages.

OtagoNet: In many cases, external contractors are still required for large projects or technically challenging tasks, where resources can be outsourced. Having a team of experienced Line Mechanics and high voltage Technicians enables PowerNet to provide an effective faults response service, reducing the impact on customers of unplanned outages, and helping the OJV network meet its regulatory outage performance targets (SAIDI & SAIFI targets). For this reason, in many cases for OJV network asset maintenance tasks, the work is allocated to PowerNet internal labour teams with the appropriate skills and equipment.

ESL: PowerNet undertakes the majority of the Annual Works Programme projects, whilst outsourcing required services when necessary.

While the project resources and materials required are planned by network engineers within the PowerNet Asset Management team, the selection of the Suppliers to provide the work is a responsibility of the respective Project Manager. In making the selection, the Project Manager is mindful of making decisions based on the best outcome on behalf of the network – and so, to protect the value and reliability of the Network Assets, the Project Manager selects the materials and scopes the design to meet the required network design standard. Outsourcing is considered for each element of the project if appropriate, and market testing performed where uncertainties exist in cost or difficulty. This selection process may not always result in the cheapest or easiest short-term option being applied, with decisions made to make sure the outcome is of a high quality and reliable standard, in the best long-term interests of the customers and stakeholders.

Materials are sourced by Corys Electrical who can provide a range of options for the Project Manager to select from, at market competitive prices.

Suitable Contractors must be capable of meeting the operating and health & safety standards of PowerNet, and there are specific controls to check new applicants, to make sure they have completed the requirements (eg. PreQual halth & safety assessment) are reputable before allowing them to be selected.

Cost of assets, goods or services from Related Party

The costs PowerNet incurs undertaking the responsibilities of managing OJV and ESL's network assets are charged to OJV & ESL respectively each month. Agreed charges are included within the Network Management Agreement, including monthly progress invoices in relation to the Annual Works Programme project activity expenditure. In return for the management of the network assets and related business support costs, PowerNet charges OJV and ESL an Agency fee, and applies an internal commercial mark-up to recover its operating costs and enable a modest commercial profit.

6. PURCHASES REQUIRED FROM A RELATED PARTY

ID Determination 2.3.12 (2)

Activities for which OJV & ESL network customers are required to use PowerNet (related party) in relation to electricity distribution services are:

- Fault Repairs;
- Requests for a new connection to OJV's network; and
- Removing trees or vegetation from proximity of power lines.

Fault Response and Reactive Maintenance

Under the Network Management Agreement, PowerNet is responsible for maintaining the OJV (including ESL) network assets in good operational order, and in an overall standard equal or better to the initial condition. Returning power to consumers safely and quickly, following a fault or outage event, is an important requirement and performance measure for OJV.

PowerNet provides on-call line mechanics and technicians, located across the Southland and Otago regions, able to respond in a very short period of time to a fault call out, to provide a reliable and efficient fault response service, and minimise the impact of a power outage on network customers. Without these remote depot locations the duration (SAIDI) of outages on the OJV regulated network would be adversely affected. Having skilled labour, trained to the network accepted standard and practices, located at various depots across the network, and having appropriate tools and equipment capable of resolving an outage safely and quickly, is a key reason why PowerNet provide the fault response services internally, rather than outsourcing.

New Connections

The process for requesting a new connection or capacity upgrade on the OJV (including ESL) network is managed by the PowerNet Distribution team (PowerNet policy FNPO-025 Commercial Terms for New and Altered Customer Connections, or "Connections" policy). This is essential to maintain a consistent design specification standard for the OJV network assets.

As highlighted in the Connections policy, depending on the nature of the customer work required, the Network will likely be required to manage parts of this work, especially where the work involves network equipment being installed or connection being made to Network assets. For high voltage lines installation (11kVA and above), requiring road side access, the Utilities Access Act 2010 controls who has the authorisation to operate in this space, and restricts the access to only approved utility companies. Hence, PowerNet, under the NMA, manages the construction of lines or installation of network equipment along road-sides on behalf of OJV and ESL, or where special easements are required across private land. However, low voltage work on private land is the responsibility of the property owner.

An application must be completed by the customer for the PowerNet Connections team to review and provide an explanation of requirements relating to the work, and any associated costs (in the form of a letter of quotation). The quote must be accepted by the customer prior to PowerNet starting work on behalf of the Network.

If PowerNet are required to undertake construction or installation work, the Project Manager will evaluate what resources are required, and who can do the work. This work may be contracted to an external supplier however due to the small number of high voltage contractors available in Otago this work is often undertaken by the PowerNet Distribution field staff.

The new connection process and responsibilities are explained on the PowerNet website, where details are provided for Customers to use an independent contractor:
https://powernet.co.nz/your-power-supply/getting-connected/

Using an Independent Contractor

It is possible for a consumer to use an independent contractor to design and build part of their new connection. If you are developing a new subdivision or if your new supply is large or remote from the existing network and will require our high voltage network extending across private land you can use an Independent Contractor to carry out some of the work. Further information is available in our Independent Contractor and Developer Reticulation in Subdivisions documents. Please note that there are some statutory tasks that only PowerNet can perform.

Arborist/Tree Management

PowerNet is responsible for vegetation management on the OJV and ESL network, in accordance with the Network Management Agreement. The PowerNet arborist team inspect the network lines and identify areas of risk where trees are growing inside the legal 'growth limit zone'. In these circumstances, PowerNet will notify the tree owners of their obligations by issuing a 'Tree Cut/Trim Notice'. Under the Tree regulations and tree management process – the first cut or trim is at the cost of the regulated network. Following the first cut, the tree owner is responsibility for keeping the tree(s) clear of the 'Growth Limit Zone' around OJV's power lines and equipment.

PowerNet provides advice on its website (https://powernet.co.nz/services/trees/) relating to tree regulations and owner's responsibilities, and offers a list of network approved contractors who can undertake tree cutting services on the regulated network for the owner.

The following content can be found on the PowerNet web page, under the services offered:

https://powernet.co.nz/services/trees/approved-contractors/

Approved Contractors

Important note: If you choose to organise your own tree cutting and are not using one of our approved contractors (listed below) please call PowerNet System Control on 0800 808 587 at least three days before proceeding to discuss the work to be undertaken . You or your contractor must apply for an Application for Approval to Operate Machinery closer than 4m to electric power lines or have the lines de-energised.

PowerNet Arborist Services – Quotes:
Phone 03 2111899 or email trees@powernet.co.nz

Asplundh (Invercargill)
Office on 03 216 8051
Ryan, Contract Manager on 027 662 1999
enquiry@asplundh.co.nz or visit Asplundh at www.asplundh.co.nz

Bruce Dickens Tree Topping – Quotes:
Phil, Operations Manager, on 0274 441 008 or 03 212 8686
Bruce on 0274 756 732
Office on 0800 001 165
office@dickenstreetopping.co.nz or visit www.dickenstreetopping.co.nz

The Tree Cut/Trim Notice issued to the tree owner, indicates available options for the work required. The tree owner responds with their preference – either to manage their own contractor, or engage PowerNet.

7. PROCUREMENT REPRESENTATIVE EXAMPLES

ID Determination 2.3.12 (3)

The OJV regulated network requires a range of services from PowerNet to manage the Network operations. These services may often have very different characteristics and may involve a different procurement process to best suit the situation or work being undertaken. The following list illustrates the categories of transactions with different procurement processes:

i. **Major Construction Projects (System Growth/Asset Replacement & Renewal/Reliability, Safety & Environment)**

Significant large-scale projects are managed by the PowerNet Asset Management – Major Projects team. These projects are often long term (greater than 12 months), complex in design, and usually greater than $1 million in cost, with additional procurement requirements. Due to the large amount of dedicated resource and long period of time required, these projects are often subcontracted out by PowerNet.

EXAMPLE: Halfway Bush-Palmerston Second Line 33 kV Conversion

The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for a 'Major Project' asset development.

Project Name:	HWB-PAL 2 110/33 kV Conversion
Project Date:	June 2018 – February 2021
Project Number:	30932
Total Project Expenditure:	$ 300,000 External labour & materials $ 90,000 PowerNet services --------------- $ 390,000 (2020/21) $ 300,000 (2018-2020) ---------------- $ 690,000 Total Cost
Expenditure Classification:	Asset Replacement and Renewal (Capital Expenditure)
Project Manager:	PowerNet Ltd
Subcontractors:	Decom Ltd, Electrix Ltd and Lumen Ltd

The pre-existing northern 33 kV network towards Dunedin was identified as requiring an upgrade to improve reliability at the end of the OtagoNet network. An opportunity arose to purchase the two Transpower Halfway Bush-Palmerston lines to enable OJV to further develop or modify the supply to increase reliability and efficiency, both of this point of supply and the downstream 33 kV network and zone substations. There were added benefits with shifting the point of supply to Halfway Bush and converting these 110kV lines to 33 kV.

The conversion project was undertaken in two stages over two years and was completed in February 2021.

ID Determination 2.3.12 (5)

Market Testing: The majority of the Halfway Bush-Palmerston Second Line 33kV Conversion project cost was outsourced by PowerNet. The rates provided by the external contractors were consistent with recent tender prices. Materials were provided mainly by Transpower New Zealand Limited and Corys. The PowerNet project management and internal labour cost is benchmarked to local market rates.

ii. **New Connection / Capacity Upgrade (System Growth)**

New connections and capacity upgrades are generally customer driven, whether it be for a new property, or expansion of an existing property. Project size can range from a small connection of a newly built house, to the construction of a new manufacturing plant or new residential subdivisions.

Characteristics:	Requirement:
- Customer driven enquiries. - Small sized projects. - Planning is high level. - Quote provided. - Customer contribution received. - Internal Distribution staff undertake work on the Networks. - External qualified electricians are given opportunity to undertake customer work, directly engaged by customer.	❖ General amount approved in Asset Management Plan. ❖ Cost estimate - Maximo work order ❖ Payment – Purchase Order

The procurement of goods and services for this type of work follows the same PowerNet procurement processes for a general construction project, only this work is more heavily influenced by a customer need rather than a network need. The PowerNet New Connection policy governs the requirements for this work.

EXAMPLE: Installation of New Pump for Shed and Irrigator in Ranfurly

The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for a 'New Connection' to the OJV network:

Project Name:	Customer Connection (OJV Works programme)
Completion Date:	November 2020
Project Number:	CC 352052 / 352051
Project Expenditure:	$ 68,000 External Materials $ 121,000 PowerNet services ------------ $ 189,000 Total Cost (2020/21)
Project Classification:	Consumer Connection (Capital Expenditure)
Project Manager:	PowerNet Ltd
Construction:	PowerNet - Distribution Team
Subcontractors:	N/a

PowerNet received a connection application for a new pump shed requiring 90kW supply for irrigation with a capacity of 150kVA. The connection required an installation of a 3 phase 200kVA transformer to meet the capacity requirement.

Market Testing: The prices charged by PowerNet have been benchmarked against similar 2019-2021 Line Mechanic or Technician roles from other available external suppliers. Of the $7.3M capital expenditure spent on New Connections and Capacity Upgrades, 58% of this cost related to external labour and materials. The materials sourced through Corys Electrical supply agreement includes a range of contractual mechanisms to ensure efficient prices are being provided to PowerNet.

iii. Distribution & Technical Projects (Asset Replacement and Renewal)

Asset Replacement and Renewal projects are generally driven by internal asset condition and monitoring assessments, performed periodically by PowerNet staff on OJV and ESL network assets. Depending on the nature of the work, this could be a small scale project relating to the replacement of an 11kV Line Pole (eg. 'Red Tag Pole') managed by the PowerNet Distribution Team, or a larger technical project (eg. 500kV transformer replacement or substation upgrade project) managed by the PowerNet Technicians team.

Team:	**Characteristics:**	**Requirement:**
Distribution	- Emergency fault repair work. - Network Lines repair and development. - Internal Distribution staff undertake work on Networks. - External contractors may be subcontracted by PowerNet to assist with this work.	❖ Planned - Asset Management Plan ❖ Project managed - Maximo work orders ❖ Payment – Purchase Order
Team:	**Characteristics:**	**Requirement:**
Technical Projects	- Technical specialised work. - Internal Technician staff undertake work on Networks. - External contractors with necessary skills may be subcontracted by PowerNet to assist with this work.	❖ Planned - Asset Management Plan ❖ May require Business Case approval ❖ Project managed - Maximo work order ❖ Payment – Purchase Order

EXAMPLE: 11 kV Line Replacement & Renewal

The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for a 'Distribution' project for the OJV network:

Project Name:	Alexander Road 11kV Rebuild
Completion Date:	February 2021
Project Number:	CC 357441
Project Expenditure:	$ 109,000 External labour & materials $ 134,000 PowerNet services -------------- $ 243,000 Total Cost (2020/21)
Regulatory Classification:	Asset Replacement & Renewal (Capital Expenditure)
Project Manager:	PowerNet Ltd
Construction:	PowerNet - Distribution Team
Subcontractors:	None

PowerNet undertook Project CC357441 to replace poles, cross arms and insulators as they were at the end of their useful life, and to improve the capacity in the Glenore area. This work is identified through PowerNet inspection and testing programmes to identify assets that are reaching the end of their economic life and was deemed essential to maintain security of supply within the area. A PowerNet Project Manager was assigned to plan and oversee the work. Consideration is given to the timing, to make sure resources are available, and to minimise the impact of a power outage to effected OJV customers. PowerNet was assigned to undertake the work, being able to provide the skilled distribution services and equipment required. Materials were sourced through the Corys Supply Agreement.

Market Testing: The prices charged by PowerNet have been benchmarked against similar roles from other external Suppliers utilised during 2019-2021. The materials sourced through Corys Electrical supply agreement includes a range of contractual mechanisms to ensure efficient prices are being provided to PowerNet.

iv. Faults Response (Service interruptions and emergencies)

Fault response is a key service provided by PowerNet. Minimising power outage time of network faults, and minimising the number of customers impacted, is an important performance measure of the OJV network (including ESL). As noted above, PowerNet provides an on-call service, able to respond quickly to an unplanned outage or event. PowerNet Line Mechanics crews are based in depots located across the Southland and Otago regions for quick response to fault call-outs and to minimise travel time across the network.

Market Testing: Market prices assumed where PowerNet is applying the same labour rates as applied across other spend categories which are more commonly market tested. The prices charged by PowerNet have been benchmarked against similar Line Mechanic or Technician roles from other external Suppliers utilised during 2019-2021.

v. Arborist Work (Vegetation Management)

Tree management costs are driven by work associated to compliance of Government regulations for proximity of branches and vegetation to power lines. OJV and ESL are responsible for encouraging property owners to comply with the regulations. PowerNet manages this service on behalf of the OtagoNet regulated network and operates a skilled vegetation management team. Inspectors identify hazards, liaise with landowners and issue Cut/Trim notices to the landowner as required.

Characteristics:	Requirement:
- Network vegetation management. - Some emergency fault repair work. - Internal Distribution staff undertake work on Networks. - External contractors subcontracted by PowerNet to complete this work.	❖ Planned - Asset Management Plan ❖ Project managed - Maximo work orders ❖ Payment – Purchase Order

EXAMPLE: Vegetation Management

The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for Vegetation Management expenditure on OJV network:

Project Description:	Vegetation Control (OJV Works Programme)	External Chargeable Work
Project Name:	Trim Hedge - Lawrence Road Stirling 11kV and 33kV Lines	Trim Hedge and Fell Tree at Naseby
Project Completion Date:	July 2020	May 2020
Project Number:	354558	357857
Total Expenditure:	$17,300	$1,500
Regulatory Classification:	Vegetation Management (Operational Expenditure)	Fully Chargeable to Customer
Project Manager:	PowerNet Ltd.	PowerNet Ltd.
Customer:	OJV Network	External Customer

Chargeable to OJV Network

The PowerNet Arborist team became aware of a shelter hedge growing within the regulatory distance of power lines during a routine Lines inspection in Lawrence Road adjacent to 11kV and 33kV lines. Details of the location and work required (trees to be felled) were noted on the PowerNet Cut/Trim Notice (CTN 201321).

In this case, for 'first cut' notification, the work is undertaken by PowerNet and charged to OJV, rather than the property owner.

Chargeable to Customer
During routine line inspection, a site was identified requiring the hedge height reduced and tree removal to meet the 1.5 meter clearance requirement, from 11kv lines in Naseby. A cut/trim notice was issued and the customer given an estimate for the work to be done. The customer requested PowerNet to undertake the work, and was charged upon completion.

Market Testing: The vegetation labour and equipment prices charged by PowerNet have been benchmarked against similar arborist roles from other external suppliers where possible.

In the instance where a second cut is required, the property owner is responsible for the cost. In the event that they chose PowerNet as the contractor of choice, the prices are consistent with prices charged to OJV for vegetation work, indicating competitive market rates being applied.

vi. Business Services (Opex)

Administration processes and systems associated with running OJV and ESL networks are managed by PowerNet support services teams (eg. Network Assets, Operations, Finance, HSE). A share of these costs are charged to OJV by way of an Agency fee, which would otherwise be directly incurred by OJV, if there was no 'Agency Agreement' (or NMA) in place with PowerNet.

Market Testing: Market testing the provision of business services is very difficult due to the lack of comparability available. However, the benefits of OJV and ESL sharing the cost of running these management and administration systems with other EDB's TPCL and EIL (economy of scale benefits), was recognised in an independent benchmarking exercise in 2018 of PowerNet business and network support services to TPCL/EIL/OJV, against other equivalent sized EDB's on a cost per ICP basis. The findings of the review rated OJV favourably against similar sized EDB's in the same peer group.

APPENDIX B:

MAP OF NETWORK EXPENDITURE AND CONSTRAINTS

ID Determination 2.3.13 - 2.3.16

Regulatory requirements

- Electricity Distribution Information Disclosure Amendments Determination 2017 (NZCC 33), clauses 2.3.13 to 2.3.16.
- Input methodologies review – related party transactions final decision and determinations guidance 21 December 2017, table 5.1 (copied below, refer to ID for precise requirements).

The purpose of this section is to identify on a map the anticipated network expenditure and network constraints in accordance with the OJV network 2021-2030 Asset Management Plan.

OJV - 10 largest forecast Network Operating Expenditure projects (Maintenance)

- Clause 2.3.13(1), 2.3.14(1) and (2).

The 10 largest forecast Operating Expenditure projects in the 2021-2031 Asset Management Plan for OJV regulated network are explained below, and indicated on the Network map above where relative to a single area:

1. Incident Response – Distribution - $14.55M

   Provision is made for staff, plant and resources to be ready for lines faults and emergencies. Fault staff respond to make the area safe, isolate the faulty equipment or network section and undertake repairs to restore supply to all customers.

2. Vegetation Management - $8.10M

   Annual tree trimming in the vicinity of overhead network is required to prevent contact with lines maintaining network reliability. The first trim of trees has to be undertaken at OJV's expense as required under the Electricity (Hazards from Trees) Regulations 2003.

3. Distribution Routine Inspections - $6.40M

   Five yearly network inspections (20% inspected annually), other routine tests and minor maintenance works on distribution assets.

4. Technical Routine Maintenance - $3.75M

   Routine scheduled maintenance (other than preventative maintenance) on technical assets including planned substation maintenance.

5. Earth Testing - $2.61M

   Routine testing of earthing assets and connections to ensure safety and functional requirements are completed for all earths on a five yearly basis.

6. Technical Routine Inspections - $2.19M

   Routine inspection and testing of assets at zone substations. Includes such things as oil DGA, breakdown, moisture and acidity, operation counts, protection testing etc. Also covers responses to maintenance triggers, such as oil processing or recalibration of relays.

7. Distribution Routine Maintenance - $1.54M

   Generally reactive work undertaken to correct issues found during the routine distribution inspection. Also a general budget for all minor distribution work.

8. Incident Response – Technical - $1.47M

   Provision is made for staff, plant and resources to be ready for substation faults and emergencies. Fault staff respond to make the area safe, isolate the faulty equipment or network section and undertake repairs to restore supply to all customers.

9. General Distribution Refurbishment - $1.15M

   Refurbishment works for plant other than that located at distribution substations which won't impact on the valuation of the distribution asset. Covers items like cross-arms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.

10. Transmission Line Minor Maintenance - $1.02M

    Five-yearly walking condition inspections are made of all subtransmission lines with remedial repairs or renewal planned based on information obtained. Repairs or renewals are planned for all poles whose condition indicates that they are likely to fail before the next inspection.

Further detail relating to OJV network Operating Expenditure is provided in a table at the end of this section.

Please Note: All of these projects -

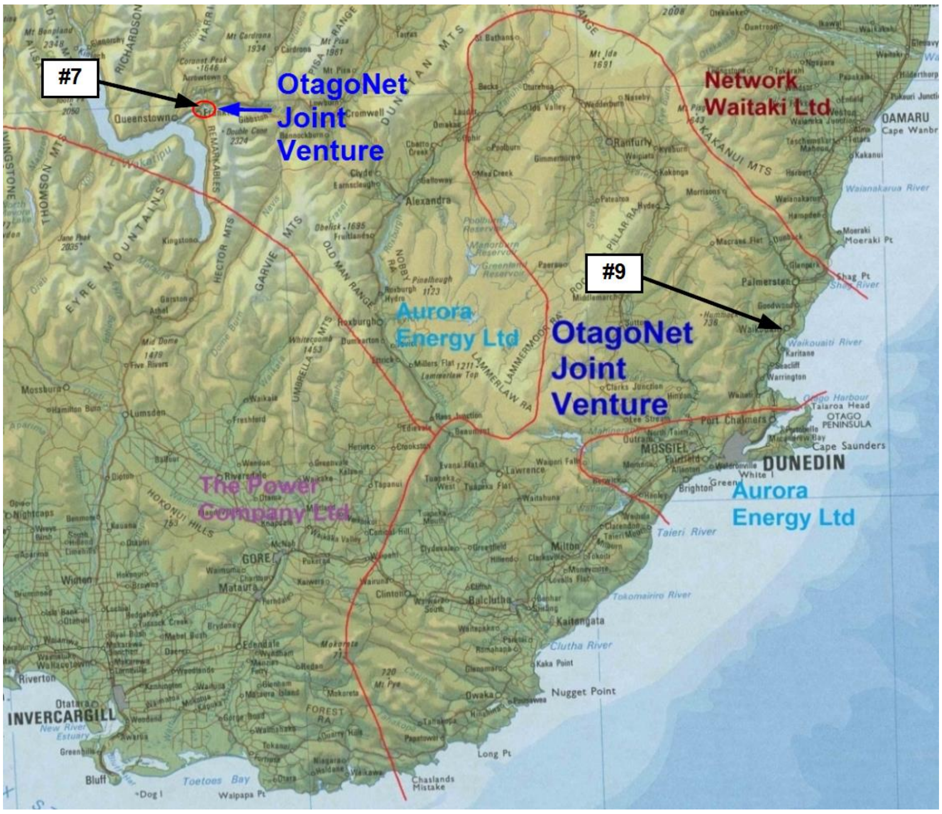
- Are network wide (apply to entire area as shown on map above).
- Have a contract in place that is with PowerNet Limited through a network management agreement (related party).
- Are forecast to require the supply of assets/goods or services by PowerNet Limited (related party).

Possible future constraints related to OJV network Operating Expenditure projects:

There are no identified constraints impacting the network Operating Expenditure budget. All costs are driven by network maintenance requirements and inspection programming.

OJV - 10 largest forecast Network Capital Expenditure projects

- Clause 2.3.13(2), 2.3.14(1) and (2).



The 10 largest forecast Capital Expenditure projects in the 2021-2031 Asset Management Plan for OJV network are explained below, and indicated on the Network map above where relative to a single area:

1. Major New Connection Projects - $47.23M

   Rapid growth areas require a corresponding expansion of the local distribution network. The rate of expansion is somewhat unpredictable as the timing and speed of developments are largely driven by commercial factors outside of OJV's ability to monitor.

   $5.5M has been budgeted under Consumer Connection in the short term for projects that have relative certainty; plus an allowance of approximately $3.5M-5.5M p.a. in the medium to long term where the location and/or scale of projects is relatively unknown.

2. 11 kV Line Replacement and Renewal - $30.70M

   Scheduled for every year, the on-going replacements of 11kV line assets. These are identified through routine inspection. As work is planned based on feeders, this renewal and refurbishment covers distribution lines, cables, dropouts and ABS's. This budget also covers red tagged pole replacement, increasing road crossing height, minor distribution renewals and upgrades.

3. 33 kV Line Replacement and Renewal - $19.05M

   33kV line work previously identified through condition assessment that is either on-going or planned. Completion of this work is dependent on customer requirements, land access permission and priority re-assignment as further network condition information becomes available.

4. Unspecified Replacement and Renewal Projects - $11.31M

   The overall objective for replacement and renewal programmes is to get the most out of the network assets by replacing assets as close as possible to their economic end of life. This is balanced by the need to manage workforce resources in the short term and delivery of desired service levels over the long term.

   Inspection and testing programmes identify assets that are reaching the end of their economic life while critical assets may be replaced on a fixed time basis. For example 11kV switchboards at zone substations are replaced at the end of their nominal life. Less critical assets or assets provided with redundancy as part of security arrangements may be run to failure and replaced reactively. Assets such as cables may be run to failure several times and repaired before the fault frequency increases to a point that complete replacement is more economic. This approach requires monitoring of failure rates.

   Apart from whole of lifecycle cost analysis there are several additional drivers for replacement (though they can often be reduced to a cost analysis) including operational or public safety, risk management, declining service levels, accessibility for maintenance, obsolescence and new technology providing options for additional features or alternative solutions.

   This provision is for asset replacement and renewal projects that are yet to be identified and are expected to be implemented in 2026-31.

5. LV Line Replacement and Renewal - $7.75M

   Low voltage line work previously identified through condition assessment that is either on-going or planned. Completion of this work is dependent on customer requirements, land access permission and priority re-assignment as further network condition information becomes available.

6. Customer Connections (≤ 20kVA) - $6.96M

   Scheduled for every year, planning for new connections uses averages based on historical trending, modified by any local knowledge if appropriate however customer requirements are generally unpredictable and quite variable. Customers tend not to disclose their intentions until connection is required so cannot be easily planned for in advance. Various options are considered generally to determine the least cost option for providing the new connection. Work required depends on the customer's location relative to existing network and the capacity of that network to supply the additional load. This can range from a simple LV connection at a fuse in a distribution pillar box at the customer's property boundary, to upgrade of LV cables or replacement of overhead lines with cables of greater rating, up to requirement for a new transformer site with associated 11kV extension if required.

7. Remarkables Substation Relocation - $5.78M

   The Remarkables zone substation is situated on Queenstown Airport Corporation (QAC) land adjacent to the airport. QAC wants to develop the site for its own purposes so the substation needs to be relocated to an alternative site.

   $5.78M has been allocated under Asset Relocations towards relocating the substation over the 2024-2027 period.

8. Unspecified System Growth Projects - $5.69M

   Development projects may be driven by the need to create additional network capacity for supplying increasing demand. These drivers are monitored and trigger points set to identify when development projects are needed. When a development trigger is reached, several options are considered with the most cost efficient option selected as a solution.

   Forecasts for demand growth are required to help OJV predict when in future years the development triggers will be reached, thus enabling effective planning of future projects. Historical demand is trended and projected into future years while accounting for foreseeable future drivers that may cause a change to the current trend. Projections and associated planning are based on what is considered the most likely scenario, while OJV's strategy of deferring capital expenditure until necessary minimises the risk of overinvestment.

   This provision is for system growth projects that are yet to be identified and are expected to be implemented in 2026-31.

9. Quarry Road Substation - $4.61M

   The present Merton substation feeding the Waikouaiti area is reaching the N-1 capacity of the transformers, and the 11kV and 33kV structures have deteriorating wooden poles and components. The supply security is below the EEA guidelines as there are insufficient 11kV back-feeds available for loss of the single 33kV supply.

   The substation is low lying alongside the Waikouaiti River and is prone to flooding and is at risk from tsunami or liquefaction following a seismic event.

   The new Quarry Road substation is to be built close to Waikouaiti, its major load centre.

10. SWER Line Replacement and Renewal - $4.53M

    Single Wire Earth Return line work previously identified through condition assessment that is either on-going or planned over the next 5 years. Completion of this work is dependent on customer requirements, land access permission and priority re-assignment as further network condition information becomes available.

Further detail relating to OJV network Capital Expenditure in a table at the end of this section.

Please Note: All of these projects -

- Are network wide (apply to entire area as shown on map above), with the exception of #7 and #9 which are pinpointed on the map above.
- Have a contract in place that is with PowerNet Limited through an agency agreement (related party).
- Are forecast to require the supply of assets/goods or services by PowerNet Limited (related party).

<u>Possible future constraints related to OJV network Capital Expenditure projects:</u>

The map above indicates where potential future constraints may impact the OJV network performance:

8. <u>Unspecified System Growth Projects</u>

   Constraint – Unable to maintain supply voltage due to forecast load growth, timing being 7-10 years.

9. <u>Quarry Road Substation</u>

   Constraint – Unable to maintain supply voltage due to potential load growth, timing being 5-8 years.

OJV - 10 largest forecast Network Operating Expenditure projects (Maintenance)

- Clause 2.3.13(1), 2.3.14(1) and (2).

Project	Project description[1]	Likely timing[2]	Value[3]	Location[4]	Contract in place[5]	Is contract with RP[6]	Forecast to include RP[7]	Currently not indicated for RP[8]
#1	Incident Response - Distribution	Every year	$14.55M	Network Wide	Yes	Yes	Very likely	N/A
#2	Vegetation Management	Every year	$8.10M	Network Wide	Yes	Yes	Very likely	N/A
#3	Distribution Routine Inspections	Every year	$6.40M	Network Wide	Yes	Yes	Very likely	N/A
#4	Technical Routine Maintenance	Every year	$3.75M	Network Wide	Yes	Yes	Very likely	N/A
#5	Earth Testing	Every year	$2.61M	Network Wide	Yes	Yes	Very likely	N/A
#6	Technical Routine Inspections	Every year	$2.19M	Network Wide	Yes	Yes	Very likely	N/A
#7	Distribution Routine Maintenance	Every year	$1.54M	Network Wide	Yes	Yes	Very likely	N/A
#8	Incident Response - Technical	Every year	$1.47M	Network Wide	Yes	Yes	Very likely	N/A
#9	General Distribution Refurbishment	Every year	$1.15M	Network Wide	Yes	Yes	Very likely	N/A
#10	Transmission Line Minor Maintenance	Every year	$1.02M	Network Wide	Yes	Yes	Very likely	N/A

[1] Clause 2.3.13(1).
[2] Clause 2.3.13(1).
[3] Clause 2.3.13(1).
[4] Clause 2.3.13(1).
[5] Clause 2.3.14(1)(a).
[6] Clause 2.3.14(1)(a).
[7] Clause 2.3.14(1)(b).
[8] Clause 2.3.14(1)(c).

OJV - 10 largest forecast Network Capital Expenditure projects

- Clause 2.3.13(2), 2.3.14(1) and (2).

Project	Project description	Likely timing	Value	Location	Contract in place?	Is contract with RP?	Forecast to include RP?	Currently not indicated for RP
#1	Major New Connections Projects	Every year	$47.23M	Network Wide	Yes	Yes	Very likely	N/A
#2	11 kV Line Replacement and Renewal	Every year	$30.70M	Network Wide	Yes	Yes	Very likely	N/A
#3	33 kV Line Replacement and Renewal	Every year	$19.05M	Network Wide	Yes	Yes	Very likely	N/A
#4	Unspecified Replacement & Renewal Projects	2026-2031	$11.31M	Network Wide	No	N/A	Very likely	N/A
#5	LV Line Replacement and Renewal	Every year	$7.75M	Network Wide	Yes	Yes	Very likely	N/A
#6	Customer Connections (≤ 20kVA)	Every year	$6.96M	Network Wide	Yes	Yes	Very likely	N/A
#7	Remarkables Substation Relocation	2024-2027	$5.78M	#7	No	N/A	Very likely	N/A
#8	Unspecified System Growth Projects	2026-2031	$5.69M	Network Wide	No	N/A	Very likely	N/A
#9	Quarry Road Substation	2025-29	$4.61M	#9	No	N/A	Very likely	N/A
#10	SWER Line Replacement and Renewal	Every year	$4.53M	Network Wide	Yes	Yes	Very likely	N/A

Possible future constraints related to OJV network Capital Expenditure projects:

- Clause 2.3.13(4), 2.3.14(1) and (2).

Description of constraint	Related to Capex project #	Expected timing of constraint
Unable to maintain supply voltage due to expected load growth	#8	7-10 years
Unable to maintain supply voltage due to potential load growth	#9	5-8 years

Independent Assurance report

To the Governing Committee of OtagoNet Joint Venture and the Commerce Commission

Assurance report pursuant to Electricity Distribution Information Disclosure Determination 2012.

We have completed our reasonable assurance engagement in respect of the compliance of OtagoNet Joint Venture (the 'Joint Venture') with the Electricity Distribution Information Disclosure Determination 2012 (the 'Determination') for the disclosure year ended 31 March 2021 where we are required to opine on:

- whether the Joint Venture has complied, in all material respects, with the Determination, in preparing the information disclosed under schedules 1 to 4, 5a to 5g, 6a and 6b, 7, 10, the related party transactions information disclosed in Appendix A, and the explanatory notes disclosed in boxes 1 to 11 in Schedule 14 ('the Disclosure Information'); and
- whether the Joint Venture 's basis for valuation of related party transactions ('valuation of related party transactions'), has complied, in all material respects, with clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 ('the IM Determination').

This assurance report should be read in conjunction with the Commerce Commission's Information Disclosure exemption, issued to all electricity distribution businesses on 17 May 2021 under clause 2.11 of the Determination. The Commerce Commission granted an exemption from the requirement that the assurance report, in respect of the information in Schedule 10 of the Determination, must take into account any issues arising out of the Joint Venture 's recording of SAIDI, SAIFI, and number of interruptions due to successive interruptions.

Qualified Opinion

In our opinion, except for the possible effect of the matter described in the Basis for Qualified Opinion section of our report, in all material respects:

- as far as appears from an examination of them, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the Joint Venture;
- as far as appears from an examination, the information used in the preparation of the Disclosure Information has been properly extracted from the Joint Venture 's accounting and other records and has been sourced, where appropriate, from the Joint Venture 's financial and non-financial systems;
- the Disclosure Information complies with the Determination; and
- the basis for valuation of related party transactions complies with the Determination and the IM Determination.

Basis for Qualified Opinion

As described in Box 13 of Schedule 14, there are inherent limitations in the ability of the Joint Venture to collect and record the network reliability information specifically the interconnection points ('ICP's') affected by an interruption and the duration of the interruption used in calculating the amounts required to be disclosed in Schedules 10(i) to 10(iv). Consequently, there is no independent evidence available to support the accuracy of the ICP's affected and duration of an interruption. Controls over the accuracy of ICP and interruption data included in the SAIDI and SAIFI outage statistics are limited throughout the year.

There are no practical audit procedures that we could adopt to independently confirm the accuracy of the ICP data used to record the number of ICP's affected and duration of the interruption 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 accuracy of the data that forms the basis of the compilation of Schedules 10(i) to 10(iv). In this respect alone we have not obtained all the recorded evidence and explanations that we have required.

We conducted our engagement in accordance with the Standard on Assurance Engagements (SAE) 3100 (Revised) Assurance Engagements on Compliance, issued by the New Zealand Auditing and Assurance Standards Board. An engagement conducted in accordance with SAE (NZ) 3100 (Revised) requires that we comply with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised) Assurance Engagements Other Than Audits or Reviews of Historical Financial Information.

We have obtained sufficient recorded evidence and explanations that we required to provide a basis for our qualified opinion.

Emphasis of Matter

We draw attention to Box 15 of Schedule 14, which describes amendments made to previously disclosed information relating to the incorrect inclusion of a commercial building development in the 2021 non-network assets commissioned. We have reissued our assurance report in accordance with clause 2.12.1(1)(f) of the Determination. Our opinion is not modified in respect of this matter.

Our assurance approach

Overview

Our assurance engagement is designed to obtain reasonable assurance about the Joint Venture's compliance, in all material respects, with the Determination and IM Determination.

Quantitative materiality levels are determined for testing purposes within individual schedules included in the Disclosure Information based on the nature of the information set out in the schedules. These thresholds are determined based on our assessment of errors that could have a material impact on key measures within the Disclosure Information:

- Financial information – any impact resulting in +/-1% of the Return of Investment ('ROI')
- Performance based schedules – 5% of non-financial measures
- Related party transactions – 2% of total related party transactions.

When assessing overall material compliance with the Determination, qualitative factors are considered such as the combined impact on ROI and other key measures as well as assessing the arm's length valuation rules on related party transactions, which may impact on users assessment on whether the purpose of Part 4 of the Commerce Act 1986 has been met.

We have determined that there are two key assurance matters:

- Regulatory Asset Base
- Related Party Transactions

Materiality
The scope of our assurance engagement was influenced by our application of materiality.

Based on our professional judgement, we determined certain quantitative thresholds for materiality. These, together with qualitative considerations, helped us to determine the scope of our assurance engagement, the nature, timing and extent of our assurance procedures and to evaluate the effect of misstatements, both individually and in aggregate on the Disclosure Information as a whole.

Scope
Our procedures included analytical procedures, evaluating the appropriateness of assumptions used and whether they have been consistently applied, agreement of the Disclosure Information to, or reconciling with, source systems and underlying records, an assessment of the significant judgements made by the Joint Venture in the preparation of the Disclosure Information and valuing the related party transactions, and evaluation of the overall adequacy of the presentation of supporting information and explanations. These procedures have been undertaken to form an opinion as to whether the Joint Venture has complied, in all material respects, with the Determination in the preparation of the Disclosure Information for the year ended 31 March 2021, and whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

Key Assurance Matters
Key assurance matters are those matters that, in our professional judgement, were of most significance in carrying out the assurance engagement during the current disclosure year. These matters were addressed in the context of our assurance engagement as a whole, and in forming our opinion. We do not provide a separate opinion on these matters. In addition to the matter described in the Basis of Qualified Opinion section of our report, we have determined the matters described below to be Key Assurance Matters

Key assurance matter	How our procedures addressed the key assurance matter
Regulatory Asset Base The Regulatory Asset Base (RAB), as set out in Schedule 4, reflects the value of the Joint Venture's electricity distribution assets. These are valued using an indexed historic cost methodology prescribed by the Determination. It is a measure which is used widely and is key to measuring the Joint Venture's return on investment and therefore important when monitoring financial performance or setting electricity distribution prices. The RAB inputs, as set out in the IM Determination, are similar to those used in the measurement of fixed assets in the financial statements, however, there are a number of different requirements and complexities which require careful consideration. As disclosed in Box 15 of schedule 14, the 2021 disclosure year RAB has been restated to remove a commercial building development previously commissioned into non-network assets.	We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Determination and the IM Determination. We have performed the following procedures: **Assets commissioned** ● We reconciled the assets commissioned, as per the regulatory fixed asset register, to the asset additions disclosed in the audited annual financial statements and investigated any reconciling items; ● We inspected the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the Determination, which are required to be removed from the RAB; ● We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification;

<table>
<tr><th>Key assurance matter</th><th>How our procedures addressed the key assurance matter</th></tr>
<tr><td>Due to the importance of the RAB within the regulatory regime, the incentives to overstate the RAB value, and complexities within the regulations, we have considered it to be a key area of focus.</td><td>Depreciation
• We compared the standard asset lives by asset category to those set out in the IM Determination;
• We verified the spreadsheet formula utilised to calculate regulatory depreciation expense is in line with IM Determination clause 2.2.5;
Revaluation
• We recalculated the revaluation rate set out in the IM Determination using the relevant Consumer Price Index indices taken from the Statistics New Zealand website;
• We tested the mathematical accuracy of the revaluation calculation performed by management;
Disposals
• We inspected the asset disposals within the accounting fixed asset register to ensure disposals in the RAB meet the definition of a disposal per the IM Determination;
Restatement
• Understood the nature of the restatement and confirmed appropriate disclosure is included in Schedule 14 including impacts on all schedules affected in accordance with the Determination clause 2.12.
• We recalculated the impact of removing the commercial building not used in providing electricity distribution services and ensured the information management used to calculate the adjustment was obtained from appropriate internal records;
• Considered whether there could be other, similar, unidentified material misstatements by inspecting the accounting fixed asset register and the RAB for other assets relating to the Joint Venture’s commercial property business and considering the Joint Venture’s other revenue streams disclosed in the audited annual financial statements that may indicate assets earning an investment income.</td></tr>
</table>

Key assurance matter	How our procedures addressed the key assurance matter
Related party transactions Disclosures over related party transactions including related party relationships, procurement policies/processes, application of these policies/processes and examples of market testing of transaction terms as required under the Determination and the IM Determination are set out in Appendix A. The Determination and the IM Determination require the Joint Venture to value its transactions with related parties, disclosed in Schedule 5b, in accordance with the principles-based approach to the arm's length valuation rule. This rule states that the value of goods or services acquired from a related party cannot be greater than if it had been acquired under the terms of an arm's length transaction with an unrelated party, nor may it exceed the actual cost to the related party. A sale or supply to a related party cannot be valued at an amount less than if it had been sold or supplied under the terms of an arm's-length transaction with an unrelated party. Arm's-length valuation, as defined in the IM Determination, is the value at which a transaction, with the same terms and conditions, would be entered into between a willing seller and a willing buyer who are unrelated and who are acting independently of each other and pursuing their own best interests. The Joint Venture is required to use an objective and independent measure to demonstrate compliance with the arm's-length principle. In the absence of an active market for similar transactions, assigning an objective arm's length value to a related party transaction is difficult and requires significant judgement. We have identified related party transactions at arm's-length as a key audit matter due to the judgement involved.	We have obtained an understanding of the compliance requirements relevant to related party transactions as set out in the Determination, and the IM Determination. We have ensured Schedule 5(b) and Appendix A includes all required disclosures including current procurement policies, descriptions of how they are applied in practice, representative example transactions and when and how market testing was last performed. We have performed the following procedures over Schedule 5(b) and Appendix A. **Completeness and accuracy of related party relationships and transactions** We have tested the completeness and accuracy of the related party relationships and transactions by: • Agreeing the disclosures within Schedule 5(b) to the audited financial statements for the year ended 31 March 2021 and to the accounting records, investigating any differences and determining whether any such differences are justified; and • Applying our understanding of the business structure against the related party definition in IM Determination clause 1.1.4(2)(b) to assess management's identification of any "unregulated parts" of the entity. **Practical application of procurement policies** • Testing a sample of operating expenditure and capital expenditure transactions disclosed in Schedule 5(b) by inspecting supporting documentation to determine compliance with the disclosed procurement policy and practices. **Arm's length valuation rule** We obtained the Joint Venture's assessment of the available independent and objective measures used in supporting the arm's length valuation principle and performed the following procedures: • Re-performed the calculations and agreed key inputs and assumptions to supporting documentation;

Key assurance matter	How our procedures addressed the key assurance matter
	• Where benchmarking or other market information was used as independent and objective measures, we assessed whether the related party transaction values fell within an acceptable range. Qualitative factors were considered in determining the appropriate acceptable range.

Governing Committee Responsibilities

The Governing Committee is responsible on behalf of the Joint Venture for compliance with the Determination and the valuation of related party transactions in accordance with the Determination, for the identification of risks that may threaten such compliance, controls that would mitigate those risks and monitoring the Joint Venture 's ongoing compliance.

Our Independence and Quality Control

We have complied with the Professional and Ethical Standard 1 *International Code of Ethics for Assurance Practitioners (including International Independence Standards) (New Zealand)* or other professional requirements, or requirements in law or regulation, that are at least as demanding, which include independence and other requirements founded on the fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behaviour.

In accordance with the Professional and Ethical Standard 3 (Amended) *Quality Control for Firms that Perform Audits and Reviews of Financial Statements, and Other Assurance Engagements* or other professional requirements, or requirements in law or regulation, that are at least as demanding, our firm 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.

We are independent of the Joint Venture. Our firm carries out other services for the Joint Venture in the areas of compliance with the Electricity Distribution Services Default Price-Quality Path Determination 2020, financial statement audit and other regulatory requirements of the Commerce Act 1986. The provision of these other services has not impaired our independence.

Assurance Practitioner's responsibilities

Our responsibility is to express an opinion on whether the Joint Venture has complied, in all material respects, with the Determination in the preparation of the Disclosure Information for the disclosure year ended 31 March 2021 and on whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

Our engagement has been conducted in accordance with ISAE (NZ) 3000 (Revised), Assurance Engagements Other than Audits or Reviews of Historical Financial Information and SAE 3100 (Revised) Compliance Engagements which require that we plan and perform our procedures to obtain reasonable assurance about whether the Joint Venture has complied in all material respects with the Determination in the preparation of the Disclosure Information for the disclosure year ended 31 March 2021, and whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

An assurance engagement to report on the Joint Venture 's compliance with the Determination and the IM Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the requirements of the Determination and the IM Determination.

The procedures selected depend on our judgement, including the identification and assessment of risks of material non-compliance with the requirements of the Determination and the IM Determination.

Inherent limitations

Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error or non-compliance may occur and not be detected. A reasonable assurance engagement for the disclosure year ended 31 March 2021 does not provide assurance on whether compliance with the Determination and the IM Determination will continue in the future.

Use of report

This report has been prepared for the Governing Committee and the Commerce Commission 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.

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 Governing Committee of the Joint Venture and the Commerce Commission, or for any purpose other than that for which it was prepared.

The engagement partner on the assurance engagement resulting in this independent auditor's report is Elizabeth Adriana (Adri) Smit.

PricewaterhouseCoopers.

Chartered Accountants
31 August 2022

Christchurch, New Zealand

Schedule 18: Certification for Year-End Disclosures

Clause 2.9.2

We, Douglas William Fraser and Peter William Moynihan, 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 the OtagoNet Joint Venture's accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained.

c) in respect of information concerning assets, costs and revenues valued or disclosed in accordance with clause 2.3.6 of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012, we are satisfied that-

   i. the costs and values of assets or goods or services acquired from a related party comply, in all material respects, with clauses 2.3.6(1) and 2.3.6(3) of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and 2.2.11(5)(a)-2.2.11(5)(b) of the Electricity Distribution Services Input Methodologies Determination 2012; and

   ii. the value of assets or goods or services sold or supplied to a related party comply, in all material respects, with clause 2.3.6(2) of the Electricity Distribution Information Disclosure Determination 2012.

Schedule 14 (Mandatory Explanatory Notes) – information regarding amendments to previously disclosed information in the 2020/21 disclosure year as included in Box 15.

Douglas William Fraser **Peter William Moynihan**

30 August 2022

Footnote:
The Governing Committee of OtagoNet Joint Venture (OtagoNet) note the amendment to the Information Disclosure exemption: Disclosure and auditing of reliability information within Schedule 10, issued by the Commerce Commission on 17 May 2021 that has removed the auditor report requirements relating to the treatment of successive interruptions for reporting SAIDI, SAIFI, and interruptions, because of potential inconsistencies in treatment approaches across the industry.

Members note that they do not appear to have been provided a similar exemption relating to treatment of successive interruptions regarding their certification. The information has been prepared on a basis consistent with the previous year's disclosure and OtagoNet network has recorded successive interruptions, originating from the same cause, as single interruptions.

APPENDIX D:

Restated 2021 Information Disclosure Schedules

SCHEDULE 1: ANALYTICAL RATIOS

1(i): Expenditure metrics

Revised

	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	20,070	499	134,550	1,926	40,038
Network	11,756	292	78,814	1,128	23,452
Non-network	8,314	207	55,736	798	16,585
Expenditure on assets	37,009	920	248,106	3,551	73,828
Network	37,009	920	248,106	3,551	73,828
Non-network	–	–	–	–	–

Previously disclosed

	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	20,070	499	134,550	1,926	40,038
Network	11,756	292	78,814	1,128	23,452
Non-network	8,314	207	55,736	798	16,585
Expenditure on assets	47,612	1,184	319,187	4,569	94,979
Network	37,009	920	248,106	3,551	73,828
Non-network	10,603	264	71,081	1,017	21,151

Difference

	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	–	–	–	–	–
Network	–	–	–	–	–
Non-network	–	–	–	–	–
Expenditure on assets	(10,603)	(264)	(71,081)	(1,017)	(21,151)
Network	–	–	–	–	–
Non-network	(10,603)	(264)	(71,081)	(1,017)	(21,151)

1(ii): Revenue metrics

	Revised: Revenue per GWh energy delivered to ICPs ($/GWh)	Revised: Revenue per average no. of ICPs ($/ICP)	Previously disclosed: Revenue per GWh energy delivered to ICPs ($/GWh)	Previously disclosed: Revenue per average no. of ICPs ($/ICP)	Difference: Revenue per GWh energy delivered to ICPs ($/GWh)	Difference: Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	76,502	1,903	76,502	1,903	–	–
Standard consumer line charge revenue	122,749	1,707	122,749	1,707	–	–
Non-standard consumer line charge revenue	17,899	1,167,785	17,899	1,167,785	–	–

1(iii): Service intensity measures

	Revised		Previously disclosed	Difference
Demand density	14	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*	14	–
Volume density	96	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*	96	–
Connection point density	4	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*	4	–
Energy intensity	24,871	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*	24,871	–

1(iv): Composition of regulatory income

	Revised ($000)	Revised % of revenue	Previously disclosed ($000)	Previously disclosed % of revenue	Difference ($000)	Difference % of revenue
Operational expenditure	8,906	26.25%	8,906	25.94%	–	0.31%
Pass-through and recoverable costs excluding financial incentives and wash-up	8,213	24.20%	8,213	23.92%	–	0.29%
Total depreciation	8,588	25.31%	8,588	25.01%	–	0.30%
Total revaluations	3,202	9.44%	3,202	9.32%	–	0.11%
Regulatory tax allowance	2,267	6.68%	2,380	6.93%	(113)	–0.25%
Regulatory profit/(loss) including financial incentives and wash-ups	9,161	27.00%	9,452	27.53%	(291)	–0.53%
Total regulatory income	33,933		34,337		(405)	

1(v): Reliability

	Revised		Previously disclosed	Difference
Interruption rate	13.84	*Interruptions per 100 circuit km*	13.84	13.84

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

2(i): Return on Investment

	Revised CY-2 31 Mar 19 %	Revised CY-1 31 Mar 20 %	Revised Current Year CY 31 Mar 21 %	Previously disclosed CY-2 31 Mar 19 %	Previously disclosed CY-1 31 Mar 20 %	Previously disclosed Current Year CY 31 Mar 21 %	Difference CY-2 31 Mar 19 %	Difference CY-1 31 Mar 20 %	Difference Current Year CY 31 Mar 21 %
ROI – comparable to a post tax WACC									
Reflecting all revenue earned	6.46%	6.57%	4.38%	6.46%	6.57%	4.43%	–	–	–0.05%
Excluding revenue earned from financial incentives	6.12%	6.63%	4.41%	6.12%	6.63%	4.46%	–	–	–0.05%
Excluding revenue earned from financial incentives and wash	5.54%	6.04%	4.41%	5.54%	6.04%	4.46%	–	–	–0.05%
Mid-point estimate of post tax WACC	4.75%	4.27%	3.72%	4.75%	4.27%	3.72%	–	–	–
25th percentile estimate	4.07%	3.59%	3.04%	4.07%	3.59%	3.04%	–	–	–
75th percentile estimate	5.43%	4.95%	4.40%	5.43%	4.95%	4.40%	–	–	–
ROI – comparable to a vanilla WACC									
Reflecting all revenue earned	6.96%	6.99%	4.71%	6.96%	6.99%	4.76%	–	–	–0.05%
Excluding revenue earned from financial incentives	6.63%	7.06%	4.74%	6.63%	7.06%	4.79%	–	–	–0.05%
Excluding revenue earned from financial incentives and wash	6.05%	6.47%	4.74%	6.05%	6.47%	4.79%	–	–	–0.05%
WACC rate used to set regulatory price path	7.19%	7.19%	4.57%	7.19%	7.19%	4.57%	–	–	–
Mid-point estimate of vanilla WACC	5.26%	4.69%	4.05%	5.26%	4.69%	4.05%	–	–	–
25th percentile estimate	4.58%	4.01%	3.37%	4.58%	4.01%	3.37%	–	–	–
75th percentile estimate	5.94%	5.37%	4.73%	5.94%	5.37%	4.73%	–	–	–

2(ii): Information Supporting the ROI

	Revised	Revised ($000)	Revised	Previously disclosed	Previously disclosed ($000)	Previously disclosed	Difference	Difference ($000)	Difference
Total opening RAB value	210,599			210,599			–		
plus Opening deferred tax	(17,118)			(17,118)			–		
Opening RIV		193,481			193,481			–	
Line charge revenue		33,948			33,948			–	
Expenses cash outflow	17,119			17,119			–		
add Assets commissioned	12,425			20,916			(8,491)		
less Asset disposals	30			30			–		
add Tax payments	(37)			88			(125)		
less Other regulated income	(15)			390			(405)		
Mid-year net cash outflows		29,492			37,703			(8,211)	
Term credit spread differential allowance		–			–			–	
Total closing RAB value	217,607			226,099			(8,491)		
less Adjustment resulting from asset allocation	(0)			(0)			–		
less Lost and found assets adjustment	–			–			–		
plus Closing deferred tax	(19,422)			(19,410)			(11)		
Closing RIV		198,186			206,689			(8,503)	
ROI – comparable to a vanilla WACC			4.71%			4.76%			–0.05%
Leverage (%)			42%			42%			–
Cost of debt assumption (%)			2.82%			2.82%			–
Corporate tax rate (%)			28%			28%			–
ROI – comparable to a post tax WACC			4.38%			4.43%			–0.05%

SCHEDULE 3: REPORT ON REGULATORY PROFIT

3(i): Regulatory Profit

		Revised ($000)	Previously disclosed ($000)	Difference ($000)
	Income			
	Line charge revenue	33,948	33,948	–
plus	Gains / (losses) on asset disposals	(29)	(29)	–
plus	Other regulated income (other than gains / (losses) on asset disposals)	14	419	(405)
	Total regulatory income	33,933	34,337	(405)
	Expenses			
less	Operational expenditure	8,906	8,906	–
less	Pass-through and recoverable costs excluding financial incentives and wash-ups	8,213	8,213	–
	Operating surplus / (deficit)	16,814	17,218	(405)
less	Total depreciation	8,588	8,588	–
plus	Total revaluations	3,202	3,202	–
	Regulatory profit / (loss) before tax	11,428	11,832	(405)
less	Term credit spread differential allowance	–	–	–
less	Regulatory tax allowance	2,267	2,380	(113)
	Regulatory profit/(loss) including financial incentives and wash-ups	9,161	9,452	(291)

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

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

Row	for year ended	Revised RAB 31 Mar 17 ($000)	Revised RAB 31 Mar 18 ($000)	Revised RAB 31 Mar 19 ($000)	Revised RAB 31 Mar 20 ($000)	Revised RAB 31 Mar 21 ($000)	Previously disclosed RAB 31 Mar 17 ($000)	Previously disclosed RAB 31 Mar 18 ($000)	Previously disclosed RAB 31 Mar 19 ($000)	Previously disclosed RAB 31 Mar 20 ($000)	Previously disclosed RAB 31 Mar 21 ($000)	Difference RAB 31 Mar 17 ($000)	Difference RAB 31 Mar 18 ($000)	Difference RAB 31 Mar 19 ($000)	Difference RAB 31 Mar 20 ($000)	Difference RAB 31 Mar 21 ($000)
10	Total opening RAB value	168,273	179,022	186,531	194,442	210,599	168,273	179,022	186,531	194,442	210,599	–	–	–	–	–
12	*less* Total depreciation	7,496	6,647	7,712	7,994	8,588	7,496	6,647	7,712	7,994	8,588	–	–	–	–	–
14	*plus* Total revaluations	3,641	1,967	2,766	4,923	3,202	3,641	1,967	2,766	4,923	3,202	–	–	–	–	–
16	*plus* Assets commissioned	14,776	12,346	12,937	19,339	12,425	14,776	12,346	12,937	19,339	20,916	–	–	–	–	(8,491)
18	*less* Asset disposals	173	157	80	111	30	173	157	80	111	30	–	–	–	–	–
20	*plus* Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
22	*plus* Adjustment resulting from asset allocation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	–	–	–	–	–
24	Total closing RAB value	179,022	186,531	194,442	210,599	217,607	179,022	186,531	194,442	210,599	226,099	–	–	–	–	(8,491)

4(ii): Unallocated Regulatory Asset Base

Row		Revised Unallocated RAB * ($000)	Revised Unallocated RAB * ($000)	Revised RAB ($000)	Revised RAB ($000)	Previously disclosed Unallocated RAB * ($000)	Previously disclosed Unallocated RAB * ($000)	Previously disclosed RAB ($000)	Previously disclosed RAB ($000)	Difference Unallocated RAB * ($000)	Difference Unallocated RAB * ($000)	Difference RAB ($000)	Difference RAB ($000)
29	Total opening RAB value		210,599		210,599		210,599		210,599		–		–
30	*less*												
31	Total depreciation		8,588		8,588		8,588		8,588		–		–
32	*plus*												
33	Total revaluations		3,202		3,202		3,202		3,202		–		–
34	*plus*												
35	Assets commissioned (other than below)	–		–		8,376		8,376		(8,376)		(8,376)	
36	Assets acquired from a regulated supplier	–		–		–		–		–		–	
37	Assets acquired from a related party	12,425		12,425		12,540		12,540		(115)		(115)	
38	Assets commissioned		12,425		12,425		20,916		20,916		(8,491)		(8,491)
39	*less*												
40	Asset disposals (other than below)	30		30		30		30		–		–	
41	Asset disposals to a regulated supplier	–		–		–		–		–		–	
42	Asset disposals to a related party	–		–		–		–		–		–	
43	Asset disposals		30		30		30		30		–		–
45	*plus* Lost and found assets adjustment		–		–		–		–		–		–
47	*plus* Adjustment resulting from asset allocation				(0)				(0)				–
49	Total closing RAB value		217,608		217,607		226,099		226,099		(8,491)		(8,491)

** 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

Row		Revised	Previously disclosed	Difference
54	CPI_4	1,068	1,068	–
55	CPI_4^{-4}	1,052	1,052	–
56	Revaluation rate (%)	1.52%	1.52%	–

Row		Revised Unallocated RAB * ($000)	Revised Unallocated RAB * ($000)	Revised RAB ($000)	Revised RAB ($000)	Previously disclosed Unallocated RAB * ($000)	Previously disclosed Unallocated RAB * ($000)	Previously disclosed RAB ($000)	Previously disclosed RAB ($000)	Difference Unallocated RAB * ($000)	Difference Unallocated RAB * ($000)	Difference RAB ($000)	Difference RAB ($000)
60	Total opening RAB value	210,599		210,599		210,599		210,599		–		–	
61	*less* Opening value of fully depreciated, disposed and lost assets	93		93		93		93		–		–	
63	Total opening RAB value subject to revaluation	210,505		210,505		210,505		210,505		–		–	
64	Total revaluations		3,202		3,202		3,202		3,202		–		–

4(iv): Roll Forward of Works Under Construction

Row		Revised Unallocated works under construction	Revised Unallocated works under construction	Revised Allocated works under construction	Revised Allocated works under construction	Previously disclosed Unallocated works under construction	Previously disclosed Unallocated works under construction	Previously disclosed Allocated works under construction	Previously disclosed Allocated works under construction	Difference Unallocated works under construction	Difference Unallocated works under construction	Difference Allocated works under construction	Difference Allocated works under construction
68	Works under construction—preceding disclosure year		2,796		2,796		5,967		5,967		(3,171)		(3,171)
69	*plus* Capital expenditure	15,067		15,067		19,772		19,772		(4,705)		(4,705)	
70	*less* Assets commissioned	12,425		12,425		20,916		20,916		(8,491)		(8,491)	
71	*plus* Adjustment resulting from asset allocation											–	
72	Works under construction - current disclosure year		5,437		5,437		4,822		4,822		615		615
74	Highest rate of capitalised finance applied				–				–				–

4(v): Regulatory Depreciation

Row		Revised Unallocated RAB * ($000)	Revised Unallocated RAB * ($000)	Revised RAB ($000)	Revised RAB ($000)	Previously disclosed Unallocated RAB * ($000)	Previously disclosed Unallocated RAB * ($000)	Previously disclosed RAB ($000)	Previously disclosed RAB ($000)	Difference Unallocated RAB * ($000)	Difference Unallocated RAB * ($000)	Difference RAB ($000)	Difference RAB ($000)
79	Depreciation - standard	8,588		8,588		8,588		8,588		–		–	
80	Depreciation - no standard life assets	–		–		–		–		–		–	
81	Depreciation - modified life assets	–		–		–		–		–		–	
82	Depreciation - alternative depreciation in accordance with CPP	–		–		–		–		–		–	
83	Total depreciation		8,588		8,588		8,588		8,588		–		–

4(vii): Disclosure by Asset Category

($000 unless otherwise specified)

Revised

Row		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
99	Total opening RAB value	25,231	2,834	35,341	98,010	11,159	22,175	11,108	3,588	1,153	210,599
100	*less* Total depreciation	1,260	61	1,571	3,968	264	805	528	118	11	8,588
101	*plus* Total revaluations	398	41	514	1,474	179	335	182	61	17	3,202
102	*plus* Assets commissioned	2,607	–	862	4,933	959	1,202	1,498	364	–	12,425
103	*less* Asset disposals	–	–	–	–	–	30	–	–	–	30
104	*plus* Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus* Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
106	*plus* Asset category transfers	–	–	–	–	–	–	–	–	–	–
107	Total closing RAB value	26,977	2,815	35,145	100,448	12,033	22,877	12,260	3,894	1,159	217,607
109	Asset Life										
110	Weighted average remaining asset life	32.0	46.3	37.9	30.5	43.1	29.0	26.0	29.4	20.8	(years)
111	Weighted average expected total asset life	55.2	49.1	50.6	56.8	49.1	49.9	38.9	40.3	33.3	(years)

Previously disclosed

Row		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
99	Total opening RAB value	25,231	2,834	35,341	98,010	11,159	22,175	11,108	3,588	1,153	210,599
100	*less* Total depreciation	1,260	61	1,571	3,968	264	805	528	118	11	8,588
101	*plus* Total revaluations	398	41	514	1,474	179	335	182	61	17	3,202
102	*plus* Assets commissioned	2,607	–	862	4,933	959	1,202	1,498	364	8,491	20,916
103	*less* Asset disposals	–	–	–	–	–	30	–	–	–	30
104	*plus* Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus* Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
106	*plus* Asset category transfers	–	–	–	–	–	–	–	–	–	–
107	Total closing RAB value	26,977	2,815	35,145	100,448	12,033	22,877	12,260	3,894	9,650	226,099
109											
110		32.0	46.3	37.9	30.5	43.1	29.0	26.0	29.4	20.8	(years)
111		55.2	49.1	50.6	56.8	49.1	49.9	38.9	40.3	33.3	(years)

Difference

Row		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
99		–	–	–	–	–	–	–	–	–	–
100		–	–	–	–	–	–	–	–	–	–
101		–	–	–	–	–	–	–	–	–	–
102		–	–	–	–	–	–	–	–	(8,491)	(8,491)
103		–	–	–	–	–	–	–	–	–	–
104		–	–	–	–	–	–	–	–	–	–
105		–	–	–	–	–	–	–	–	–	–
106		–	–	–	–	–	–	–	–	–	–
107		–	–	–	–	–	–	–	–	(8,491)	(8,491)
109											
110		–	–	–	–	–	–	–	–	–	(years)
111		–	–	–	–	–	–	–	–	–	(years)

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

		Revised		Previously disclosed		Difference	
5a(i): Regulatory Tax Allowance			($000)		($000)		($000)
Regulatory profit / (loss) before tax			11,428		11,832		(405)
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	1,338		1,338		–	
	Amortisation of revaluations	886		886		–	
			2,223		2,223		–
less	Total revaluations	3,202		3,202		–	
	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	94 *		94 *		– *	
	Notional deductible interest	2,260		2,260		–	
			5,556		5,556		–
Regulatory taxable income			8,095		8,500		(405)
less	Utilised tax losses	–		–		–	
	Regulatory net taxable income		8,095		8,500		(405)
	Corporate tax rate (%)	28%		28%		–	
Regulatory tax allowance			2,267		2,380		(113)

* 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).

		Revised		Previously disclosed		Difference	
5a(iii): Amortisation of Initial Difference in Asset Values			($000)		($000)		($000)
	Opening unamortised initial differences in asset values	26,753		26,753		–	
less	Amortisation of initial differences in asset values	1,338		1,338		–	
plus	Adjustment for unamortised initial differences in assets acquired	–		–		–	
less	Adjustment for unamortised initial differences in assets disposed	19		19		–	
	Closing unamortised initial differences in asset values		25,396		25,396		–
	Opening weighted average remaining useful life of relevant assets (years)		20		20		–
5a(iv): Amortisation of Revaluations			($000)		($000)		($000)
	Opening sum of RAB values without revaluations	190,808		190,808		–	
	Adjusted depreciation	7,702		7,702		–	
	Total depreciation	8,588		8,588		–	
	Amortisation of revaluations		886		886		–
5a(v): Reconciliation of Tax Losses			($000)		($000)		($000)
Opening tax losses		–		–		–	
plus	Current period tax losses	–		–		–	
less	Utilised tax losses	–		–		–	
Closing tax losses			–		–		–
5a(vi): Calculation of Deferred Tax Balance			($000)		($000)		($000)
Opening deferred tax		(17,118)		(17,118)		–	
plus	Tax effect of adjusted depreciation	2,157		2,157		–	
less	Tax effect of tax depreciation	4,369		4,357		11	
plus	Tax effect of other temporary differences*	286		286		–	
less	Tax effect of amortisation of initial differences in asset values	375		375		–	
plus	Deferred tax balance relating to assets acquired in the disclosure year	–		–		–	
less	Deferred tax balance relating to assets disposed in the disclosure year	3		3		–	
plus	Deferred tax cost allocation adjustment	0		0		–	
Closing deferred tax			(19,422)		(19,410)		(11)

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).

		Revised		Previously disclosed		Difference	
5a(viii): Regulatory Tax Asset Base Roll-Forward			($000)		($000)		($000)
Opening sum of regulatory tax asset values		97,948		97,948		–	
less	Tax depreciation	15,603		15,562		41	
plus	Regulatory tax asset value of assets commissioned	13,630		22,121		(8,491)	
less	Regulatory tax asset value of asset disposals	36		36		–	
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			95,939		104,471		(8,532)

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

sch ref		Revised		Previously disclosed		Difference	
7	**5b(i): Summary—Related Party Transactions**	($000)	($000)	($000)	($000)	($000)	($000)
8	**Total regulatory income**		–		405		(405)
9							
10	**Market value of asset disposals**		–		–		–
11							
12	Service interruptions and emergencies	1,827		1,827		–	
13	Vegetation management	1,270		1,270		–	
14	Routine and corrective maintenance and inspection	1,914		1,914		–	
15	Asset replacement and renewal (opex)	206		206		–	
16	**Network opex**		5,217		5,217		–
17	Business support	1,735		1,735		–	
18	System operations and network support	1,010		1,010		–	
19	**Operational expenditure**		7,962		7,962		–
20	Consumer connection	7,398		7,398		–	
21	System growth	46		46		–	
22	Asset replacement and renewal (capex)	7,631		7,631		–	
23	Asset relocations	610		610		–	
24	Quality of supply	464		464		–	
25	Legislative and regulatory	–		–		–	
26	Other reliability, safety and environment	274		274		–	
27	**Expenditure on non-network assets**		–		115		(115)
28	**Expenditure on assets**		16,423		16,538		(115)
29	Cost of financing		–		–		–
30	Value of capital contributions		–		–		–
31	Value of vested assets		–		–		–
32	**Capital Expenditure**		16,423		16,538		(115)
33	**Total expenditure**		24,385		24,500		(115)
34							
35	**Other related party transactions**		–		–		–

sch ref			Revised	Previously disclosed	Difference
36	**5b(iii): Total Opex and Capex Related Party Transactions**				
37	**Name of related party**	**Nature of opex or capex service provided**	**Total value of transactions ($000)**	**Total value of transactions ($000)**	**Total value of transactions ($000)**
38	PowerNet Limited	Service interruptions and emergencies	1,827	1,827	–
39	PowerNet Limited	Vegetation management	1,270	1,270	–
40	PowerNet Limited	Routine and corrective maintenance and inspection	1,914	1,914	–
41	PowerNet Limited	Asset replacement and renewal (opex)	206	206	–
42	PowerNet Limited	System operations and network support	950	950	–
43	PowerNet Limited	Business support	1,735	1,735	–
44	PowerNet Limited	Consumer connection	7,398	7,398	–
45	PowerNet Limited	System growth	46	46	–
46	PowerNet Limited	Asset replacement and renewal (capex)	7,631	7,631	–
47	PowerNet Limited	Asset relocations	610	610	–
48	PowerNet Limited	Quality of supply	464	464	–
49	PowerNet Limited	Other reliability, safety and environment	274	274	–
50	PowerNet Limited	Expenditure on non-network assets	–	115	(115)
51	The Power Company Limited	System operations and network support	60	60	–
52					
53	**Total value of related party transactions**		24,385	24,500	(115)
54	** include additional rows if needed*				
55					

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

sch ref		Revised	Previously disclosed	Revised
7	**5e(i): Regulated Service Asset Values**			
8		Value allocated ($000s)	Value allocated ($000s)	Value allocated ($000s)
9		Electricity distribution services	Electricity distribution services	Electricity distribution services
10	**Subtransmission lines**			
11	Directly attributable	26,977	26,977	–
12	Not directly attributable	–	–	–
13	**Total attributable to regulated service**	26,977	26,977	–
14	**Subtransmission cables**			
15	Directly attributable	2,815	2,815	–
16	Not directly attributable	–	–	–
17	**Total attributable to regulated service**	2,815	2,815	–
18	**Zone substations**			
19	Directly attributable	35,145	35,145	–
20	Not directly attributable	–	–	–
21	**Total attributable to regulated service**	35,145	35,145	–
22	**Distribution and LV lines**			
23	Directly attributable	100,448	100,448	–
24	Not directly attributable	–	–	–
25	**Total attributable to regulated service**	100,448	100,448	–
26	**Distribution and LV cables**			
27	Directly attributable	12,033	12,033	–
28	Not directly attributable	–	–	–
29	**Total attributable to regulated service**	12,033	12,033	–
30	**Distribution substations and transformers**			
31	Directly attributable	22,877	22,877	–
32	Not directly attributable	–	–	–
33	**Total attributable to regulated service**	22,877	22,877	–
34	**Distribution switchgear**			
35	Directly attributable	12,260	12,260	–
36	Not directly attributable	–	–	–
37	**Total attributable to regulated service**	12,260	12,260	–
38	**Other network assets**			
39	Directly attributable	3,894	3,894	–
40	Not directly attributable	–	–	–
41	**Total attributable to regulated service**	3,894	3,894	–
42	**Non-network assets**			
43	Directly attributable	1,159	9,650	(8,491)
44	Not directly attributable	–	–	–
45	**Total attributable to regulated service**	1,159	9,650	(8,491)
46				
47	**Regulated service asset value directly attributable**	217,607	226,099	(8,491)
48	**Regulated service asset value not directly attributable**	–	–	–
49	**Total closing RAB value**	217,607	226,099	(8,491)
50				

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

		Revised		Previously disclosed		Difference	
7	**6a(i): Expenditure on Assets**	($000)	($000)	($000)	($000)	($000)	($000)
8	Consumer connection		7,398		7,398		–
9	System growth		46		46		–
10	Asset replacement and renewal		7,631		7,631		–
11	Asset relocations		610		610		–
12	Reliability, safety and environment:						
13	Quality of supply	464		464		–	
14	Legislative and regulatory	–		–		–	
15	Other reliability, safety and environment	274		274		–	
16	**Total reliability, safety and environment**		738		738		–
17	**Expenditure on network assets**		16,423		16,423		–
18	Expenditure on non-network assets		–		4,705		(4,705)
19							
20	**Expenditure on assets**		16,423		21,128		(4,705)
21	*plus* Cost of financing		–		–		–
22	*less* Value of capital contributions		1,356		1,356		–
23	*plus* Value of vested assets		–		–		–
24							
25	**Capital expenditure**		15,067		19,772		(4,705)
106	**6a(ix): Non-Network Assets**						
107	**Routine expenditure**						
108	*Project or programme**	($000)	($000)	($000)	($000)	($000)	($000)
109						–	
110						–	
111						–	
112						–	
113						–	
114	** include additional rows if needed*						
115	All other projects or programmes - routine expenditure					–	
116	**Routine expenditure**		–		–		–
117	**Atypical expenditure**						
118	*Project or programme**	($000)	($000)	($000)	($000)	($000)	($000)
119	0	–		4,705		(4,705)	
120						–	
121						–	
122						–	
123						–	
124	** include additional rows if needed*						
125	All other projects or programmes - atypical expenditure	–		–		–	
126	**Atypical expenditure**		–		4,705		(4,705)
127							
128	**Expenditure on non-network assets**		–		4,705		(4,705)

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

Line		Revised			Previously disclosed			Difference		
7	**7(i): Revenue**	Target ($000) [1]	Actual ($000)	% variance	Target ($000) [1]	Actual ($000)	% variance	Target ($000) [1]	Actual ($000)	% variance
8	Line charge revenue	33,418	33,948	2%	33,418	33,948	2%	–	–	–
9	**7(ii): Expenditure on Assets**	Forecast ($000) [2]	Actual ($000)	% variance	Forecast ($000) [2]	Actual ($000)	% variance	Forecast ($000) [2]	Actual ($000)	% variance
10	Consumer connection	6,566	7,398	13%	6,566	7,398	13%	–	–	–
11	System growth	246	46	(81%)	246	46	(81%)	–	–	–
12	Asset replacement and renewal	7,565	7,631	1%	7,565	7,631	1%	–	–	–
13	Asset relocations	79	610	672%	79	610	672%	–	–	–
14	Reliability, safety and environment:									
15	Quality of supply	456	464	2%	456	464	2%	–	–	–
16	Legislative and regulatory	–	–	–	–	–	–	–	–	–
17	Other reliability, safety and environment	858	274	(68%)	858	274	(68%)	–	–	–
18	**Total reliability, safety and environment**	1,314	738	(44%)	1,314	738	(44%)	–	–	–
19	**Expenditure on network assets**	15,770	16,423	4%	15,770	16,423	4%	–	–	–
20	Expenditure on non-network assets	–	–	–	–	4,705	–	–	(4,705)	–
21	Expenditure on assets	15,770	16,423	4%	15,770	21,128	34%	–	(4,705)	(30%)
22	**7(iii): Operational Expenditure**									
23	Service interruptions and emergencies	1,617	1,827	13%	1,617	1,827	13%	–	–	–
24	Vegetation management	1,118	1,270	14%	1,118	1,270	14%	–	–	–
25	Routine and corrective maintenance and inspection	1,835	1,914	4%	1,835	1,914	4%	–	–	–
26	Asset replacement and renewal	217	206	(5%)	217	206	(5%)	–	–	–
27	**Network opex**	4,787	5,217	9%	4,787	5,217	9%	–	–	–
28	System operations and network support	1,224	1,293	6%	1,224	1,293	6%	–	–	–
29	Business support	2,328	2,396	3%	2,328	2,396	3%	–	–	–
30	**Non-network opex**	3,552	3,689	4%	3,552	3,689	4%	–	–	–
31	**Operational expenditure**	8,339	8,906	7%	8,339	8,906	7%	–	–	–
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	–	610	–	–	610	–	–	–	–
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	187	171	(8%)	187	171	(8%)	–	–	–
42										

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

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

pwc