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 2022

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 2022**

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.

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	19,462	472	128,379	1,890	38,058
Network	11,685	283	77,079	1,135	22,850
Non-network	7,777	189	51,300	755	15,208
Expenditure on assets	43,632	1,058	287,808	4,236	85,320
Network	43,632	1,058	287,808	4,236	85,320
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	74,717	1,812
Standard consumer line charge revenue	118,359	1,619
Non-standard consumer line charge revenue	18,256	1,194,807

1(iii): Service intensity measures

Demand density	15	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	97	*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	24,255	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	8,765	26.17%
Pass-through and recoverable costs excluding financial incentives and wash-ups	8,688	25.94%
Total depreciation	8,881	26.51%
Total revaluations	15,060	44.96%
Regulatory tax allowance	2,024	6.04%
Regulatory profit/(loss) including financial incentives and wash-ups	20,196	60.30%
Total regulatory income	33,494	

1(v): Reliability

Interruption rate	21.71	*Interruptions per 100 circuit km*

Company Name: OtagoNet Joint Venture
For Year Ended: 31 March 2022

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 20	31 Mar 21	31 Mar 22
9	**ROI – comparable to a post tax WACC**	%	%	%
10	Reflecting all revenue earned	6.57%	4.38%	9.72%
11	Excluding revenue earned from financial incentives	6.63%	4.41%	10.34%
12	Excluding revenue earned from financial incentives and wash-ups	6.04%	4.41%	10.42%
13				
14	**Mid-point estimate of post tax WACC**	4.27%	3.72%	3.52%
15	25th percentile estimate	3.59%	3.04%	2.84%
16	75th percentile estimate	4.95%	4.40%	4.20%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	6.99%	4.71%	10.02%
21	Excluding revenue earned from financial incentives	7.06%	4.74%	10.64%
22	Excluding revenue earned from financial incentives and wash-ups	6.47%	4.74%	10.72%
23				
24	**WACC rate used to set regulatory price path**	7.19%	4.57%	4.57%
25				
26	**Mid-point estimate of vanilla WACC**	4.69%	4.05%	3.82%
27	25th percentile estimate	4.01%	3.37%	3.14%
28	75th percentile estimate	5.37%	4.73%	4.50%
29				

sch ref				($000)	
30	**2(ii): Information Supporting the ROI**				
31					
32		Total opening RAB value	217,607		
33	*plus*	Opening deferred tax	(19,422)		
34	**Opening RIV**			198,185	
35					
36	**Line charge revenue**			33,648	
37					
38		Expenses cash outflow	17,453		
39	*add*	Assets commissioned	16,874		
40	*less*	Asset disposals	165		
41	*add*	Tax payments	(218)		
42	*less*	Other regulated income	(154)		
43	**Mid-year net cash outflows**			34,097	
44					
45	**Term credit spread differential allowance**			–	
46					
47		Total closing RAB value	240,495		
48	*less*	Adjustment resulting from asset allocation	(0)		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(21,664)		
51	**Closing RIV**			218,831	
52					
53	**ROI – comparable to a vanilla WACC**				10.02%
54					
55		Leverage (%)			42%
56		Cost of debt assumption (%)			2.55%
57		Corporate tax rate (%)			28%
58					
59	**ROI – comparable to a post tax WACC**				9.72%
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	10.69%
Year-end ROI – comparable to a post tax WACC	10.39%

** 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	(1,668)	
Purchased assets – avoided transmission charge	–	
Energy efficiency and demand incentive allowance		
Quality incentive adjustment	6	
Other financial incentives	–	
Financial incentives		(1,662)
Impact of financial incentives on ROI		–0.62%
Input methodology claw-back	–	
CPP application recoverable costs	–	
Catastrophic event allowance	–	
Capex wash-up adjustment	(222)	
Transmission asset wash-up adjustment	–	
2013–15 NPV wash-up allowance	–	
Reconsideration event allowance	–	
Other wash-ups	–	
Wash-up costs		(222)
Impact of wash-up costs on ROI		–0.08%

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2022

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			($000)
7		**3(i): Regulatory Profit**	($000)
8		**Income**	
9		Line charge revenue	33,648
10	*plus*	Gains / (losses) on asset disposals	(156)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	2
12			
13		**Total regulatory income**	33,494
14		**Expenses**	
15	*less*	Operational expenditure	8,765
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	8,688
18			
19		**Operating surplus / (deficit)**	16,042
20			
21	*less*	Total depreciation	8,881
22			
23	*plus*	Total revaluations	15,060
24			
25		**Regulatory profit / (loss) before tax**	22,221
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	2,024
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	20,196
32			

sch ref		($000)	
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	($000)	
34	**Pass through costs**		
35	Rates	167	
36	Commerce Act levies	116	
37	Industry levies	92	
38	CPP specified pass through costs	–	
39	**Recoverable costs excluding financial incentives and wash-ups**		
40	Electricity lines service charge payable to Transpower	6,804	
41	Transpower new investment contract charges	275	
42	System operator services	–	
43	Distributed generation allowance	1,234	
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**		8,688
47			

sch ref				
48	**3(iii): Incremental Rolling Incentive Scheme**		($000)	
49			CY-1	CY
50			31 Mar 21	31 Mar 22
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 17	–	–
58	CY-4	31 Mar 18	–	–
59	CY-3	31 Mar 19	–	–
60	CY-2	31 Mar 20	–	–
61	CY-1	31 Mar 21	–	–
62	**Net incremental rolling incentive scheme**			–
63				
64	**Net recoverable costs allowed under incremental rolling incentive scheme**			–

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

Company Name	OtagoNet Joint Venture
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SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

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

sch ref

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

	RAB	RAB	RAB	RAB	RAB
for year ended	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22
	($000)	($000)	($000)	($000)	($000)
Total opening RAB value	179,022	186,531	194,442	210,599	217,607
less **Total depreciation**	6,647	7,712	7,994	8,588	8,881
plus **Total revaluations**	1,967	2,766	4,923	3,202	15,060
plus **Assets commissioned**	12,346	12,937	19,339	12,425	16,874
less **Asset disposals**	157	80	111	30	165
plus **Lost and found assets adjustment**	–	–	–	–	–
plus **Adjustment resulting from asset allocation**	(0)	(0)	(0)	(0)	(0)
Total closing RAB value	186,531	194,442	210,599	217,607	240,495

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Total opening RAB value		217,607		217,607
less				
Total depreciation		8,881		8,881
plus				
Total revaluations		15,060		15,060
plus				
Assets commissioned (other than below)	–		–	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	16,874		16,874	
Assets commissioned		16,874		16,874
less				
Asset disposals (other than below)	165		165	
Asset disposals to a regulated supplier	–		–	
Asset disposals to a related party	–		–	
Asset disposals		165		165
plus **Lost and found assets adjustment**		–		–
plus **Adjustment resulting from asset allocation**				(0)
Total closing RAB value		240,495		240,495

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

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

CPI_4				1,142
CPI_4^{-4}				1,068
Revaluation rate (%)				6.93%
	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Total opening RAB value	217,607		217,607	
less Opening value of fully depreciated, disposed and lost assets	256		256	
Total opening RAB value subject to revaluation	217,351		217,351	
Total revaluations		15,060		15,060

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction		Allocated works under construction	
Works under construction—preceding disclosure year		5,437		5,437
plus Capital expenditure	17,816		17,816	
less Assets commissioned	16,874		16,874	
plus Adjustment resulting from asset allocation				
Works under construction - current disclosure year		6,379		6,379
Highest rate of capitalised finance applied				–

4(v): Regulatory Depreciation

	Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
Depreciation - standard	8,881		8,881	
Depreciation - no standard life assets	–		–	
Depreciation - modified life assets	–		–	
Depreciation - alternative depreciation in accordance with CPP	–		–	
Total depreciation		8,881		8,881

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	26,977	2,815	35,145	100,448	12,033	22,877	12,260	3,894	1,159	217,607
less	Total depreciation	1,322	62	1,611	4,028	287	829	574	130	37	8,881
plus	Total revaluations	1,867	195	2,432	6,958	834	1,574	849	270	80	15,060
plus	Assets commissioned	1,811	138	1,016	5,872	4,151	1,484	1,921	480	–	16,874
less	Asset disposals	–	–	13	–	–	153	–	–	–	165
plus	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
plus	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
plus	Asset category transfers	–	–	–	–	–	–	–	–	–	–
	Total closing RAB value	29,333	3,086	36,969	109,250	16,731	24,953	14,456	4,515	1,202	240,495

Asset Life

	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	
Weighted average remaining asset life	34.1	45.3	37.9	30.8	42.3	29.1	26.6	29.8	19.2	(years)
Weighted average expected total asset life	55.5	49.1	50.7	57.1	48.8	49.9	39.0	40.6	33.1	(years)

Company Name **OtagoNet Joint Venture**
For Year Ended **31 March 2022**

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref					
7	**5a(i): Regulatory Tax Allowance**				**($000)**
8		**Regulatory profit / (loss) before tax**			22,221
9					
10	*plus*	Income not included in regulatory profit / (loss) before tax but taxable	–	*	
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible	–	*	
12		Amortisation of initial differences in asset values	1,337		
13		Amortisation of revaluations	952		
14					2,288
15					
16	*less*	Total revaluations	15,060		
17		Income included in regulatory profit / (loss) before tax but not taxable	–	*	
18		Discretionary discounts and customer rebates	–		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax	124	*	
20		Notional deductible interest	2,096		
21					17,280
22					
23		**Regulatory taxable income**			7,229
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			7,229
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			2,024
30					
31	* Workings to be provided in Schedule 14				
32	**5a(ii): Disclosure of Permanent Differences**				
33		In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i).			
34	**5a(iii): Amortisation of Initial Difference in Asset Values**				**($000)**
35					
36		Opening unamortised initial differences in asset values	25,396		
37	*less*	Amortisation of initial differences in asset values	1,337		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	119		
40		Closing unamortised initial differences in asset values			23,941
41					
42		Opening weighted average remaining useful life of relevant assets (years)			19
43					

5a(iv): Amortisation of Revaluations

			($000)
	Opening sum of RAB values without revaluations	195,901	
	Adjusted depreciation	7,929	
	Total depreciation	8,881	
	Amortisation of revaluations		952

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	(19,422)	
plus	Tax effect of adjusted depreciation	2,220	
less	Tax effect of tax depreciation	4,382	
plus	Tax effect of other temporary differences*	309	
less	Tax effect of amortisation of initial differences in asset values	374	
plus	Deferred tax balance relating to assets acquired in the disclosure year	–	
less	Deferred tax balance relating to assets disposed in the disclosure year	15	
plus	Deferred tax cost allocation adjustment	0	
	Closing deferred tax		(21,664)

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	95,939	
less	Tax depreciation	15,649	
plus	Regulatory tax asset value of assets commissioned	18,917	
less	Regulatory tax asset value of asset disposals	80	
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		99,128

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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	2,001	
13	Vegetation management	808	
14	Routine and corrective maintenance and inspection	2,245	
15	Asset replacement and renewal (opex)	209	
16	**Network opex**		5,262
17	Business support	1,739	
18	System operations and network support	971	
19	**Operational expenditure**		7,973
20	Consumer connection	8,995	
21	System growth	329	
22	Asset replacement and renewal (capex)	7,842	
23	Asset relocations	691	
24	Quality of supply	506	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	1,286	
27	**Expenditure on non-network assets**		–
28	**Expenditure on assets**		19,649
29	Cost of financing		–
30	Value of capital contributions		–
31	Value of vested assets		–
32	**Capital Expenditure**		19,649
33	**Total expenditure**		27,622
34			
35	**Other related party transactions**		–

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

	Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
37			
38	PowerNet Limited	Service interruptions and emergencies	2,001
39	PowerNet Limited	Vegetation management	808
40	PowerNet Limited	Routine and corrective maintenance and inspection	2,245
41	PowerNet Limited	Asset replacement and renewal (opex)	209
42	PowerNet Limited	System operations and network support	911
43	PowerNet Limited	Business support	1,739
44	PowerNet Limited	Consumer connection	8,995
45	PowerNet Limited	System growth	329
46	PowerNet Limited	Asset replacement and renewal (capex)	7,842
47	PowerNet Limited	Asset relocations	691
48	PowerNet Limited	Quality of supply	506
49	PowerNet Limited	Other reliability, safety and environment	1,286
50	The Power Company Limited	System operations and network support	60
51			
52			
53	**Total value of related party transactions**		27,622
54	** include additional rows if needed*		
55			

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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

7
8 **5c(i): Qualifying Debt (may be Commission only)**
9

sch ref	Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
10									
11									
12									
13									
14									
15									
16	** include additional rows if needed*						–	–	–

17
18 **5c(ii): Attribution of Term Credit Spread Differential**
19

sch ref			
20	**Gross term credit spread differential**		–
21			
22	Total book value of interest bearing debt		
23	Leverage	42%	
24	Average opening and closing RAB values		
25	**Attribution Rate (%)**		–
26			
27	**Term credit spread differential allowance**		–

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SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref						
7	**5d(i): Operating Cost Allocations**					
8				Value allocated ($000s)		
9		Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
10	**Service interruptions and emergencies**					
11	Directly attributable		2,001			
12	Not directly attributable		–		–	
13	**Total attributable to regulated service**		2,001			
14	**Vegetation management**					
15	Directly attributable		808			
16	Not directly attributable		–		–	
17	**Total attributable to regulated service**		808			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		2,245			
20	Not directly attributable		–		–	
21	**Total attributable to regulated service**		2,245			
22	**Asset replacement and renewal**					
23	Directly attributable		209			
24	Not directly attributable		–		–	
25	**Total attributable to regulated service**		209			
26	**System operations and network support**					
27	Directly attributable		1,372			
28	Not directly attributable		–		–	
29	**Total attributable to regulated service**		1,372			
30	**Business support**					
31	Directly attributable		2,130			
32	Not directly attributable		–		–	
33	**Total attributable to regulated service**		2,130			
34						
35	**Operating costs directly attributable**		8,765			
36	**Operating costs not directly attributable**	–	–	–	–	–
37	**Operational expenditure**		8,765			
38						

sch ref		
39	**5d(ii): Other Cost Allocations**	
40	**Pass through and recoverable costs**	($000)
41	**Pass through costs**	
42	Directly attributable	375
43	Not directly attributable	–
44	**Total attributable to regulated service**	375
45	**Recoverable costs**	
46	Directly attributable	8,313
47	Not directly attributable	–
48	**Total attributable to regulated service**	8,313
49		

sch ref					
50	**5d(iii): Changes in Cost Allocations* †**				
51				($000)	
52	**Change in cost allocation 1**			CY-1	Current Year (CY)
53	Cost category		Original allocation		
54	Original allocator or line items		New allocation		
55	New allocator or line items		Difference	–	–
56					
57	Rationale for change				
58					
59					
60				($000)	
61	**Change in cost allocation 2**			CY-1	Current Year (CY)
62	Cost category		Original allocation		
63	Original allocator or line items		New allocation		
64	New allocator or line items		Difference	–	–
65					
66	Rationale for change				
67					
68					
69				($000)	
70	**Change in cost allocation 3**			CY-1	Current Year (CY)
71	Cost category		Original allocation		
72	Original allocator or line items		New allocation		
73	New allocator or line items		Difference	–	–
74					
75	Rationale for change				
76					
77					

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

pwc

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2022**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

7 5e(i): Regulated Service Asset Values

sch ref		Value allocated ($000s) Electricity distribution services
10	**Subtransmission lines**	
11	Directly attributable	29,333
12	Not directly attributable	–
13	**Total attributable to regulated service**	29,333
14	**Subtransmission cables**	
15	Directly attributable	3,086
16	Not directly attributable	–
17	**Total attributable to regulated service**	3,086
18	**Zone substations**	
19	Directly attributable	36,969
20	Not directly attributable	–
21	**Total attributable to regulated service**	36,969
22	**Distribution and LV lines**	
23	Directly attributable	109,250
24	Not directly attributable	–
25	**Total attributable to regulated service**	109,250
26	**Distribution and LV cables**	
27	Directly attributable	16,731
28	Not directly attributable	–
29	**Total attributable to regulated service**	16,731
30	**Distribution substations and transformers**	
31	Directly attributable	24,953
32	Not directly attributable	–
33	**Total attributable to regulated service**	24,953
34	**Distribution switchgear**	
35	Directly attributable	14,456
36	Not directly attributable	–
37	**Total attributable to regulated service**	14,456
38	**Other network assets**	
39	Directly attributable	4,515
40	Not directly attributable	–
41	**Total attributable to regulated service**	4,515
42	**Non-network assets**	
43	Directly attributable	1,202
44	Not directly attributable	–
45	**Total attributable to regulated service**	1,202
46		
47	**Regulated service asset value directly attributable**	240,495
48	**Regulated service asset value not directly attributable**	–
49	**Total closing RAB value**	240,495
50		

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

sch ref				($000) CY-1	Current Year (CY)
53	**Change in asset value allocation 1**				
54	Asset category		Original allocation		
55	Original allocator or line items		New allocation		
56	New allocator or line items		Difference	–	–
57					
58	Rationale for change				
59					
60					
62	**Change in asset value allocation 2**				
63	Asset category		Original allocation		
64	Original allocator or line items		New allocation		
65	New allocator or line items		Difference	–	–
66					
67	Rationale for change				
68					
69					
71	**Change in asset value allocation 3**				
72	Asset category		Original allocation		
73	Original allocator or line items		New allocation		
74	New allocator or line items		Difference	–	–
75					
76	Rationale for change				
77					
78					

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

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2022**

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**	($000)	($000)
8		Consumer connection		8,995
9		System growth		329
10		Asset replacement and renewal		7,842
11		Asset relocations		691
12		Reliability, safety and environment:		
13		Quality of supply	506	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	1,286	
16		**Total reliability, safety and environment**		1,792
17		**Expenditure on network assets**		19,649
18		Expenditure on non-network assets		–
19				
20		**Expenditure on assets**		19,649
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		1,833
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		17,816

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	285
29	Research and development	–

30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	($000)	($000)
32		Customer Connections < 20 kVA	1,312	
33		Customer Connections 21 - 99 kVA	221	
34		Customer Connections > 100 kVA	184	
35		New Subdivisions	7,278	
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		8,995
39				
40	*less*	Capital contributions funding consumer connection expenditure	1,063	
41		**Consumer connection less capital contributions**		7,932

42		**6a(iv): System Growth and Asset Replacement and Renewal**		Asset Replacement
43			System Growth	and Renewal
44			($000)	($000)
45		Subtransmission	–	1,750
46		Zone substations	0	401
47		Distribution and LV lines	2	5,293
48		Distribution and LV cables	327	–
49		Distribution substations and transformers	–	202
50		Distribution switchgear	–	133
51		Other network assets	–	63
52		**System growth and asset replacement and renewal expenditure**	329	7,842
53	*less*	Capital contributions funding system growth and asset replacement and renewal	–	21
54		**System growth and asset replacement and renewal less capital contributions**	329	7,821
55				

56		**6a(v): Asset Relocations**		
57		*Project or programme**	($000)	($000)
58		Beaumont Bridge Alteration	579	
59				
60				
61				
62				
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	112	
65		**Asset relocations expenditure**		691
66	*less*	Capital contributions funding asset relocations	749	
67		**Asset relocations less capital contributions**		(58)
68				

69		**6a(vi): Quality of Supply**		
70		*Project or programme**	($000)	($000)
71		Finegand 33kV Smart Network Automation	38	
72		Network Improvement Projects	20	
73		Mobile substation Site Made Ready	388	
74				
75				
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply	60	
78		**Quality of supply expenditure**		506
79	*less*	Capital contributions funding quality of supply	–	
80		**Quality of supply less capital contributions**		506
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	580	
96		Replacement of OH Structures with Ground Mounted	85	
97		Earth Refurbishment	296	
98		Clydevale 33 kV Ring Rebuild and Protection	227	
99				
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment	97	
102		**Other reliability, safety and environment expenditure**		1,286
103	*less*	Capital contributions funding other reliability, safety and environment	–	
104		**Other reliability, safety and environment less capital contributions**		1,286
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 2022**

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	2,001	
9	Vegetation management	808	
10	Routine and corrective maintenance and inspection	2,245	
11	Asset replacement and renewal	209	
12	**Network opex**		5,262
13	System operations and network support	1,372	
14	Business support	2,130	
15	**Non-network opex**		3,502
16			
17	**Operational expenditure**		8,765
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		198
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2022**

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	33,297	33,648	1%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	6,622	8,995	36%
11	System growth	195	329	69%
12	Asset replacement and renewal	7,013	7,842	12%
13	Asset relocations	20	691	3,296%
14	Reliability, safety and environment:			
15	Quality of supply	379	506	33%
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	1,273	1,286	1%
18	**Total reliability, safety and environment**	1,653	1,792	8%
19	**Expenditure on network assets**	15,503	19,649	27%
20	Expenditure on non-network assets	–	–	–
21	Expenditure on assets	15,503	19,649	27%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,602	2,001	25%
24	Vegetation management	810	808	(0%)
25	Routine and corrective maintenance and inspection	1,986	2,245	13%
26	Asset replacement and renewal	328	209	(36%)
27	**Network opex**	4,726	5,262	11%
28	System operations and network support	1,450	1,372	(5%)
29	Business support	2,049	2,130	4%
30	**Non-network opex**	3,499	3,502	0%
31	**Operational expenditure**	8,225	8,765	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	–	285	–
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	198	198	0%
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 2022**
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(i): Billed Quantities by Price Component

					Billed quantities by price component					
				Price component	Variable day energy sales	Variable night energy sales	Variable day energy purchases	Variable night energy purchases	Variable energy sales	
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)**	kWh	KWh	kWh	kWh	kWh	
1	Domestic	Standard	6,650	50,715			40,425,430	14,833,920		
2	Commerical	Standard	3,323	51,681			41,195,432	15,116,468		
4	Major Customers	Standard	107	83,900	54,688,384					
5	Unmetered	Standard	83	150			119,670	43,912		
6	Street lights	Standard	10	694			553,186	202,989		
7 & 8	Low user	Standard	5,207	28,365	20,680,145	7,685,348				
Non Standard	Commerical	Non-standard	3	196,337	134,185,603					
LLNW	Domestic	Standard	2,745	18,582					18,582	
LLNW	Non Domestic	Standard	427	10,857						
LLNW	Half Hour	Standard	12	9,061						
Add extra rows for additional consumer groups or price category codes as necessary										
		Standard consumer totals	18,564	254,004	75,368,529	7,685,348	82,293,717	30,197,289	18,582	–
		Non-standard consumer totals	3	196,337	134,185,603	–	–	–	–	–
		Total for all consumers	18,567	450,341	209,554,132	7,685,348	82,293,717	30,197,289	18,582	–

Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.): kWh / KWh / kWh / kWh / kWh

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

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

32

33 Line charge revenues ($000) by price component

34

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; Rate: $/Day	Price component: Variable - Day; Rate: $/kwh	Price component: Variable Night; Rate: $/kWh	Price component: Kva; Rate: Per/kVa	Price component: Fixed; Rate: $/kW	Price component: Variable; Rate: $/kWh
35													
36													
37	1	Domestic	Standard	$8,881		$7,886	$995		$4,902	$208	$3,772		
38	2	Commerical	Standard	$8,632		$7,665	$967		$4,995	$212	$3,425		
	4	Major Customers	Standard	$3,351		$1,457	$1,893	$2,505	$846				
39	5	Unmetered	Standard	$36		$32	$4	$21	$15	$1			
40	6	Street lights	Standard	$130		$116	$15	$60	$67	$3			
41	7 & 8	Low user	Standard	$4,677		$4,153	$524	$285	$4,194	$197			
42	Non Standard	Major Customers	Non-standard	$3,584		$486	$3,098	$3,584					
43	Generation	Generation	Standard	$342		$341	$1	$342					
44	LLNW	Domestic	Standard	$2,318		$1,954	$364.05	$149					$2,169
45	LLNW	Non Domestic	Standard	$1,112		$915	$196.94	$548				$563	
46	LLNW	Half Hour	Standard	$587		$330	$257	$587					
47	*Add extra rows for additional consumer groups or price category codes as necessary*												
48			Standard consumer totals	$30,064	–	$24,848	$5,216	$4,497	$15,018	$620	$7,197	$563	$2,169
49			Non-standard consumer totals	$3,584	–	$486	$3,098	$3,584	–	–	–	–	–
50			Total for all consumers	$33,648	–	$25,335	$8,314	$8,081	$15,018	$620	$7,197	$563	$2,169

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

51

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 2022
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(i): Billed Quantities by Price Component

					Billed quantities by price component					
				Price component	Variable day energy sales	Variable night energy sales	Variable day energy purchases	Variable night energy purchases	Variable energy sales	
Consumer group name or price category code	**Consumer type or types (eg, residential, commercial etc.)**	**Standard or non-standard consumer group (specify)**	**Average no. of ICPs in disclosure year**	**Energy delivered to ICPs in disclosure year (MWh)** / **Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)**	kWh	Kwh	kwh	kwh	kwh	
1	Domestic	Standard	6,650	50,715			40,425,430	14,833,920		
2	Commerical	Standard	3,323	51,681			41,195,432	15,116,468		
4	Major Customers	Standard	107	83,900	54,688,384					
5	Unmetered	Standard	83	150			119,670	43,912		
6	Street lights	Standard	10	694			553,186	202,989		
7 & 8	Low user	Standard	5,207	28,365	20,680,145	7,685,348				
Non Standard	Commerical	Non-standard	3	196,337	134,185,603					
		Standard consumer totals	15,380	215,504	75,368,529	7,685,348	82,293,717	30,197,289	–	–
		Non-standard consumer totals	3	196,337	134,185,603	–	–	–	–	–
		Total for all consumers	15,383	411,842	209,554,132	7,685,348	82,293,717	30,197,289	–	–

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

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

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

32
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)	Fixed	Variable - Day	Variable Night	Kva	Fixed	Variable
34							Price component	Fixed	Variable - Day	Variable Night	Kva	Fixed	Variable
35							Rate (eg, $ per day, $ per kWh, etc.)	$/Day	$/kwh	$/kWh	Per/kVa	$/kW	$/kWh
36													
37	1	Domestic	Standard	$8,881		$7,886	$995		$4,902	$208	$3,772		
38	2	Commerical	Standard	$8,632		$7,665	$967		$4,995	$212	$3,425		
	4	Major Customers	Standard	$3,351		$1,457	$1,893	$2,505	$846				
39	5	Unmetered	Standard	$36		$32	$4	$21	$15	$1			
40	6	Street lights	Standard	$130		$116	$15	$60	$67	$3			
41	7 & 8	Low user	Standard	$4,677		$4,153	$524	$285	$4,194	$197			
42	Non Standard	Major Customers	Non-standard	$3,584		$486	$3,098	$3,584					
43	Generation	Generation	Standard	$342		$341	$1	$342					
44				–									
45				–									
46				–									
47	*Add extra rows for additional consumer groups or price category codes as necessary*												
48			Standard consumer totals	$26,048	–	$21,650	$4,398	$3,213	$15,018	$620	$7,197	–	–
49			Non-standard consumer totals	$3,584	–	$486	$3,098	$3,584	–	–	–	–	–
50			Total for all consumers	$29,632	–	$22,137	$7,496	$6,797	$15,018	$620	$7,197	–	–

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

51
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 2022**
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(i): Billed Quantities by Price Component

					Billed quantities by price component					
				Price component	Variable day energy sales	Variable night energy sales	Variable day energy purchases	Variable night energy purchases	Variable energy sales	
Consumer group name or price category code	**Consumer type or types (eg, residential, commercial etc.)**	**Standard or non-standard consumer group (specify)**	**Average no. of ICPs in disclosure year**	**Energy delivered to ICPs in disclosure year (MWh)** / **Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)**	kWh	kWh	kWh	kWh	kWh	*Add extra columns for additional billed quantities by price component as necessary*
LLNW	Domestic	Standard	2,314	16,152					16,152	
LLNW	Non Domestic	Standard	407	10,676						
LLNW	Half Hour	Standard	12	9,061						
Add extra rows for additional consumer groups or price category codes as necessary										
		Standard consumer totals	2,733	35,889	–	–	–	–	16,152	–
		Non-standard consumer totals	–	–	–	–	–	–	–	–
		Total for all consumers	2,733	35,889	–	–	–	–	16,152	–

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Line charge revenues ($000) by price component: 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	$2,020		$1,655	$364.05	$126					$1,894
LLNW	Non Domestic	Standard	$1,101		$904	$196.94	$548				$553	
LLNW	Half Hour	Standard	$587		$330	$257	$587					
			–									
			–									
			–									
			–									
			–									
			–									
			–									
			–									
		Standard consumer totals	$3,708	–	$2,890	$818	$1,261	–	–	–	$553	$1,894
		Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	$3,708	–	$2,890	$818	$1,261	–	–	–	$553	$1,894

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 2022**
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.	34,997	35,449	452	3
10	All	Overhead Line	Wood poles	No.	15,129	14,963	(166)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	697	697	(1)	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	18	19	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.	46	45	(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.	7	7	–	3
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	215	214	(1)	2
29	HV	Zone substation switchgear	33kV RMU	No.	–	1	1	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	7	7	–	3
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	35	35	–	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.	44	44	–	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,340	2,343	3	2
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	902	904	3	2
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	85	89	4	1
39	HV	Distribution Cable	Distribution UG PILC	km	4	4	0	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.	32	32	–	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.	5,058	5,132	74	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.	90	98	8	2
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,024	4,054	30	1
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	339	345	6	2
48	HV	Distribution Transformer	Voltage regulators	No.	42	42	–	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	16	16	–	3
50	LV	LV Line	LV OH Conductor	km	468	469	0	1
51	LV	LV Cable	LV UG Cable	km	114	115	0	1
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	101	107	6	1
53	LV	Connections	OH/UG consumer service connections	No.	19,153	19,866	713	1
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	244	251	7	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 2022**
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	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.	34,997	35,449	452	3
10	All	Overhead Line	Wood poles	No.	15,129	14,963	(166)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	697	697	(1)	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	11	13	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	44	(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.	7	7	–	3
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	215	214	(1)	2
29	HV	Zone substation switchgear	33kV RMU	No.	–	1	1	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	7	7	–	3
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	35	35	–	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.	42	42	–	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,340	2,343	3	2
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	902	904	3	2
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	36	37	2	1
39	HV	Distribution Cable	Distribution UG PILC	km	3	3	0	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.	32	32	–	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.	5,058	5,132	74	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.	10	10	–	2
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,024	4,054	30	1
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	263	257	(6)	2
48	HV	Distribution Transformer	Voltage regulators	No.	42	42	–	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	16	16	–	3
50	LV	LV Line	LV OH Conductor	km	468	469	0	1
51	LV	LV Cable	LV UG Cable	km	48	47	(1)	1
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	78	82	4	1
53	LV	Connections	OH/UG consumer service connections	No.	16,117	16,258	141	1
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	234	241	7	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 2022**
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

	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	–	–	–	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	0	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	47	49	1	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.	71	74	3	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	–	N/A
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	67	88	21	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	60	55	(5)	2
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	23	25	2	4
53	LV	Connections	OH/UG consumer service connections	No.	2,651	3,068	417	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 2022
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 2022

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
9																	
10	All	Overhead Line	Concrete poles / steel structure	No.	248	746	4,320	3,852	4,812	6,460	1,903	133	233	53	267	119	123
11	All	Overhead Line	Wood poles	No.	20	232	1,631	1,281	767	681	3,586	405	738	518	517	269	503
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	13	63	157	116	86	67	0	4	3	18	1	–
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	0	0	–	–	–	–	0	1	–
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	2	10	7	5	7	–	–	–	–	–	–
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	6	1	–	–	–	–	–	–
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	14	24	23	49	30	–	1	1	11	2	5
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	2	1	11	6	–	–	–	–	–	–
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	3	9	8	41	–	1	–	–	2	6
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	2	8	6	7	2	–	–	–	–	–	–
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3	31	149	217	250	310	335	76	93	45	42	25	51
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–
38	HV	Distribution Line	SWER conductor	km	–	–	190	110	98	154	103	3	2	2	8	3	5
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	0	0	0	0	2	1	0	0	1	2	2
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	1	–	–	–	–	–	–	–	0	0
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	–	2	–	–	–	–	–	–	–
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	24	663	692	771	522	496	26	92	89	68	63	93
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	–	–	4	–	–	1	2	–	–
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	24	659	544	547	409	453	25	76	73	53	51	77
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	1	30	7	21	4	9	5	4	3	14
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	1	4	–	–	–	1	2	2
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	7	–	3	–	–	–	–	–	–
51	LV	LV Line	LV OH Conductor	km	1	4	153	47	63	37	28	2	5	6	5	2	4
52	LV	LV Cable	LV UG Cable	km	–	–	0	1	4	3	0	0	0	0	1	2	2
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	0	0	1	1	–	–	–	–	–	–	–
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	10,937	916	107	101	484	545	515
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	9	33	36	–	4	–	–	7	4
56	All	SCADA and communications	SCADA and communications equipment operating as a single systen	Lot	–	–	–	–	–	–	–	1	–	–	–	–	–
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	1	–	1	–	–	–	–
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–

sch ref	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)
9																								
10	46	47	197	949	1,011	1,091	1,074	876	920	939	642	972	713	449	632	501	17	–	–	–	1,104	35,449		3
11	558	799	655	221	33	10	21	22	90	62	53	64	61	42	138	101	5	–	–	–	880	14,963		3
12	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
13	1	2	–	2	2	–	48	1	–	13	2	–	–	0	0	–	–	–	–	–	96	697		3
14	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
15	–	1	–	6	–	–	–	1	–	1	0	–	–	–	8	0	1	–	–	–	0	19		3
16	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
17	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
18	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
19	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
20	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
21	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
22	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
23	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
24	1	1	2	1	–	1	–	1	–	–	2	–	–	–	–	–	–	–	–	–	5	45		3
25	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
26	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
27	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7		3
28	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
29	2	3	7	–	3	2	7	–	2	3	2	1	3	6	8	2	–	–	–	–	3	214		3
30	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	1		4
31	–	–	7	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7		3
32	1	1	–	–	–	1	1	1	–	1	2	2	3	1	–	–	–	–	–	–	1	35		3
33	11	2	–	1	10	–	–	9	1	–	8	2	–	–	2	–	–	–	–	–	–	116		3
34	–	–	–	2	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	3		3
35	4	2	1	2	1	–	2	2	2	–	1	1	–	–	1	–	–	–	–	–	–	44		3
36	33	61	59	67	101	50	61	76	36	46	22	18	4	5	21	12	0	–	–	–	42	2,343		2
37	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
38	22	3	11	20	11	44	43	16	15	2	0	3	23	1	4	6	–	–	–	–	4	904		2
39	1	2	2	10	2	2	2	5	6	13	5	11	6	3	5	2	1	–	–	–	3	89		1
40	0	–	0	0	–	–	1	–	0	–	0	–	–	0	0	–	–	–	–	–	–	4		1
41	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
42	–	–	2	–	3	–	–	–	–	7	4	2	6	5	–	1	–	–	–	–	–	32		2
43	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
44	104	116	110	104	114	82	82	48	71	100	64	66	89	65	82	115	26	–	–	–	95	5,132		1
45	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
46	–	–	1	5	3	1	–	4	8	10	11	7	12	10	8	11	–	–	–	–	–	98		2
47	80	98	99	76	80	59	55	36	52	80	47	49	66	45	50	75	16	–	–	–	–	4,054		1
48	11	15	13	18	10	6	14	11	16	20	21	16	13	18	19	22	4	–	–	–	–	345		2
49	–	–	1	2	2	–	2	2	2	11	3	2	2	1	2	–	–	–	–	–	–	42		3
50	–	1	–	1	2	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	16		3
51	4	4	3	2	3	2	2	3	2	3	2	1	2	2	3	4	0	–	–	–	71	469		1
52	1	6	2	2	1	2	1	3	8	7	11	13	13	8	7	2	–	–	–	–	10	115		1
53	0	0	1	–	0	0	–	1	0	5	3	4	3	2	5	4	–	–	–	–	77	107		1
54	512	440	216	139	103	107	92	113	191	334	380	451	686	615	800	492	–	–	–	–	590	19,866		1
55	8	7	15	6	13	3	1	14	1	11	18	7	13	22	8	5	6	–	–	–		251		3
56	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2		3
57	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
58	–	–	–	–	–	1	–	–	–	–	–	–	–	1	1	–	–	–	–	–	–	5		3
59	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
60	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2022
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 2022

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
10	All	Overhead Line	Concrete poles / steel structure	No.	248	746	4,320	3,852	4,812	6,460	1,903	133	233	53	267	119	123	46
11	All	Overhead Line	Wood poles	No.	20	232	1,631	1,281	767	681	3,586	405	738	518	517	269	503	558
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	13	63	157	116	86	67	0	4	3	18	1	–	1
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	0	–	0	–	–	–	0	1	–	–
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	2	10	7	5	7	–	–	–	–	–	–	–
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	6	1	–	–	–	–	–	–	–
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	14	24	23	49	30	–	1	1	11	2	5	2
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	2	1	11	6	–	–	–	–	–	–	1
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	3	9	8	41	–	1	–	–	2	6	1
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	2	8	6	7	2	–	–	–	–	–	–	4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3	31	149	217	250	310	335	76	93	45	42	25	51	33
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
38	HV	Distribution Line	SWER conductor	km	–	–	190	110	98	154	103	3	2	2	8	3	5	22
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	0	0	0	0	2	1	0	0	1	2	1	1
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	1	–	–	–	–	–	–	–	–	0	0
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	–	2	–	–	–	–	–	–	–	–
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	24	663	692	771	522	496	26	92	89	68	63	93	104
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	–	–	4	–	–	–	2	–	–	–
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	24	659	544	547	409	453	25	76	73	53	51	77	80
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	1	30	7	21	4	9	5	4	3	13	11
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	1	4	–	–	–	1	2	2	–
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	7	–	3	–	–	–	–	–	–	–
51	LV	LV Line	LV OH Conductor	km	1	4	153	47	63	37	28	2	5	6	5	2	4	4
52	LV	LV Cable	LV UG Cable	km	–	–	0	1	4	3	0	0	0	0	1	1	2	1
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	0	0	1	1	–	–	–	–	–	–	–	0
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	10,937	916	107	101	472	534	487	479
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	9	33	36	–	4	–	–	7	4	4
56	All	SCADA and communications	SCADA and communications equipment operating as a single systen	Lot	–	–	–	–	–	–	–	1	–	–	–	–	–	–
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	1	–	1	–	–	–	–	–
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–

sch ref	Asset class	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	Concrete poles / steel structure	47	197	949	1,011	1,091	1,074	876	920	939	642	972	713	449	632	501	17	–	–	–	1,104	35,449	–	3
11	Wood poles	799	655	221	33	10	21	22	90	62	53	64	61	42	138	101	5	–	–	–	880	14,963	–	3
12	Other pole types	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
13	Subtransmission OH up to 66kV conductor	2	–	2	2	–	48	1	–	13	2	–	–	0	0	–	–	–	–	–	96	697	–	3
14	Subtransmission OH 110kV+ conductor	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
15	Subtransmission UG up to 66kV (XLPE)	1	–	0	–	–	–	1	–	1	0	–	–	0	8	1	–	–	–	–	0	13	–	3
16	Subtransmission UG up to 66kV (Oil pressurised)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
17	Subtransmission UG up to 66kV (Gas pressurised)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
18	Subtransmission UG up to 66kV (PILC)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
19	Subtransmission UG 110kV+ (XLPE)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
20	Subtransmission UG 110kV+ (Oil pressurised)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
21	Subtransmission UG 110kV+ (Gas Pressurised)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
22	Subtransmission UG 110kV+ (PILC)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
23	Subtransmission submarine cable	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
24	Zone substations up to 66kV	1	2	1	–	1	–	1	–	–	2	–	–	–	–	–	–	–	–	–	5	44	–	3
25	Zone substations 110kV+	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
26	50/66/110kV CB (Indoor)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
27	50/66/110kV CB (Outdoor)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	3
28	33kV Switch (Ground Mounted)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
29	33kV Switch (Pole Mounted)	3	7	–	3	2	7	–	2	3	2	1	3	6	8	2	–	–	–	–	3	214	–	3
30	33kV RMU	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	1	–	4
31	22/33kV CB (Indoor)	–	7	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	3
32	22/33kV CB (Outdoor)	1	–	–	–	1	1	1	–	1	2	2	3	1	–	–	–	–	–	–	1	35	–	3
33	3.3/6.6/11/22kV CB (ground mounted)	2	–	1	10	–	–	9	1	–	8	2	–	–	2	–	–	–	–	–	–	106	–	3
34	3.3/6.6/11/22kV CB (pole mounted)	–	–	2	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	3	–	3
35	Zone Substation Transformers	2	1	–	1	–	2	2	2	–	1	1	–	–	1	–	–	–	–	–	–	42	–	3
36	Distribution OH Open Wire Conductor	61	59	67	101	50	61	76	36	46	22	18	4	5	21	12	0	–	–	–	42	2,343	–	2
37	Distribution OH Aerial Cable Conductor	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
38	SWER conductor	3	11	20	11	44	43	16	15	2	0	3	23	1	4	6	–	–	–	–	4	904	–	2
39	Distribution UG XLPE or PVC	2	2	1	1	2	2	1	3	6	1	3	0	0	3	1	–	–	–	–	1	37	–	1
40	Distribution UG PILC	–	–	0	–	–	1	–	0	–	0	–	–	0	–	–	–	–	–	–	–	3	–	1
41	Distribution Submarine Cable	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
42	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	–	2	–	3	–	–	–	–	7	4	2	6	5	–	1	–	–	–	–	–	32	–	2
43	3.3/6.6/11/22kV CB (Indoor)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
44	3.3/6.6/11/22kV Switches and fuses (pole mounted)	116	110	104	114	82	82	48	71	100	64	66	89	65	82	115	26	–	–	–	95	5,132	–	1
45	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
46	3.3/6.6/11/22kV RMU	–	1	–	1	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	10	–	2
47	Pole Mounted Transformer	98	99	76	80	59	55	36	52	80	47	49	66	45	50	75	16	–	–	–	–	4,054	–	1
48	Ground Mounted Transformer	14	12	11	8	6	14	8	10	9	14	6	5	10	12	8	2	–	–	–	–	257	–	2
49	Voltage regulators	–	1	2	2	–	2	2	2	11	3	2	2	1	2	–	–	–	–	–	–	42	–	3
50	Ground Mounted Substation Housing	1	–	1	2	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	16	–	3
51	LV OH Conductor	4	3	2	3	2	2	3	2	3	2	1	2	2	3	4	0	–	–	–	71	469	–	1
52	LV UG Cable	6	2	1	1	2	1	2	1	2	2	3	2	1	2	1	–	–	–	–	4	47	–	1
53	LV OH/UG Streetlight circuit	0	1	–	0	0	–	–	–	1	0	1	1	0	1	2	–	–	–	–	73	82	–	1
54	OH/UG consumer service connections	398	196	134	89	101	87	73	96	126	85	104	122	147	157	133	–	–	–	–	177	16,258	–	1
55	Protection relays (electromechanical, solid state and numeric)	3	15	4	13	3	1	14	1	11	18	7	13	22	8	5	6	–	–	–	–	241	–	3
56	SCADA and communications equipment operating as a single systen	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	3
57	Capacitors including controls	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
58	Centralised plant	–	–	–	–	1	–	–	–	–	–	–	–	1	1	–	–	–	–	–	–	5	–	3
59	Relays	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
60	Cable Tunnels	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A

Company Name: OtagoNet Joint Venture
For Year Ended: 31 March 2022
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 2022

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.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	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	8	5	2	1	1	1	–	–	–	2	49	–	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	–	4	8	10	10	5	11	8	4	5	–	–	–	–	–	74	–	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	10	8	8	7	14	2	–	–	–	–	88	–	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	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
52	LV	LV Cable	LV UG Cable	km	–	–	–	–	–	–	–	–	–	–	–	1	0	0	0	0	0	0	–	–	2	7	5	10	7	8	4	3	1	–	–	–	–	6	55	–	2
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–	–	–	1	0	4	3	3	3	2	4	2	–	–	–	–	4	25	–	4
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	–	–	–	–	12	11	28	33	42	20	5	14	6	5	40	95	208	295	322	461	362	529	272	–	–	–	–	308	3,068	–	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 2022**
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	74	–	74
13	33kV	622	19	641
14	SWER (all SWER voltages)	899	6	904
15	22kV (other than SWER)	0	46	46
16	6.6kV to 11kV (inclusive—other than SWER)	2,343	47	2,390
17	Low voltage (< 1kV)	469	115	583
18	**Total circuit length (for supply)**	4,407	231	4,638
19				
20	Dedicated street lighting circuit length (km)	78	29	107
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	328	7%	
25	Rural	900	20%	
26	Remote only	591	13%	
27	Rugged only	1,808	41%	
28	Remote and rugged	674	15%	
29	Unallocated overhead lines	106	2%	
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)	1,121	24%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	645	15%	

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2022**
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	74	–	74
13	33kV	622	13	635
14	SWER (all SWER voltages)	899	6	904
15	22kV (other than SWER)	0	0	0
16	6.6kV to 11kV (inclusive—other than SWER)	2,343	40	2,383
17	Low voltage (< 1kV)	469	47	516
18	**Total circuit length (for supply)**	4,407	106	4,513
19				
20	Dedicated street lighting circuit length (km)	78	5	82
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	328	7%	
25	Rural	900	20%	
26	Remote only	591	13%	
27	Rugged only	1,808	41%	
28	Remote and rugged	674	15%	
29	Unallocated overhead lines	106	2%	
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)	1,121	25%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	645	15%	

Company Name **OtagoNet Joint Venture**
For Year Ended **31 March 2022**
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)	–	46	46
16	6.6kV to 11kV (inclusive—other than SWER)	–	3	3
17	Low voltage (< 1kV)	0	55	55
18	**Total circuit length (for supply)**	0	110	110
19				
20	Dedicated street lighting circuit length (km)	–	25	25
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 2022**

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			
8	**Location ***	**Number of ICPs served**	**Line charge revenue ($000)**
9	Lakeland Wanaka GXP NLK0111 [used Average ICP Count as per Schedule 8(i)]	437	313
10	Lakeland Clearview GXP CLV0111 [used Average ICP Count as per Schedule 8(i)]	9	3
11	Lakeland Wooing Tree GXP WRT0111 [used Average ICP Count as per Schedule 8(i)]	5	1
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 2022**
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	653	
12		Half Hour Individual	5	
13		Non Domestic	92	
14		Unmetered	3	
15				
16		** include additional rows if needed*		
17	**Connections total**		753	
18				
19	**Distributed generation**			
20		Number of connections made in year	49	**connections**
21		Capacity of distributed generation installed in year	0.32	**MVA**
22	**9e(ii): System Demand**			
23				
24			**Demand at time of maximum coincident demand (MW)**	
25	**Maximum coincident system demand**			
26		GXP demand	63	
27	*plus*	Distributed generation output at HV and above	5	
28	**Maximum coincident system demand**		68	
29	*less*	Net transfers to (from) other EDBs at HV and above	(0)	
30	**Demand on system for supply to consumers' connection points**		68	
31	**Electricity volumes carried**		**Energy (GWh)**	
32		Electricity supplied from GXPs	388	
33	*less*	Electricity exports to GXPs	–	
34	*plus*	Electricity supplied from distributed generation	81	
35	*less*	Net electricity supplied to (from) other EDBs	(3)	
36	**Electricity entering system for supply to consumers' connection points**		471	
37	*less*	Total energy delivered to ICPs	450	
38	**Electricity losses (loss ratio)**		21	4.4%
39				
40	**Load factor**		0.79	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43		Distribution transformer capacity (EDB owned)	230	
44		Distribution transformer capacity (Non-EDB owned, estimated)	9	
45	**Total distribution transformer capacity**		239	
46				
47	**Zone substation transformer capacity**		162	

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2022**
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

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		153	
12	Half Hour Individual		1	
13	Non Domestic		37	
14	Unmetered		3	
15				
16	** include additional rows if needed*			
17	**Connections total**		194	
18				
19	**Distributed generation**			
20	Number of connections made in year		23	connections
21	Capacity of distributed generation installed in year		0.17	MVA
22	**9e(ii): System Demand**			
23				
24			**Demand at time of maximum coincident demand (MW)**	
25	**Maximum coincident system demand**			
26		GXP demand	58	
27	*plus*	Distributed generation output at HV and above	5	
28		**Maximum coincident system demand**	63	
29	*less*	Net transfers to (from) other EDBs at HV and above	–	
30		**Demand on system for supply to consumers' connection points**	63	
31	**Electricity volumes carried**		**Energy (GWh)**	
32		Electricity supplied from GXPs	351	
33	*less*	Electricity exports to GXPs	–	
34	*plus*	Electricity supplied from distributed generation	80	
35	*less*	Net electricity supplied to (from) other EDBs	–	
36		**Electricity entering system for supply to consumers' connection points**	431	
37	*less*	Total energy delivered to ICPs	412	
38		**Electricity losses (loss ratio)**	20	4.5%
39				
40		**Load factor**	0.78	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43		Distribution transformer capacity (EDB owned)	194	
44		Distribution transformer capacity (Non-EDB owned, estimated)	9	
45		**Total distribution transformer capacity**	203	
46				
47		**Zone substation transformer capacity**	137	

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2022**
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				
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		326	
12	Half Hour Individual		4	
13	Non Domestic		53	
14				
15				
16	** include additional rows if needed*			
17	**Connections total**		383	
18				
19	**Distributed generation**			
20	Number of connections made in year		16	**connections**
21	Capacity of distributed generation installed in year		0.10	**MVA**
22	**9e(ii): System Demand**			
23				
24			**Demand at time of maximum coincident demand (MW)**	
25	**Maximum coincident system demand**			
26	GXP demand		5	
27	Distributed generation output at HV and above	*plus*	–	
28	**Maximum coincident system demand**		5	
29	Net transfers to (from) other EDBs at HV and above	*less*		
30	**Demand on system for supply to consumers' connection points**		5	
31	**Electricity volumes carried**		**Energy (GWh)**	
32	Electricity supplied from GXPs		37	
33	Electricity exports to GXPs	*less*	–	
34	Electricity supplied from distributed generation	*plus*	–	
35	Net electricity supplied to (from) other EDBs	*less*	–	
36	**Electricity entering system for supply to consumers' connection points**		37	
37	Total energy delivered to ICPs	*less*	36	
38	**Electricity losses (loss ratio)**		1	2.8%
39				
40	**Load factor**		0.85	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43	Distribution transformer capacity (EDB owned)		34	
44	Distribution transformer capacity (Non-EDB owned, estimated)		–	
45	**Total distribution transformer capacity**		34	
46				
47	**Zone substation transformer capacity**		25	

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2022**
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	Interruptions by class	Number of interruptions
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	385
12	Class C (unplanned interruptions on the network)	620
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)	1
18	Class I (interruptions caused by parties not included above)	–
19	**Total**	1,007

sch ref	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	415	205

sch ref	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.78	221.19
27	Class C (unplanned interruptions on the network)	2.38	213.28
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)	0.02	0.75
32	Class H (planned interruptions caused by another disclosing entity)	0.02	11.3
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	3.21	446.5

sch ref	Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
37	Classes B & C (interruptions on the network)	3.16	419.34

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

sch ref	Cause	SAIFI	SAIDI
42	Lightning	0.08	5.62
43	Vegetation	0.22	26.03
44	Adverse weather	0.38	51.84
45	Adverse environment	0.00	0.08
46	Third party interference	0.28	19.47
47	Wildlife	0.21	9.96
48	Human error	0.07	1.76
49	Defective equipment	0.77	74.16
50	Cause unknown	0.38	24.36

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

sch ref	Main equipment involved	SAIFI	SAIDI
55	Subtransmission lines	0.02	9.73
56	Subtransmission cables	–	–
57	Subtransmission other	0.00	0.27
58	Distribution lines (excluding LV)	0.69	194.85
69	Distribution cables (excluding LV)	0.01	2.24
60	Distribution other (excluding LV)	0.06	14.09

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

sch ref	Main equipment involved	SAIFI	SAIDI
64	Subtransmission lines	0.64	65.61
65	Subtransmission cables	–	–
66	Subtransmission other	0.16	14.67
67	Distribution lines (excluding LV)	1.24	106.90
68	Distribution cables (excluding LV)	0.00	0.03
69	Distribution other (excluding LV)	0.34	26.07

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

sch ref	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
72	Subtransmission lines	25	696	3.59
73	Subtransmission cables	–	19	–
74	Subtransmission other	4		
75	Distribution lines (excluding LV)	479	3,242	14.77
76	Distribution cables (excluding LV)	2	98	2.04
77	Distribution other (excluding LV)	110		
78	**Total**	620		

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2022**
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**

sch ref	Interruptions by class	Number of interruptions
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	374
12	Class C (unplanned interruptions on the network)	613
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**	987
20		

sch ref	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	412	201
23			

sch ref	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.90	260.08
27	Class C (unplanned interruptions on the network)	2.82	249.46
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**	3.72	509.54
35			

sch ref	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

sch ref	Cause	SAIFI	SAIDI
42	Lightning	0.09	6.73
43	Vegetation	0.27	31.31
44	Adverse weather	0.45	62.05
45	Adverse environment	0.00	0.09
46	Third party interference	0.34	23.46
47	Wildlife	0.26	11.95
48	Human error	0.08	2.13
49	Defective equipment	0.88	82.71
50	Cause unknown	0.45	29.04
51			

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

53

sch ref	Main equipment involved	SAIFI	SAIDI
55	Subtransmission lines	0.03	11.69
56	Subtransmission cables	–	–
57	Subtransmission other	0.00	0.32
58	Distribution lines (excluding LV)	0.83	234.77
69	Distribution cables (excluding LV)	–	–
60	Distribution other (excluding LV)	0.05	13.30

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

62

sch ref	Main equipment involved	SAIFI	SAIDI
64	Subtransmission lines	0.76	78.75
65	Subtransmission cables	–	–
66	Subtransmission other	0.20	17.54
67	Distribution lines (excluding LV)	1.49	128.63
68	Distribution cables (excluding LV)	–	–
69	Distribution other (excluding LV)	0.37	24.54

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

sch ref	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
72	Subtransmission lines	25	696	3.59
73	Subtransmission cables	–	13	–
74	Subtransmission other	4		
75	Distribution lines (excluding LV)	479	3,242	14.77
76	Distribution cables (excluding LV)	–	46	–
77	Distribution other (excluding LV)	105		
78	**Total**	613		

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2022
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	Interruptions by class	Number of interruptions
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	10
12	Class C (unplanned interruptions on the network)	5
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**	15

sch ref	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	3	2

sch ref	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.12	22.26
27	Class C (unplanned interruptions on the network)	0.13	12.83
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**	0.25	35.09

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

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

sch ref	Cause	SAIFI	SAIDI
42	Lightning	–	–
43	Vegetation	–	–
44	Adverse weather	–	–
45	Adverse environment	–	–
46	Third party interference	–	–
47	Wildlife	–	–
48	Human error	–	–
49	Defective equipment	0.09	11.49
50	Cause unknown	0.03	1.34

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

sch ref	Main equipment involved	SAIFI	SAIDI
55	Subtransmission lines	–	–
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	–	–
69	Distribution cables (excluding LV)	0.05	13.00
60	Distribution other (excluding LV)	0.07	9.26

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

sch ref	Main equipment involved	SAIFI	SAIDI
64	Subtransmission lines	–	–
65	Subtransmission cables	–	–
66	Subtransmission other	–	–
67	Distribution lines (excluding LV)	–	–
68	Distribution cables (excluding LV)	0.01	0.16
69	Distribution other (excluding LV)	0.12	12.67

70 ### 10(v): Fault Rate

sch ref	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
72	Subtransmission lines	–	–	–
73	Subtransmission cables	–	6	–
74	Subtransmission other	–		
75	Distribution lines (excluding LV)	–	–	–
76	Distribution cables (excluding LV)	2	49	4.08
77	Distribution other (excluding LV)	3		
78	**Total**	5		

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 9.72% which is above the 75th percentile estimate of post-tax WACC of 4.20% and 10.02% vanilla ROI which is above the 75th percentile estimate of vanilla WACC of 4.50%. The ROI has increased this year from 4.38% to 9.72% mainly due to increase in CPI from 1.52% to 6.93%. 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 2021 closing figure of $217,607k as a starting point with inflationary indexing over the year to 31 March 2022 plus additions less disposals resulting to a $240,495k 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 $124k 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:	$ 1,102
	$ 1,102
Tax Rate:	28%
Temporary Differences	$ 309

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 27% above budget. Cost increases in materials resulting from supply shortages, commodity price increases, increased shipping costs and general inflationary pressures have led to increased capital expenditure costs.

Consumer connection:

- 36% overspent due to increased customer driven demand for subdivision reticulation.

System Growth:

- 69% overspent due to more than expected new medium voltage cabling works for load growth.

Asset replacement and renewal:

- 12% overspent mainly due to higher spending on distribution and LV lines' renewal than planned, and to a lesser extent additional spending on relay replacements and pole reinforcement but partially off-set by lower expenditure on Remote Area Power Supplies because a planned medium-sized site was found to be uneconomic.

Asset Relocations:

- Budget overspent by 671k (3,296%) due to unforeseen works relocating and undergrounding power lines for third parties.

Quality of supply:

- 33% overspent attributed to expenditure being above plan for reactive supply quality upgrades.

Other reliability, safety and environment:

- 1% or $13k higher than forecasted spend mainly on installation of substation NERs & 33kV Transformer Circuit Breakers and earth refurbishments.

Operational Expenditure:

Network opex was 11% above budget. Overall opex was 7% above budget.

Service interruptions and emergencies:

- 25% overspent due to a larger amount of distribution and technical faults than allowed for.

Vegetation management:

- Vegetation management expenditure met the budget.

Routine and corrective maintenance and inspection:

- 13% overspent due to additional routine and corrective maintenance activities.

Asset replacement and renewal:

- 36% underspent, attributed to a lower spend than planned on distribution refurbishment work resulting from inspections and reactive network chargeable maintenance.

Non-network opex:

- Expenditure within the budget.

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 year was $33.297 million. The total billed revenue for the year was $33.648 million, which is $351k (1%) 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 Lakeland Network Limited network continued to grow in Frankton and Wanaka with a 19% increase in Active Residential ICPs, however not all these ICPs were livened or consuming electricity for the whole year.

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 419.34 and normalised SAIFI at 3.16 for 2021/22.

This compares with the 2020/21 year OJV published ID Determination values for normalised SAIDI of 323.39 and normalised SAIFI of 2.66 – meaning increased SAIDI and increased average frequency of interruptions compared with last year.

The total number of power interruptions in 2021/22 on the total OJV network is significantly higher than 2020/21 – with increases for both Class B & Class C interruption. The number of Class C interruptions almost doubled compared with the previous year.

SAIFI for Class B was only slightly higher than last year, and SAIDI slightly increased. For Class C interruptions, SAIFI increased to 2.38 and SAIDI increased markedly from 133.20 to 213.28 indicating longer duration interruptions.

The highest frequency (SAIFI) cause was defective equipment, although there was a notable increase in adverse weather interruptions. Defective equipment and adverse weather were also the greatest cause of SAIDI, with duration of adverse weather interruptions increasing markedly.

The majority of interruptions occurred on distribution lines, with the fault rate per 100km of line almost doubling across the distribution network compared with the previous year. SAIDI and SAIFI for both Class B and Class C interruptions on distribution cables was lower than last year. All other equipment showed increases.

The results were reflective of interruptions occurring predominantly on the Otago sub-network. Of note, Lakeland sub-network experienced Class C interruptions for the first time in over 12 months, mostly caused by defective equipment. These interruptions occurred on distribution cables and distribution other equipment.

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.

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 $73.5 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

The opening balances for the 2021/22 year for the RAB have reduced by $8,491k while works under construction increased by $615k.

Schedule 2: Return on Investment

The opening balance for the 2021/22 year for the RIV has reduced by $8,506k.

Schedule 5a: Regulatory Tax Allowance

The opening balance for the 2021/22 year for the sum of regulatory tax asset values and deferred tax balance have reduced by $8,532k and $11k, respectively.

Due to above restatements, the following schedules in 2020/21 have been recalculated.

- Schedule 1: Analytical Ratios
- Schedule 2: Return on Investment
- Schedule 3: Regulatory Profit
- Schedule 4: RAB Value
- Schedule 5a: Regulatory Tax Allowance
- Schedule 5b: Related Party Transactions
- Schedule 5e: Asset Allocations
- Schedule 6a: Actual Expenditure Capex
- Schedule 7: Actual vs Forecast

For full details of the above adjustments, refer to the Restated 2021 Information Disclosure Schedules, which is published at the following URL.

OJV Information disclosure statements – PowerNet

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) 2020 report released in December 2020:

	2022	2023	2024	2025	2026
Inflator (CAPEX & OPEX)	1.2%	1.4%	1.8%	2.1%	2.1%

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 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 due to the manual nature of the outage reporting process, 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). There is currently no independent evidence to support the accuracy of installation control points (‘ICP’s’) affected by an interruption, impacting the completeness and accuracy of ICP data included in the SAIDI and SAIFI outage statistics.

A number of actions and initiatives are being taken to overcome limitations, including roll out and/or access to smart meter data, strengthening of processes relating to the recording of outages from the outage system, and retention of documentation.

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

A. Related Party Transaction Additional Information Disclosure

APPENDIX A:

Related Party Transactions:

Additional Information Disclosures

1. INTRODUCTION

For the purpose of meeting the 2022 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 2022 - 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 Lakeland Network Limited (LNL), formerly 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.

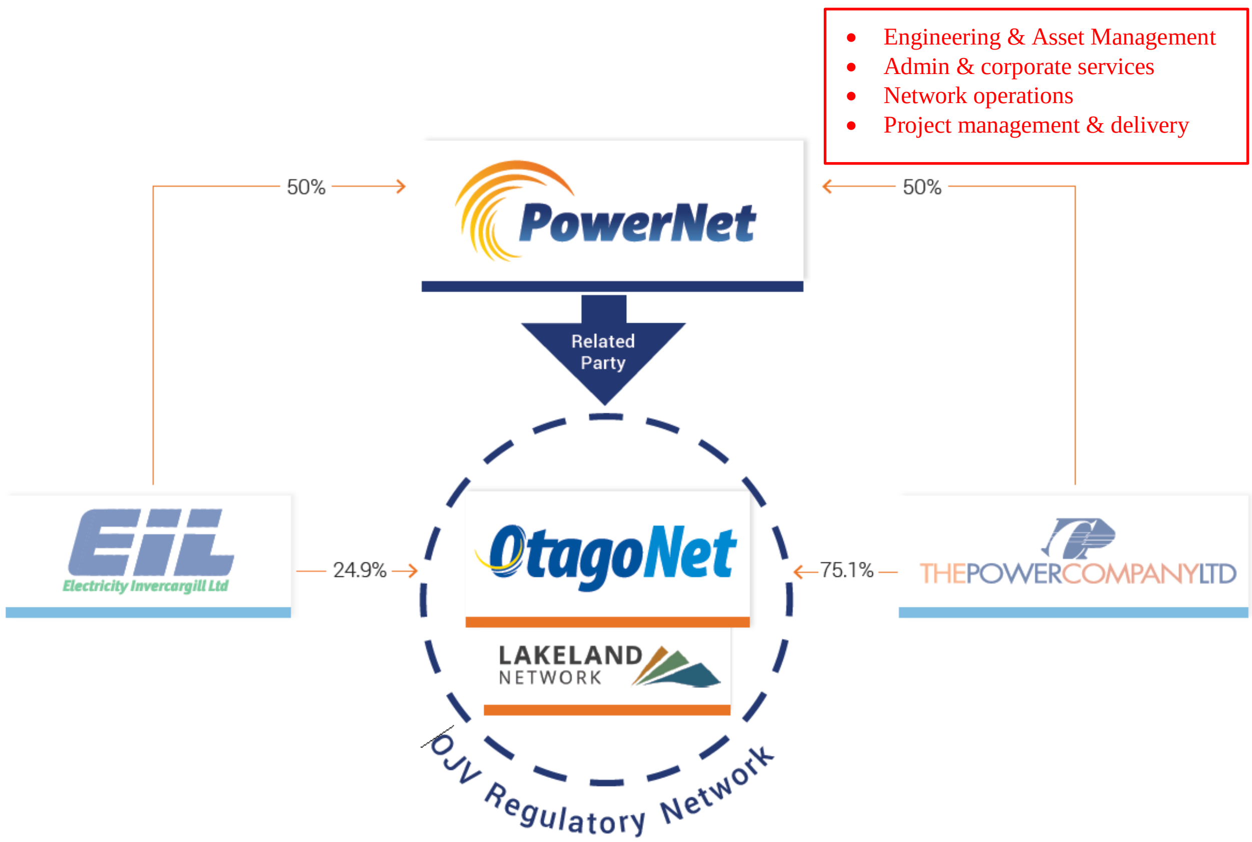
During the year ending 31 March 2022, OJV Regulated Network had related party transactions with the following entities:

- Goods and services provided by – PowerNet Limited and The Power Company 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 LNL 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 LNL). 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 2022 is categorised as follows:

		($000)
Operating Expenditure:		
i.	Service interruptions and emergencies	2,001
ii.	Vegetation management	808
iii.	Routine and corrective maintenance and inspection	2,245
iv.	Asset replacement and renewal (opex)	209
v.	System operations and network support	911
vi.	Business support	1,739
Capital Expenditure:		
vii.	Consumer connection	8,995
viii.	System growth	329
ix.	Asset replacement and renewal (capex)	7,842
x.	Asset relocations	691
xi.	Quality of supply	506
xii.	Other reliability, safety and environment	1,286
	Total Related Party expenditure from PowerNet	**27,562**

In the year to 31 March 2022, PowerNet provided 100% of the OJV and LNL Lines Business Capital Expenditure, and 90% 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 LNL, 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 LNL. The value of the related party transaction with TPCL during the year ended 31 March 2022, 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 LNL) 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 & LNL 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 LNL.

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 2018 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 LNL 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 LNL 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 LNL, the PowerNet **Procurement Policy** (including the **Procurement Strategy**), is implied as also being the procurement practices followed by OJV and LNL. 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 LNL 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 LNL network assets and project manage the replacement or development of new assets. PowerNet recovers this expenditure through charging OJV and LNL 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 LNL) 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 & LNL 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 operational expenditure (asset maintenance, replacement and/or development) required. The AMP is reviewed and approved by the OJV Governing Committee and LNL 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 & LNL 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 LNL, gives PowerNet a stronger position to negotiate more favourable competitive prices for goods and services, through the greater purchasing volumes and activity, than would otherwise be possible by OJV and LNL 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 & LNL'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.

LNL: 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 health & safety assessment) and 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 LNL's network assets are charged to OJV & LNL 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 LNL 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 & LNL 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 LNL) 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 LNL) 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 LNL, 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/individual-connection/

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 LNL 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 responsible 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/

PowerNet

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 to work closer than 4m to electric power lines or cables. Click here to complete a close approach permit form and view the close approach permit guidelines.*

Asplundh (Invercargill)

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

Delta – Quotes:

Enquiries phone 03 21516499

Ngaio Rhodes, Tree Service Administrator cell: 021 516400

ngaio.rhodes@thinkdelta.co.nz or visit THINKDELTA.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: Substation NERs and 33kV Transformer Circuit Breakers
The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for a 'Major Project' asset development.

Project Name:	Substation NERs and 33kV Transformer Circuit Breakers
Project Date:	2015 - current
Project Number:	30588
Total Project Expenditure:	$ 431,000 External labour & materials $ 149,000 PowerNet services --------------- $ 580,000 (2021/22) $2,802,000 (prior years) ---------------- $3,382, 000 Total Cost
Expenditure Classification:	Reliability, Safety and Environment
Project Manager:	PowerNet Ltd
Subcontractors:	Decom Ltd and E3 Scientific Ltd

Earthing Resistors (NERs) are being installed where necessary on zone substations to limit earth fault currents on the 11kV network. The installation of an NER reduces the fault current of 11 kV winding faults, thus reducing the level of protection provided by 33 kV transformer fuses. A 33 kV Circuit Breaker offers greater sensitivity to 11 kV winding faults particularly when used with a transformer differential protection scheme.

The installation project is ongoing and is planned for completion on 2025/26.

ID Determination 2.3.12 (5)

Market Testing: The majority of installation of substation NERs and 33kV transformer circuit breakers 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.

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 500KVA Supply in Milton

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:	March 2022
Project Number:	CC 381340 / 381339
Project Expenditure:	$ 62,000 External labour & materials $ 64,000 PowerNet services ------------ $ 126,000 Total Cost (2021/22)
Project Classification:	Consumer Connection (Capital Expenditure)
Project Manager:	PowerNet Ltd
Construction:	PowerNet - Distribution Team
Subcontractors:	N/a

PowerNet received an application for an electricity connection in Milton at a supply capacity of 500kVA.

Market Testing: The prices charged by PowerNet have been benchmarked against similar 2020-2022 Line Mechanic or Technician roles from other available external suppliers. Of the $8.2M capital expenditure spent on New Connections and Capacity Upgrades, 60% 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. <u>Distribution & Technical Projects (Asset Replacement and Renewal)</u>

Asset Replacement and Renewal projects are generally driven by internal asset condition and monitoring assessments, performed periodically by PowerNet staff on OJV and LNL 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.

<u>EXAMPLE: LV Line Replacement & Renewal</u>

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:	Kaitangata LV Line Upgrade
Completion Date:	November 2021
Project Number:	CC 375874
Project Expenditure:	\$ 49,000 External labour & materials \$ 72,000 PowerNet services -------------- \$ 121,000 Total Cost (2021/22)
Regulatory Classification:	Asset Replacement & Renewal (Capital Expenditure)
Project Manager:	PowerNet Ltd
Construction:	PowerNet - Distribution Team
Subcontractors:	Chorus Ltd

PowerNet undertook Project CC375874 to replace 400V overhead line, poles, cross arms, insulators and transformer as they were at the end of their useful life, and to improve the capacity in Summer Hill Road, Kaitangata. 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 2020-2022. 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 LNL). 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 2020-2022.

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 LNL 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.

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 Network)	External Chargeable Work
Project Name:	Trim & Fell Trees – SH1 Blue Skin Bay 11kV Lines	Trim Tree at Clinton
Project Completion Date:	November 2021	August 2021
Project Number:	387146	382751
Total Expenditure:	$6,500	$1,100
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 hazard trees within the regulatory distance of 11 kV lines during a routine Lines inspection in State Highway 1 between Waitati and Evansdale. Details of the location and work required (trees to be trim and felled) were noted on the PowerNet Cut/Trim Notice (CTN 225004).

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 tree height to be reduced to meet the 1.5 meter clearance requirement, from 11kv lines in the main road of Clinton. 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. <u>Business Services (Opex)</u>

Administration processes and systems associated with running OJV and LNL 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 LNL 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 2022-2032 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 2022-2032 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 - $20.23M

   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 - $9.78M

   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. Network Routine Inspections - Distribution - $9.42M

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

4. Technical Routine Maintenance - $5.83M

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

5. Incident Response – Technical - $1.63M

   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.

6. Network Routine Inspections - Technical - $1.62M

   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 - $1.60M

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

8. Transmission Line Minor Maintenance - $0.87M

   Generally reactive work undertaken to correct issues found on sub-transmission lines during the routine line condition survey. Also a general budget for all minor sub-transmission work.

9. Distribution Corrective Maintenance - $0.86M

   Permanent repairs carried out on faulted distribution assets that had been temporarily been made safe/functional during the initial incident response.

10. Technical Corrective Maintenance - $0.48M

   Permanent repairs carried out on faulted technical assets that had been temporarily been made safe/functional during the initial incident response.

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 -

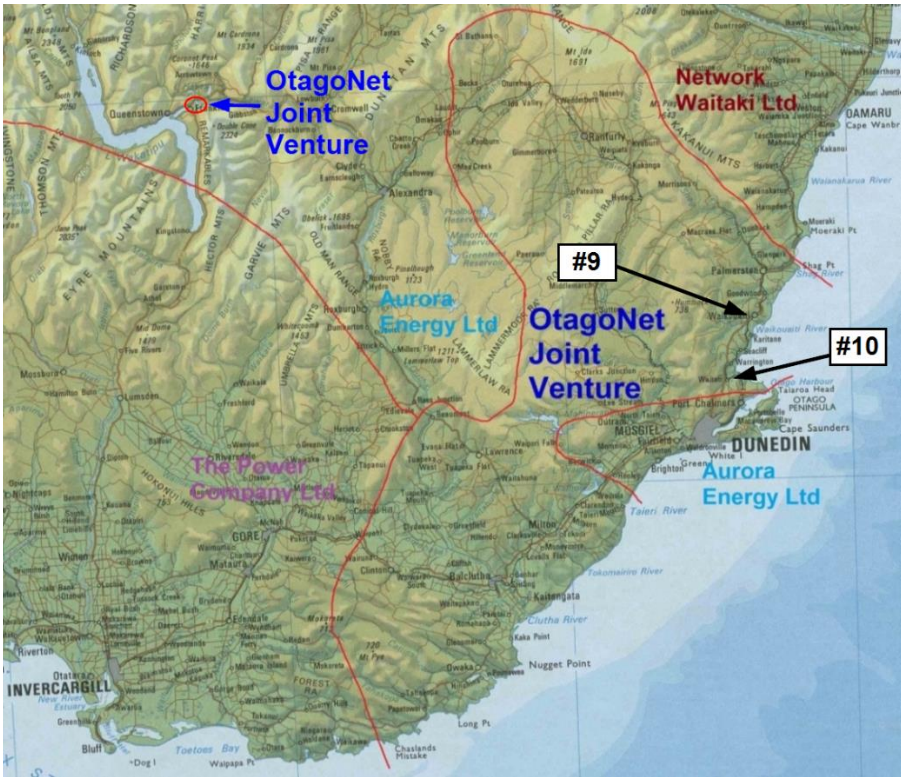
- Are network wide (apply to entire area as shown on map above).
- Have a contract in place that is with PowerNet Limited through a network management agreement (related party).
- Are forecast to require the supply of assets/goods or services by PowerNet Limited (related party).

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 2022-2032 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 - $38.15M

   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.

   $3.6M has been budgeted under Consumer Connection in the short term for projects that have relative certainty; plus an allowance of approximately $2.3M-4.3M 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 - $31.78M

   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 - $19.17M

   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 - $18.28M

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 2027-32.

5. Customer Connections (≤ 20kVA) - $8.37M

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.

6. LV Line Replacement and Renewal - $8.01M

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.

7. Unspecified System Growth Projects - $6.83M

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 2027-32.

8. <u>SWER Line Replacement and Renewal - $5.11M</u>

   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.

9. <u>Quarry Road Substation - $5.07M</u>

   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. <u>Waitati Zone Sub Relocation (Blueskin Bay) - $4.55M</u>

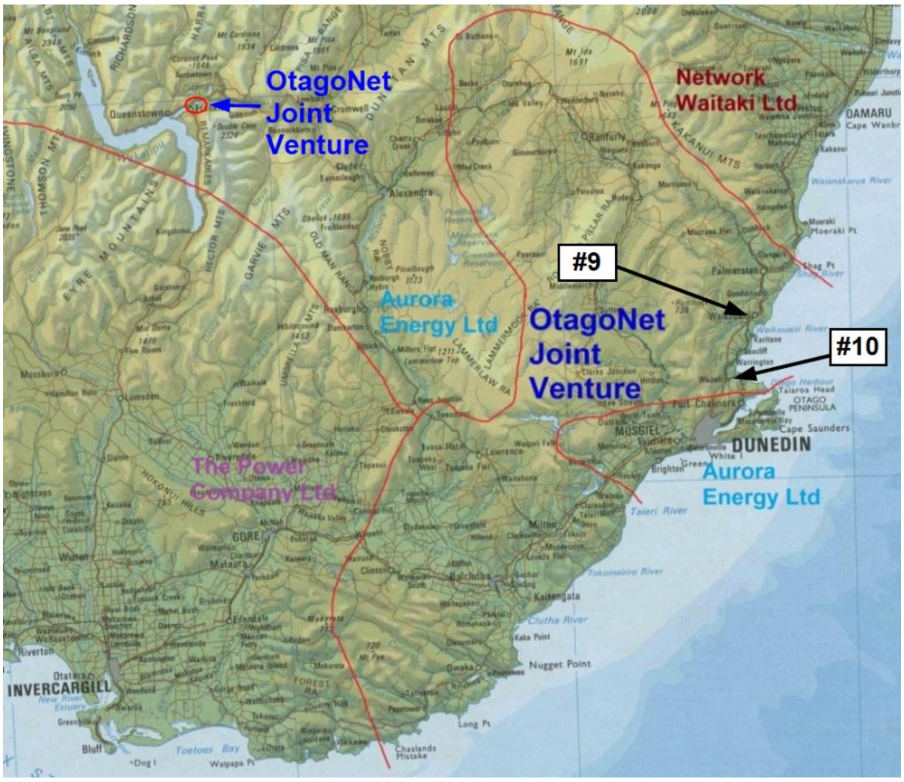
    The existing substation is flood prone and is located within a residential area. Both the transformer and switchgear are approaching end of life although at present, condition testing is not indicating that end of life is imminent. Conversion of a former 110kV line to 33kV has allowed for redundant 33kV line circuits to be provided most of the way to Waitati, but a section of single 33kV line remains. Redeveloping on a new site is the best strategic solution with the lowest future risk.

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 #9 and #10 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).

Possible future constraints related to OJV network Capital Expenditure projects:



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

7. Unspecified System Growth Projects

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

9. Quarry Road Substation

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

10. Waitati Zone Sub Relocation (Blueskin Bay)

   Constraint – Unable to maintain supply voltage due to potential load growth, timing being 6-10 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	$20.23M	Network Wide	Yes	Yes	Very likely	N/A
#2	Vegetation Management	Every year	$9.78M	Network Wide	Yes	No	Very likely	N/A
#3	Network Routine Inspections - Distribution	Every year	$9.42M	Network Wide	Yes	Yes	Very likely	N/A
#4	Technical Routine Maintenance	Every year	$5.83M	Network Wide	Yes	Yes	Very likely	N/A
#5	Incident Response - Technical	Every year	$1.63M	Network Wide	Yes	Yes	Very likely	N/A
#6	Network Routine Inspections - Technical	Every year	$1.62M	Network Wide	Yes	Yes	Very likely	N/A
#7	Distribution Routine Maintenance	Every year	$1.60M	Network Wide	Yes	Yes	Very likely	N/A
#8	Transmission Line Minor Maintenance	Every year	$0.87M	Network Wide	Yes	Yes	Very likely	N/A
#9	Distribution Corrective Maintenance	Every year	$0.86M	Network Wide	Yes	Yes	Very likely	N/A
#10	Technical Corrective Maintenance	Every year	$0.48M	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	$38.15M	Network Wide	Yes	Yes	Very likely	N/A
#2	11 kV Line Replacement and Renewal	Every year	$31.78M	Network Wide	Yes	Yes	Very likely	N/A
#3	33 kV Line Replacement and Renewal	Every year	$19.17M	Network Wide	Yes	Yes	Very likely	N/A
#4	Unspecified Replacement & Renewal Projects	2027-2032	$18.28M	Network Wide	No	N/A	Very likely	N/A
#5	Customer Connections (≤ 20kVA)	Every year	$8.37M	Network Wide	Yes	Yes	Very likely	N/A
#6	LV Line Replacement and Renewal	Every year	$8.01M	Network Wide	Yes	Yes	Very likely	N/A
#7	Unspecified System Growth Projects	2027-2032	$6.83M	Network Wide	No	N/A	Very likely	N/A
#8	SWER Line Replacement and Renewal	Every year	$5.11M	Network Wide	Yes	Yes	Very likely	N/A
#9	Quarry Road Substation	2025-29	$5.07M	#9	No	N/A	Very likely	N/A
#10	Waitati Zone Sub Relocation (Blueskin Bay)	2027-29	$4.55M	#10	No	N/A	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	#7	7-10 years
Unable to maintain supply voltage due to expected load growth	#9	7-10 years
Unable to maintain supply voltage due to potential load growth	#10	8-10 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 (Consolidated 9 December 2021)

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 (consolidated 9 December 2021) (the 'Determination') for the disclosure year ended 31 March 2022 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 1 of Schedule 15, 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. 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 user's 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 2022, 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. 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.	We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Determination and the IM Determination. Our procedures included the following: ● We verified that the restated 2021 RAB balances have been appropriately rolled forward into the Schedule 4 opening balances. **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, and to identify assets commissioned relating to the Joint Venture's commercial building business 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. **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.

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. Our procedures over Schedule 5(b) and Appendix A included the following: **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 2022 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; • 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's 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 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 2022 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 2022, 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 2022 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, as a body, 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.

Douglas William Fraser **Peter William Moynihan**

31 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.