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 2024

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 2023), issued 6 July 2023,
- The Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 2020), issued 20 May 2020.

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 2024**

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 this ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of this determination.
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

1(i): Expenditure metrics

	Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
Operational expenditure	21,134	505	138,550	2,156	41,258
Network	12,672	303	83,072	1,293	24,738
Non-network	8,462	202	55,478	863	16,520
Expenditure on assets	45,269	1,081	296,771	4,618	88,374
Network	45,269	1,081	296,771	4,618	88,374
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	71,795	1,714
Standard consumer line charge revenue	113,960	1,572
Non-standard consumer line charge revenue	14,149	952,806

1(iii): Service intensity measures

Demand density	15	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	102	*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	23,877	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	10,107	29.51%
Pass-through and recoverable costs excluding financial incentives and wash-ups	7,467	21.80%
Total depreciation	10,555	30.82%
Total revaluations	10,591	30.92%
Regulatory tax allowance	1,071	3.13%
Regulatory profit/(loss) including financial incentives and wash-ups	15,643	45.67%
Total regulatory income	34,252	

1(v): Reliability

Interruption rate	21.76	*Interruptions per 100 circuit km*

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2024**

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 this 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 this 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 22**	**31 Mar 23**	**31 Mar 24**
9	**ROI – comparable to a post tax WACC**	**%**	**%**	**%**
10	Reflecting all revenue earned	9.72%	8.16%	5.69%
11	Excluding revenue earned from financial incentives	10.34%	8.92%	6.15%
12	Excluding revenue earned from financial incentives and wash-ups	10.42%	9.00%	6.22%
13				
14	**Mid-point estimate of post tax WACC**	3.52%	4.88%	6.05%
15	25th percentile estimate	2.84%	4.20%	5.37%
16	75th percentile estimate	4.20%	5.56%	6.73%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	10.02%	8.67%	6.39%
21	Excluding revenue earned from financial incentives	10.64%	9.44%	6.85%
22	Excluding revenue earned from financial incentives and wash-ups	10.72%	9.52%	6.92%
23				
24	**WACC rate used to set regulatory price path**	4.57%	4.57%	4.57%
25				
26	**Mid-point estimate of vanilla WACC**	3.82%	5.39%	6.75%
27	25th percentile estimate	3.14%	4.71%	6.07%
28	75th percentile estimate	4.50%	6.07%	7.43%
29				

30	**2(ii): Information Supporting the ROI**			**($000)**	
31					
32		Total opening RAB value	263,617		
33	*plus*	Opening deferred tax	(23,927)		
34	**Opening RIV**			239,690	
35					
36	**Line charge revenue**			34,335	
37					
38		Expenses cash outflow	17,574		
39	*add*	Assets commissioned	22,136		
40	*less*	Asset disposals	111		
41	*add*	Tax payments	(1,208)		
42	*less*	Other regulated income	(83)		
43	**Mid-year net cash outflows**			38,474	
44					
45	**Term credit spread differential allowance**			–	
46					
47		Total closing RAB value	285,678		
48	*less*	Adjustment resulting from asset allocation	(0)		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(26,205)		
51	**Closing RIV**			259,473	
52					
53	**ROI – comparable to a vanilla WACC**				6.39%
54					
55		Leverage (%)			42%
56		Cost of debt assumption (%)			5.97%
57		Corporate tax rate (%)			28%
58					
59	**ROI – comparable to a post tax WACC**				5.69%
60					

2(iii): Information Supporting the Monthly ROI

Opening RIV	N/A

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

Tax payments	N/A
Term credit spread differential allowance	N/A
Closing RIV	N/A
Monthly ROI – comparable to a vanilla WACC	N/A
Monthly ROI – comparable to a post tax WACC	N/A

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

Year-end ROI – comparable to a vanilla WACC	6.95%
Year-end ROI – comparable to a post tax WACC	6.25%

** 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

IRIS incentive adjustment	(1,473)	
Purchased assets – avoided transmission charge	–	
Energy efficiency and demand incentive allowance		
Quality incentive adjustment	(74)	
Other financial incentives	–	
Financial incentives		(1,547)
Impact of financial incentives on ROI		–0.47%
Input methodology claw-back	–	
CPP application recoverable costs	–	
Catastrophic event allowance	–	
Capex wash-up adjustment	(235)	
Transmission asset wash-up adjustment	–	
2013–15 NPV wash-up allowance	–	
Reconsideration event allowance	–	
Other wash-ups	–	
Wash-up costs		(235)
Impact of wash-up costs on ROI		–0.07%

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2024**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref				
7		**3(i): Regulatory Profit**		**($000)**
8		**Income**		
9		Line charge revenue		34,335
10	*plus*	Gains / (losses) on asset disposals		(83)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		–
12				
13		**Total regulatory income**		34,252
14		**Expenses**		
15	*less*	Operational expenditure		10,107
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		7,467
18				
19		**Operating surplus / (deficit)**		16,678
20				
21	*less*	Total depreciation		10,555
22				
23	*plus*	Total revaluations		10,591
24				
25		**Regulatory profit / (loss) before tax**		16,714
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		1,071
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		15,643
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	192	
36		Commerce Act levies	130	
37		Industry levies	93	
38		CPP specified pass through costs	–	
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	6,965	
41		Transpower new investment contract charges	87	
42		System operator services	–	
43		Distributed generation allowance	–	
44		Extended reserves allowance	–	
45		Other recoverable costs excluding financial incentives and wash-ups	–	
46		**Pass-through and recoverable costs excluding financial incentives and wash-ups**		7,467
47				
48		**3(iv): Merger and Acquisition Expenditure**		
49				**($000)**
50		Merger and acquisition expenditure		–
51				
52		*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)*		
53		**3(v): Other Disclosures**		
54				**($000)**
55		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 this 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 31 Mar 20 ($000)	RAB 31 Mar 21 ($000)	RAB 31 Mar 22 ($000)	RAB 31 Mar 23 ($000)	RAB 31 Mar 24 ($000)
Total opening RAB value	194,442	210,599	217,607	240,495	263,617
less **Total depreciation**	7,994	8,588	8,881	9,688	10,555
plus **Total revaluations**	4,923	3,202	15,060	15,995	10,591
plus **Assets commissioned**	19,339	12,425	16,874	16,920	22,136
less **Asset disposals**	111	30	165	105	111
plus **Lost and found assets adjustment**	–	–	–	–	–
plus **Adjustment resulting from asset allocation**	–	–	–	–	(0)
Total closing RAB value	210,599	217,608	240,495	263,617	285,678

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
Total opening RAB value		263,617		263,617
less				
Total depreciation		10,555		10,555
plus				
Total revaluations		10,591		10,591
plus				
Assets commissioned (other than below)	–		–	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	22,136		22,136	
Assets commissioned		22,136		22,136
less				
Asset disposals (other than below)	111		111	
Asset disposals to a regulated supplier	–		–	
Asset disposals to a related party	–		–	
Asset disposals		111		111
plus **Lost and found assets adjustment**		–		–
plus **Adjustment resulting from asset allocation**				(0)
Total closing RAB value		285,678		285,678

** 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	1,267
CPI_4^{-4}	1,218
Revaluation rate (%)	4.02%

	Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
Total opening RAB value	263,617		263,617	
less Opening value of fully depreciated, disposed and lost assets	170		170	
Total opening RAB value subject to revaluation	263,447		263,447	
Total revaluations		10,591		10,591

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction		Allocated works under construction	
Works under construction—preceding disclosure year		7,544		7,544
plus Capital expenditure	19,787		19,787	
less Assets commissioned	22,136		22,136	
plus Adjustment resulting from asset allocation			–	
Works under construction - current disclosure year		5,195		5,195
Highest rate of capitalised finance applied				–

4(v): Regulatory Depreciation

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Depreciation - standard	10,555		10,555	
Depreciation - no standard life assets				
Depreciation - modified life assets				
Depreciation - alternative depreciation in accordance with CPP				
Total depreciation		10,555		10,555

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	32,243	3,223	38,982	118,443	20,907	26,702	16,705	5,165	1,247	263,617
less	Total depreciation	1,547	73	1,832	4,709	470	964	756	169	35	10,555
plus	Total revaluations	1,296	130	1,566	4,760	840	1,069	671	208	50	10,591
plus	Assets commissioned	939	6	3,883	3,595	8,422	1,955	2,454	881	–	22,136
less	Asset disposals	–	–	13	–	–	98	–	–	–	111
plus	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
plus	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
plus	Asset category transfers	–	–	–	–	–	–	–	–	–	–
	Total closing RAB value	32,931	3,286	42,586	122,090	29,699	28,665	19,074	6,085	1,262	285,678
	Asset Life										
	Weighted average remaining asset life	37.4	43.9	40.0	32.0	45.6	29.9	27.4	31.2	16.9	(years)
	Weighted average expected total asset life	56.4	49.4	51.0	57.6	51.1	49.9	39.0	41.2	31.5	(years)

pwc

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2024**

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 this 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**			16,714
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	1,327		
13		Amortisation of revaluations	2,256		
14					3,583
15					
16	*less*	Total revaluations	10,591		
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	43	*	
20		Notional deductible interest	5,838		
21					16,473
22					
23		**Regulatory taxable income**			3,824
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			3,824
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			1,071
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	22,560		
37	*less*	Amortisation of initial differences in asset values	1,327		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	56		
40		Closing unamortised initial differences in asset values			21,177
41					
42		Opening weighted average remaining useful life of relevant assets (years)			17
43					

5a(iv): Amortisation of Revaluations

			($000)
	Opening sum of RAB values without revaluations	213,020	
	Adjusted depreciation	8,299	
	Total depreciation	10,555	
	Amortisation of revaluations		2,256

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	(23,927)	
plus	Tax effect of adjusted depreciation	2,324	
less	Tax effect of tax depreciation	4,457	
plus	Tax effect of other temporary differences*	203	
less	Tax effect of amortisation of initial differences in asset values	372	
plus	Deferred tax balance relating to assets acquired in the disclosure year	–	
less	Deferred tax balance relating to assets disposed in the disclosure year	(23)	
plus	Deferred tax cost allocation adjustment	0	
	Closing deferred tax		(26,205)

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	101,474	
less	Tax depreciation	15,918	
plus	Regulatory tax asset value of assets commissioned	23,396	
less	Regulatory tax asset value of asset disposals	27	
plus	Lost and found assets adjustment	–	
plus	Adjustment resulting from asset allocation	–	
plus	Other adjustments to the RAB tax value	(466)	
	Closing sum of regulatory tax asset values		108,459

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2024

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

sch ref

		($000)	($000)
7	**5b(i): Summary—Related Party Transactions**		
8	**Total regulatory income**		–
9			
10	**Market value of asset disposals**		–
11			
12	Service interruptions and emergencies	2,261	
13	Vegetation management	1,323	
14	Routine and corrective maintenance and inspection	2,374	
15	Asset replacement and renewal (opex)	102	
16	**Network opex**		6,060
17	Business support	2,061	
18	System operations and network support - other	1,006	
19	Non-network solutions provided by a related party or third party (not required before DY2025)	–	
20	**Operational expenditure**		9,127
21	Consumer connection	8,113	
22	System growth	53	
23	Asset replacement and renewal (capex)	11,107	
24	Asset relocations	470	
25	Quality of supply	771	
26	Legislative and regulatory	–	
27	Other reliability, safety and environment	1,135	
28	**Expenditure on non-network assets**		–
29	**Expenditure on assets**		21,649
30	Cost of financing		–
31	Value of capital contributions		–
32	Value of vested assets		–
33	**Capital Expenditure**		21,649
34	**Total expenditure**		30,776
35			
36	**Other related party transactions**		–

37 **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)
39	The Power Company Limited	System operations and network support - other	60
40	PowerNet Limited	Service interruptions and emergencies	2,261
41	PowerNet Limited	Vegetation management	1,323
42	PowerNet Limited	Routine and corrective maintenance and inspection	2,374
43	PowerNet Limited	Asset replacement and renewal (opex)	102
44	PowerNet Limited	System operations and network support - other	946
45	PowerNet Limited	Business support	1,877
46	PowerNet Limited	Consumer connection	8,113
47	PowerNet Limited	System growth	53
48	PowerNet Limited	Asset replacement and renewal (capex)	11,107
49	PowerNet Limited	Asset relocations	470
50	PowerNet Limited	Quality of supply	771
51	PowerNet Limited	Other reliability, safety and environment	1,135
52	Directors	Business support	184
53			
54	**Total value of related party transactions**		30,776

55 ** include additional rows if needed*

Company Name	**OtagoNet Joint Venture**
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SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

5d(i): Operating Cost Allocations

	Value allocated ($000s)				
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
Service interruptions and emergencies					
Directly attributable		2,261			
Not directly attributable				–	
Total attributable to regulated service		2,261			
Vegetation management					
Directly attributable		1,323			
Not directly attributable				–	
Total attributable to regulated service		1,323			
Routine and corrective maintenance and inspection					
Directly attributable		2,374			
Not directly attributable				–	
Total attributable to regulated service		2,374			
Asset replacement and renewal					
Directly attributable		102			
Not directly attributable				–	
Total attributable to regulated service		102			
Non-network solutions provided by a related party or third party *Not required before DY2025*					
Directly attributable		–			
Not directly attributable				–	
Total attributable to regulated service		–			
System operations and network support					
Directly attributable		1,734			
Not directly attributable				–	
Total attributable to regulated service		1,734			
Business support					
Directly attributable		2,313			
Not directly attributable				–	
Total attributable to regulated service		2,313			
Operating costs directly attributable		10,107			
Operating costs not directly attributable	–	–	–	–	–
Operational expenditure		10,107			

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	415
Not directly attributable	–
Total attributable to regulated service	415
Recoverable costs	
Directly attributable	7,052
Not directly attributable	–
Total attributable to regulated service	7,052

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

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

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

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

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

pwc

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2024

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 this ID determination), and so is subject to the assurance report required by section 2.8.

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	32,931
Not directly attributable	
Total attributable to regulated service	32,931
Subtransmission cables	
Directly attributable	3,286
Not directly attributable	
Total attributable to regulated service	3,286
Zone substations	
Directly attributable	42,586
Not directly attributable	
Total attributable to regulated service	42,586
Distribution and LV lines	
Directly attributable	122,090
Not directly attributable	
Total attributable to regulated service	122,090
Distribution and LV cables	
Directly attributable	29,699
Not directly attributable	
Total attributable to regulated service	29,699
Distribution substations and transformers	
Directly attributable	28,665
Not directly attributable	
Total attributable to regulated service	28,665
Distribution switchgear	
Directly attributable	19,074
Not directly attributable	
Total attributable to regulated service	19,074
Other network assets	
Directly attributable	6,085
Not directly attributable	
Total attributable to regulated service	6,085
Non-network assets	
Directly attributable	1,262
Not directly attributable	
Total attributable to regulated service	1,262
Regulated service asset value directly attributable	285,678
Regulated service asset value not directly attributable	–
Total closing RAB value	285,678

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

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

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

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

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

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2024

SCHEDULE 5h: REPORT ON CYBERSECURITY EXPENDITURE

This schedule requires details on the cybersecurity expenditure for various categories. This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref		Target ($000)	Actual ($000)	% variance
7				
8	**5h(i): Actual Expenditure Capex (where known)**			
9				
10	Cybersecurity (Commission only)	–		
11				
12	**5h(ii): Actual Expenditure Opex (where known)**			
13				
14	Cybersecurity (Commission only)	33		
15				
16	**5h(iii): Actual vs Forecast (where known)**			
17		**Target ($000)**	**Actual ($000)**	**% variance**
18	Cybersecurity (Commission only)	33	33	–
19				
20				
21				
22				
23				

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2024**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref			($000)	($000)
7		**6a(i): Expenditure on Assets**		
8		Consumer connection		8,113
9		System growth		53
10		Asset replacement and renewal		11,107
11		Asset relocations		470
12		Reliability, safety and environment:		
13		Quality of supply	771	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	1,135	
16		**Total reliability, safety and environment**		1,906
17		**Expenditure on network assets**		21,649
18		Expenditure on non-network assets		–
19				
20		**Expenditure on assets**		21,649
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		1,862
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		19,787

			($000)
26		**6a(ii): Subcomponents of Expenditure on Assets (where known)**	
27		Energy efficiency and demand side management, reduction of energy losses	–
28		Overhead to underground conversion	–
29		Research and development	–

			($000)	($000)
31		**6a(iii): Consumer Connection**		
32		*Consumer types defined by EDB**		
33		Customer Connections < 20 kVA	1,014	
34		Customer Connections 21 - 99 kVA	425	
35		Customer Connections > 100 kVA	611	
36		New Subdivisions	6,063	
37				
38				
39		**Consumer connection expenditure**		8,113
40				
41	*less*	Capital contributions funding consumer connection expenditure	1,640	
42		**Consumer connection less capital contributions**		6,473

			System Growth ($000)	Asset Replacement and Renewal ($000)
43		**6a(iv): System Growth and Asset Replacement and Renewal**		
44				
45				
46		Subtransmission	–	935
47		Zone substations	–	2,272
48		Distribution and LV lines	53	7,039
49		Distribution and LV cables	–	93
50		Distribution substations and transformers	–	215
51		Distribution switchgear	–	324
52		Other network assets	–	229
53		**System growth and asset replacement and renewal expenditure**	53	11,107
54	*less*	Capital contributions funding system growth and asset replacement and renewal	–	19
55		**System growth and asset replacement and renewal less capital contributions**	53	11,088
56				

			($000)	($000)
57		**6a(v): Asset Relocations**		
58		*Project or programme**		
59		Milton Main Street Undergrounding	470	
60				
61				
62				
63				
64				
65		All other projects or programmes - asset relocations		
66		**Asset relocations expenditure**		470
67	*less*	Capital contributions funding asset relocations	203	
68		**Asset relocations less capital contributions**		267

69				
70	**6a(vi): Quality of Supply**			
71		*Project or programme**	($000)	($000)
72		Finegand 33kV Smart Network Automation	335	
73		Network Improvement Projects	15	
74		Mobile substation Site Made Ready	219	
75				
76				
77				
78		All other projects programmes - quality of supply	202	
79	**Quality of supply expenditure**			771
80	*less*	Capital contributions funding quality of supply	–	
81	**Quality of supply less capital contributions**			771
82	**6a(vii): Legislative and Regulatory**			
83		*Project or programme**	($000)	($000)
84			–	
85			–	
86			–	
87			–	
88			–	
89				
90		All other projects or programmes - legislative and regulatory	–	
91	**Legislative and regulatory expenditure**			–
92	*less*	Capital contributions funding legislative and regulatory	–	
93	**Legislative and regulatory less capital contributions**			–
94	**6a(viii): Other Reliability, Safety and Environment**			
95		*Project or programme**	($000)	($000)
96		Substation NER`s and 33kV Transformer Circuit Breakers	158	
97		Replacement of OH Structures with Ground Mounted	44	
98		Earth Refurbishment	741	
99				
100				
101				
102		All other projects or programmes - other reliability, safety and environment	192	
103	**Other reliability, safety and environment expenditure**			1,135
104	*less*	Capital contributions funding other reliability, safety and environment	–	
105	**Other reliability, safety and environment less capital contributions**			1,135
106				
107	**6a(ix): Non-Network Assets**			
108	**Routine expenditure**			
109		*Project or programme**	($000)	($000)
110			–	
111			–	
112			–	
113			–	
114			–	
115				
116		All other projects or programmes - routine expenditure	–	
117	**Routine expenditure**			–
118	**Atypical expenditure**			
119		*Project or programme**	($000)	($000)
120			–	
121			–	
122			–	
123			–	
124			–	
125				
126		All other projects or programmes - atypical expenditure	–	
127	**Atypical expenditure**			–
128				
129	**Expenditure on non-network assets**			–

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2024**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref			($000)	($000)
7	**6b(i): Operational Expenditure** *Required for DY2024 and DY2025 only*		($000)	($000)
8	Service interruptions and emergencies		2,261	
9	Vegetation management		1,323	
10	Routine and corrective maintenance and inspection		2,374	
11	Asset replacement and renewal		102	
12	**Network opex**			6,060
13	Non-network solutions provided by a related party or third party	*Required for DY2025 only*		
14	System operations and network support		1,734	
15	Business support		2,313	
16	**Non-network opex**			4,047
17				
18	**Operational expenditure**			10,107
19	**6b(i): Operational Expenditure** *Not Required before DY2026*		($000)	($000)
20	Service interruptions and emergencies:			
21	Vegetation-related			
22	Other			
23	**Total service interruptions and emergencies**		–	
24	Vegetation management:			
25	Assessment and notification costs			
26	Felling or trimming vegetation - in-zone			
27	Felling or trimming vegetation - out-of-zone			
28	Other			
29	**Total vegetation management**		–	
30				
31	Routine and corrective maintenance and inspection:			
32	Asset replacement and renewal			
33	**Network opex**			–
34	Non-network solutions provided by a related party or third party			
35	System operations and network support			
36	Business support			
37	**Non-network opex**			–
38				
39	**Operational expenditure**			–
40	**6b(ii): Subcomponents of Operational Expenditure (where known)**			
41	Energy efficiency and demand side management, reduction of energy losses			–
42	Direct billing*			–
43	Research and development			–
44	Insurance			287
45	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*			

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2024**

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 this 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	33,698	34,335	2%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	5,020	8,113	62%
11	System growth	693	53	(92%)
12	Asset replacement and renewal	9,246	11,107	20%
13	Asset relocations	1,839	470	(74%)
14	Reliability, safety and environment:			
15	Quality of supply	1,051	771	(27%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	881	1,135	29%
18	**Total reliability, safety and environment**	1,932	1,906	(1%)
19	**Expenditure on network assets**	18,730	21,649	16%
20	Expenditure on non-network assets	27	–	(100%)
21	Expenditure on assets	18,757	21,649	15%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	2,108	2,261	7%
24	Vegetation management	1,213	1,323	9%
25	Routine and corrective maintenance and inspection	2,242	2,374	6%
26	Asset replacement and renewal	229	102	(55%)
27	**Network opex**	5,792	6,060	5%
28	Non-network solutions provided by a related party or third party *Not Required before DY2025*		–	–
29	System operations and network support	1,993	1,734	(13%)
30	Business support	2,040	2,313	13%
31	**Non-network opex**	4,033	4,047	0%
32	**Operational expenditure**	9,825	10,107	3%
33	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
34	Energy efficiency and demand side management, reduction of energy losses	–	–	–
35	Overhead to underground conversion	–	–	–
36	Research and development	–	–	–
37				
38	**7(v): Subcomponents of Operational Expenditure (where known)**			
39	Energy efficiency and demand side management, reduction of energy losses	–	–	–
40	Direct billing	–	–	–
41	Research and development	–	–	–
42	Insurance	215	287	33%
43				

44 *1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of this determination*

45 *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 2024**
Network / Sub-Network Name	**OtagoNet Joint Venture**

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.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
1	Domestic	Standard	6,921	52,746
2	Non Domestic	Standard	3,331	53,769
4	Half Hour	Standard	110	87,213
5	Unmetered	Standard	82	149
6	Street lights	Standard	9	718
7 & 8	Low user	Standard	5,136	28,091
Non Standard	Half Hour	Non-standard	3	202,025
LLNW	Domestic	Standard	3,901	28,218
LLNW	Non Domestic	Standard	523	14,056
LLNW	Half Hour	Standard	13	11,245
		Standard consumer totals	20,026	276,205
		Non-standard consumer totals	3	202,025
		Total for all consumers	20,029	478,230

Billed quantities by price component *Not Required after DY2024*

Price component	Variable day energy sales	Variable Peak energy Sales	Variable Shoulder energy sales	Variable Night energy sales	Variable Peak energy purchases	Variable Shoulder energy purchases	Variable Night energy purchases
Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh	kWh	kWh	kWh
1					21,968,180	19,557,217	15,444,752
2					22,367,413	19,826,415	15,786,976
4	60,998,683						
5					61,991	54,948	43,753
6					298,683	264,752	210,811
7 & 8		10,845,599	9,534,738	7,711,079			
Non Standard	134,367,698						
LLNW	28,217,724						
LLNW							
LLNW							
Standard consumer totals	89,216,407	10,845,599	9,534,738	7,711,079	44,696,267	39,703,332	31,486,293
Non-standard consumer totals	134,367,698	–	–	–	–	–	–
Total for all consumers	223,584,105	10,845,599	9,534,738	7,711,079	44,696,267	39,703,332	31,486,293

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

Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Total distribution line charge revenue *Not Required after DY2024*	Total transmission line charge revenue *Not Required after DY2024*
1	Domestic	Standard	$8,649	7,963	687
2	Non Domestic	Standard	$8,291	7,421	870
4	Half Hour	Standard	$3,365	1,471	1,893
5	Unmetered	Standard	$31	27	5
6	Street lights	Standard	$120	106	14
7 & 8	Low user	Standard	$4,553	4,095	458
Non Standard	Half Hour	Non-standard	$2,858	463	2,395
Generation	Generation	Standard	$363	362	1
LLNW	Domestic	Standard	$3,971	3,681	290
LLNW	Non Domestic	Standard	$1,379	1,273	106
LLNW	Half Hour	Standard	$754	421	333
		Standard consumer totals	$31,476	$26,819	$4,657
		Non-standard consumer totals	$2,858	$463	$2,395
		Total for all consumers	$34,335	$27,283	$7,052
				Check	OK

Line charge revenues ($000) by price component *Not Required after DY2024*

Price component	Fixed	Kva	Variable day energy sales	Variable Peak energy Sales	Variable Shoulder energy sales	Variable Night energy sales	Variable Peak energy purchases
Rate (eg, $ per day, $ per kWh, etc.)	$/Day	Per/kVa	kWh	kWh	kWh	kWh	kWh
1		$3,861					$2,436
2		$3,422					$2,480
4	$2,599		$766				
5	$18						$7
6	$55						$33
7 & 8	$847			$1,910	$1,588	$208	
Non Standard	$2,858						
Generation	$363						
LLNW	$642						
LLNW	$681						
LLNW	$754						
Standard consumer totals	$5,958	$7,283	$766	$1,910	$1,588	$208	$4,956
Non-standard consumer totals	$2,858	–	–	–	–	–	–
Total for all consumers	$8,817	$7,283	$766	$1,910	$1,588	$208	$4,956

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	1

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2024**
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.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

sch ref

8(i): Billed Quantities by Price Component

Mixed Purchases & Sales Energy

Sales Energy

Billed quantities by price component — *Not Required after DY2024*

sch ref	Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Variable day energy sales	Variable Peak energy Sales	Variable Shoulder energy sales	Variable Night energy sales	Variable Peak energy purchases	Variable Shoulder energy purchases	Variable Night energy purchases
13					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh	kWh	kWh	kWh
15	1	Domestic	Standard	6,921	52,746					21,968,180	19,557,217	15,444,752
16	2	Non Domestic	Standard	3,331	53,769					22,367,413	19,826,415	15,786,976
17	4	Half Hour	Standard	110	87,213	60,998,683						
18	5	Unmetered	Standard	82	149					61,991	54,948	43,753
19	6	Street lights	Standard	9	718					298,683	264,752	210,811
20	7 & 8	Low user	Standard	5,136	28,091		10,845,599	9,534,738	7,711,079			
21	Non Standard	Half Hour	Non-standard	3	202,025	134,367,698						
22												
23												
24												
26			Standard consumer totals	15,589	222,686	60,998,683	10,845,599	9,534,738	7,711,079	44,696,267	39,703,332	31,486,293
27			Non-standard consumer totals	3	202,025	134,367,698	–	–	–	–	–	–
28			Total for all consumers	15,592	424,711	195,366,381	10,845,599	9,534,738	7,711,079	44,696,267	39,703,332	31,486,293

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

Line charge revenues ($000) by price component — *Not Required after DY2024*

sch ref	Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Total distribution line charge revenue	Total transmission line charge revenue	Fixed	Kva	Variable day energy sales	Variable Peak energy Sales	Variable Shoulder energy sales	Variable Night energy sales	Variable Peak energy purchases	Variable Shoulder energy purchases	Variable Night energy purchases
36						Rate (eg, $ per day, $ per kWh, etc.)	$/Day	Per/kVa	kWh	kWh	kWh	kWh	kWh	kWh	kWh
37					*Not Required after DY2024*	*Not Required after DY2024*									
38	1	Domestic	Standard	$8,649	7,963	687		$3,861					$2,436	$2,000	$353
39	2	Non Domestic	Standard	$8,291	7,421	870		$3,422					$2,480	$2,027	$361
40	4	Half Hour	Standard	$3,365	1,471	1,893	$2,599		$766						
41	5	Unmetered	Standard	$31	27	5	$18						$7	$6	$1
42	6	Street lights	Standard	$120	106	14	$55						$33	$27	$5
43	7 & 8	Low user	Standard	$4,553	4,095	458	$847			$1,910	$1,588	$208			
44	Non Standard	Half Hour	Non-standard	$2,858	463	2,395	$2,858								
45	Generation	Generation	Standard	$363	362	1	$363								
46				–											
47				–											
49			Standard consumer totals	$25,372	$21,445	$3,928	$3,882	$7,283	$766	$1,910	$1,588	$208	$4,956	$4,060	$720
50			Non-standard consumer totals	$2,858	$463	$2,395	$2,858	–	–	–	–	–	–	–	–
51			Total for all consumers	$28,231	$21,908	$6,323	$6,741	$7,283	$766	$1,910	$1,588	$208	$4,956	$4,060	$720

53 **8(iii): Number of ICPs directly billed** — Check: OK

54 Number of directly billed ICPs at year end: 1

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2024
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.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

sch ref

8(i): Billed Quantities by Price Component

Sales Energy as ICP Based

Sales Energy

Billed quantities by price component *Not Required after DY2024*

Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Price component: Variable energy sales					
				Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh					
LLNW	Domestic	Standard	3,120	23,331	23,331,185					
LLNW	Non Domestic	Standard	466	13,609						
LLNW	Half Hour	Standard	13	11,245						
		Standard consumer totals	3,599	48,184	23,331,185	–	–	–	–	–
		Non-standard consumer totals	–	–	–	–	–	–	–	–
		Total for all consumers	3,599	48,184	23,331,185	–	–	–	–	–

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

Line charge revenues ($000) by price component *Not Required after DY2024*

Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Total distribution line charge revenue *Not Required after DY2024*	Total transmission line charge revenue *Not Required after DY2024*	Price component: Fixed	Fixed	Variable			
					Rate (eg, $ per day, $ per kWh, etc.)	$/Day	$/kW	$/kWh			
LLNW	Residential	Standard	$3,268	2,978	290	$512		$2,756			
LLNW	General	Standard	$1,291	1,185	106	$641	$650				
LLNW	Half Hour	Standard	$754	421	333	$754					
			–								
			–								
			–								
			–								
			–								
			–								
			–								
		Standard consumer totals	$5,313	$4,584	$729	$1,907	$650	$2,756	–	–	–
		Non-standard consumer totals	–	–	–	–	–	–	–	–	–
		Total for all consumers	$5,313	$4,584	$729	$1,907	$650	$2,756	–	–	–

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

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	–
Check	OK

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2024
Network / Sub-network Name	OtagoNet Joint Venture

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

9a: Asset Register

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.	35,684	35,932	248	3
10	All	Overhead Line	Wood poles	No.	14,778	14,546	(232)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	698	698	0	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	19	19	0	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	45	–	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.	214	212	(2)	3
29	HV	Zone substation switchgear	33kV RMU	No.	1	2	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.	38	37	(1)	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	114	114	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	5	5	–	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	44	44	–	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,345	2,344	(1)	2
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	895	895	0	2
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	92	107	16	2
39	HV	Distribution Cable	Distribution UG PILC	km	4	5	1	1
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	32	32	–	3
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.	5,171	5,204	33	2
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.	107	117	10	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,067	4,030	(37)	2
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	360	364	4	3
48	HV	Distribution Transformer	Voltage regulators	No.	41	41	–	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	15	15	–	3
50	LV	LV Line	LV OH Conductor	km	465	462	(3)	1
51	LV	LV Cable	LV UG Cable	km	127	158	31	1
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	117	140	23	1
53	LV	Connections	OH/UG consumer service connections	No.	20,480	21,229	749	1
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	258	259	1	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	2	2	–	3
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	5	5	–	3
58	All	Load Control	Relays	No	–	–	–	N/A
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**OtagoNet 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

9a: Asset Register

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.	35,684	35,932	248	3
10	All	Overhead Line	Wood poles	No.	14,778	14,546	(232)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	698	698	0	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	13	13	0	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	44	44	–	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.	214	212	(2)	3
29	HV	Zone substation switchgear	33kV RMU	No.	1	2	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.	38	37	(1)	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	104	104	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	5	5	–	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	42	42	–	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,345	2,344	(1)	2
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	895	895	0	2
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	37	39	2	2
39	HV	Distribution Cable	Distribution UG PILC	km	3	4	1	1
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	32	32	–	3
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.	5,171	5,204	33	2
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	11	1	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,067	4,030	(37)	2
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	264	259	(5)	3
48	HV	Distribution Transformer	Voltage regulators	No.	41	41	–	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	15	15	–	3
50	LV	LV Line	LV OH Conductor	km	465	462	(3)	1
51	LV	LV Cable	LV UG Cable	km	47	52	5	1
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	85	87	2	1
53	LV	Connections	OH/UG consumer service connections	No.	16,271	16,405	134	1
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	248	249	1	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	3
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	5	5	–	3
58	All	Load Control	Relays	No	–	–	–	N/A
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2024**
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

9a: Asset Register

	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	–	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	50	61	11	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.	82	85	3	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	–	N/A
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	96	85	(11)	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	–	–	–	N/A
51	LV	LV Cable	LV UG Cable	km	61	83	22	2
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	32	53	21	4
53	LV	Connections	OH/UG consumer service connections	No.	3,469	3,870	401	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 2024
Network / Sub-network Name	OtagoNet Joint Venture

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

9b: Asset Age Profile

8 Disclosure Year (year ended)

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.	244	654	4,022	3,757	4,712	6,343	1,876	130	231	52	261	119	125	46	46	197	941	1,000	1,087	1,072	884	918	903	641	1,012	698	449	666	546	521	587	124	–	1,068	35,932		3
11	All	Overhead Line	Wood poles	No.	15	222	1,479	1,148	700	663	3,505	390	731	513	493	258	498	548	796	642	221	33	10	21	24	90	62	54	64	59	41	148	107	84	90	16	–	821	14,546		3
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	4	63	156	116	85	67	0	4	3	18	0	–	1	2	–	2	2	–	49	1	–	13	2	4	–	0	1	–	–	7	0	–	96	698		3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	0	–	0	–	–	–	0	1	–	–	1	–	6	–	–	–	1	–	1	0	–	–	0	8	1	–	0	–	–	0	19		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	2	10	6	5	7	–	–	–	–	–	–	–	1	2	2	–	1	–	1	–	–	2	–	–	–	–	–	–	1	–	–	5	45		3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	6	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7		3
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	10	23	15	61	29	–	1	1	9	–	5	2	3	5	–	3	2	6	–	2	3	2	–	3	4	5	2	1	8	1	–	6	212		3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	–	–	2		4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7		3
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	–	–	10	5	–	–	–	–	–	–	1	1	–	–	–	–	1	1	–	–	2	1	3	4	2	–	1	2	3	–	–	37		3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	3	5	8	39	–	1	–	–	2	6	–	2	–	11	10	–	–	9	1	–	8	2	–	–	2	–	1	4	–	–	–	114		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	1	–	–	–	–	–	–	–	2	–	–	–	–	5		3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	1	–	2	8	6	6	2	–	–	–	–	–	–	4	2	1	2	1	–	2	2	2	–	1	1	–	–	1	–	–	–	–	–	–	44		3
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2	28	126	211	248	303	334	76	93	45	42	25	51	33	61	59	67	99	50	61	78	37	46	22	18	4	5	23	14	21	15	5	–	41	2,344		2
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
38	HV	Distribution Line	SWER conductor	km	–	–	181	106	98	147	103	3	2	2	8	3	5	22	3	9	20	11	44	43	16	15	2	0	3	21	1	4	7	11	3	–	–	3	895		2
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	0	0	0	0	2	1	0	0	1	2	2	1	2	2	10	2	2	2	5	7	12	5	11	6	4	5	3	4	8	–	–	8	107		2
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	1	–	–	–	–	–	–	–	0	0	0	–	0	0	–	–	1	–	0	–	0	–	–	0	0	–	–	–	–	–	1	5		1
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	2	–	3	–	–	–	–	7	4	2	6	5	–	1	–	–	–	–	–	32		3
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.	–	22	620	668	739	509	473	25	92	87	69	61	92	102	113	111	100	108	82	83	46	71	97	61	65	87	64	89	119	127	108	19	–	95	5,204		2
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	–	–	4	–	–	–	2	–	–	1	–	1	5	3	1	–	4	8	10	10	6	12	10	8	11	9	7	5	–	–	117		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	22	613	529	532	394	437	24	76	73	52	49	77	81	96	98	76	79	58	55	36	52	79	46	48	63	40	38	61	68	64	14	–	–	4,030		2
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	1	28	7	21	4	9	5	4	3	14	11	15	13	18	9	6	14	10	16	20	21	14	12	18	10	15	19	18	8	–	1	364		3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	1	4	–	–	–	1	2	2	–	–	1	2	2	–	2	1	2	11	3	2	2	1	2	–	–	–	–	–	–	41		3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	7	–	3	–	–	–	–	–	–	–	1	–	1	1	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	15		3
51	LV	LV Line	LV OH Conductor	km	1	4	144	34	41	11	7	0	1	3	2	1	3	3	4	2	1	2	2	2	2	2	3	1	1	2	2	3	5	4	5	1	–	164	462		1
52	LV	LV Cable	LV UG Cable	km	–	–	0	1	4	3	0	0	0	0	1	2	2	1	6	2	2	1	2	1	3	8	8	11	13	13	9	12	8	16	12	–	–	17	158		1
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	0	0	1	1	–	–	–	–	–	–	–	0	0	0	–	0	0	–	1	1	6	3	4	3	2	7	7	11	10	1	–	81	140		1
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	10,864	911	106	101	482	543	514	511	438	216	139	102	107	92	113	191	332	380	447	685	612	797	709	848	732	186	–	71	21,229		1
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	7	33	30	–	4	–	–	6	4	4	4	15	10	13	3	4	12	1	11	18	6	13	22	8	4	5	13	2	–	7	259		3
56	All	SCADA and communications	SCADA and communications equipment operating as a single systen	Lot	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2		3
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	1	–	1	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	1	–	–	–	–	–	–	5		3
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2024
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

9b: Asset Age Profile

8 Disclosure Year (year ended)

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	244	654	4,022	3,757	4,712	6,343	1,876	130	231	52	261	119	125	46	46	197	941	1,000	1,087	1,072	884	918	903	641	1,012	698	449	666	546	521	587	124	–	1,068	35,932		3
11	All	Overhead Line	Wood poles	No.	15	222	1,479	1,148	700	663	3,505	390	731	513	493	258	498	548	796	642	221	33	10	21	24	90	62	54	64	59	41	148	107	84	90	16	–	821	14,546		3
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	4	63	156	116	85	67	0	4	3	18	0	–	1	2	–	2	2	–	49	1	–	13	2	4	–	0	1	–	–	7	0	–	96	698		3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	0	–	0	–	–	–	0	1	–	–	1	–	0	–	–	–	1	–	1	0	–	–	0	8	1	–	0	–	–	0	13		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	2	10	6	5	7	–	–	–	–	–	–	–	1	2	1	–	1	–	1	–	–	2	–	–	–	–	–	–	1	–	–	5	44		3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	6	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7		3
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	10	23	15	61	29	–	1	1	9	–	5	2	3	5	–	3	2	6	–	2	3	2	–	3	4	5	2	1	8	1	–	6	212		3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	–	–	2		4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7		3
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	–	–	10	5	–	–	–	–	–	–	1	1	–	–	–	–	1	1	–	–	2	1	3	4	2	–	1	2	3	–	–	37		3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	3	5	8	39	–	1	–	–	2	6	–	2	–	1	10	–	–	9	1	–	8	2	–	–	2	–	1	4	–	–	–	104		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	1	–	–	–	–	–	–	–	2	–	–	–	–	5		3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	1	–	2	8	6	6	2	–	–	–	–	–	–	4	2	1	–	1	–	2	2	2	–	1	1	–	–	1	–	–	–	–	–	–	42		3
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2	28	126	211	248	303	334	76	93	45	42	25	51	33	61	59	67	99	50	61	78	37	46	22	18	4	5	23	14	21	15	5	–	41	2,344		2
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
38	HV	Distribution Line	SWER conductor	km	–	–	181	106	98	147	103	3	2	2	8	3	5	22	3	9	20	11	44	43	16	15	2	0	3	21	1	4	7	11	3	–	–	3	895		2
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	0	0	0	0	2	1	0	0	1	2	1	1	2	2	1	1	2	2	1	3	6	1	3	0	0	3	1	1	0	–	–	1	39		2
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	1	–	–	–	–	–	–	–	–	0	0	–	–	0	–	–	1	–	0	–	0	–	–	0	–	–	–	–	–	–	1	4		1
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	2	–	3	–	–	–	–	7	4	2	6	5	–	1	–	–	–	–	–	32		3
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.	–	22	620	668	739	509	473	25	92	87	69	61	92	102	113	111	100	108	82	83	46	71	97	61	65	87	64	89	119	127	108	19	–	95	5,204		2
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	–	–	4	–	–	–	2	–	–	–	–	1	–	1	–	–	–	–	–	–	–	–	–	–	2	–	1	–	–	–	11		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	22	613	529	532	394	437	24	76	73	52	49	77	81	96	98	76	79	58	55	36	52	79	46	48	63	40	38	61	68	64	14	–	–	4,030		2
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	1	28	7	21	4	9	5	4	3	13	11	14	12	11	7	6	14	7	10	9	14	6	5	10	5	6	8	7	1	–	1	259		3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	1	4	–	–	–	1	2	2	–	–	1	2	2	–	2	1	2	11	3	2	2	1	2	–	–	–	–	–	–	41		3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	7	–	3	–	–	–	–	–	–	–	1	–	1	1	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	15		3
51	LV	LV Line	LV OH Conductor	km	1	4	144	34	41	11	7	0	1	3	2	1	3	3	4	2	1	2	2	2	2	2	3	1	1	2	2	3	5	4	5	1	–	164	462		1
52	LV	LV Cable	LV UG Cable	km	–	–	0	1	4	3	0	0	0	0	1	1	2	1	6	2	1	1	2	1	2	1	2	2	3	2	1	2	1	2	1	–	–	6	52		1
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	0	0	1	1	–	–	–	–	–	–	–	0	0	0	–	0	0	–	–	–	1	0	1	1	0	1	2	3	2	1	–	72	87		1
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	10,864	911	106	101	470	532	486	478	396	196	134	88	101	87	73	96	125	85	103	122	147	157	192	167	149	21	–	18	16,405		1
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	7	33	30	–	4	–	–	6	4	4	4	15	3	13	3	1	12	1	11	18	6	13	22	8	4	5	13	2	–	7	249		3
56	All	SCADA and communications	SCADA and communications equipment operating as a single systen	Lot	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1		3
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	1	–	1	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	1	–	–	–	–	–	–	5		3
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2024
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

9b: Asset Age Profile

8 Disclosure Year (year ended)

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
11	All	Overhead Line	Wood poles	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	6	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–	–	6		4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1		3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	10	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	10		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
38	HV	Distribution Line	SWER conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	–	–	–	–	–	–	–	–	–	–	1	0	0	–	9	1	0	–	4	4	6	4	8	5	2	2	0	2	7	–	–	6	61		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	4	11	8	4	5	6	3	3	–	–	85		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	6	7	8	4	7	6	4	4	–	–	85		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	–	–	1	7	5	9	7	8	5	5	4	11	8	–	–	10	83		2
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–	–	–	1	1	4	3	4	3	2	6	4	8	8	–	–	9	53		4
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	–	–	–	–	12	11	28	33	42	19	5	14	6	5	40	95	207	295	319	460	359	527	368	495	352	132	–	46	3,870		3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	–	3	–	–	–	–	–	–	–	–	–	–	–	–	–	–	10		3
56	All	SCADA and communications	SCADA and communications equipment operating as a single systen	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 2024**
Network / Sub-network Name	**OtagoNet Joint Venture**

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 **9c: Overhead Lines and Underground Cables**

sch ref		Overhead (km)	Underground (km)	Total circuit length (km)
11	**Circuit length by operating voltage (at year end)**			
12	> 66kV	–	–	–
13	50kV & 66kV	74	–	74
14	33kV	624	19	642
15	SWER (all SWER voltages)	885	10	895
16	22kV (other than SWER)	0	57	57
17	6.6kV to 11kV (inclusive—other than SWER)	2,344	55	2,399
18	Low voltage (< 1kV)	462	158	620
19	**Total circuit length (for supply)**	4,389	299	4,688
20				
21	Dedicated street lighting circuit length (km)	82	58	140
22	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			
23				

sch ref		Circuit length (km)	(% of total overhead length)
24	**Overhead circuit length by terrain (at year end)**		
25	Urban	329	7%
26	Rural	904	21%
27	Remote only	593	14%
28	Rugged only	1,793	41%
29	Remote and rugged	673	15%
30	Unallocated overhead lines	96	2%
31	**Total overhead length**	4,389	100%
32			

sch ref		Circuit length (km)	(% of total circuit length)
34	Length of circuit within 10km of coastline or geothermal areas (where known)	1,083	23%
35			

sch ref		Circuit length (km)	(% of total overhead length)	
37	Overhead circuit requiring vegetation management	688	16%	*Not required after DY2025*

sch ref		Total newly identified throughout the disclosure year	Total remaining at high risk at the disclosure year-end	
39	Number of overhead circuit sites at high risk from vegetation damage		–	*Not required before DY2026*
40				

41 **Breakdown of overhead circuit sites at high risk from vegetation damage at disclosure year-end**

sch ref	Category of overhead circuit site	Number of overhead circuit sites at high risk from vegetation damage at disclosure year-end	Number of overhead circuit sites involving critical assets at disclosure year-end	
43	[Single tree]			*Not required before DY2026*
44	[Single tree - Urban]			*Not required before DY2026*
45	[Single tree - Rural]			*Not required before DY2026*
46	[Row of trees]			*Not required before DY2026*
47	[Span between two poles (X metres)]			*Not required before DY2026*
48	[Other]			*Not required before DY2026*
49	**Total number of sites**	–	–	*Not required before DY2026*

50 ** Insert new rows in table above Total line as necessary*

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2024
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

9c: Overhead Lines and Underground Cables

sch ref		Overhead (km)	Underground (km)	Total circuit length (km)
10				
11	**Circuit length by operating voltage (at year end)**			
12	> 66kV	–	–	–
13	50kV & 66kV	74	–	74
14	33kV	624	13	636
15	SWER (all SWER voltages)	885	10	895
16	22kV (other than SWER)	0	0	0
17	6.6kV to 11kV (inclusive—other than SWER)	2,344	43	2,387
18	Low voltage (< 1kV)	462	52	514
19	**Total circuit length (for supply)**	4,389	118	4,507
20				
21	Dedicated street lighting circuit length (km)	82	5	87
22	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			
23				

sch ref		Circuit length (km)	(% of total overhead length)
24	**Overhead circuit length by terrain (at year end)**		
25	Urban	329	7%
26	Rural	904	21%
27	Remote only	593	14%
28	Rugged only	1,793	41%
29	Remote and rugged	673	15%
30	Unallocated overhead lines	96	2%
31	**Total overhead length**	4,389	100%
32			

sch ref		Circuit length (km)	(% of total circuit length)
33			
34	Length of circuit within 10km of coastline or geothermal areas (where known)	1,083	24%
35			

sch ref		Circuit length (km)	(% of total overhead length)	
36				
37	Overhead circuit requiring vegetation management	688	16%	*Not required after DY2025*

sch ref		Total newly identified throughout the disclosure year	Total remaining at high risk at the disclosure year-end	
38				
39	Number of overhead circuit sites at high risk from vegetation damage		–	*Not required before DY2026*
40				

41 **Breakdown of overhead circuit sites at high risk from vegetation damage at disclosure year-end**

sch ref	Category of overhead circuit site	Number of overhead circuit sites at high risk from vegetation damage at disclosure year-end	Number of overhead circuit sites involving critical assets at disclosure year-end	
42				
43	[Single tree]			*Not required before DY2026*
44	[Single tree - Urban]			*Not required before DY2026*
45	[Single tree - Rural]			*Not required before DY2026*
46	[Row of trees]			*Not required before DY2026*
47	[Span between two poles (X metres)]			*Not required before DY2026*
48	[Other]			*Not required before DY2026*
49	**Total number of sites**	–	–	*Not required before DY2026*

50 ** Insert new rows in table above Total line as necessary*

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2024**
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	**9c: Overhead Lines and Underground Cables**				
10					
11	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**	
12	> 66kV	–	–	–	
13	50kV & 66kV	–	–	–	
14	33kV	–	6	6	
15	SWER (all SWER voltages)	–	–	–	
16	22kV (other than SWER)	–	57	57	
17	6.6kV to 11kV (inclusive—other than SWER)	–	5	5	
18	Low voltage (< 1kV)	–	83	83	
19	**Total circuit length (for supply)**	–	150	150	
20					
21	Dedicated street lighting circuit length (km)			–	
22	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)				
23					
24	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**		
25	Urban	–	–		
26	Rural	–	–		
27	Remote only	–	–		
28	Rugged only	–	–		
29	Remote and rugged	–	–		
30	Unallocated overhead lines	–	–		
31	**Total overhead length**	–	–		
32					
33		**Circuit length (km)**	**(% of total circuit length)**		
34	Length of circuit within 10km of coastline or geothermal areas (where known)	–	–		
35					
36		**Circuit length (km)**	**(% of total overhead length)**		
37	Overhead circuit requiring vegetation management	–	–		*Not required after DY2025*
38		**Total newly identified throughout the disclosure year**	**Total remaining at high risk at the disclosure year-end**		
39	Number of overhead circuit sites at high risk from vegetation damage		–		*Not required before DY2026*
40					
41	**Breakdown of overhead circuit sites at high risk from vegetation damage at disclosure year-end**				
42	Category of overhead circuit site	Number of overhead circuit sites at high risk from vegetation damage at disclosure year-end	Number of overhead circuit sites involving critical assets at disclosure year-end		
43	[Single tree]				*Not required before DY2026*
44	[Single tree - Urban]				*Not required before DY2026*
45	[Single tree - Rural]				*Not required before DY2026*
46	[Row of trees]				*Not required before DY2026*
47	[Span between two poles (X metres)]				*Not required before DY2026*
48	[Other]				*Not required before DY2026*
49	**Total number of sites**	–	–		*Not required before DY2026*
50	** Insert new rows in table above Total line as necessary*				

Company Name **OtagoNet Joint Venture**
For Year Ended **31 March 2024**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref

	Location *	Average number of ICPs in disclosure year	Line charge revenue ($000)
8			
9	Lakeland Wanaka GXP NLK0111 [used Average ICP Count as per Schedule 8(i)]	653	659
10	Lakeland Clearview GXP CLV0111 [used Average ICP Count as per Schedule 8(i)]	67	50
11	Lakeland Wooing Tree GXP WRT0111 [used Average ICP Count as per Schedule 8(i)]	90	62
12	Lakeland NgaiTahu GXP NTU0111 [used Average ICP Count as per Schedule 8(i)]	28	19
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 2024**
Network / Sub-network Name	**OtagoNet Joint Venture**

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 and Decommissionings**		
9	*Number of ICPs connected during year by consumer type*		
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11	Domestic	732	
12	Half Hour	3	
13	Low User	20	
14	Non Domestic	133	
15	Streetlight	5	
16	Unmetered	2	
17	**Connections total**	895	
18			
19	*Number of ICPs decommissioned during year by consumer type*		
20	*Consumer types defined by EDB**	**Number of decommissionings**	
21	Low user	5	
22	Domestic	14	
23	Non Domestic	27	
24	Unmetered	1	
26	** include additional rows if needed*		
27	**Decommissionings total**	47	
28			
29	**Distributed generation**		
30	Number of connections made in year	98	**connections**
31	Capacity of distributed generation installed in year	0.69	**MVA**
32			
33	**9e(ii): System Demand**		
34			
35			
36	**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
37	GXP demand	64	
38	*plus* Distributed generation output at HV and above	8	
39	**Maximum coincident system demand**	72	
40	*less* Net transfers to (from) other EDBs at HV and above	(1)	
41	**Demand on system for supply to consumers' connection points**	73	
42	**Electricity volumes carried**	**Energy (GWh)**	
43	Electricity supplied from GXPs	401	
44	*less* Electricity exports to GXPs	–	
45	*plus* Electricity supplied from distributed generation	92	
46	*less* Net electricity supplied to (from) other EDBs	(5.38)	
47	**Electricity entering system for supply to consumers' connection points**	498	
48	*less* Total energy delivered to ICPs	478	
49	**Electricity losses (loss ratio)**	20	3.9%
50			
51	**Load factor**	0.78	
52	**9e(iii): Transformer Capacity**		
53		**(MVA)**	
54	Distribution transformer capacity (EDB owned)	245	
55	Distribution transformer capacity (Non-EDB owned)	9	
56	**Total distribution transformer capacity**	254	
57			
58		**(MVA)**	
59	Zone substation transformer capacity (EDB owned)	162	
60	Zone substation transformer capacity (Non-EDB owned)	–	
61	**Total zone substation transformer capacity**	162	

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2024**
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				
8	**9e(i): Consumer Connections and Decommissionings**			
9	*Number of ICPs connected during year by consumer type*			
10		*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11		Domestic	120	
12		Half Hour	3	
13		Low User	20	
14		Non Domestic	45	
15		Streetlight	5	
		Unmetered	2	
16				
17	**Connections total**		195	
18				
19	*Number of ICPs decommissioned during year by consumer type*			
20		*Consumer types defined by EDB**	**Number of decommissionings**	
21		Low user	5	
22		Domestic	9	
23		Non Domestic	16	
24		Unmetered	1	
25				
26				
27	**Decommissionings total**		31	
28				
29	**Distributed generation**			
30		Number of connections made in year	35	**connections**
31		Capacity of distributed generation installed in year	0.28	**MVA**
32				
33	**9e(ii): System Demand**			
34				
35			**Demand at time of maximum coincident demand (MW)**	
36	**Maximum coincident system demand**			
37		GXP demand	56	
38	*plus*	Distributed generation output at HV and above	8	
39	**Maximum coincident system demand**		64	
40	*less*	Net transfers to (from) other EDBs at HV and above	–	
41	**Demand on system for supply to consumers' connection points**		64	
42	**Electricity volumes carried**		**Energy (GWh)**	
43		Electricity supplied from GXPs	352	
44	*less*	Electricity exports to GXPs	–	
45	*plus*	Electricity supplied from distributed generation	91	
46	*less*	Net electricity supplied to (from) other EDBs	–	
47	**Electricity entering system for supply to consumers' connection points**		443	
48	*less*	Total energy delivered to ICPs	425	
49	**Electricity losses (loss ratio)**		18	4.0%
50				
51	**Load factor**		0.79	
52	**9e(iii): Transformer Capacity**			
53			**(MVA)**	
54		Distribution transformer capacity (EDB owned)	198	
55		Distribution transformer capacity (Non-EDB owned)	9	
56	**Total distribution transformer capacity**		207	
57				
58			**(MVA)**	
59		Zone substation transformer capacity (EDB owned)	137	
60		Zone substation transformer capacity (Non-EDB owned)	–	
61	**Total zone substation transformer capacity**		137	

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2024**
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 and Decommissionings**			
9	*Number of ICPs connected during year by consumer type*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11	Domestic		420	
12	Non Domestic		24	
13				
14				
15				
16				
17	**Connections total**		444	
18				
19	*Number of ICPs decommissioned during year by consumer type*			
20	*Consumer types defined by EDB**		**Number of decommissionings**	
21	Domestic		4	
22	Non Domestic		7	
23				
24				
25				
26				
27	**Decommissionings total**		11	
28				
29	**Distributed generation**			
30	Number of connections made in year		32	**connections**
31	Capacity of distributed generation installed in year		0.22	**MVA**
32				
33	**9e(ii): System Demand**			
34				
35				
36	**Maximum coincident system demand**		**Demand at time of maximum coincident demand (MW)**	
37	GXP demand		8	
38	Distributed generation output at HV and above	*plus*	–	
39	**Maximum coincident system demand**		8	
40	Net transfers to (from) other EDBs at HV and above	*less*	–	
41	**Demand on system for supply to consumers' connection points**		8	
42	**Electricity volumes carried**		**Energy (GWh)**	
43	Electricity supplied from GXPs		49	
44	Electricity exports to GXPs	*less*	–	
45	Electricity supplied from distributed generation	*plus*	0.42	
46	Net electricity supplied to (from) other EDBs	*less*	–	
47	**Electricity entering system for supply to consumers' connection points**		50	
48	Total energy delivered to ICPs	*less*	48	
49	**Electricity losses (loss ratio)**		1.45	2.9%
50				
51	**Load factor**		0.72	
52	**9e(iii): Transformer Capacity**			
53			**(MVA)**	
54	Distribution transformer capacity (EDB owned)		40	
55	Distribution transformer capacity (Non-EDB owned)		–	
56	**Total distribution transformer capacity**		40	
57				
58			**(MVA)**	
59	Zone substation transformer capacity (EDB owned)		25	
60	Zone substation transformer capacity (Non-EDB owned)		–	
61	**Total zone substation transformer capacity**		25	

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**OtagoNet Joint Venture**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

10(i): Interruptions

Interruptions by class	Number of interruptions
Class A (planned interruptions by Transpower)	
Class B (planned interruptions on the network)	392
Class C (unplanned interruptions on the network)	625
Class D (unplanned interruptions by Transpower)	
Class E (unplanned interruptions of EDB owned generation)	
Class F (unplanned interruptions of generation owned by others)	
Class G (unplanned interruptions caused by another disclosing entity)	2
Class H (planned interruptions caused by another disclosing entity)	1
Class I (interruptions caused by parties not included above)	
Total	1,020

Interruption restoration	≤3Hrs	>3hrs
Class C interruptions restored within	431	193

SAIFI and SAIDI by class	SAIFI	SAIDI
Class A (planned interruptions by Transpower)		
Class B (planned interruptions on the network)	1.1167	331.77
Class C (unplanned interruptions on the network)	2.3426	230.52
Class D (unplanned interruptions by Transpower)		
Class E (unplanned interruptions of EDB owned generation)		
Class F (unplanned interruptions of generation owned by others)		
Class G (unplanned interruptions caused by another disclosing entity)	0.0714	1.69
Class H (planned interruptions caused by another disclosing entity)	0.0324	3.36
Class I (interruptions caused by parties not included above)		
Total	3.5631	567.35

Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI	
Classes B & C (interruptions on the network)	3.0040	491.05	*Not required after DY2024*

Transitional SAIFI and SAIDI (previous method)	SAIFI	SAIDI
Class B (planned interruptions on the network)	1.1167	331.77
Class C (unplanned interruptions on the network)	1.9720	230.52

Where EDBs do not currently record their SAIFI and SAIDI values using the 'multi-count' approach, they shall continue to record their SAIFI and SAIDI values on the same basis that they employed as at 31 March 2023 as 'Transitional SAIFI' and 'Transitional SAIDI' values, in addition to their SAIFI and SAIDI values (Classes B & C) using the 'multi-count approach'. ***This is a transitional reporting requirement that shall be in place for the 2024, 2025, and 2026 disclosure years.***

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

Cause	SAIFI	SAIDI	
Lightning	0.0074	0.88	
Vegetation	0.3587	71.83	
Adverse weather	0.8432	73.21	
Adverse environment	0.0010	1.13	
Third party interference	0.1168	12.09	
Wildlife	0.1213	8.29	
Human error			
Defective equipment	0.4926	31.51	
Cause unknown	0.4006	31.36	*Not required after DY2024*
Other cause			*Not required before DY2025*
Unknown			*Not required before DY2025*

Breakdown of third party interference	SAIFI	SAIDI
Dig-in	0.0002	0.01
Overhead contact	0.0554	4.79
Vandalism		
Vehicle damage	0.0584	6.97
Other	0.0028	0.33

Breakdown of vegetation interruptions (vegetation cause)	SAIFI	SAIDI	
In-zone			*Not required before DY2026*
Out-of-zone			*Not required before DY2026*

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.0726	32.41
Subtransmission cables		
Subtransmission other	0.0320	6.23
Distribution lines (excluding LV)	0.9089	273.47
Distribution cables (excluding LV)		
Distribution other (excluding LV)	0.1032	19.67

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.8281	64.55
Subtransmission cables	0.1266	1.82
Subtransmission other	0.0094	0.24
Distribution lines (excluding LV)	1.1979	142.78
Distribution cables (excluding LV)	0.0116	0.89
Distribution other (excluding LV)	0.1690	20.25

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	27	698	3.87
Subtransmission cables	3	19	16.01
Subtransmission other	3		
Distribution lines (excluding LV)	345	3,229	10.68
Distribution cables (excluding LV)	5	122	4.09
Distribution other (excluding LV)	242		
Total	625		

pwc

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2024
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 this 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)	382
12	Class C (unplanned interruptions on the network)	619
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**	1,001

sch ref	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	426	192

sch ref	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)		
26	Class B (planned interruptions on the network)	1.3426	398.49
27	Class C (unplanned interruptions on the network)	2.9928	294.84
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**	4.3354	693.33

sch ref	Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI	
37	Classes B & C (interruptions on the network)	N/A	N/A	*Not required after DY2024*

sch ref	Transitional SAIFI and SAIDI (previous method)	SAIFI	SAIDI
40	Class B (planned interruptions on the network)	1.3425	398.49
41	Class C (unplanned interruptions on the network)	2.5162	294.84

43 *Where EDBs do not currently record their SAIFI and SAIDI values using the 'multi-count' approach, they shall continue to record their SAIFI and SAIDI values on the same basis that they employed as at 31 March 2023 as 'Transitional SAIFI' and 'Transitional SAIDI' values, in addition to their SAIFI and SAIDI values (Classes B & C) using the 'multi-count approach'. **This is a transitional reporting requirement that shall be in place for the 2024, 2025, and 2026 disclosure years.***

44 10(ii): Class C Interruptions and Duration by Cause

sch ref	Cause	SAIFI	SAIDI	
47	Lightning	0.0096	1.13	
48	Vegetation	0.4608	92.27	
49	Adverse weather	1.0832	94.04	
50	Adverse environment	0.0013	1.45	
51	Third party interference	0.1500	15.53	
52	Wildlife	0.1558	10.65	
53	Human error			
54	Defective equipment	0.6165	39.29	
55	Cause unknown	0.5144	40.17	*Not required after DY2024*
56	Other cause	0.0012	0.30	*Not required before DY2025*
57	Unknown			*Not required before DY2025*

sch ref	Breakdown of third party interference	SAIFI	SAIDI
60	Dig-in	0.0003	0.01
61	Overhead contact	0.0711	6.15
62	Vandalism		
63	Vehicle damage	0.0750	8.95
64	Other	0.0036	0.42

sch ref	Breakdown of vegetation interruptions (vegetation cause)	SAIFI	SAIDI	
67	In-zone			*Not required before DY2026*
68	Out-of-zone			*Not required before DY2026*

70 10(iii): Class B Interruptions and Duration by Main Equipment Involved

sch ref	Main equipment involved	SAIFI	SAIDI
73	Subtransmission lines	0.0933	41.63
74	Subtransmission cables		
75	Subtransmission other	0.0411	8.00
76	Distribution lines (excluding LV)	1.1006	328.76
77	Distribution cables (excluding LV)		
78	Distribution other (excluding LV)	0.1077	20.09

79 10(iv): Class C Interruptions and Duration by Main Equipment Involved

sch ref	Main equipment involved	SAIFI	SAIDI
82	Subtransmission lines	1.0638	82.92
83	Subtransmission cables	0.1626	2.34
84	Subtransmission other	0.0121	0.31
85	Distribution lines (excluding LV)	1.5387	183.41
86	Distribution cables (excluding LV)	0.0148	1.14
87	Distribution other (excluding LV)	0.2005	24.71

88 10(v): Fault Rate

sch ref	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
90	Subtransmission lines	27	698	3.87
91	Subtransmission cables	3	13	23.79
92	Subtransmission other	3		
93	Distribution lines (excluding LV)	345	3,229	10.68
94	Distribution cables (excluding LV)	4	53	7.49
95	Distribution other (excluding LV)	237		
96	**Total**	619		

Company Name	Otago Joint Venture
For Year Ended	31 March 2024
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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

10(i): Interruptions

Interruptions by class	Number of interruptions
Class A (planned interruptions by Transpower)	
Class B (planned interruptions on the network)	4
Class C (unplanned interruptions on the network)	6
Class D (unplanned interruptions by Transpower)	
Class E (unplanned interruptions of EDB owned generation)	
Class F (unplanned interruptions of generation owned by others)	
Class G (unplanned interruptions caused by another disclosing entity)	
Class H (planned interruptions caused by another disclosing entity)	
Class I (interruptions caused by parties not included above)	
Total	10

Interruption restoration	≤3Hrs	>3hrs
Class C interruptions restored within	5	1

SAIFI and SAIDI by class	SAIFI	SAIDI
Class A (planned interruptions by Transpower)		
Class B (planned interruptions on the network)	0.1086	22.00
Class C (unplanned interruptions on the network)	0.0711	5.55
Class D (unplanned interruptions by Transpower)		
Class E (unplanned interruptions of EDB owned generation)		
Class F (unplanned interruptions of generation owned by others)		
Class G (unplanned interruptions caused by another disclosing entity)		
Class H (planned interruptions caused by another disclosing entity)		
Class I (interruptions caused by parties not included above)		
Total	0.1797	27.54

Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI	
Classes B & C (interruptions on the network)	N/A	N/A	*Not required after DY2024*

Transitional SAIFI and SAIDI (previous method)	SAIFI	SAIDI
Class B (planned interruptions on the network)	0.1086	22.00
Class C (unplanned interruptions on the network)	0.0711	5.55

*Where EDBs do not currently record their SAIFI and SAIDI values using the 'multi-count' approach, they shall continue to record their SAIFI and SAIDI values on the same basis that they employed as at 31 March 2023 as 'Transitional SAIFI' and 'Transitional SAIDI' values, in addition to their SAIFI and SAIDI values (Classes B & C) using the 'multi-count approach'. **This is a transitional reporting requirement that shall be in place for the 2024, 2025, and 2026 disclosure years.***

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

Cause	SAIFI	SAIDI	
Lightning			
Vegetation			
Adverse weather			
Adverse environment			
Third party interference			
Wildlife			
Human error			
Defective equipment	0.0703	5.10	
Cause unknown	0.0008	0.45	*Not required after DY2024*
Other cause			*Not required before DY2025*
Unknown			*Not required before DY2025*

Breakdown of third party interference	SAIFI	SAIDI
Dig-in		
Overhead contact		
Vandalism		
Vehicle damage		
Other		

Breakdown of vegetation interruptions (vegetation cause)	SAIFI	SAIDI	
In-zone			*Not required before DY2026*
Out-of-zone			*Not required before DY2026*

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines		
Subtransmission cables		
Subtransmission other		
Distribution lines (excluding LV)	0.0475	17.78
Distribution cables (excluding LV)		
Distribution other (excluding LV)	0.0611	4.22

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines		
Subtransmission cables		
Subtransmission other		
Distribution lines (excluding LV)		
Distribution cables (excluding LV)	0.0003	0.02
Distribution other (excluding LV)	0.0708	5.53

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	0	0	–
Subtransmission cables	0	6	–
Subtransmission other	0		
Distribution lines (excluding LV)	0	0	–
Distribution cables (excluding LV)	1	62	1.61
Distribution other (excluding LV)	5		
Total	6		

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 5.69% which is under the 75th percentile estimate of post-tax WACC of 6.73%. OtagoNet also achieved a 6.39% vanilla ROI which is under the 75th percentile estimate of vanilla WACC of 7.43%.

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 2023 closing figure of $263,617k as a starting point with inflationary indexing over the year to 31 March 2024 plus additions less disposals resulting to a $285,678k 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 $43k 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:	$ 1,191
	$ 1,191
Tax Rate:	28%
Temporary Differences	$ 333

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

OtagoNet costs are directly attributable as all costs were 100% electricity distribution business.

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's 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 have been no material items atypical of expenditure incurred during the year and none 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 16% above budget. Cost increases in materials resulting from supply shortages, commodity price increases, increased shipping costs and general inflationary pressures have led to increased expenditure costs.

Consumer connection:

- 62% overspent due to high levels of customer driven demand for subdivision reticulation, and increased activity in new house connections.

System Growth:

- 92% underspent due to Lakeland Frankton sub-network. Kawarau South Bank Cable project scoping delay, and District Council delays affecting the Frankton Road 22kV extension project.

Asset replacement and renewal:

- 20% overspent largely due to Otago sub-network. Expenditure on LV Lines higher in urban areas and additional work on SWER lines and 11kV feeder refurbishment work derived from inspection data. Increasing cost for materials, traffic management and costs for night shutdowns were also factors in the overspend.

Asset Relocations:

- 74% underspent due to Otago sub-network. Planned Milton undergrounding works delayed by projects initiator.

Quality of supply:

- 27% underspent due to Otago sub-network. Finegand 33kV project work delayed until 2025/2026 year.

Reliability, Safety & Environment

- 29% overspent due to Otago sub-network. Stirling NER and arc flash protection installation work plus the provision of generation during associated outages costing more than expected.

Operational Expenditure:

Total operating expenditure was 3% above budget.

Service interruptions and emergencies:

- 7% overspent due to technical faults being ahead of budget (substation, SCADA & load control faults in Otago sub-network. Winter load related customer faults and transformer fuse failures in Lakeland Frankton sub-network.

Routine and corrective maintenance and inspection:

- 6% overspent due to Otago sub-network. Mainly due to Merton T1 oil leak repair, Danone Dairy Factory 1600A fuseway replacement, Owaka CB22 BSI hot spot repair and Greenfield T4 33kV cable repair projects. There was also additional costs temporary disconnecting customers, minor maintenance, and removals of customer ICP's.

Asset replacement and renewal:

- 55% underspent on both the Otago sub-network and Lakeland Frankton sub-network. Less minor refurbishment, replacement and renewal work was required.

Vegetation management:

- 9% overspent due to Otago sub-network. More arborist work completed than budgeted.

Non-network opex:

- Expenditure as budgeted.

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 $33k per 2023-2024 Line Pricing method. The total billed revenue for the year was $34k, which is $637k over.

The increase in revenue is attributable to the higher chargeable volumes than forecast in the Otago sub-network (Mass Market consumption exceeding budget). The Lakeland Frankton sub-network continued to grow with an 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

OtagoNet has calculated and disclosed SAIDI and SAIFI metrics consistent with the 2012 Electricity Distribution Business (EDB) ID Determination, incorporating all amendments up to 29 February 2024.

SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) are consumer-focused measures of average outage duration and frequency. SAIDI is calculated using the duration of each interruption stage and the number of consumers affected. SAIFI is now calculated using the 'multi-count' methodology, which counts successive interruptions within a main outage.

In previous years, OtagoNet did not include successive interruptions after the initial interruption when calculating SAIFI. For continuity, this calculation method is recorded in Schedule 10, reference rows 39-41 (Transitional SAIFI and SAIDI – previous method). Only these and the normalised SAIFI figures are comparable to previous disclosures.

For the 2023/24 disclosure year, OtagoNet has reported a normalised SAIDI of 491.05 and a normalised SAIFI of 3.0040. These figures represent increases of 7.8% and 3.9%, respectively, compared to the 2022/23 year. OtagoNet's ID Determination values for the 2022/23 disclosure year were 455.33 for normalised SAIDI and 2.8920 for normalised SAIFI.

The total number of power interruptions for OtagoNet increased to 1020 in the 2023/24 disclosure year, up 5.3% from 969 in 2022/23.

Class C (unplanned) SAIFI was 2.3426, accounting for 66% of the overall SAIFI. Class C SAIDI was 10% lower, while Class B (planned) SAIDI was 32% higher than in 2022/23.

As in the previous disclosure year 2022/23, the most significant causes of Class C interruptions were adverse weather and vegetation. The level of Class C SAIDI attributed to defective equipment fell by nearly 50%.

Eighty percent of OtagoNet's network comprises overhead distribution lines, with 82% of planned interruptions and 62% of unplanned interruptions occurring on these lines. Subtransmission lines contributed over 28% of unplanned interruptions (based on SAIDI), representing a sevenfold increase from the previous year.

Fault rates per 100 km of circuit improved for both distribution lines and cables, decreasing by 15% and 21%, respectively. However, the fault rate on subtransmission lines increased by 8% to 3.87 faults per 100 km of circuit. While there were no subtransmission cable faults last year, three were recorded this year.

These results predominantly reflect interruptions on the Otago sub-network. The Lakeland Frankton sub-network experienced six Class C interruptions this year, mostly caused by defective distribution equipment.

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 regarding 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 $142.2 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
No amendments were disclosed.

SCHEDULE 14A MANDATORY EXPLANATORY NOTES ON FORECAST INFORMATION

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10-year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

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

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

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the 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) report released in December 2022:

	2023/24	2024/25	2025/26	2026/27	2027/28
Inflator (CAPEX & OPEX)	6.9%	4.5%	2.8%	2.2%	2.0%

In addition to the general inflation, material costs have increased by a weighted average of 5.2% in 2022 and labour and external services costs have increased by 6.5%. These increases are included in the CAPEX forecasts for 2023 onwards.

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

SCHEDULE 15 VOLUNTARY EXPLANATORY NOTES

5. This Schedule enable EDBs to provide, should they wish to-

    5.1 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;

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

6. 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.

7. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Schedule 5a(vi) and 5a(viii)
In March 2024, the New Zealand Government enacted the Taxation (Annual Rates for 2023/24, Multinational Tax and Remedial Matters) Bill. As a result, from the 2024/25 income tax year onwards, OtagoNet can no longer claim any tax depreciation on their buildings with estimated useful lives of 50 years or more in New Zealand. OtagoNet assessed the impact of this change in regulatory assets, which resulted in the removal of buildings from the tax asset register amounting to $466,000. An associated increased deferred tax liability of $130,000 was also recognised during the year.

Schedule 5f – 5g (Cost and Asset Allocation Support)
Disclosure was made on Cybersecurity Expenditure only.

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 OtagoNet 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.

Several 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.

4. APPENDICES

APPENDIX A:

Related Party Transactions:

Additional Information Disclosures

1. INTRODUCTION

For the purpose of meeting the 2024 Related Party Transaction reporting requirements, in accordance with section 2.3.6 of the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC 2, the following information is provided in support of:

- **OtagoNet Joint Venture's Information Disclosure**, for the year ended 31 March 2024 - 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 its respective wholly owned subsidiary companies Pylon Limited and Last Tango Limited.

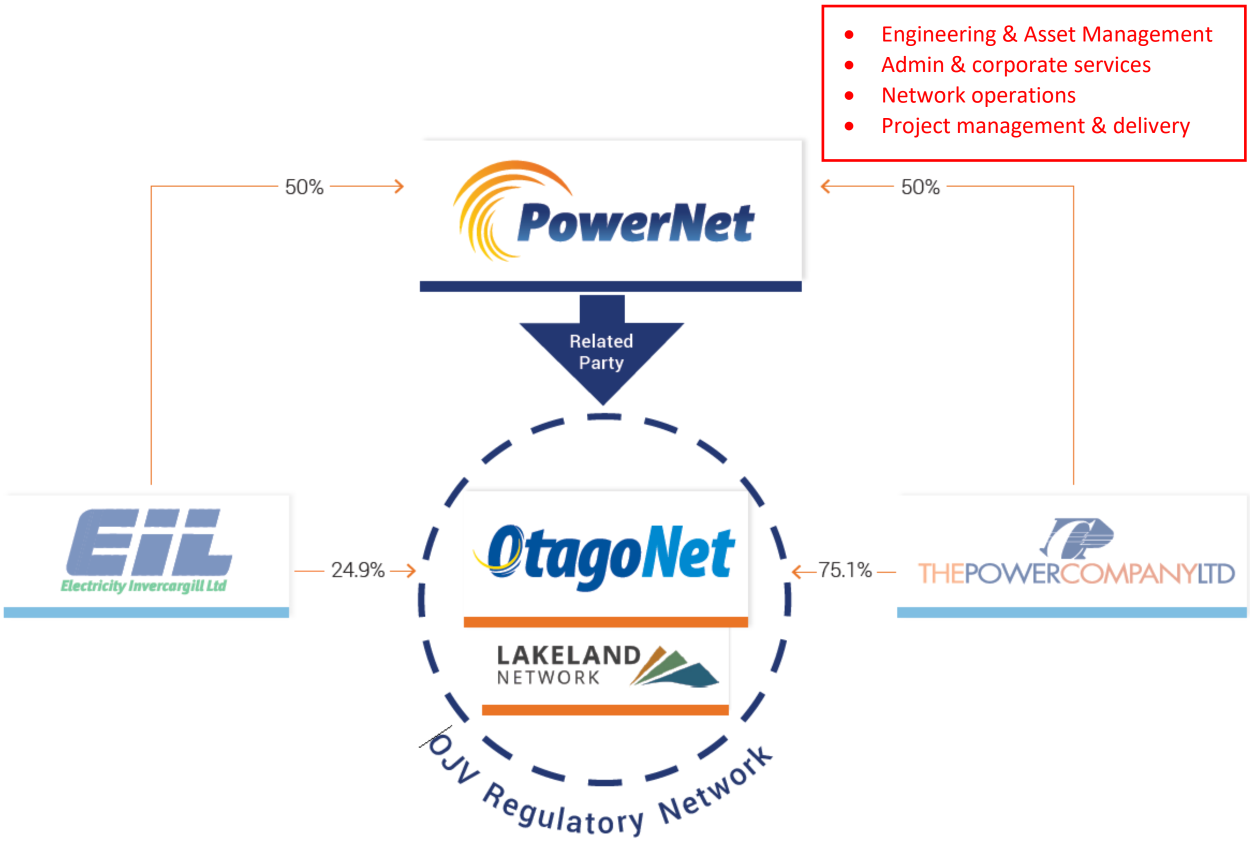
During the year ending 31 March 2024, OJV Regulated Network had related party transactions with the following entities:

- Goods and services provided by – PowerNet and TPCL
- Directors services were provided by – EIL and TPCL

Ownership Structure

The parties to the OJV 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 , 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 2024 is categorised as follows:

		($000)
Operating Expenditure:		
i.	Service interruptions and emergencies	2,261
ii.	Vegetation management	1,323
iii.	Routine and corrective maintenance and inspection	2,374
iv.	Asset replacement and renewal (opex)	102
v.	System operations and network support	947
vi.	Business support	1,877
Capital Expenditure:		
vii.	Consumer connection	8,113
viii.	System growth	53
ix.	Asset replacement and renewal (capex)	11,107
x.	Asset relocations	470
xi.	Quality of supply	770
xii.	Other reliability, safety and environment	1,135
	Total Related Party expenditure from PowerNet	**30,532**

In the year to 31 March 2024, PowerNet provided 100% of the OJV and LNL Lines Business Capital Expenditure, and 88% of all Operating Expenditure. The high percentage of related party transactions relative to total expenditure is due to PowerNet operating under a Management Agreement (MA) with OJV and LNL.

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 the EDB and meter business
- Health, 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 OJV and LNL. The value of the related party transaction with TPCL during the year ended 31 March 2024, 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**

c. Directors Fees

In the year to 31 March 2024, OJV paid Directors Fees which represented 2% of all Operating Expenditure.

	($'000)
Operating Expenditure:	
Directors Fees	184
Total Related Party expenditure to Directors by OJV	**184**

The directors are appointed by the shareholder Southland Electric Power Supply Consumer Trust (SEPSCT). Fees are set on an annual basis and are bulk funded as agreed between the SEPSCT Trustees and the OJV Board members. A report from independent consultants was obtained in relation to director's fees and this information was used when setting the directors fees. TPCL was on-charged directors fees of $147,000 and EIL was on-charged $37,000.

Management Agreement ('MA')

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

While OJV and LNL own the Network distribution assets and provide electricity distribution services through their respective electricity networks in the Clutha, Waitaki, 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 provides Line Function Services and 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 drivers 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 acknowledged 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 a Management Fee to the EDB's and metering businesses it manages under the MA'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 PowerNet 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 management 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 2022 of the allocation methodology ensured all parties that are charged management and other fees by PowerNet, are treated consistently and appropriately for each party. No changes have been made to the methodology since 2022.

4. PROCUREMENT POLICY

ID Determination 2.3.10 and 2.3.11

Under the Management Agreement (MA), 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.

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 a management 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 and 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 and 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 and 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 and LNL's Works Programme projects completed in a timely manner, to the required standard, by securing 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 and 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 and safety standards of PowerNet, and there are specific controls to check new applicants, to make sure they have completed the requirements (e.g. PreQual health and 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 and LNL respectively each month. Agreed charges are included within the Management Agreement, including the application of unit rate pricing and monthly progress invoices in relation to the Annual Works Programme project activity expenditure. Unit Rate pricing was introduced in April 2023 for PowerNet labour and plant resources charged on network project activity. The unit rates are based on standard usage of time and resources for particular tasks. An important aspect of the transition has been monitoring the unit rate progress carefully to ensure the rates are set appropriately.

Industry expertise was utilised in establishing the unit rates, which are reviewed quarterly with approved adjustments made if required. Otherwise the unit rates are approved annually by each network during the annual business planning process. In return for the management of the network assets and related business support costs, PowerNet charges OJV and LNL a management 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 and 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 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 time period 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 provides 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 roadside 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 roadsides 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 is 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 Management Agreement. The PowerNet approved arborist contractor Asplundh, 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 to engage a PowerNet approved contractor.

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 (Asset Replacement and Renewal)**
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: Port Molyneux Substation Upgrade
The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for a 'Major Project' asset development.

Project Name:	Port Molyneux Substation Outdoor to Indoor Upgrade
Project Date:	2022 - 2024
Project Number:	30959
Total Project Expenditure:	$1,476,000 External labour and materials $ 586,000 PowerNet services -------------- $2,062,000 Total Cost (2023/24) $ 549,000 Total Cost (2022/23) -------------- $2,611,000 Total Project Cost
Expenditure Classification:	Asset Replacement and Renewal
Project Manager:	PowerNet Limited
Subcontractors:	Energetick Limited, Decom Limited

The Port Molyneux substation is located near the coast at Kaka Point. The 33kV and 11kV outdoor structures were assessed as being near end of life and were difficult to access for maintenance. The coastal location increases the vulnerability of the outdoor structure and switchgear to corrosion and salt pollution. This project will replace the 33kV and 11kV outdoor structures with indoor switchgear.

This project was completed in 2024.

ID Determination 2.3.12 (5)

Market Testing: The majority of this substation upgrade project activity was outsourced by PowerNet. The rates provided by the external contractors were consistent with recent tender prices. The materials sourced through the 2022 Corys Electrical supply agreement included a range of contractual mechanisms to ensure efficient prices were being provided to PowerNet. The PowerNet project management and internal labour cost was benchmarked to local market rates. Where a unit rate pricing has been applied for internal labour and plant utilisation on a project, comparison is made to the actual time and resources incurred to make sure there are no material variances.

i. **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 300KVA Supply in Ranfurly

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

Project Name:	Customer Connection (OJV Works programme)
Completion Date:	February 2024
Project Number:	CC 466598 / 466603
Project Expenditure:	$ 47,951 External labour and materials $ 17,358 PowerNet services ------------- $ 65,309 Total Cost (2023/24)
Project Classification:	Consumer Connection (Capital Expenditure)
Project Manager:	PowerNet Limited
Construction:	PowerNet - Distribution Team
Subcontractors:	Hazlett and Sons (civil works)

PowerNet received an application for an electricity connection in Ranfurly at a supply capacity of 300kVA.

Market Testing: The prices charged by PowerNet have been benchmarked against similar 2022-2024 Line Mechanic or Technician roles from other available external suppliers. Of the $8.1M capital expenditure spent on New Connections and Capacity Upgrades, 57% 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. Where a unit rate pricing has been applied for internal labour and plant utilisation on a project, comparison is made to the actual time and resources incurred to make sure there are no material variances.

i. **Distribution and Technical Projects (Asset Replacement and Renewal)**

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

EXAMPLE: 11kV Line Replacement and Renewal

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

Project Name:	Pole and Conductor replacement Falla Burn Road
Completion Date:	Jan 2024
Project Number:	CC 468011
Project Expenditure:	\$ 26,000 External labour and materials \$ 66,000 PowerNet services ------------- \$ 92,000 Total Cost (2023/24)
Regulatory Classification:	Asset Replacement and Renewal (Capital Expenditure)
Project Manager:	PowerNet Limited
Construction:	PowerNet - Distribution Team
Subcontractors:	Blackhead Quarries Limited (civil works)

PowerNet undertook Project CC 468011 to replace 11kV poles and conductors along part of Falla Burn Road, inland from Milton, near the end of their useful life. This work is identified through PowerNet inspection and testing programmes to identify assets 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 2022-2024. The materials sourced through Corys Electrical supply agreement includes a range of contractual mechanisms to ensure efficient prices are being provided to PowerNet. Where a unit rate pricing has been applied for internal labour and plant utilisation on a project, comparison is made to the actual time and resources incurred to make sure there are no material variances.

ii. **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 Mechanic and Technical crews are based in depots located across the Southland and Otago regions for quick response to fault callouts 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 2022-2024.

ii. 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 contracts Asplundh an external vegetation management contractor. Inspectors identify hazards, liaise with landowners and issue Cut/Trim notices to the landowner as required. 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 to engage a PowerNet approved contractor. This ensures the costs involved are at current market rates.

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)
Project Name:	Blue Mountain project vegetation clearance
Project Completion Date:	November 2023
Project Number:	469915
Total Expenditure:	$25,877
Regulatory Classification:	Vegetation Management (Operating Expenditure)
Project Manager:	PowerNet Limited
Subcontractors:	Asplundh

Chargeable to OJV Network

Vegetation clearance was required to reestablish access to power poles on the Blue Mountains SWER line, prior to the line being refurbished.

Market Testing: While PowerNet manages vegetation control work across OJV network, this work is outsourced to external contractors under a preferred supplier agreement, with set prices for different components of work undertaken. These prices are reviewed and agreed periodically by PowerNet and are benchmarked where possible.

iii. Business Services (Opex)

Administration processes and systems associated with running OJV and LNL networks are managed by PowerNet support service teams (eg. Network Assets, Operations, Finance, HSE). A share of these costs are charged to OJV by way of a Management fee, which would otherwise be directly incurred by OJV, if there was no 'MA in place with PowerNet.

Market Testing: Market testing the provision of business services is very difficult due to the lack of comparable data being 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 2022 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 2024-2034 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 2024-2034 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 - $19.97M

   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. Distribution Routine Inspections - $11.12M

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

3. Vegetation Management - $11.05M

   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.

4. Technical Routine Maintenance - $10.11M

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

5. Technical Routine Inspections - $3.51M

   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.

6. Technical Corrective Maintenance - $2.56M

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

7. Distribution Routine Maintenance - $2.19M

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

8. Incident Response – Technical - $2.12M

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

9. Distribution Corrective Maintenance - $1.02M

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

10. Transmission Line Minor Maintenance - $1.00M

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

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

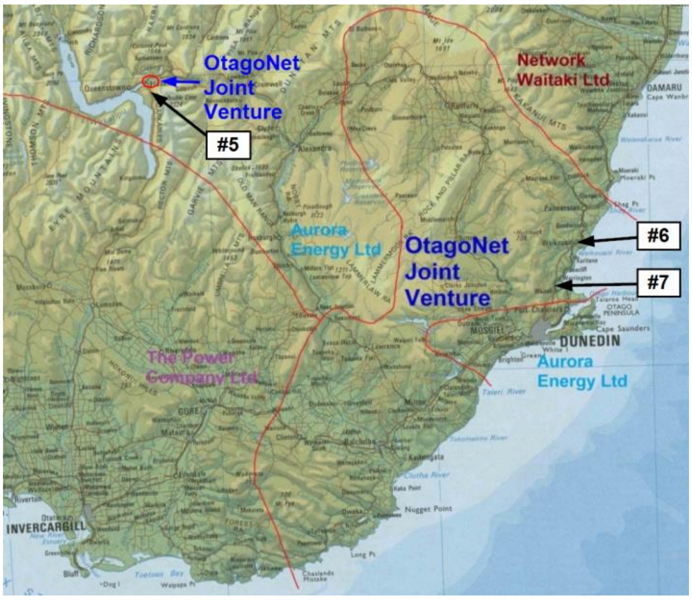
Please Note: All of these projects -
- Are network wide (apply to entire area as shown on map above).
- Have a contract in place that is with PowerNet through a management agreement (related party).
- Are forecast to require the supply of assets/goods or services by PowerNet (related party).

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 2024-2034 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 - $49.46M

   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 $3.7M - $5.0M 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 - $37.09M

   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 and dropout fuses. This budget also covers red tagged pole replacement, increasing road crossing height, minor distribution renewals and upgrades.

3. 33 kV Line Replacement and Renewal - $21.06M

   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. Reliability and Resilience Projects - $20.00M

   In electricity networks, reliability primarily focuses on the prevention of power outages and the consistent delivery of electricity, emphasising the quality and stability of service. Resilience focuses on the network's ability to recover and adapt to disruptions, ensuring that power can be restored quickly after incidents or adverse events. Both reliability and resilience are critical for maintaining a dependable and secure electricity distribution network, and they often go hand in hand to provide a high level of service to customers, especially in the face of changing climate conditions and other external challenges.

This provision is for reliability and resilience projects that are yet to be identified and are expected to be implemented in 2030-34.

5. Southern Corridor Zone Substation - $14.48M

   Rapid growth in the Wakitipu Basin area indicates that a new zone substation will be required in the long term to provide capacity and diversity.

   Establishing a new zone substation will provide for future growth and enhance supply security. The project's planned completion date is 2029/30.

6. Quarry Road Substation - $12.33M

   The present Merton substation feeding the Waikouaiti area has peak demand above the n-1 capacity of the transformers, and the 11kV and 33kV structures have deteriorating wooden poles and components.

   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 substation is beside SH1 to the south of Waikouaiti, its major load centre, meaning there is only one line route to the main loads.

   A new site has been secured in Quarry Road close to Waikouaiti. The new substation will be connected to the 110kV lines purchased from Transpower, now converted to 33kV, that run past the site. Connecting the new substation to these 33kV lines will improve security of supply and reduce losses with a more direct supply than the existing configuration.

   The Quarry Road substation completion is planned for 2026/27, with reconfiguration of a 33kV line to a fourth Quarry Road 11kV feeder to be completed in 2029/30 following completion of the Blueskin Bay substation project.

7. Blueskin Bay Substation - $11.77M

   The existing Waitati substation is flood prone and is located within a residential area. Both the transformer and switchgear are approaching end of life. There is modest load growth in the Waitati area, and the present 33kV supply arrangement from Halfway Bush via Palmerston is near to being voltage constrained during peak loads.

   A new site has been secured in Manse Road close to Waitati and with proximity to the two 33kV lines from Halfway Bush. Connecting the new substation to both 33kV lines will improve security of supply and reduce losses with a more direct supply than the existing configuration.

   The Blueskin Bay substation completion is planned for 2028/29 with removal of a redundant 33kV line the following year.

8. Unspecified Replacement and Renewal Projects - $10.17M

   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 2031-34.

9. Customer Connections (≤ 20kVA) - $9.79M

   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.

10. LV Line Replacement and Renewal - $9.04M

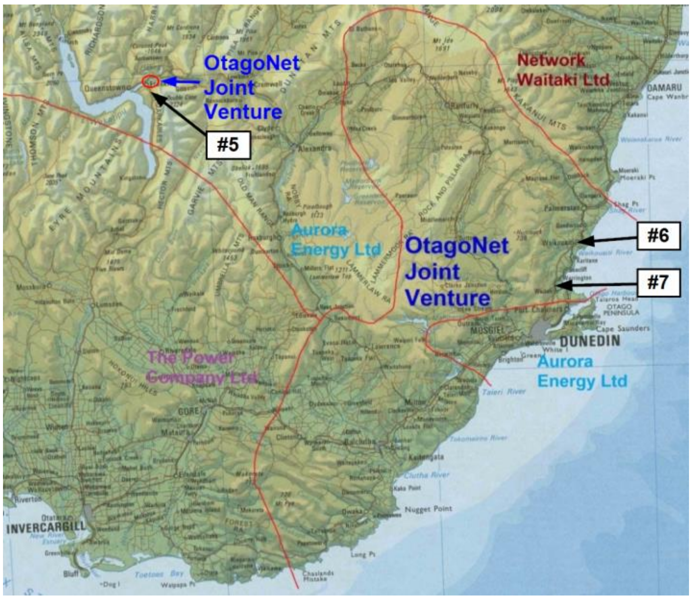
    Low voltage line work previously identified through condition assessment that is either on-going or planned. Completion of this work is dependent on customer requirements, land access permission and priority re-assignment as further network condition information becomes available.

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 #5, #6 and #7 which are pinpointed on the map above.
- Have a contract in place that is with PowerNet through a Management greement (related party).
- Are forecast to require the supply of assets/goods or services by PowerNet (related party).

Possible future constraints related to OJV network Operating Expenditure projects:



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

5. Southern Corridor Zone Substation

   Constraint – Unable to maintain supply voltage due to expected load growth, timing being 4-6 years

6. Quarry Road Substation

   Constraint – Unable to maintain supply voltage due to potential load growth, timing being 4-7 years.

7. Blueskin Bay Zone Substation

   Constraint – Unable to maintain supply voltage due to potential load growth, timing being 4-8 years.

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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	$19.97M	Network Wide	Yes	Yes	Very likely	N/A
#2	Distribution Routine Inspections	Every year	$11.12M	Network Wide	Yes	Yes	Very likely	N/A
#3	Vegetation Management	Every year	$11.05M	Network Wide	Yes	Yes	Very likely	N/A
#4	Technical Routine Maintenance	Every year	$10.11M	Network Wide	Yes	Yes	Very likely	N/A
#5	Technical Routine Inspections	Every year	$3.51M	Network Wide	Yes	Yes	Very likely	N/A
#6	Technical Corrective Maintenance	Every year	$2.56M	Network Wide	Yes	Yes	Very likely	N/A
#7	Distribution Routine Maintenance	Every year	$2.19M	Network Wide	Yes	Yes	Very likely	N/A
#8	Incident Response - Technical	Every year	$2.12M	Network Wide	Yes	Yes	Very likely	N/A
#9	Distribution Corrective Maintenance	Every year	$1.02M	Network Wide	Yes	Yes	Very likely	N/A
#10	Transmission Line Minor Maintenance	Every year	$1.00M	Network Wide	Yes	Yes	Very likely	N/A

Clause 2.3.13(1).
[1] Clause 2.3.13(1).
[1] Clause 2.3.13(1).
[1] Clause 2.3.13(1).
[1] Clause 2.3.14(1)(a).
[1] Clause 2.3.14(1)(a).
[1] Clause 2.3.14(1)(b).
[1] Clause 2.3.14(1)(c).

[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	$49.46M	Network Wide	Yes	Yes	Very likely	N/A
#2	11 kV Line Replacement and Renewal	Every year	$37.09M	Network Wide	Yes	Yes	Very likely	N/A
#3	33 kV Line Replacement and Renewal	Every year	$21.06M	Network Wide	Yes	Yes	Very likely	N/A
#4	Reliability and Resilience Projects	2030-2034	$20.00M	Network Wide	No	N/A	Very Likely	N/A
#5	Southern Corridor Zone Substation	2028-2030	$14.48M	#5	No	N/A	Very likely	N/A
#6	Quarry Road Substation	2025-2027	$12.33M	#6	No	N/A	Very likely	N/A
#7	Blueskin Bay Substation	2027-2029	$11.77M	#7	No	N/A	Very likely	N/A
#8	Unspecified Replacement and Renewal Projects	2031-2034	$10.71M	Network Wide	No	N/A	Very likely	N/A
#9	Customer Connections (≤ 20kVA)	Every year	$9.79M	Network Wide	Yes	Yes	Very likely	N/A
#10	LV Line Replacement and Renewal	Every year	$9.04M	Network Wide	Yes	Yes	Very likely	N/A

Possible future constraints related to OJV network Capital Expenditure projects:

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

Description of constraint	Related to Capex project #	Expected timing of constraint
Unable to maintain supply voltage due to expected load growth	#5	4-6 years
Unable to maintain supply voltage due to potential load growth	#6	4-7 years
Unable to maintain supply voltage due to potential load growth	#7	4-8 years

Independent Assurance Report

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

Assurance report pursuant to the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC 2

We have undertaken a reasonable assurance engagement in respect of the compliance of OtagoNet Joint Venture (the "Joint Venture") with the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC 2, (the "Determination") for the disclosure year ended 31 March 2024 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 (limited to SAIDI and SAIFI information), the related party transactions 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 (consolidated 23 April 2024) ("the IM Determination").

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 the Schedules 10(i) to 10(iv). Consequently, there is no independent evidence available to support the completeness and accuracy of recorded faults, and control over the completeness and accuracy of interconnection point ('ICP') data included in the SAIDI and SAIFI calculations was limited throughout the year.

There are no practical audit procedures that we could adopt to independently confirm that all the faults and ICP data were properly recorded for the purposes of inclusion in the amounts relating to quality measures set out in Schedules 10(i) to 10(iv).

Because of the potential effect of these limitations, we are unable to obtain sufficient appropriate audit evidence to confirm the completeness and accuracy of the data that forms the basis of the compilation of Schedules 10(i) to 10(iv).

We have conducted our engagement in accordance with the Standard on Assurance Engagements (SAE) 3100 (Revised) *Compliance Engagements* ("SAE 3100 (Revised)"), issued by the New Zealand

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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 believe the evidence we have obtained is sufficient and appropriate to provide a basis for our qualified opinion.

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 +/-100 basis points of the Return of Investment ('ROI')
- Performance based schedules – 5% of non-financial measures
- Related party transactions – 2% of total related party transactions.

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

We have determined that there are two key assurance matters:

- Regulatory Asset Base
- Related Party Transactions

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

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

Scope
Our procedures included analytical procedures, evaluating the appropriateness of assumptions used and whether they have been consistently applied, agreement of the Disclosure Information to, or reconciling with, source systems and underlying records, an assessment of the significant judgements made by the Joint Venture in the preparation of the Disclosure Information and valuing the related party transactions, and evaluation of the overall adequacy of the presentation of supporting information and explanations.

These procedures have been undertaken to form an opinion as to whether the Joint Venture has complied, in all material respects, with the Determination in the preparation of the Disclosure Information for the year ended 31 March 2024, 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 OtagoNet 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 OtagoNet 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 over the regulatory asset base included the following: **Assets commissioned** • We considered the nature of the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the Determination, which are required to be removed from the RAB; • We 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 material reconciling items; and • We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification. **Depreciation** • We compared the spreadsheet formula utilised to calculate regulatory depreciation expense with IM Determination clause 2.2.5; • We compared the standard asset lives by asset category to those set out in the IM Determination; and • We have performed a reasonableness test to ensure regulatory depreciation expense is calculated in line with IM Determination clause 2.2.5. **Revaluation** • We recalculated the revaluation rate set out in the IM Determination using the relevant

Key Assurance Matter	How our procedures addressed the key assurance matter
	Consumer Price Index indices taken from the Statistics New Zealand website; and • We tested the mathematical accuracy of the revaluation calculation performed by management. **Disposals** • We reconciled the disposals, as per the regulatory fixed asset register, to the asset disposals disclosed in the audited annual financial statements and investigated any material reconciling items; and • We inspected the asset disposals within the accounting fixed asset register to ensure disposals in the RAB meet the definition of a disposal per the IMs
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.	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 the related party transactions 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 2023 and to the accounting records, investigating any material 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

Key Assurance Matter	How our procedures addressed the key assurance matter
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.OtagoNet 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.	Schedule 5(b) by inspecting supporting documentation to determine compliance with the disclosed procurement policy and practices. **Arm's length valuation rule** We obtained OtagoNet Joint Venture's assessment of available independent and objective measures used in supporting the arm's length valuation principal and performed the following procedures: ● Re-performed the calculations within OtagoNet Joint Venture's benchmarking assessment 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 a reasonable range. Qualitative factors were considered in determining the appropriate acceptable range.

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

Our Independence and Quality Management
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.

We apply Professional and Ethical Standard 3 *Quality Management for Firms that Perform Audits or Reviews of Financial Statements, or Other Assurance or Related Services Engagements*, which requires our firm to design, implement and operate a system of quality management including policies or procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

We are independent of OtagoNet Joint Venture. Our firm carries out other services for the Joint Venture in the areas of compliance with other regulatory requirements of the Commerce Act 1986, audit of the financial statements, and provision of advisory services including specific procedures over the price-setting compliance statement. 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 2024 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) and SAE 3100 (Revised) 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 2024, 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 2024 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 Body 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 Body 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
30 August 2024

Christchurch, New Zealand

6. Directors' Certificate

Schedule 18: Certification for Year-End Disclosures

Clause 2.9.2

We, Peter William Moynihan and James Albert Carmichael, 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.

Peter William Moynihan **James Albert Carmichael**

29 August 2024